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June 14, 2011

VIA RESS, EMAIL and COURIER

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

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. ("the Company" or "Enbridge")
2010 Earnings Sharing Mechanism and Other Deferral
And Variance Accounts Clearance Review
Ontario Energy Board ("Board") File No. EB-2011-0008

Procedural Order No. 1 of the Board dated May 13, 2011 directs Enbridge to provide all interrogatory responses by June 14, 2011. Accordingly, attached please find the Company's interrogatory responses to Board Staff, APPrO, BOMA, CME, FRPO, and VECC.

This evidence is being filed through the Board's RESS system and it will be available on the Company's website @ www.enbridgegas.com/ratecase, as of May 15, 2011.

Yours truly,

Shari Lynn Spratt
Supervisor Regulatory Proceedings

Encl.

cc: Mr. F. Cass, Aird & Berlis LLP
All Interested Parties EB-2011-0008 (via email)

BOARD STAFF INTERROGATORY #1

INTERROGATORY

Ref: ExA/T2/S1/Appendix A

Please list the accounts and associated balances that have already undergone a formal Board review process and have obtained Board approval for the amount of clearance.

RESPONSE

The following are the accounts that have already been reviewed and received Board approval for clearance.

Witnesses: K. Culbert
R. Small

Account	Principal Balance ($)		Board Review Proceeding
2009 Demand Side Management V/A	1,165,061		EB-2010-0277
2009 Lost Revenue Adjustment Mechanism	(45,722)		EB-2010-0277
2009 Shared Savings Mechanism V/A	5,364,212		EB-2010-0277
2011 Class Action Suit D/A	23,547,735	1	EB-2007-0731
2011 Open Bill Service D/A	526,150	2	EB-2009-0043/EB-2010-0042
2011 Open Bill Access V/A	476,667	2	EB-2009-0043

Notes:

1. The EB-2007-0731 Decision approved the clearance of the CASDA balance in equal installments over a five year period beginning in 2008. The 2008 installment was approved in EB-2007-0615 and cleared in July and August 2008. The 2009 installment was approved in EB-2009-0055 and cleared in April and May 2010. The 2010 installment was approved in EB-2010-0042 and cleared in January 2011. The resulting balance at February 2011 is $9,419,094 (($23,547,735 - ($4,709,547 x 3 clearance installments)). The Company is seeking clearance of the 2011 portion within this proceeding.

2. In the EB-2009-0043 Decision/Settlement Agreement the Board approved the clearance of the balances in the 2008 Open Bill Service D/A of $309,370 and 2008 Open Bill Access V/A of $476,667. An additional $216,780 for TMG, OBA stakeholder, and start up legal charges was recorded in the 2009 Open Bill Service D/A during 2009 and was explained, reviewed, and approved for clearance in the same manner as the other costs in these accounts within EB-2010-0042. The additional costs were also considered in EB-2009-0043, but the exact amount was not known at the time of that proceeding. The balances are to be cleared over a three year period, 2010 to 2012, and are to be shared equally between the Company and ratepayers. The 2010 ratepayer share was approved for clearance in EB-2010-0042 and cleared in January 2011. The Company is seeking clearance of the 2011 ratepayer share in this proceeding.

Witnesses: K. Culbert
R. Small

BOARD STAFF INTERROGATORY #2

INTERROGATORY

Ref: ExB/T1/S1/page 5 of 6 para 17

Please provide the calculation details underpinning the ROE established for 2010 for which the earnings sharing formula applies. Please provide the reference to the proceeding in which the Board approved this particular ROE for use in 2010 earnings sharing.

RESPONSE

Determination of ROE for 2010

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*
Yield on 10s 3 Months Out[a]	Yield 10s 12 Months Out[a]	Average 10s Yield	Average Spread (30s-10s)[b]	Long Bond Forecast	Difference in Long Bond Forecast	0.75xDifference (Rounded to 2 Decimal Places)	ROE (%)
		(Col. 1+Col. 2)/2		Col. 3+Col. 4	Col. 5-4.14	0.75xCol. 6	8.31+Col. 7
3.50	3.90	3.70	0.53	4.23	0.09	0.06	8.37

Notes:
2009 ROE: 8.31
2009 Long Canada Forecast: 4.14
[a] From Consensus Forecasts October 12, 2009
[b] From Financial Post

Based on the October 2009 Consensus Forecasts publication and the data provided in the Financial Post, ROE for use in 2010 earnings sharing is 8.37%.

While the parameters to be used within the applicable ROE formula are previously approved by the Board, the results of the application of the parameters and the results of the formula for use in the 2010 earnings sharing calculation have not previously been approved. The Company is seeking approval of the formula results within this proceeding.

Witnesses: K. Culbert
I. McLeod
R. Small

BOARD STAFF INTERROGATORY #3

INTERROGATORY

Ref: ExB/T1/S3/ page 2 / para c)

The evidence at paragraph c) states: "The other income change of $13.1 million is mainly due to revenue from the management of fee for service, external 3rd party energy efficiency initiatives."

Please describe the nature of the above captioned energy efficiency initiatives and the fee for service structure.

RESPONSE

The primary energy efficiency initiative that led to this other income change is the High Performance New Construction Program ("HPNC") with the Ontario Power Authority ("OPA"). The HPNC provides financial incentives for qualifying participants and qualifying architects in order to encourage implementation of energy efficient construction and renovation electricity projects.

The fee for service structure is O&M costs, Management Fees, and Performance Bonus.

Witnesses: K. Culbert
R. Small

BOARD STAFF INTERROGATORY #4

INTERROGATORY

Ref: ExB/T1/S5/ Appendix A

This appendix shows the beneficial revenue requirement and earnings impact of the HST implementation analysis for years 2010, 2011 and 2012. How will the implementation of IFRS affect the analysis?

RESPONSE

The estimated impact of the implementation of HST is a sales tax related issue which ultimately has an effect within utility earnings. As per the 2008 through 2012 Incentive Regulation ("IR") agreement, utility earnings are to be calculated using the same accounting principles as were in place at the outset of the IR term. As such, any IFRS implementation would not have any effect on the estimated impacts within the HST implementation analysis.

Witnesses: K. Culbert
R. Small

BOARD STAFF INTERROGATORY #5

INTERROGATORY

Ref: ExB/T3/S1/ page 3 and 4

Please explain the composition of the Transactional Services and TSDA amounts and the basis for the adjustment to utility revenue.

RESPONSE

Please see the response to VECC Interrogatory #10 at Exhibit I, Tab 3, Schedule 10.

Witnesses: K. Culbert
R. Small

BOARD STAFF INTERROGATORY #6

INTERROGATORY

Ref: ExB/T3/S5/ page 1

Please explain the nature and composition of the $11.7 million item at Line 1.6 of this schedule – "Ontario Power Authority Program Revenue".

RESPONSE

Please see the responses to Board Staff Interrogatory #3 at Exhibit I, Tab 1, Schedule 3 and CME Interrogatories #1 and 2 at Exhibit I, Tab 4, Schedules 1 and 2, respectively.

Witnesses: K. Culbert
R. Lei
R. Small

BOARD STAFF INTERROGATORY #7

INTERROGATORY

Ref: ExB/T4/S2/ page 1

Please explain the nature and composition of Line 15 of this schedule – "Non Departmental Expenses".

RESPONSE

Non Departmental Expenses include the following:

i. Executive & Administration Expenses $3.1M (costs related to EGD's executive management team and related administration costs)
ii. Audit Fees $2.0M
iii. Short Term Incentive Plan (STIP) $18.5M (costs for incentive compensation for Enbridge employees)

Witnesses: R. Lei
A. Patel

BOARD STAFF INTERROGATORY #8

INTERROGATORY

Ref: ExC/T2/S1/paragraph 3

Please discuss the pros and cons of splitting the customer's actual 2010 volumetric consumption into two periods: i) January to June, and ii) July to December, for the purposes of applying the GST and HST.

RESPONSE

EGD has not split the actual customer consumption for 2010 into two periods for the purpose of applying GST and HST.

As indicated in evidence, the selection of accounts with either GST or HST applicable to them for purposes of clearance was determined in conjunction with the interpretation contained within the CRA's ruling, attached as Appendix C within the 2009, EB-2010-0042 Rate Order, in relation to the same question about the clearance of deferral and variance accounts in the EB-2010-0042, 2009 ESM proceeding.

The one-time billing adjustments to customers, if based on January to June volume for GST and on July to December volume for HST, would vary immaterially as compared to the proposed clearance based on 12-month of volume. The reason is that customers are grouped into rate classes based on load profile and load factor (for large volume rates). Therefore, all customers within a rate class have a similar load profile (in the first and second part of the year). Given that the GST ($11.6 million collection) and HST ($14.8 million refund) applicable clearing amounts are fixed, only insignificant changes would occur to one-time billing adjustments if the disposition would be determined based on 6-month volume versus the proposed 12-month volume.

Further, changing the clearance methodology to accommodate January to June and July to December volumes would necessitate changes to Enbridge's existing approach which would introduce increased complexity and costs (such as modifications to the billing system). Given that the proposed one-time billing adjustment is approximately $3 for a typical residential customer and the insignificant change to the billing

Witnesses: K. Culbert
J. Collier
A. Kacicnik
M. Suarez-Sharma

adjustment for each customer that would result from using two sets of volumes, Enbridge submits that using two sets of volume is not warranted.

Witnesses: K. Culbert
J. Collier
A. Kacicnik
M. Suarez-Sharma

BOARD STAFF INTERROGATORY #9

INTERROGATORY

Ref: ExC/T2/S2/page 9

The typical Rate 6 customer is shown as 43,285 annual volume in cubic meters. Is this a new standard relative to past bill impact comparisons that have used 22,606 cubic meters?

RESPONSE

No, it is not. EGD has consistently used the 43,285 m^3 annual volumetric profile for Rate 6 since the application to clear the 2008 deferral and variance account balances. This profile is one of several used to typify impacts for the class.

For comparison, the impact of clearing the 2010 deferral and variance account balances to a Rate 6 customer with annual consumption of 22,606 m^3 is provided below:

	Annual Volume m^3		Unit Rates: Sales cents/m^3	Unit Rates: Ontario TS cents/m^3	Unit Rates: Western TS cents/m^3	Bill Adjustment: Sales Customers $	Bill Adjustment: Ontario TS Customers $	Bill Adjustment: Western TS Customers $
RATE 6 COMMERCIAL								
General Use	22,606	GST	0.0260	0.0260	0.0260	6	6	6
		HST	(0.2733)	(0.2246)	(0.2733)	(62)	(51)	(62)
						(56)	(45)	(56)

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

BOARD STAFF INTERROGATORY #10

INTERROGATORY

Ref: ExA/T2/S1/Appendix A/line 19

The amount for clearance in the Unaccounted for Gas Variance Account (2010 UAFVA) shows a debit balance for clearance of $8.7294 million.

I. When was the variance account established by the Board?
II. Please provide the historic amounts associated with this account including the Board approved UAFVA levels associated with each of the years.
III. What is the amount embedded within rates relative to the variance amounts?
IV. Please describe the outcome of any reviews the company has undertaken to determine the causes of the unaccounted for gas variances. Please comment on meter error, metering and regulating performance, the impact of new system improvement capital, the effects of cast iron replacement program, and general system gas escape.

RESPONSE

I. The variance account was established and approved for Fiscal year 2002 within regulatory proceeding RP-2001-0032.

II. The principal balances approved for clearance by the Board are in ($000's);

a. 2002 - (15,901.3),
b. 2003 - (1,507.0),
c. 2004 - (39,952.0),
d. 2005 - 3,857.8,
e. 2006 - (11,739.1),
f. 2007 - 6,112.1,
g. 2008 - 621.2, and
h. 2009 - 9,596.7

Witnesses: I. Chan
K. Culbert
D. Small
R. Small

III. As per the Final Rate Order, the Board approved amount embedded in rates is as follows, in $millions:

a. 2002* - $14.7 M,
b. 2003* - $15.5 M,
c. 2004*- $17.7 M,
d. 2005* - $23.1 M,
e. 2006 - $12.3 M,
f. 2007 - $15.0 M,
g. 2008 - $12.8 M,
h. 2009 - $12.3 M, and
i. 2010 - $ 9.0 M.

Note: The value for unaccounted for gas in rates is subject to adjustment quarterly in each QRAM.

Note: *Denotes fiscal year data, i.e. for the year ended 30-September.

IV. During year-end, Energy Supply and Policy, and Customer Care groups would confirm the validity of invoices and billing records respectively that were used to calculate the actual unaccounted for gas, i.e., the difference between customer metered consumption and total sendout.

As stated at RP-2001-0032, Exhibit A, Tab 12, Schedule 5, page 1, actual unaccounted for gas arises because of meter differences, billing differences, line leakage, unmetered uses, and other factors. Since the unaccounted for gas forecast is calculated using a regression model based upon historical trend, it is by nature impossible to determine the causes of the unaccounted for gas variances between the forecast generated from aggregate actual data and actual as determined by a combination of multiple factors mentioned above.

Witnesses: I. Chan
K. Culbert
D. Small
R. Small

BOARD STAFF INTERROGATORY #11

INTERROGATORY

Ref: ExD - Reference Material

4. Please file the Annual Information Form for Enbridge Gas Distribution Inc. for the year ended December 31, 2010.

RESPONSE

Please see attached.

Witness: J. Jozsa

ENBRIDGE

ENBRIDGE GAS DISTRIBUTION INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2010

February 18, 2011

TABLE OF CONTENTS

PRESENTATION OF INFORMATION

Unless otherwise noted, the information contained in this Annual Information Form (AIF) for Enbridge Gas Distribution Inc. (Enbridge Gas Distribution or the Company) is given at or for the year ended December 31, 2010. Amounts are expressed in Canadian dollars unless otherwise indicated. Financial information is presented in accordance with Canadian generally accepted accounting principles (GAAP).

The Company's Management's Discussion and Analysis (MD&A), dated February 18, 2011, and the Company's Audited Consolidated Financial Statements, dated February 18, 2011, as at and for the year ended December 31, 2010 are incorporated by reference into this AIF and can be found on SEDAR at www.sedar.com.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this AIF to provide the Company's shareholders and potential investors with information about the Company and its subsidiaries, including management's assessment of the Company's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as ''anticipate'', ''expect'', ''project'', ''estimate'', ''forecast'', ''plan'', ''intend'', ''target'', ''believe'' and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to expected capital expenditures.

Although the Company believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for natural gas; prices of natural gas; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer project approvals; maintenance of support and regulatory approvals for the Company's projects; anticipated in-service dates and weather. Assumptions regarding the expected supply and demand of natural gas and the prices of natural gas are material to and underlay all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company's services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates, may impact levels of demand for the Company's services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty. The most relevant assumptions associated with forward-looking statements on expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.

The Company's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, exchange rates, interest rates, natural gas prices and supply and demand for natural gas, including but not limited to those risks and uncertainties discussed in this AIF and in the Company's other filings with Canadian securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and the Company's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, the Company assumes no obligation to publicly update or revise any forward-looking statements made in this AIF or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward looking statements, whether written or oral, attributable to the Company or persons acting on the Company's behalf, are expressly qualified in their entirety by these cautionary statements.

CORPORATE STRUCTURE

Enbridge Gas Distribution was incorporated in 1848 by Special Act, II Victoria Cap. XIV, of the Province of Canada. By letters patent dated September 30, 1954, Enbridge Gas Distribution was continued under the Corporations Act, 1953 (Ontario) and is now subject to the Business Corporations Act (Ontario). The Company changed its name from The Consumers' Gas Company Ltd. to Enbridge Gas Distribution Inc. on July 25, 2002.

Enbridge Gas Distribution's head office and registered office are located at 500 Consumers Road, Toronto, Ontario, M2J 1P8.

Enbridge Gas Distribution is an indirect wholly owned subsidiary of Enbridge Inc. (Enbridge). Enbridge Energy Distribution Inc., itself an indirect wholly owned subsidiary of Enbridge, owns all of the issued and outstanding common shares of Enbridge Gas Distribution.

GENERAL DEVELOPMENT OF THE BUSINESS

The Company was incorporated in 1848 to provide manufactured coal gas for lighting to customers in the City of Toronto. By 1948, Enbridge Gas Distribution was serving 180,000 customers.

Natural gas was introduced to Ontario in the 1950s, replacing manufactured coal gas. Natural gas was first imported from the United States and later shipped from Alberta via the facilities of TransCanada PipeLines Limited (TransCanada). During the same period, the Company also expanded service to the Niagara Peninsula, Ottawa and Peterborough areas through acquisitions. In the 1960s, St. Lawrence Gas Company, Inc. (St. Lawrence), a wholly owned subsidiary of Enbridge Gas Distribution, began delivering Canadian natural gas to customers in northern New York State.

The 1970s and 1980s were periods of significant growth for Enbridge Gas Distribution. By 1989, the Company was serving one million customers. Growth during this period resulted from the widening of the price advantage of natural gas over oil and electricity, the expansion of population and industry in the Company's franchise area, various government programs promoting natural gas usage, natural gas' environmental and supply advantages and the Company's marketing efforts. This growth continued in the 1990s, with the addition of more than 480,000 customers during the decade. Customer additions between fiscal 2008 and fiscal 2010 averaged approximately 37,000 customers per year.

Enbridge Gas Distribution is a rate-regulated natural gas distribution utility serving approximately 2 million residential, commercial and industrial customers in its franchise areas of central and eastern Ontario, including the City of Toronto and the surrounding areas of Peel, York and Durham regions, as well as the Niagara Peninsula, Ottawa, Brockville, Peterborough, Barrie and many other Ontario communities. In addition, the Company serves Massena, Ogdensburg, Potsdam and surrounding areas in northern New York State through St. Lawrence.

The utility business is conducted under statutes and municipal by-laws which grant the right to operate in the areas served. The utility operations of the Company and St. Lawrence are regulated by the Ontario Energy Board (OEB) and by the New York State Public Service Commission, respectively.

As at December 31, 2010, the Company owned and operated a network of approximately 35,000 kilometres of mains (2009 - approximately 35,000; 2008 - approximately 34,000 kilometres) for the transportation and distribution of natural gas, as well as the service pipes to transfer natural gas from mains to meters on customers' premises.

THREE-YEAR HISTORY

WEATHER

The Company operates in a seasonal industry and earnings vary significantly according to weather patterns. Periods of colder than normal weather would typically result in higher earnings compared to periods of warmer than normal weather.

(Warmer)/colder than normal weather affected earnings in the past three years as follows:

Year Ended December 31,	**2010**	2009	2008
(millions of Canadian dollars) After-Tax Earnings (Decrease)/Increase	**(12)**	17	23

NATURAL GAS PRICES

Higher natural gas market prices result in a higher OEB approved charge to customers for the natural gas commodity. While higher natural gas commodity charges to customers result in higher revenues, there is no corresponding impact on the Company's earnings, since the cost of natural gas is flowed through to customers at cost. The Company does not earn a margin on the sale of natural gas.

REGULATORY ENVIRONMENT

Incentive Regulation (IR)

In 2008, the OEB approved the Company's application to move to a five year IR methodology for the years 2008 through 2012. Under IR, the Company's distribution revenue requirement and associated rates are based on a formulaic approach, using prior year cumulative data with 2007 as the starting point.

The objectives of the IR plan are as follows:

- reduce regulatory costs;
- provide incentives for improved efficiency;
- provide more flexibility for utility management; and
- provide more stable rates to customers.

2011 Rate Adjustment Application

In September 2010, the Company filed an application with the OEB to adjust rates for 2011 pursuant to the approved IR formula. The total distribution revenue applied for was approved by the OEB, with the rate adjustment being effective January 1, 2011.

Cost of Capital

In December 2009, the OEB issued a report making several changes to the cost of capital for Ontario's regulated utilities. The new policy guidelines forecasted a new base level return on equity (ROE) of approximately 9.85% for the Company's 2010 rate year, which is higher than the 8.37% currently permitted. In its 2010 rate application, the Company applied to the OEB for approval to use the new ROE formula to determine the annual earnings sharing with customers for 2010 and the remainder of the IR term. While the OEB issued a decision in May 2010 that the new ROE is not to be used for such earnings sharing determinations, the Company anticipates applying the new ROE to determine rates after the conclusion of the IR term, effective for the rate year beginning 2013. In addition, the Company has appealed the OEB's May 2010 decision to the Ontario Divisional Court. The Company's appeal was heard by the Divisional Court in January 2011, but the Court has not yet released its decision.

2010 Rate Adjustment Application

In September 2009, the Company filed an application with the OEB to adjust rates for 2010 pursuant to the approved IR formula and to seek approval for specific changes to the Rate Handbook. Pursuant to the subsequent filing with the OEB of a settlement agreement with ratepayer groups, the Company received approval of a fiscal 2010 final rate order from the OEB in March 2010 approving the implementation of a rate change effective April 1, 2010, which enabled the Company to recover the approved revenues as if rates were effective January 1, 2010.

2009 Rate Adjustment Application
In September 2008, the Company filed an application with the OEB to adjust rates for 2009 pursuant to the approved IR formula and to seek approval for specific changes to the Rate Handbook. A settlement agreement containing all applied for aspects of the formulaic component of the IR rate setting process was approved by the OEB in December 2008.

The Company received a fiscal 2009 final rate order from the OEB in February 2009 approving the implementation of a rate change effective April 1, 2009, which enabled the Company to recover the approved revenues as if rates were effective January 1, 2009.

2008 Rates
In 2007, the Company filed a rate application requesting a revenue cap incentive rate mechanism calculated on a revenue per customer basis for the 2008 to 2012 period. The OEB approved the IR Settlement Agreement (the Settlement) with customer representatives.

The key terms of the the Settlement are summarized as follows:

Revenue Per Customer Cap – The Settlement provides an incentive for the Company to continue growing its customer base and provides the opportunity annually to adjust distribution volumes for rate-setting to protect the Company from exposure to declining average use of natural gas by residential and small commercial customers.

Revenue Escalation – Distribution revenues were adjusted by 60% of the rate of inflation[♦] in 2008, by 55% in 2009, by 55% in 2010, and will be adjusted by 50% in 2011 and 45% in 2012. In addition to the annual inflation adjustment, revenues will also grow by the annual increase in the number of customers. Based on an assumed inflation rate of 2%, the combined inflation and growth factors are forecast to result in an overall revenue escalation averaging approximately 3% per year through the term of the plan.

Earnings Sharing – To the extent the actual utility return on the approved equity level represented by normalized earnings (i.e., excluding the effects of weather) (ROE) exceeds the notional allowed utility return on equity (NROE) by certain prescribed thresholds, earnings are shared with customers. The shareholder retains the first 100 basis points of ROE above the NROE (up to 9.66% in 2008), while earnings represented by the ROE in excess of 100 basis points above the NROE are shared equally with customers.

Adjustments – There are several cost and deferral accounts that fall outside of the revenue escalation formula, including the amount of capital invested in new power generation laterals. The Company is also allowed to apply for recovery of expenses above a defined threshold to the extent any such expenses meet certain criteria set out in the IR plan.

Off Ramps – An OEB review will be triggered if the Company's ROE on a normalized basis varies more than 300 basis points (either negatively or positively) relative to the NROE. The review, if triggered, would determine the reasons for the variance in earnings and in such circumstances could result in adjustments to the Settlement or a return to Cost of Service (COS) regulation. The review would not have an impact on earnings for prior years. The Settlement does not preclude the Company from applying to the OEB for an increase in the embedded ROE.

The Company received a fiscal 2008 final rate order from the OEB in May 2008, approving the implementation of a change in rates effective July 1, 2008, which enabled the Company to recover the

[♦] The inflation index is defined as the year-over-year change in the annualized average of four quarters of Statistics Canada's Gross Domestic Product Implicit Price Index Final Domestic Demand.

approved revenues retroactively to January 1, 2008 and to refund or collect from customers specified deferral and variance accounts commencing July 1, 2008. The final rate order also approved a change in customer billing to increase the fixed charge portion and decrease the per unit volumetric charge, with no material annual earnings impact. The fixed charge portion will increase progressively over the IR term.

CUSTOMER GROWTH

Business development is positively impacted by customer growth. Customer additions for the last three fiscal years were as follows:

Year Ended December 31,	**2010**	2009	2008
New Customer Additions[1]	**37,023**	32,275	41,297

[1] New customer additions is the number of new service lines installed during the year.

The global credit crisis disrupted the debt and equity capital markets in the fall of 2008 and early 2009, adversely impacting economic growth. The slower economic growth in turn resulted in a decline in housing starts of approximately 35% in the Company's franchise area, leading to lower residential customer additions in 2009. However, in 2010, strong economic recovery, improved consumer confidence and low financing rates increased new home purchases. In addition, the introduction of the harmonized sales tax effective July 1, 2010 accelerated new home purchases in the first half of 2010, leading to higher customer additions in 2010.

NEW CUSTOMER INFORMATION SYSTEM (CIS) IMPLEMENTED

In September 2009, the Company successfully implemented its new CIS, which replaced the Company's legacy system. The Company is recovering in rates the total cost of the project in accordance with an agreement with customer groups that was approved by the OEB in 2007.

DESCRIPTION OF THE BUSINESS

CORE BUSINESS – GAS DISTRIBUTION

There are four principal interrelated aspects of the natural gas distribution business in which the Company is directly involved: Distribution Service, Gas Supply, Transportation and Storage.

Distribution Service

The Company's principal source of revenue arises from distribution of natural gas to customers. The services provided to residential, small commercial and industrial heating customers are primarily on a general service basis (without a specific fixed term or fixed price contract). The services provided to larger commercial and industrial customers are usually on an annual contract basis under firm or interruptible service contracts. Under a firm contract, the Company is obligated to deliver natural gas to the customer up to a maximum daily volume. The service provided under an interruptible contract is similar to that of a firm contract, except that it allows for service interruption at the Company's option to meet seasonal or peak demands. The OEB approves rates for both contract and general services.

Customers have a choice with respect to natural gas supply. One option is a sales service option, whereby the customer purchases natural gas from the Company's supply portfolio (system supply). The Company does not earn a margin on the natural gas commodity it provides to customers. Alternatively, a natural gas user may select a direct purchase option, which is a transportation service arrangement. Under the transportation service arrangement, a customer supplies natural gas at a TransCanada receipt point in western Canada or at a TransCanada delivery point in Ontario, and the Company redelivers an equivalent amount of natural gas to the customer's end-use location. As a third option, a customer may select an unbundled service arrangement. Similar to the transportation service arrangement, customers deliver their own natural gas into the Company's distribution system, but they are responsible for balancing consumption with deliveries on a daily basis. These arrangements are billed under the OEB approved rate schedules.

Gas Supply

To acquire the necessary volume of natural gas to serve its customers, the Company maintains a diversified natural gas supply portfolio. During the year ended December 31, 2010, the Company acquired approximately 5.9 billion cubic metres of natural gas (2009 - 5.5 billion cubic metres), of which 36.6% (2009 – 25.5%) was acquired from western Canadian producers, 41.6% (2009 – 45.5%) was acquired from suppliers in Chicago and 21.8% (2009 – 29.0%) was acquired on a delivered basis in Ontario. The Company also transported 6.1 billion cubic metres (2009 – 6.6 billion cubic metres) of natural gas on behalf of direct purchase customers operating under a transportation service arrangement.

The Company's system supply natural gas contracts have pricing structures responsive to supply and demand conditions in the North American natural gas market. The prices in these contracts may be indexed to Alberta, Chicago or New York based prices.

Transportation

TransCanada transports approximately 64.3% or 7.5 billion cubic metres (2009 – 61.4% or 7.4 billion cubic metres) of the annual natural gas supply requirements of the Company's customers. The Company has firm transportation service contracts with TransCanada for a portion of this requirement, while direct purchase customers contract directly with TransCanada or with natural gas marketers for the remainder.

The transportation service contracts are not directly linked with any particular source of natural gas supply. Separating transportation contracts from natural gas supply allows the Company flexibility in obtaining its own natural gas supply and accommodating the requests of its direct purchase customers for assignment of TransCanada capacity. The Company forecasts the natural gas supply needs of its customers, including the associated transportation and storage requirements.

TransCanada's transportation tolls, which are approved by the National Energy Board, consist of a demand component to recover fixed costs and a commodity component to recover variable costs for Firm Transportation (FT) service. An FT shipper, such as the Company, must pay the demand component regardless of the volume of natural gas that TransCanada actually transports for the FT shipper. Under the terms of TransCanada's tariff, if an FT shipper does not utilize all of its FT capacity rights, the FT shipper would nonetheless incur demand charges in respect of the unutilized portion.

In addition, the Company contracts for FT service on the pipelines of Alliance Pipeline Canada, Alliance Pipeline U.S. (collectively referred to as the Alliance network) and Vector Pipeline (Vector). The Alliance network of pipelines extends over 3,000 kilometres and runs from northeast British Columbia and northwest Alberta to the Chicago area hub, where it interconnects with the North American pipeline grid. Vector is a 560 kilometre pipeline that connects the hub facilities in the Chicago area to Dawn, Ontario. Enbridge has interests in these three pipeline facilities.

The Company relies on its long-term contracts with Union Gas Limited (Union) for transportation of natural gas from Dawn, located in south-western Ontario, to the Company's major market in the Greater Toronto Area (GTA). These contracts effectively provide the Company with access to United States sourced natural gas at Dawn. These contracts also provide transportation for natural gas received at Dawn via the Vector Pipeline as well as natural gas stored at the Company's and Union's storage pools in the Sarnia, Ontario area to the market area.

Storage

The Company's business is highly seasonal as daily market demand for natural gas fluctuates with changes in weather, with peak consumption occurring in the winter months. Utilization of storage facilities permits the Company to take delivery of natural gas on favourable terms during off-peak summer periods for subsequent use during the winter heating season. This practice permits the Company to minimize the annual cost of transportation of natural gas from its supply basins, assists in reducing its overall cost of natural gas supply and adds a measure of security in the event of any short-term interruption of transportation of natural gas to the Company's franchise area.

The Company's principal storage facilities are located in south-western Ontario, near Dawn, and have a total working capacity of approximately 2.9 billion cubic metres. Approximately 2.8 billion cubic metres of the total working capacity are available to the Company. The Company also has storage contracts with third parties for 595 million cubic metres of storage capacity.

The Company-operated storage facilities are connected to the Dawn storage and transmission hub. In the summer, natural gas is delivered to Dawn for injection into storage through the transmission facilities of Union, TransCanada and Vector. In the winter, natural gas is withdrawn from storage and delivered to Dawn and transported from there to the Company's major market in the GTA through the transmission facilities of Union and TransCanada. The Company has transportation contracts with TransCanada, Vector and Union for the delivery of natural gas to and from storage.

ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT (DSM)

The Company not only promotes the use of natural gas as an environmentally preferred fuel, but also develops and delivers energy efficiency and conservation programs which enable customers to optimize their energy usage.

The Company invests in collaborative research, development, demonstration and implementation of more efficient natural gas technologies. Through Enbridge’s demand side management programs, incentives are provided to customers to encourage the adoption of more energy efficient space conditioning, water heating, commercial cooking and industrial process equipment.

The Company is facilitating the emergence of Distributed Energy (DE), which is localized electric power generation close to the site of use. Localized DE technologies constitute a supplement or support to the larger electric power grid system. DE technologies include gas-fired cogeneration or combined heat and power systems that utilize waste heat and increase efficiencies, thus conserving resources.

The Company continues to work with municipalities to assist with their development of community energy plans, which are typically implemented under the Partners for Climate Protection Program, a Federation of Canadian Municipalities program.

HISTORICAL OPERATING STATISTICS

The following table presents statistics relating to the past three years of the Company's operations.

Year Ended December 31,	**2010**	2009	2008
Gas Supply and Sendout (10^6m^3)[1]			
Natural gas purchased	**5,850**	5,530	5,474
Gas into storage	**(2,869)**	(2,124)	(2,832)
Gas out of storage	**2,564**	2,252	2,767
Total gas sendout	**5,545**	5,658	5,409
Transportation of gas	**6,083**	6,329	6,971
	11,628	11,987	12,380
Gas sales to customers (10^6m^3)[1]	**5,550**	5,513	5,346
Transportation of gas (10^6m^3)[1]	**5,584**	6,035	6,906
Total sales (10^6m^3)[1]	**11,134**	11,548	12,252
Used by the Company (10^6m^3)[1]	**6**	6	4
Other volumetric variations (10^6m^3)[1,2]	**488**	433	124
	11,628	11,987	12,380
Maximum daily sendout (10^6m^3)[1]	**84**	86	81
Minimum daily sendout (10^6m^3)[1]	**11**	10	10
Average daily sendout (10^6m^3)[1]	**32**	33	34
Heating Degree Days[3]			
Actual	**3,466**	3,767	3,802
Forecast based on normal weather	**3,546**	3,514	3,543
Number of Active Customers[4] – end of year			
Residential	**1,340,135**	1,274,680	1,114,878
Commercial	**117,461**	111,276	105,056
Industrial	**4,352**	4,067	3,912
Wholesale	**1**	1	1
Transportation	**518,729**	547,241	674,382
	1,980,678	1,937,265	1,898,229
Average Revenue (per 10^3m^3) [1]			
Residential	**$357**	$433	$478
Commercial	**$289**	$374	$413
Industrial	**$244**	$316	$381
Wholesale	**$177**	$246	$258
Average Use per Residential Customer (m^3)[1]	**2,507**	2,726	2,744
Number of Employees – end of year	**1,873**	1,859	1,869

[1] m^3 = cubic metre; 10^3m^3 = thousand cubic metres; 10^6m^3 = million cubic metres; 28.369 10^6m^3 = 1 billion cubic feet (bcf)

[2] Includes volumes for unbundled customers who deliver their own natural gas into the Company's distribution system and manage their load balancing independent of the Company.

[3] Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's franchise area. It is calculated by accumulating, for the fiscal year, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A daily mean temperature of zero degrees Celsius on any day equals 18 heating degree days for that day. The figures given are those accumulated in the GTA.

[4] Active customers is the number of natural gas consuming customers at the end of the year and includes natural gas sales and transportation service customers. As the commodity cost of natural gas is flowed through to natural gas sales customers with no mark up, the composition of customers between natural gas sales and transportation service has no material impact on the Company's earnings.

BUSINESS OUTLOOK

Customer Care Agreement Extension

In February 2011, the Company's Board of Directors approved a five-year nine month extension, beginning in 2012, to the Company's customer care services contract with a third party service provider for call centre services, collections and billing. The contract extension has been structured to provide enhanced levels of customer service. The total cost of the customer care services during the term of the extension is approximately $360 million. To become effective, the recovery of costs associated with this agreement must still be approved by the OEB. Steps are presently being taken by the Company to obtain the OEB's approval in this regard.

Unregulated Storage Services

The deregulation of new natural gas storage in Ontario, coupled with the growing need for high-deliverability storage services by gas-fired power generators and other users, has created unregulated storage growth opportunities for the Company. As of December 31, 2010, the Company had expanded its storage capacity by 8% (0.2 billion cubic metres or 7.5 bcf) and sold unregulated storage services into the storage market. A further expansion was approved by the Board of Directors in February 2011 to add an incremental 4.5 bcf of capacity.

Green Energy Initiatives

In September 2009, Ontario's Minister of Energy and Infrastructure issued a Directive that permits the Company to own and operate stationary fuel cells, wind, water, biomass, biogas, solar and geothermal energy generation facilities up to 10 megawatts in capacity. The Company will also be permitted to own and operate district and distributed energy systems, including facilities that produce power and thermal energy from a single source. Finally, the Minister's Directive permits the Company to own and operate assets that would assist the Government of Ontario in achieving its goals in energy conservation, including assets related to solar-thermal water and ground source heat pumps.

In the absence of the Minister's Directive, the Company's Undertakings to the Lieutenant Governor in Council would not have permitted the Company to engage in the foregoing activities directly. The Company plans to increase its role in this area and is looking to expand its efforts to explore and pursue alternative and/or renewable energy technologies subject to OEB approval, where appropriate.

While the Directive permits the Company to engage in such activities, in December 2009 the OEB determined that it would not allow such activities to be included in rate-making for the purposes of setting 2010 rates. The Company continues to engage the government, regulators and other stakeholders to determine what alternatives are available to the Company to undertake these investments in the future.

Price Advantage of Natural Gas

Natural gas is the predominant fuel of choice in the residential heating market throughout the Company's franchise area. The primary competition for natural gas remains domestic fuel oil and electricity. Natural gas has continued to provide both environmental and price advantages, and this is expected to continue. During 2010, natural gas in the residential market experienced, on average, a price advantage on an equivalent annual volume basis of 60% (2009 – 54%) against electricity and 58% (2009 – 49%) against domestic fuel oil.

Customer Growth

The Ontario franchise area remains one of the most rapidly growing regions in North America. As such, the Company will continue to grow its natural gas distribution business by adding customers to existing infrastructure and through geographic extension of the distribution system.

While customer growth results in increased distribution volumes, this increase is partially offset by the impact of lower average annual consumption. Lower average annual consumption results from customers' increased adoption of energy efficient technologies along with more energy efficient building construction.

Electricity conservation efforts have included programs to encourage fuel switching from electricity to natural gas. The Company leverages its expertise in DSM to offer fee-for-service conservation services that can include fuel switching.

Energy Efficiency
Enbridge's 2.2 megawatt hybrid fuel cell power plant (the plant) completed its second year of operations in 2010. The plant produces clean, low-carbon electricity from waste energy that is recovered from the pressure reduction process necessary to distribute natural gas. Enbridge is reviewing its pipeline network in Ontario to understand where additional applications would be appropriate. Further deployment of the technology will be contingent on the price established by the Province of Ontario for clean power generation of this type and the operating reliability of the technology.

GENERAL

EMPLOYEES

The Company has 1,873 employees, 35% of whom are unionized. The Company's unionized employees are represented either by the Communications, Energy and Paperworkers Union, Local 975 (CEPU) or the International Brotherhood of Electrical Workers (IBEW), Local 97. The current collective agreement with CEPU expired in December 2010 and a new collective agreement is being negotiated. The terms of the prior agreement remain in force until the new agreement is ratified by the union members. Also in December 2010, a four-year collective agreement was signed with the IBEW, expiring in February 2015.

ENVIRONMENTAL MATTERS

The Canadian Federal Government has indicated that Canada will target a 17% reduction of greenhouse gas (GHG) emissions by 2020, based on 2006 emission levels. It has also signaled that 90% of Canada's electricity will be provided by non-emitting sources, such as hydro, nuclear, clean-coal, solar and wind, by 2020. Details of Canada's GHG management plan will not be released until there is clarity in the United States about its intention to regulate GHG emissions. Canadian regulations will likely be compatible with those of the United States in order for Canadian businesses to remain competitive and avoid the potential for punitive trade sanctions. It is uncertain how climate legislation could affect the industry. The Company continues to monitor developments.

For the fourth year in a row, the Canadian Standards Association (CSA) has awarded Enbridge's Canadian operations with the Gold Champion Level Status for its GHG emissions reporting to the CSA Challenge Registry. The CSA Challenge Registry is Canada's only voluntary and publicly accessible national registry of greenhouse gas baselines, targets and reductions. Its objective is to challenge companies from all economic sectors and geographic regions to demonstrate meaningful actions that contribute to reducing GHG emissions in Canada. Developing a Gold Champion Level GHG management plan requires that Enbridge track and monitor its energy consumption and use the information to find opportunities to make reductions.

Incidental emissions during production and distribution may also be of environmental concern. The Company has policies and procedures in place to minimize these emissions. Programs have been implemented to ensure adherence to Enbridge's Environment, Health and Safety policy. These programs include environmental training for specific employee groups, implementation of environmentally sound construction practices, production of environmental communication materials to increase awareness of key issues, on-site environmental auditing, and a continuing focus on corporate due diligence.

The Company continues to be on track for the implementation of an enterprise-wide Emissions Data Management System. Deployment of this system will improve tracking of the Company's carbon data, enable full auditing, help identify additional reduction measures, and help prepare the Company for a future in which carbon emissions will be monetized.

Former Manufactured Coal Gas Plant Sites
Information related to Former Manufactured Coal Gas Plant Sites can be found in Note 20 “Commitments and Contingencies” to the 2010 Audited Annual Consolidated Financial Statements.

RISK FACTORS

A discussion of the Company’s risk factors can be found in the Company’s MD&A for the year ended December 31, 2010 under the subheading “Risk Management and Financial Instruments”.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

(millions of Canadian dollars except per share amounts) Year Ended December 31,	**2010**	2009	2008
Total Revenue[1]	**2,475**	2,903	3,105
Earnings Applicable to the Common Shareholder[1]	**191**	218	207
Dividends Declared Per Share			
Common Shares	**1.53**	1.34	1.12
Preferred Shares – Group 3, Series D	**0.52**	0.84	1.23

[1] Revenues include amounts billed to customers for natural gas, which varies with fluctuations in natural gas prices. Higher natural gas prices would increase revenues, but would not similarly impact earnings, given that the cost of natural gas flows through to customers. Earnings in two successive years may vary significantly primarily due to potentially varying weather patterns. Specifically, periods of colder than normal weather would typically result in higher earnings compared to periods of warmer than normal weather. As a result, a meaningful comparison can only be achieved after adjusting earnings for the impact of weather.

Since the issuer is an indirect wholly owned subsidiary of Enbridge, earnings per share is not provided.

DIVIDENDS

The declaration of dividends on the common shares is at the discretion of the Board of Directors. The Company targets to pay out approximately 90% to 100% of adjusted operating earnings as dividends. However, this policy range is subject to the Company’s obligation to maintain average common equity in line with the deemed regulatory level, which may lead to a payout ratio outside of this range.

Floating adjustable cumulative cash dividends on the Group 3, Series D preferred shares are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preferred shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case.

On July 1, 2014, and every five years thereafter, the Group 3, Series D preferred shares can be converted, at the holder’s option, into Group 2, Series D preferred shares, on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period.

The Group 2, Series D preferred shares can be redeemed, at the Company’s option, for $25.00 per share. The Group 2, Series D preferred shares can also be converted into Group 3, Series D preferred shares on a one-for-one basis at the holder’s option on July 1, 2014 and every five years thereafter.

There are no restrictions that currently prevent the Company from paying dividends. However, in the event of liquidation, dissolution or winding-up of the Company, the preferred shareholders have priority in the payment of dividends over the common shareholder. As well, restrictions in the credit or financing agreements entered into by the Company or the provisions of applicable law may preclude the payment of dividends in certain circumstances.

DESCRIPTION OF CAPITAL STRUCTURE

Information related to the Company's capital structure can be found in Note 9 "Debt" and Note 11 "Share Capital" to the 2010 Audited Annual Consolidated Financial Statements.

RATINGS

The following table sets forth the ratings assigned to the Company's Group 3, Series D preferred shares, medium-term notes (MTNs) and unsecured debt, and commercial paper by DBRS Limited (DBRS) and Standard & Poor's Ratings Services (S&P).

	DBRS	S&P
Preferred Shares, Group 3, Series D	Pfd-2 (low)	BBB
MTNs and Unsecured Debt	A	A-
Commercial Paper	R-1 (low)	A-1 (low)
Rating Outlook	Stable	Stable

The credit ratings accorded by these rating agencies are not recommendations to purchase, hold or sell the shares or securities and such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant. A description from the rating agency for each credit rating listed in the table above is set out below.

DBRS has different rating scales for short and long-term debt and preferred shares. ''High'' or ''low'' grades are used to indicate the relative standing within a rating category. The absence of either a ''high'' or ''low'' designation indicates the rating is in the ''middle'' of this category. The Pfd-2 (low) rating assigned to the Company's preferred shares is the second highest of six rating categories for preferred shares. Preferred shares rated Pfd-2 are of satisfactory credit quality. Protection of dividends and principal is still substantial, but earnings, the balance sheet and coverage ratios are not as strong as Pfd-1 rated companies. The A rating assigned to the Company's MTNs and unsecured debentures is the third highest of eight categories for long-term debt. Long-term debt rated A is of satisfactory credit quality. Protection of interest and principal is still substantial, but the degree of strength is less than that of AA rated entities.

While A is a respectable rating, entities in this category are considered to be more susceptible to adverse economic conditions and have greater cyclical tendencies than higher-rated securities. The R-1 (low) rating assigned to the Company's commercial paper is the third highest of ten rating categories and indicates satisfactory credit quality. The overall strength and outlook for key liquidity, debt and profitability ratios is not normally as favourable as with higher rating categories, but these considerations are still respectable. Any qualifying negative factors that exist are considered manageable, and the entity is normally of sufficient size to have some influence on its industry.

S&P has different rating scales for short and long-term obligations. Ratings may be modified by the addition of a plus (+) or a minus (-) sign to show the relative standing within a particular rating category. The BBB rating assigned to the Company's preferred shares is the fourth highest of eleven rating categories for long-term obligations. An obligor rated BBB has adequate capacity to meet its financial commitments; however, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments. The A- rating assigned to the Company's MTNs and unsecured debentures is the third highest of eleven rating categories. An A rating indicates the obligor has strong capacity to meet its financial commitments, but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher-rated categories. The rating of A-1 (low) assigned to the Company's commercial paper is the highest of nine rating categories for short-term obligations. An obligor rated A-1 has strong capacity to meet its financial commitments.

CREDIT FACILITIES

Credit facilities carried a weighted average standby fee of 0.60% per annum from January to July 2010 and 0.38% per annum from August to December 2010 on the unused portion and draws bear interest at market rates.

In 2010, the Company elected to reduce its committed credit facilities and commercial paper program limit by $100 million. The Company currently has a $700 million commercial paper program limit that is backstopped by committed lines of credit of $700 million. The term of any commercial paper issued under this program may not exceed one year. The Company has the option, at its discretion, to extend the maturity date of the committed lines of credit for an additional year.

December 31, 2010	Total Facilities	Credit Facility Draws[1]	Available
(millions of Canadian dollars)			
Enbridge Gas Distribution Inc.	**700**	**325**	**375**
St. Lawrence Gas Company, Inc.	**12**	**8**	**4**
Total Credit Facilities	**712**	**333**	**379**

1. Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the credit facility.

DIRECTORS AND OFFICERS

DIRECTORS

The following table sets forth the names of the Directors of the Company as at February 18, 2011, their municipalities of residence, their respective principal occupations within the five preceding years and the year from which they first became a Director of the Company. Each Director who is elected holds office until the next annual proceedings of shareholders or until a successor is duly elected or appointed. The Company has an Audit, Finance & Risk Committee. The Directors and Officers do not beneficially own, directly or indirectly, any voting securities of the Company or its subsidiaries.

Name and Place of Residence	**Principal Occupation During the Five Preceding Years**	**Year First Became a Director**
J. Richard Bird(1) Calgary, Alberta Canada	Executive Vice President, Chief Financial Officer & Corporate Development, Enbridge Inc. since January 2008. Executive Vice President, Liquids Pipelines, Enbridge Inc. from May 2006 to January 2008. Group Vice President, Liquids Pipelines, Enbridge Inc. from May 2005 to May 2006.	2008
J. Lorne Braithwaite (1) Thornhill, Ontario Canada	Corporate Director. President and Chief Executive Officer of Build Toronto Inc. since April 2009.	2002
Patrick D. Daniel Calgary, Alberta Canada	President & Chief Executive Officer, Enbridge Inc. since January 2001.	1998

Name and Place of Residence	Principal Occupation During the Five Preceding Years	Year First Became a Director
Janet A. Holder Toronto, Ontario Canada	President, Gas Distribution of Enbridge Inc. since October 2010 and President of the Company since January 2008. Vice President, Support Services, Enbridge Pipelines Inc. from April 2006 to January 2008. Vice President, Market Services, Enbridge Inc. from December 2004 to April 2006.	2008
David A. Leslie [(1)] [(2)] Toronto, Ontario Canada	Corporate Director.	2007
David T. Robottom, Q.C. Calgary, Alberta Canada	Executive Vice President & Chief Legal Officer of Enbridge Inc. since October 2010. Executive Vice President, Law of Enbridge Inc. from February 2010 to October 2010. Group Vice President, Corporate Law of Enbridge Inc. from June 2006 to February 2010. Partner at Stikeman Elliott LLP (law firm) from February 2004 to May 2006.	2010

1. Member of the Audit, Finance & Risk Committee of the Board of Directors.
2. Mr. Leslie served as a member of the Board of Directors of Canwest Global Communications Corp. from March 26, 2007 to January 14, 2009. On October 6, 2009, Canwest Global Communications Corp. voluntarily entered into, and successfully obtained, an Order from the Ontario Superior Court of Justice (Commercial Division) commencing proceedings under the Companies' Creditors Arrangement Act.

OFFICERS

The following table sets forth the names of the Executive Officers, their current office with the Company on February 18, 2011, their municipalities of residence and their principal occupations for the five preceding years.

Name, Position and Place of Residence	Principal Occupation During the Five Preceding Years
Janet A. Holder President Toronto, Ontario Canada	President, Gas Distribution of Enbridge Inc. since October 2010 and President of the Company since January 2008. Vice President, Support Services, Enbridge Pipelines Inc. from April 2006 to January 2008. Vice President, Market Services, Enbridge Inc. from December 2004 to April 2006.
Glenn W. Beaumont Senior Vice President, Operations Richmond Hill, Ontario Canada	Senior Vice President, Operations since October 2010. Vice President, Operations from May 2008 to October 2010. Vice President, Planning & Opportunity Development from February 2007 to May 2008. Vice President, Engineering & Technology from August 2006 to February 2007. Vice President, Engineering from April 2003 to August 2006. President of Enbridge Gas New Brunswick Inc. since May 2009.

Name, Position and Place of Residence	Principal Occupation During the Five Preceding Years
Mark R. Boyce Vice President, Law & Information Technology and Corporate Secretary Barrie, Ontario Canada	Vice President, Law & Information Technology and Corporate Secretary since October 2010. Vice President, Gas Distribution Law & Deputy General Counsel and Corporate Secretary from May 2007 to October 2010. Associate General Counsel & Corporate Secretary from June 2001 to May 2007.
James C. Grant Vice President, Energy Supply, Storage Development & Regulatory Aurora, Ontario Canada	Vice President, Energy Supply, Storage Development & Regulatory since July 2008. Senior Director, Energy Supply, Storage Development & Regulatory from May 2008 to July 2008. Director, Storage Operations & Development from April 2006 to May 2008. Director, Gas, Electricity & Storage Opportunities from January 2004 to April 2006.
Narinder K. Kishinchandani Vice President, Finance Markham, Ontario Canada	Vice President, Finance since November 2010. Director, Finance & Control from December 2006 to November 2010. Chief Accountant from June 2005 to December 2006. Manager, Financial Reporting from September 2003 to June 2005.
James W. Milner Vice President, Pipeline Integrity & Safety Thornhill, Ontario Canada	Vice President, Pipeline Integrity & Safety since October 2010. Vice President, Engineering from February 2007 to October 2010. General Manager, Eastern Region from March 2001 to February 2007.
Arunas J. Pleckaitis Vice President, Business Development & Customer Strategy Scarborough, Ontario Canada	Vice President, Business Development & Customer Strategy since May 2008. Vice President, Operations from December 2004 to May 2008. President of Enbridge Gas New Brunswick Inc. from October 1999 to May 2009.
Marc N. Weil Director, Human Resources & Facilities Thornhill, Ontario Canada	Director, Human Resources & Facilities since January 2010. Director, Information Technology from January 2006 to January 2010.

LEGAL PROCEEDINGS

Information related to the Company's legal proceedings can be found in Note 20 "Commitments and Contingencies" to the 2010 Audited Annual Consolidated Financial Statements.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, executive officer or principal shareholder of the Company, or associate or affiliate of these persons, has any material interest, direct or indirect, in any transaction within the last three years that has materially affected or will materially affect the Company.

TRANSFER AGENTS AND REGISTRARS

TRUSTEE AND REGISTRARS

Debentures
9.85% and 10.80% debentures

BNY Mellon Trust Company
Corporate Trust Services
320 Bay Street, P.O. Box 1
Toronto, Ontario, M5H 4A6
and in Halifax, Montreal, Winnipeg, Regina, Calgary and Vancouver

For each of the above group of debentures, BNY Mellon Trust Company is the Interest Dispersing Agent.

REGISTRAR AND PAYING AGENT

Medium Term Notes
Canadian Imperial Bank of Commerce
Debt Management Service
22 Front Street, 5^{th} Floor
Toronto, Ontario, M5J 2W5

TRUSTEE

Medium Term Notes
BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, P.O. Box 1
Toronto, Ontario, M5H 4A6

REGISTRAR AND TRANSFER AGENT

Group 3 Preferred Shares
Computershare Investor Services Inc.
100 University Avenue
Toronto, Ontario, M5J 2Y1

MATERIAL CONTRACTS

The Company has not entered into any material contracts outside the ordinary course of business.

INTERESTS OF EXPERTS

The Company's auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have prepared an independent auditors' report dated February 18, 2011 in respect of the Company's consolidated financial statements as at December 31, 2010 and 2009 and for each of the years then ended. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Ontario.

ADDITIONAL INFORMATION

Additional information is provided in the Company's 2010 Audited Annual Consolidated Financial Statements and MD&A for the most recently completed financial year.

ADDITIONAL DISCLOSURE

VOTING SECURITIES AND PRINCIPAL HOLDERS OF VOTING SECURITIES

As of the date hereof, the only outstanding voting securities of the Company, which are 140,732,747 common shares, are held directly by Enbridge Energy Distribution Inc., an indirect wholly owned subsidiary of Enbridge. Each common share is entitled to one vote.

EXECUTIVE COMPENSATION

The Company's Statement of Executive Compensation is attached as Schedule A.

DIRECTORS AND OFFICERS OF ENBRIDGE INC.

The name and province, state or country of residence of each Director or Executive Officer of Enbridge as at February 18, 2011 are as follows:

David A. Arledge, Florida	James J. Blanchard, Michigan	J. Lorne Braithwaite, Ontario
Patrick D. Daniel, Alberta	J. Herb England, Florida	Charles W. Fischer, Alberta
V. Maureen Kempston Darkes, Ontario	David A. Leslie, Ontario	George K. Petty, California
Charles E. Shultz, Alberta	Dan C. Tutcher, Texas	Catherine L. Williams, Alberta
Janet A. Holder, Ontario	Al Monaco, Alberta	Stephen J. Wuori, Alberta
J. Richard Bird, Alberta	David T. Robottom, Alberta	D. Guy Jarvis, Alberta

SCHEDULE A
ENBRIDGE GAS DISTRIBUTION INC.
STATEMENT OF EXECUTIVE COMPENSATION

COMPENSATION DISCUSSION AND ANALYSIS

This Compensation Discussion and Analysis describes Enbridge Inc.'s (Enbridge) executive compensation program for 2010 and applies to senior executives of Enbridge Gas Distribution Inc. (EGD). This program is administered by the Human Resources & Compensation Committee (the Committee) of the Enbridge Board of Directors (the Enbridge Board).

The following pages describe the compensation philosophy and programs for the named executives of EGD:

- President (Janet Holder)
- Vice President, Finance (Narin Kishinchandani) *current;*
- Vice President, Finance and Information Technology (William Ross) *prior*; and
- The next three most highly compensated executives (Glenn Beaumont, Arunas Pleckaitis and James Grant)

In addition to her role as principal officer of EGD, Ms. Holder has a strategic leadership role with Enbridge and reports to the President & Chief Executive Officer of Enbridge. The remaining executives reported in this schedule report to Ms. Holder and have significant responsibilities in the operating aspects of EGD.

Executive Summary

Enbridge's vision is to be the leading energy delivery company in North America. While Enbridge may be viewed as having achieved elements of this vision, enhancing and sustaining this position remains a continuing long-term pursuit. Enbridge's objective is to generate superior economic value for shareholders through investing capital in a low-risk and disciplined manner. Consistently applied, such stewardship should continue to generate attractive risk adjusted returns and, in turn, provide for consistent and growing dividend distributions and related capital appreciation. The business is capital intensive and long-term in nature, therefore the impact of decisions made today may not be realized until several years in the future. However, Enbridge has made the commitment to its shareholders to deliver steady, visible and predictable results in the short-term and to operate its assets in a responsible manner.

The compensation programs at Enbridge reflect a blend of short and longer-term incentive awards to support its pay for performance philosophy. Relevant Enbridge corporate and business unit (EGD and certain affiliates) performance measures are established for the short-term compensation plan that focus on the critical financial, operational, safety and environmental aspects of the business. The performance measures for the longer-term plans focus on overall Enbridge performance aligned with its shareholder expectations for earnings growth and share price appreciation.

When assessing performance, the Committee takes into consideration both the objective pre-defined performance metrics as well as qualitative factors not captured in the formal metrics. For example, a decision to complete a certain acquisition may have long-term strategic benefits to Enbridge that may not be reflected in the short-term performance metrics. Also playing a role are a number of market-based and earnings-based key performance indicators that compare Enbridge's results to a peer group and to the broader market over a one to ten year time horizon. Therefore, the Committee's assessment of overall performance is based on a combination of the pre-defined performance metrics, the key performance indicators, as well as the qualitative aspects of management's responsibilities.

2010 Performance

2010 was a year of strong performance and unprecedented challenges. The incident in Marshall, Michigan put Enbridge's incident and crisis response capabilities to the test unlike anything previously experienced. Despite this, Enbridge achieved strong growth in earnings and cash flow in 2010. Adjusted earnings of $984 million (or $2.66 per share) represent a 13% increase over 2009. Enbridge also brought $6.5 billion in projects into service this year ($12 billion in total over the past three years), including the Alberta Clipper, Southern Lights and Sarnia Solar projects.

Enbridge continued to secure a strong presence in the oil sands with seven new growth and expansion projects of $2.6 billion in total that will go into service between 2011 and 2014 including the Athabasca Pipeline Expansion, Waupisoo Pipeline Expansion and the Norealis and Wood Buffalo pipelines.

Enbridge's Green Energy business expanded substantially in 2010. The Greenwich Wind Energy Project in Ontario and the Cedar Point Wind Energy Project in Colorado were secured and construction has commenced. At the end of 2010, the Talbot Wind Energy Project was complete.

All of these developments had an impact on Enbridge's share performance in 2010. Its shares reached a 52-week trading high of $58.25 on the TSX on December 2, before closing the year at $56.27 per share. Over the last 50-plus years, Enbridge has delivered an average annual total shareholder return of 13.6%, outperforming the TSX Composite Index by approximately 4% a year.

In December 2010, the Enbridge Board declared a quarterly dividend of $0.49 per common share in 2011, a 15% increase over the quarterly dividend paid in 2010.

Enbridge's sustained earnings, increasing cash flow and growing dividend, combined with a reliable business model, have generated substantial value for its shareholders - a trend that is expected to continue. Enbridge's 2011 earnings guidance is about 10 percent higher than the guidance for 2010. This rate of growth is expected to continue through to the middle of the decade. The overall performance of Enbridge in 2010 was above target.

EGD measures performance in the areas of financial, safety, governance, customer satisfaction and employee engagement. 2010 earnings were strong with total business unit earnings at $171 million due to customer growth and lower borrowing costs. EGD made significant headway towards achieving a longer-term goal of having top decile safety performance through an enhanced Near Miss program and an internal safety challenge. While EGD continues to look for opportunities to improve customer service, it scored the highest compared to benchmark utilities in terms of overall value, customer communication quality, and overall billing. Employee engagement scores were up 2% over last year, placing EGD solidly within the "Best Employer" zone. The overall performance of EGD in 2010 was above target.

2010 Pay Decisions

Early in 2010, the Committee determined base salary increases and longer-term incentive awards. Base salary increases of 3-4%, depending on the executive, were implemented on April 1, 2010 to maintain a competitive position. In October 2010, Enbridge and EGD restructured resulting in changed responsibilities for Ms. Holder and Messrs. Beaumont, Ross and Kishinchandani. To reflect these changes, some further base pay adjustments were applied.

In February 2010, Enbridge granted 70,500 stock options to the named executives. This grant reflected target delivery for this compensation program and the Black-Scholes value of the stock options at the time of grant. Effective January 1, 2010, Enbridge granted 8,200 performance stock units to the named executives, which resulted in total direct compensation (base salary + short-term incentive + longer-term incentives) being positioned in the top quartile of the competitive market. The grant included additional performance stock units to recognize the outstanding performance Enbridge achieved in 2009 and over a sustained period of time. On November 12, 2010, the President was granted 46,000 stock options based on her appointment to the executive team of Enbridge. This grant was in lieu of performance stock options that she is eligible for in her new role.

In early 2011, the Committee determined short-term incentive awards of $917,190 for the named executives including an award of $244,000 to the President. These awards were determined based on above target performance for Enbridge, above target performance of the business unit, and the individual performance of each named executive relative to objectives established at the start of 2010.

Changes in 2011
The Committee reviews Enbridge's compensation philosophy and practices every year. A 2010 review focused on total direct compensation and whether the individual components are competitive, complementary and aligned with performance. After completing the review, the Committee recommended two changes to the short-term incentive plan, which have been approved by the Enbridge Board for implementation in 2011.

Performance Measures
The Committee determined the adjusted return on equity metric (adjusted ROE) was not appropriately capturing the performance of Enbridge on an annual basis. A number of alternatives were considered before deciding to move to adjusted earnings per share (adjusted EPS) to measure corporate performance. Enbridge believes adjusted EPS better reflects its overall corporate performance on an annual basis. It is also a metric that is easily understood by employees, given the prominence it is given in Enbridge's quarterly results discussions with external stakeholders. Adjusted EPS will be the only corporate metric and will be measured against the guidance range provided to Enbridge shareholders.

EGD will continue to measure performance in the areas of financial, safety, governance, customer satisfaction and employee engagement, where there is a strong line of sight on performance from administrative levels to the President. The President and named executives for EGD will define the measures that EGD will be measured against, subject to the approval of the President & Chief Executive Officer of Enbridge.

The Committee retains the right to exercise discretion in determining awards where the formulaic result does not fairly or accurately represent the outcomes and/or extra-ordinary events that occurred during the year that were not contemplated in the original measures or targets.

Weightings
Enbridge performance at the corporate level is currently emphasized in the short-term incentive plan for EGD executives. Starting in 2011, there will be more emphasis on EGD's performance in the overall mix. This reflects the changes in Enbridge to increase accountability at the business unit level. There is no change to the target setting and approval process. The Committee sets the corporate performance metric and target annually.

Approach

Enbridge's approach to executive compensation is set by the Committee and approved by the Enbridge Board. The programs are designed to accomplish three things:

- attract and retain a highly effective executive team;
- align executives' actions with Enbridge's business strategy and the interests of Enbridge shareholders; and,
- reward executives for both short and long-term performance.

Benchmarking to Peers
Total compensation for Ms. Holder is benchmarked against a North American group of companies based on her strategic role with Enbridge.

The Canadian companies are large pipeline, energy, utility and industrial companies that are similar to Enbridge in size. Together they reflect the Canadian business environment that Enbridge operates in.

The US companies are mainly oil and gas pipelines and utilities, because the US energy sector is much larger and has more depth than Canada's.

Peer Group

Canada	United States
Agrium Inc.	Ameren Corp.
Atco Ltd.	Centerpoint Energy Inc.
Canadian National Railway Company	DTE Energy Co.
Canadian Pacific Railway Ltd.	El Paso Corp.
Husky Energy	Nisource Inc.
Nexen Inc.	OGE Energy Corp.
SNC-Lavalin Group Inc.	Oneok Inc.
	PG&E Corp.
Suncor Energy Inc.	PPL Corp.
Talisman Energy Inc.	Questar Corp.
Teck Cominco Ltd.	Sempra Energy
TELUS Corp.	Spectra Energy Corp.
TransAlta Corp.	Williams. Co. Inc.
TransCanada Corp.	Xcel Energy Inc.

How Enbridge Compares

	Canada	United States
Revenue	Above 75th percentile	Above 75th percentile
Total assets	Above 75th percentile	Above 75th percentile
Number of employees	Between 25th and 50th percentile	Between 25th and 50th percentile
Market capitalization[1]	Between 50th and 75th percentile	Above 75th percentile

[1] As of June 30, 2010. All other information is based on most recently reported data.

Setting Compensation Targets

Base pay is targeted between the median and the 75th percentile, considering the skill, competency and experience of each individual. Targets for short and longer-term incentives are linked to base salary levels.

Total direct compensation is targeted at the median of comparator companies in North America. The market data for Ms. Holder (in respect of 2010 compensation) is weighted 80% on the Canadian comparator group and 20% on the United States comparator group.

The compensation for the other named executives is managed within a framework applicable to all Senior Vice President and Vice President level positions across Enbridge. The competitiveness of this framework is based on market data extracted from third party compensation surveys. Two general surveys are used as well as energy industry specific surveys. The market data is considered from several perspectives including organization size (revenue greater than $5 billion) and industry sector (pipeline, energy and utility criteria). There is no one set of comparator companies from which the competitiveness of Enbridge's senior management programs is compared.

Share Ownership

It is important for all Enbridge executives to have a meaningful equity stake in Enbridge because owning shares is a tangible way to align their interest with Enbridge shareholders.

Target ownership is a multiple of base salary, depending on position level, and executives are required to meet the target within four years of being appointed to the position. Shares can be acquired by making contributions to the employee savings plan, exercising stock options or by making personal investments in Enbridge common shares. Shares that an executive holds personally, or in the name of a spouse, dependent child or trust, all count toward meeting the guidelines. Stock options do not.

Target and actual share ownership as of December 31, 2010:

Executive	Target ownership	Actual ownership	Meets requirements
Janet Holder	2x base salary	2x	✓
Narin Kishinchandani	1x base salary	1x	✓
William Ross	1x base salary	1x	✓
Glenn Beaumont	1x base salary	2x	✓
Arunas Pleckaitis	1x base salary	4x	✓
James Grant	1x base salary	1x	✓

Paying for Performance

Performance is the cornerstone of Enbridge's executive compensation programs. The programs are designed to motivate management to achieve the high return, low risk business model Enbridge shareholders expect, with a focus on the long-term. The Committee reviews Enbridge's business plans over the short, medium and longer-term and links the compensation programs to these timeframes. The performance of Enbridge's peer group is also considered. Together, this ensures that management is focused on delivering value to Enbridge shareholders not only in the short-term, but also continued performance in the long-term.

Annual Compensation Decision-Making Process

Each year, the President and EGD executive team establish objectives for the upcoming year, which include financial objectives as well as other key priorities. Performance relative to the objectives is reviewed at the end of the year. The President completes a self assessment and her performance is reviewed by Enbridge's President & Chief Executive Officer. In February of each year, the President & Chief Executive Officer of Enbridge recommends to the Committee the compensation of Ms. Holder including base salary and short-term and longer-term incentive awards. In making these decisions, the Committee is provided the award calculations based on the approved programs and competitive information compiled by the Committee's external compensation consultant.

The President follows this same process for the other EGD executives. Each executive completes a self assessment. Their performance during the year is documented, detailing accomplishments, areas of strength, and areas for development. In making the compensation recommendations, the performance evaluation, calculations based on approved programs, market information and internal equity with other senior executive roles across Enbridge is taken into consideration. Compensation recommendations are approved by the Committee.

About the External Compensation Consultant

Mercer (Canada) Limited (Mercer) advises the Committee on compensation, actuarial and benefit matters. While the Committee takes the information and recommendations Mercer provides into consideration, it has full responsibility for its own decisions, which may reflect other factors and considerations.

In 2010, Mercer was paid $420,000 in respect of actuarial and benefits services specifically for EGD.

Elements of Total Compensation

Total compensation is made up of five components.

Base salary	Short-term incentive	Longer-term incentives	Retirement benefits	Other benefits
	• annual cash bonus	• performance stock units • stock options • restricted stock units	• pension plans • other retirement benefits	• savings plan • perquisites • medical, dental and insurance

Base Salary

Enbridge base salaries offer fixed compensation for performing day-to-day responsibilities, while balancing the individual's role and competency, market conditions and issues of attraction and retention.

Short-Term Incentive

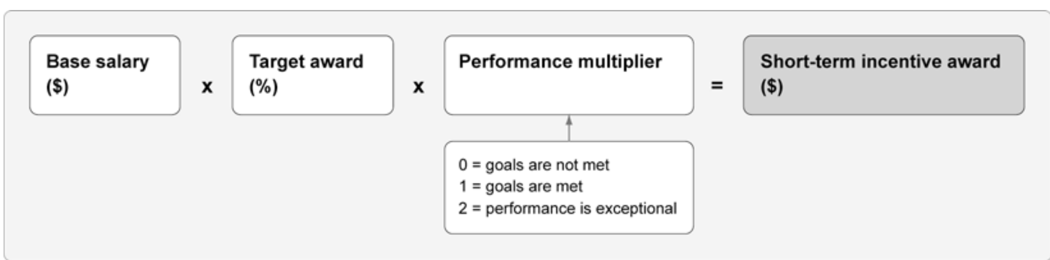
The short-term incentive plan is an annual performance bonus plan, paid out in cash. It is designed to motivate management to achieve objectives tied to executing the business strategy and to reward them according to their level of achievement for the year.

Each executive's target award and payout range reflect the level of responsibility associated with the role, as well as competitive practice, and is calculated as a percentage of base salary.

The award is paid out based on performance against a combination of Enbridge corporate, business unit and individual goals. Enbridge corporate goals are given the most weight.

	Target award (as a % of base salary)	Payout range (as a % of base salary)	Performance measures		
			Corporate	Business unit	Individual
Janet Holder	50%	0 – 100%	70%	15%	15%
Narin Kishinchandani	35%	0 – 70%	40%	30%	30%
William Ross	35%	0 – 70%	40%	30%	30%
Glenn Beaumont	40%	0 – 80%	50%	25%	25%
Arunas Pleckaitis	35%	0 – 70%	40%	30%	30%
James Grant	35%	0 – 70%	40%	30%	30%

Actual awards are calculated using a performance multiplier that ranges from 0 to 2, depending on whether the combination of goals has been met.



Using Discretion

The President & Chief Executive Officer of Enbridge can recommend to the Committee to adjust the calculated short-term incentive award for his direct reports, upwards or downwards, at his discretion. The President may adjust the calculated awards for her direct reports at her discretion. Discretion may be exercised when the formulaic result does not fairly or accurately represent the outcomes and/or extra-ordinary events that occurred during the year that were not contemplated in the original measures or targets.

The Committee can change or waive the eligibility criteria, performance measures and the levels of target and maximum awards when it believes it is reasonable to do so. In doing so, the Committee may take into consideration broader levels of performance evidenced by the key performance indicators and the environment in which the performance was achieved.

Longer-Term Incentives

Enbridge's longer-term incentives include two plans: the performance stock unit plan and stock option plan. These plans motivate executives to deliver strong performance and reward them for achieving earnings targets, maintaining top quartile price-to-earnings performance compared to Enbridge peers, and appreciation in the Enbridge share price over the longer-term. Prior grants are not considered in determining future grants.

Enbridge also has a performance stock option plan and a restricted stock unit plan. The performance stock option plan has share price targets that must be attained for the options to become exercisable. No performance stock options have been granted to the executives of EGD. The restricted stock unit plan has no performance conditions and is designed only for retention of middle management. Restricted stock units were granted to Messrs. Kishinchandani and Grant before they were promoted to their current roles.

The performance stock unit plan and stock option plan each have different terms, vesting conditions and performance criteria. This mitigates the risks associated with incentive compensation programs by ensuring that executive decisions and actions are not incented to produce only short-term results for individual profit. This approach benefits Enbridge shareholders and maximizes the value of the longer-term incentives granted to executives.

	Performance stock unit plan	**Stock option plan**
Term	3 years	10 years
Description	Phantom shares with performance conditions that affect payout.	Options to acquire Enbridge shares.
Frequency	Granted every year	Granted every year
Performance Conditions	Two performance conditions, weighted 50% each: • Enbridge EPS relative to a target set at the start of the term • Enbridge price to earnings performance relative to Enbridge peers	
Vesting	Units mature in full after three years	Options vest at 25% per year over four years, starting on the first anniversary of the grant date
Payout	Paid out in cash at the end of three years based on: • the market value of an Enbridge common share at the end of three years • Enbridge performance	Participant acquires Enbridge shares at the exercise price defined at the time of grant (fair market value).

The table below shows the target amount that is granted to an executive in longer-term incentives each year (as a percentage of base salary) and the amount that each plan can contribute to that total.

	Target longer-term incentive grant (as % of base salary)	**Amount each plan contributes to total grant** (as % of base salary)		
		Performance stock unit plan	Performance stock option plan	Stock option plan
Janet Holder[1]	200%	70%	60%	70%
Narin Kishinchandani	50%	15%	-	35%
William Ross	50%	15%	-	35%
Glenn Beaumont	65%	19.5%	-	45.5%
Arunas Pleckaitis	50%	15%	-	35%
James Grant	50%	15%	-	35%

[1] From January 1, 2010 to September 30, 2010 Ms. Holder's target longer-term incentive grant was 65% (19.5% performance stock units and 45.5% stock options). On October 1, 2010 Ms. Holder was promoted to the executive team of Enbridge. With this change, her target longer-term incentive grant was increased to 200%, including a portion delivered in performance stock options. Due to the timing of her appointment, Ms. Holder did not receive performance stock options in 2010. In lieu of this, Ms. Holder was granted additional stock options on November 12, 2010.

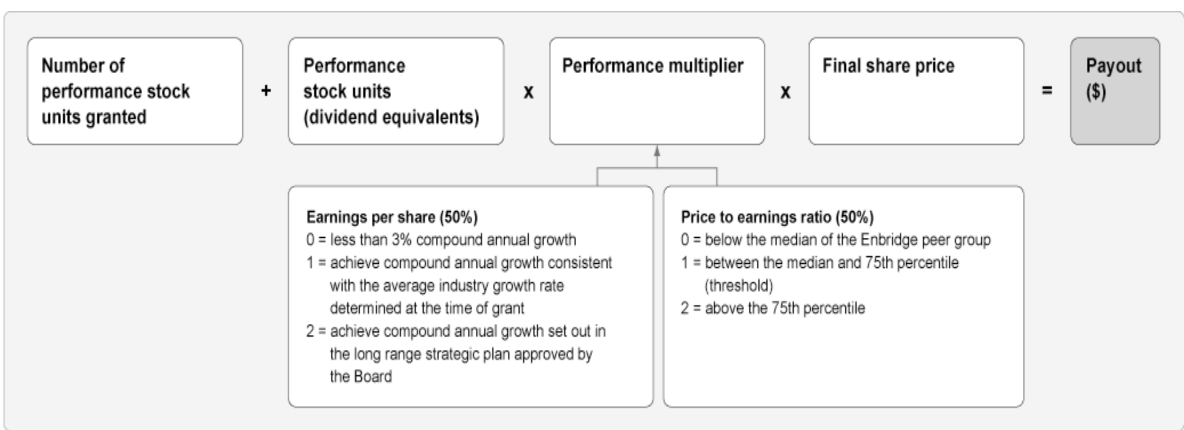
Target awards for all executives except the President are adjusted by a multiplier. The multiplier is based on individual performance history, succession potential, retention considerations and market competitiveness. Actual awards are calculated as follows:

Performance Stock Units
Performance stock units give executives the opportunity to earn up to two times the value of their units when they mature after three years by achieving performance conditions. Enbridge typically grants performance stock units annually at the beginning of each year.

There are two performance measures, each weighted 50%:

- **Earnings per share (EPS) of Enbridge.** Enbridge uses this measure because it represents a commitment to Enbridge shareholders to achieve earnings that meet or exceed the industry growth rates projected at the time of grant. Executives are incented to meet or exceed the average growth rate forecasted for peer companies over a comparable time period.
- **Price-to-earnings ratio (P/E) of Enbridge.** Enbridge uses this measure because it is a strong reflection of how shareholders view Enbridge stock and its growth potential relative to peer companies. Enbridge compares itself against the group of companies in the table below, chosen because they are all capital market competitors, have a similar risk profile and operate in a comparable sector of Enbridge.

Price-to-earnings ratio comparator group	
Ameren Corp.	OGE Energy Corp.
Canadian Utilities	Oneok Inc.
Centerpoint Energy Inc.	PG&E Corp.
Emera Inc.	Sempra Energy
Fortis Inc.	Spectra Energy Corp.
National Fuel Gas Corp.	TransAlta Corp.
Nisource Inc.	TransCanada Corporation



The payout is calculated using a performance multiplier that ranges from 0 to 2, depending on whether the performance measures are met. The final share price at the end of the term is the weighted average trading price of an Enbridge share on the TSX for twenty days prior to the end of the term.

Stock Options
A stock option gives an employee the option to buy one Enbridge share at some point in the future, at the exercise price defined at the time of grant.

Enbridge typically grants stock options in February of each year. Options vest in equal installments over a four-year period. The maximum term of an option is 10 years, but the term can be reduced if the executive leaves Enbridge. See page A24 for details.

The exercise price of an option is the weighted average trading price of an Enbridge share on the TSX for the last five trading days before the grant date. If the grant date is during a trading blackout period, Enbridge will adjust the grant date to no earlier than the sixth trading day after the trading blackout period ends. Enbridge does not backdate stock options.

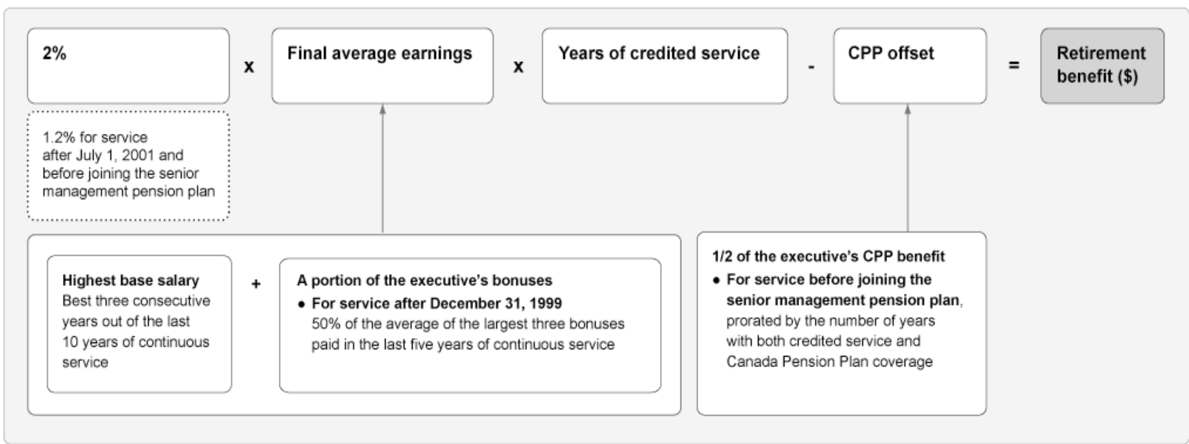
Stock options may be granted to executives joining EGD. In this case, Enbridge normally grants the options on the executive's date of hire. If the hire date falls within a blackout period, the grant is delayed until after the end of the blackout period.

Retirement Benefits

As of January 1, 2000 (or at the date they became a member of management if later), the executives joined the senior management pension plan which is a non-contributory defined benefit plan that pays out an enhanced retirement income to all senior management employees. Prior to becoming members of the senior management pension plan, the executives participated in a defined benefit pension plan.

Defined Benefit Plan

The table below shows how the retirement benefit payable is calculated under the defined benefit pension plans applicable to the named executives:



Some key terms of the plan:

- Retirement age: Executives can retire with an unreduced pension at age 60 or as early as age 55 with 30 years of service. Otherwise, they can retire as early as age 55 in which case their retirement benefit is reduced by 3% per year before age 60. The reduction is 5% per year before age 60 for service prior to January 1, 2000 and prior to joining the senior management pension plan.
- Adjustment for inflation: Retirement benefits are indexed at 50% (55% for retirement benefits in respect of service prior to January 1, 2000) of the annual increase in the consumer price index.
- Survivor benefits: the pension is payable for the life of the member with 60% continuing to the spouse after the member's death.
- Flexibility: To attract and retain executives, Enbridge can negotiate additional years of credited service or higher pension accruals, subject to approval by the Committee.

Other Retirement Terms

- The short-term incentive is pro-rated for service in the last year of employment.
- Unvested performance stock units are pro-rated for the period of active employment during the term of the grant. The units will continue to vest according to the terms of the plan.
- Unvested stock options will continue to vest. Executives can exercise stock options up to three years after retirement, or up to the date the option expires (whichever is earlier).

Other Benefits

The savings plan, perquisites and benefits plans are key elements of Enbridge's total compensation package for executives.

Savings Plan

The savings plan encourages share ownership by matching employee contributions of up to 2.5% of base salary toward the purchase of Enbridge shares. The executives participate in this plan along with all other employees.

Perquisites

Executives receive an annual perquisite allowance to offset expenses related to their position. This includes the cost of owning and operating a vehicle, parking and recreational clubs. These allowance levels are reviewed regularly for competitiveness. Ms. Holder is also reimbursed for a portion of costs for personal financial planning.

	Perquisite allowance (2010)	Financial planning reimbursement
Janet Holder[1]	$28,000	50%, up to $5,000
Narin Kishinchandani[1]	$12,500	-
William Ross	$20,000	-
Glenn Beaumont	$20,000	-
Arunas Pleckaitis	$25,000	-
James Grant	$20,000	-

1 These are pro-rated based on promotions that occurred during the year

Medical, Dental and Insurance Benefits

Medical, dental and insurance benefits are available to meet the specific needs of individuals and their families. The executives participate in the same plan as all other employees. The plans are structured to provide minimum basic coverage with the option of enhanced coverage at a level that is competitive and affordable.

The Committee reviews the retirement and other benefits regularly. These benefits are a key element of a total compensation package, and are designed to be competitive and reasonably meet the needs of executives in their current roles and when they retire.

2010 Performance and Compensation

Base Salary

The following table outlines the base salary of the executives as of December 31 of the year indicated:

	2010 base pay ($)	Increase from 2009 (%)	2009 base pay ($)	Increase from 2008 (%)
Janet Holder	400,000	27.0	315,000	-
Narin Kishinchandani	200,000	24.9	160,115	8.1
William Ross	230,000	8.3	212,302	-
Glenn Beaumont	300,000	22.6	244,725	-
Arunas Pleckaitis	281,360	2.5	274,500	-
James Grant	221,000	8.9	202,910	3.0

See the discussion for each executive starting on page A14 for information about base salary increases.

Short-Term Incentive

The short-term incentive is awarded based on performance against a combination of Enbridge corporate, business unit and individual objectives. Corporate objectives are given the most weight.

Corporate Performance

2010 Enbridge corporate performance was measured by ROE. This metric reflects the overall success in bringing new investments into service and managing existing assets to generate earnings. Strong earnings enable Enbridge to achieve steady growth and income for its shareholders. The ROE metric applies to the named executives and represents a significant component of their short-term incentive award.

The 2010 ROE target, which was approved by the Enbridge Board at the beginning of the year, was 12.65%. This represents the performance target from Enbridge's annual budget. Actual performance was 12.82% based on adjusted earnings.

Adjustments were made to ensure the result is a fair reflection of performance. Approximately $19.5 million of net gains/earnings were adjusted out of the calculation for the measure in 2010, which included mark to market gains, gains and losses from asset dispositions, and the impact of the incident that occurred in Marshall, Michigan (an event which is considered unusual). Based on this, the corporate performance multiplier was calculated to be 1.13. Overall, Enbridge's 2010 performance was very strong, evidenced by the following:

- 13% EPS growth;
- Dividend/share growth of 15%, the highest in its peer group;
- A reward to risk ratio which is at the 80th percentile of the industry;
- One year total shareholder return at the 51st percentile; three year at 93rd percentile; five year at 75th percentile and 10 year at 89th percentile of its peer group; and
- A very successful year in terms of new business development, which secures 10% growth per year in EPS through the middle of the decade.

Notwithstanding this performance, the incident in Marshall, Michigan impacted the communities Enbridge works in and affected its customers. Taking both 2010 performance and the incident into consideration, the Committee and Enbridge Board applied discretion to increase the corporate performance multiplier to 1.5. This multiplier was applied to employees across Enbridge except the executive team of Enbridge and employees in Enbridge's Liquids Pipelines business unit.

Business Unit Performance

Business unit performance for EGD is measured by a variety of metrics tailored to reflect the success in executing EGD's operations, strategies and initiatives for which the executives are accountable, including certain affiliate operations[1].

Performance Area	Weight	Measures	Results (% of target)
Financial	50%	Net Income that is weather normalized to provide a fair assessment of performance. The 2010 results were $171.1 million compared to a target of $162.1 million[2].	191%
Safety	25%	Measured by two indices: • Public Safety and Reliability Index which gauges program effectiveness for condition monitoring, emergency response, quality acceptance faults, third party damages and unplanned outages; and • Employee Safety Index which measures safety inspections, training and quality assurance as well as injuries and accidents.	86%
Governance	5%	Governance Index that measures SOx compliance, IT security policy compliance, implementation of internal audit findings and successful completion of governance related training.	100%
Customer Satisfaction	10%	Index that measures customer satisfaction and company image.	51%
Employee Satisfaction	10%	Composite that measures employee engagement, critical retention, attraction/recruitment effectiveness and career/learning opportunities.	183%

1 Affiliate operations include Enbridge Gas New Brunswick Inc., Gazifère Inc. and St. Lawrence Gas Company, Inc.
2 The 2010 target earnings for EGD represent 80% of the total earnings target for which the executives are accountable.

The results, as a percentage of target, translate into an overall multiplier of 1.45 out of 2.0 for EGD.

Individual Performance

Individual performance is measured by objectives established at the start of the year by each executive. The President's objectives are established taking into account EGD's financial, operational and strategic priorities.

The President establishes individual objectives for the other executives, also at the beginning of the year, basing them on areas of strategic and operational emphasis related to their portfolio, the development of succession candidates, employee engagement, community involvement and leadership.

See the discussion for each executive starting on page A14, for information about business unit and individual performance.

Overall Performance

The table below shows how each executive's overall performance multiplier was calculated in 2010.

	A – Enbridge Corporate performance					B - Business unit performance					C - Individual performance					Overall performance multiplier[4]
	Weight	×	Corporate multiplier	=	Total A	Weight	×	Business unit multiplier	=	Total B	Weight	×	Individual multiplier	=	Total C	Total A+B+C
Janet Holder[1]	55%		1.41		0.76[2]	22.5%		1.45		0.33	22.5%		1.60		0.36	1.45
Narin Kishinchandani	40%		1.50		0.60	30%		1.45		0.44	30%		1.35		0.41	1.44
William Ross[3]	40%		1.44		0.58	30%		1.43		0.43	30%		1.50		0.45	1.45
Glenn Beaumont	50%		1.50		0.75	25%		1.45		0.36	25%		1.40		0.35	1.46
Arunas Pleckaitis	40%		1.50		0.60	30%		1.45		0.44	30%		1.50		0.45	1.49
James Grant	40%		1.50		0.60	30%		1.45		0.44	30%		1.45		0.44	1.47

1 Ms. Holder's 2010 STIP is prorated based on targets/weightings associated with the Enbridge Senior Vice President level for nine months and targets/weightings associated with her executive role with Enbridge for three months.
2 The difference in the calculated amount and the total (A) for Ms. Holder is due to rounding.
3 Mr. Ross' 2010 STIP is prorated based on Enbridge corporate performance and business unit performance associated with ten months in EGD and two months in Enbridge's Liquids Pipelines business unit.
4 Differences in the calculated amounts and the overall performance multipliers are due to rounding.

We used the overall performance multiplier to calculate each executive's short-term incentive as follows:

	Base salary ($)	×	Target	×	Overall performance multiplier	=	Calculated short-term incentive award[1] ($)	Actual short-term incentive award ($)
Janet Holder	400,000		42.5%		1.45		243,930	244,000
Narin Kishinchandani	200,000		35%		1.44		100,800	100,800
William Ross	230,000		35%		1.45		116,953	116,950
Glenn Beaumont	300,000		40%		1.46		175,500	175,500
Arunas Pleckaitis	281,360		35%		1.49		146,240	156,240
James Grant	221,000		35%		1.47		113,700	123,700

1 The calculated short-term incentive awards vary from the amount obtained by applying the formula because of rounding. Discretionary adjustments were made to the calculated award for Messrs. Pleckaitis and Grant.

Longer-Term Incentives

Awards in 2010

Performance Stock Units

The table below shows the performance stock units granted to the named executives in early 2010.

	A Performance stock units granted (#)	B Value ($) (A x $47.23[1])	C Value (%) (B / salary on Dec. 31, 2009)
Janet Holder	3,400	160,582	51
Narin Kishinchandani[2]	-	-	-
William Ross	1,000	47,230	22
Glenn Beaumont	1,300	61,399	25
Arunas Pleckaitis	1,500	70,845	26
James Grant	1,000	47,230	23

1 For more information on the value of the 2010 Performance Stock Unit grant see Note 1 under the heading "Summary Compensation Table" on page A20 of this Schedule.
2 Mr. Kishinchandani was not granted performance stock units. Instead he was granted 500 restricted stock units valued at $23,615. This represented 15% of his December 31, 2009 base salary.

Stock Options

The table below shows the stock options granted to the named executives in early 2010.

	A Stock options granted (#)	B Value[2] ($) (A x $9.31)	C Value (%) (B / salary on Dec. 31, 2009)
Janet Holder[1]	29,200	271,852	86
Narin Kishinchandani	5,900	54,929	34
William Ross	7,400	68,894	32
Glenn Beaumont	9,500	88,445	36
Arunas Pleckaitis	10,700	99,617	36
James Grant	7,800	72,618	36

1 In addition to the above, Ms. Holder was granted 46,000 stock options on November 12, 2010 in respect of her appointment to the executive team of Enbridge. The value of these options was $364,320.
2 For more information on the value of the 2010 Stock Option grant see Note 2 under the heading "Summary Compensation Table" on page A20 of this Schedule.

Forecast Payouts

The performance stock units granted in 2008 vested on December 31, 2010. The forecast performance multiplier is 2.0 based on the following:

	Target	Result	Forecast Performance multiplier
EPS	$2.10	$2.66 (Actual)	2 X (50% weighting)
P/E ratio	75th percentile	86th percentile (Forecast)	2 X (50% weighting)

The table below shows the forecast performance stock unit payouts to the named executives in March 2011:

	Performance stock units granted in 2008	+	Equivalent to reinvested dividends	=	Total performance stock units	x	Forecast performance multiplier[2]	x	Final share price ($)	=	Payout[3] ($)
Janet Holder	1,700		182.68		1,882.68		2		55.89		210,446
William Ross	1,000		107.46		1,107.46		2		55.89		123,791
Glenn Beaumont	1,000		107.46		1,107.46		2		55.89		123,791
Arunas Pleckaitis	1,000		107.46		1,107.46		2		55.89		123,791

1 Messrs. Kishinchandani and Grant were not members of the EGD executive team at the time of grant in 2008 and did not receive performance stock units. They were granted restricted stock units that matured in 2010. See the table below for amounts paid out.
2 The final performance multiplier will be determined in March 2011.
3 Differences in the calculated amounts and the forecast payout values are due to rounding.

The table below shows the restricted stock unit payouts to the named executives on December 31, 2010.

	Restricted stock units granted in 2008	+	Equivalent to reinvested dividends	=	Total restricted stock units	x	Final share price ($)	=	Payout ($)
Narin Kishinchandani	500		53.73		553.73		56.09		31,059
James Grant	400		42.98		442.98		56.09		24,847

Named Executive Profiles

The profiles for each of the named executives provide the following information:

- A summary of the total direct compensation over the past 3 year period;
- A summary of the individual accomplishments in 2010; and
- The award decisions by the Committee and the President.

Janet Holder

President

Total Direct Compensation

	2010		2009	2008
	$	%	$	$
Cash				
Base salary	340,975	8.2	315,000	311,083
Short-term incentive	244,000	(4.0)	254,050	224,720
	$584,975	**2.8**	**569,050**	**535,803**
Equity				
Performance stock units	160,582	80.4	89,033	65,909
Stock options	636,172	184.7	223,436	163,060
	$796,754	**155.0**	**312,469**	**228,969**

Information on the values presented in this table is provided in the notes to the Summary Compensation Table found on page A20 of this Schedule.

Base Salary

Ms. Holder has been President of EGD since January 9, 2008 and received a 3% increase on April 1, 2010 to $324,450 to maintain market competitiveness. On October 1, 2010 she was appointed to the executive team of Enbridge. At this time, Ms. Holder received a 23% increase to base pay to reflect the change in her responsibilities and position her pay at $400,000 annually.

Short-Term Incentive

Until September 30, 2010 Ms. Holder led EGD under the direction of the Executive Vice President, Gas Transportation and International. With the appointment to her current role, her target short-term incentive opportunity increased and there is an increased emphasis on Enbridge performance. Based on this, her 2010 short-term incentive award takes into consideration the targets, weights, and performance in her prior and current role on a pro-rata basis.

In both roles held by Ms. Holder, a portion of her short-term incentive award is based on Enbridge corporate performance measured in 2010 by ROE. Corporate performance on this measure was determined to be 1.5 for the nine months she reported to the Executive Vice President, Gas Transportation and International, and 1.13 for the last three months of 2010 in which she was on the executive team of Enbridge. See page A11 for information about the corporate performance multiplier.

As a business unit of Enbridge, the performance of EGD accounted for 22.5% of Ms. Holder's short-term incentive award calculation. EGD's performance was determined by measures and targets established at the beginning of the year in the areas of financial, safety, governance, customer satisfaction and employee engagement. The performance multiplier for EGD was determined to be 1.45 out of 2.0. See page A11 for more information.

Approximately 22.5% of Ms. Holder's short-term incentive award is based on an individual performance multiplier of 1.6 out of 2.0. Key highlights of her 2010 accomplishments include:

- Facilitated or spoke at various national policy forums designed to engage policy makers and influencers in a dialogue on the "Utility of the Future". These policy forums are expected to continue in 2011 and are designed to help align the strategic thinking between regulators, government policy makers and energy utilities.
- Continued to build on the Enbridge brand and leverage it by developing and growing new markets / partnerships of service offerings with a focus on thermal energy.
- Continued to operationalize EGD's safety program and initiatives to achieve top decile safety performance.
- Achieved the sale of Enbridge Electric Connections Inc.

Overall, Ms. Holder's combined short-term incentive award based on her performance in the combined roles was determined to be $244,000.

Longer-Term Incentives

Ms. Holder was awarded 29,200 stock options and 3,400 performance stock units in early 2010. The performance stock unit grant included a discretionary top-up of units so that the total direct compensation for Ms. Holder was positioned in the top quartile of the market. The top-up was intended to reward outstanding Enbridge performance achieved by the senior management team in recent years, including Ms. Holder, which was evidenced by sustained top quartile earnings per share growth and total shareholder return of Enbridge on the TSX60 and the TSX Composite Indices. On November 12, 2010 Ms. Holder was granted 46,000 stock options in respect of her appointment to the executive team of Enbridge.

Narin Kishinchandani

Vice President, Finance (current)

Total Direct Compensation

	2010		2009	2008
	$	%	$	$
Cash				
Base salary	173,289	13.0	153,286	146,288
Short-term incentive	100,800	45.5	69,270	68,250
	$274,089	**23.2**	**222,556**	**214,538**
Equity				
Restricted stock units	23,615	1.7	23,226	19,385
Stock options	54,929	(2.8)	56,532	39,680
	$78,544	**(1.5)**	**$79,758**	**59,065**

Information on the values presented in this table is provided in the notes to the Summary Compensation Table found on page A20 of this Schedule.

Base Salary

On April 1, 2010 Mr. Kishinchandani was in the position of Director of Finance and Control for EGD and received an increase of 4% to maintain market competitiveness. Mr. Kishinchandani was promoted to the position of Vice President, Finance effective November 1, 2010. His base salary was increased 20.1% to $200,000 to reflect the change in his responsibilities.

Short-Term Incentive

Enbridge corporate performance, measured in 2010 by ROE, accounted for 40% of Mr. Kishinchandani's short-term incentive award. The performance multiplier on this measure was determined to be 1.5 out of 2.0. See page A11 for information about the corporate performance multiplier.

As a business unit of Enbridge, the performance of EGD accounted for 30% of Mr. Kishinchandani's short-term incentive award calculation. EGD's performance was determined by measures and targets established at the beginning of the year in the areas of financial, safety, governance, customer satisfaction and employee engagement. The performance multiplier for EGD was determined to be 1.45 out of 2.0. See page A11 for more information.

Individual performance, with a multiplier of 1.35 out of 2.0, accounted for 30% of Mr. Kishinchandani's short-term incentive award. Key highlights of his 2010 accomplishments, primarily based on his role as Director, Finance and Control, include:

- Developed and implemented processes and systems to assist in setting strategic direction.
- Facilitated enhanced documentation and application of key controls to ensure the continued fair disclosure of information in the financial statements.
- Delivered planned improvements to capital management and financial reporting processes.
- Enabled the delivery of systems and processes that ensured smooth transition to the new Harmonized Sales Tax regime.

Overall, Mr. Kishinchandani's short-term incentive award was $100,800.

Longer-Term Incentives

Based on his role at the time of the annual 2010 longer-term incentive grant, Mr. Kishinchandani was granted 5,900 stock options and 500 restricted stock units.

William Ross

Vice President, Finance and Information Technology (Prior)

Total Direct Compensation

	2010		2009	2008
	$	%	$	$
Cash				
Base salary	218,966	3.1	212,302	208,371
Short-term incentive	116,950	(10.3)	130,330	125,960
	$335,916	**(2.0)**	**342,632**	**334,331**
Equity				
Performance stock units	47,230	35.6	34,839	38,770
Stock options	68,894	(19.4)	85,471	78,740
	$116,124	**(3.5)**	**120,310**	**117,510**

Information on the values presented in this table is provided in the notes to the Summary Compensation Table found on page A20 of this Schedule.

Base Salary

Mr. Ross was in the lead finance role of EGD from 2006 to the end of October 2010. On April 1, 2010 Mr. Ross received an increase of 3% to maintain market competitiveness. On November 1, 2010 Mr. Ross transferred to another business unit in Enbridge and received a 5.2% base salary increase to reflect the change in his responsibilities.

Short-Term Incentive

In both roles held by Mr. Ross, a portion of his short-term incentive award is based on Enbridge corporate performance measured in 2010 by ROE. Corporate performance on this measure was determined to be 1.44 reflecting his pro-rata employment in EGD and the Enbridge Liquids Pipelines business unit. See page A11 for information about the corporate performance multiplier.

2010 business unit performance was determined on a pro-rata basis for his time employed with EGD and the Enbridge Liquids Pipelines business unit. Overall, the performance of these two business units was above target and accounted for 30% of Mr. Ross' short-term incentive award calculation using a combined multiplier of 1.43.

Individual performance accounted for 30 % of Mr. Ross' short-term incentive award with a multiplier of 1.5 out of 2.0. Key highlights of his 2010 accomplishments, primarily based on his role as Vice President, Finance and Information Technology of EGD include:

- Delivered planned improvements to capital management and control processes, operating costs monitoring and cross enterprise collaboration tools.
- Identified and implemented enhanced processes relating to the revenue cycle.
- Implemented tax and financing strategies to optimize earnings.
- Enhanced governance effectiveness through the delivery of fraud awareness programs, streamlining and improving the effectiveness of internal controls.

Mr. Ross' combined 2010 short-term incentive award, based on the performance described above, was $116,950.

Longer-Term Incentives

Mr. Ross was awarded 7,400 stock options and 1,000 performance stock units in early 2010. The performance stock unit grant included a discretionary top-up of units so that the total direct compensation for Mr. Ross was positioned in the top quartile of the market. The top-up was intended to reward outstanding Enbridge performance achieved by the senior management team in recent years, including Mr. Ross, which was evidenced by sustained top quartile earnings per share growth and total shareholder return of Enbridge on the TSX60 and the TSX Composite Indices.

Glenn Beaumont

Senior Vice President, Operations

Total Direct Compensation

	2010		2009	2008
	$	%	$	$
Cash				
Base salary	262,826	7.4	244,725	236,919
Short-term incentive	175,500	17.8	148,950	145,200
	$438,326	**11.3**	**393,675**	**382,119**
Equity				
Performance stock units[1]	61,399	58.6	38,710	38,770
Stock options[2]	88,445	(5.5)	93,547	86,180
	$149,844	**13.3**	**132,257**	**124,950**

Information on the values presented in this table is provided in the notes to the Summary Compensation Table found on page A20 of this Schedule.

Base Salary

Mr. Beaumont was in the position of Vice President, Operations for EGD from February 2007 to October 2010. On April 1, 2010 he received an increase of 3.5% to maintain market competitiveness. In October 2010 Mr. Beaumont was promoted to the position of Senior Vice President, Operations and his base salary was increased 18.4% to $300,000 to reflect the change in his responsibilities.

Short-Term Incentive

Enbridge corporate performance, measured in 2010 by ROE, accounted for 50% of Mr. Beaumont's short-term incentive award. The performance multiplier on this measure was determined to be 1.5 out of 2.0. See page A11 for information about the corporate performance multiplier.

As a business unit of Enbridge, the performance of EGD accounted for 25% of Mr. Beaumont's s short-term incentive award. Performance was determined by measures and targets established at the beginning of the year in the areas of financial, safety, governance, customer satisfaction and employee engagement. The performance multiplier for EGD was determined to be 1.45 out of 2.0. See page A11 for more information.

Individual performance accounted for 25% of Mr. Beaumont's short-term incentive award with a performance multiplier of 1.4 out of 2.0. Key highlights of his 2010 accomplishments include:

- Delivered strong earnings performance in EGD and its affiliates.
- Strengthened the relationship with contractors introducing new quality management systems and delivering on quality, safety, customer and efficiency metrics.
- Introduced a functional model across regional operations to drive consistency and strengthen oversight and initiated a process teaming approach to drive out operational efficiencies, enhance safety and improve the customer and employee experience.
- Ensured delivery on all key company obligations under the current collective agreements with CEP and IBEW. Initiated negotiation process with both unions for contracts expiring December 31, 2010.

Mr. Beaumont's combined 2010 short-term incentive award, based on the performance described above, was $175,500.

Longer-Term Incentives

Mr. Beaumont was awarded 9,500 stock options and 1,300 performance stock units in early 2010. The performance stock unit grant included a discretionary top-up of units so that the total direct compensation for Mr. Beaumont was positioned at the top quartile of the market. The top-up was intended to reward outstanding Enbridge performance achieved by the senior management team in recent years, including Mr. Beaumont, which was evidenced by sustained top quartile earnings per share growth and total shareholder return of Enbridge on the TSX60 and the TSX Composite Indices.

Arunas Pleckaitis

Vice President, Business Development & Customer Strategy

Total Direct Compensation

	2010		2009	2008
	$	%	$	$
Cash				
Base salary	279,645	1.9	274,500	267,375
Short-term incentive	156,240	(9.6)	172,840	165,750
	$435,885	**(2.6)**	**447,340**	**433,125**
Equity				
Performance stock units	70,845	66.4	42,581	38,770
Stock options	99,617	(0.7)	100,277	92,380
	$170,462	**19.3**	**142,858**	**131,150**

Information on the values presented in this table is provided in the notes to the Summary Compensation Table found on page A20 of this Schedule.

Base Salary

Mr. Pleckaitis received an increase of 2.5% on April 1, 2010 to maintain market competitiveness.

Short-Term Incentive

Enbridge corporate performance accounts measured in 2010 by ROE accounts for 40% of Mr. Pleckaitis' short-term incentive award. Corporate performance on this measure was determined to be 1.5 out of 2.0. See page A11 for information about the corporate performance multiplier.

As a business unit of Enbridge, the performance of EGD accounted for 30% of Mr. Pleckaitis' short-term incentive award calculation. Performance was determined by measures and targets established at the beginning of the year in the areas of financial, safety, governance, customer satisfaction and employee engagement. The performance multiplier for EGD was determined to be 1.45 out of 2.0. See page A11 for more information.

Individual performance accounts for 30% of Mr. Pleckaitis' short-term incentive award where the performance multiplier was 1.5 out of 2.0. Key highlights of his 2010 accomplishments include:

- Contributed significantly to the Company's year-end earnings results through effective revenue generating and cost management initiatives.
- Advanced the Company's key future growth initiatives including Renewable Natural Gas and a strategic partnership with with Toronto Hydro. Developed a strategy for the Company's next generation of Customer Care and successfully negotiated an extension to the Customer Care Services Agreement to December 31, 2017 with Accenture Business Services for Utilities Inc.
- Led the successful divestiture of Enbridge Electric Connections Inc.

Mr. Pleckaitis' combined 2010 short-term incentive award, based on the performance described above, was $156,240.

Longer-Term Incentives

Mr. Pleckaitis was awarded 10,700 stock options and 1,500 performance stock units in early 2010. The performance stock unit grant included a discretionary top-up of units so that the total direct compensation for Mr. Pleckaitis was positioned at the top quartile of the market. The top-up was intended to reward outstanding Enbridge performance achieved by the senior management team in recent years, including Mr. Pleckaitis, which was evidenced by sustained top quartile earnings per share growth and total shareholder return of Enbridge on the TSX60 and the TSX Composite Indices.

James Grant

Vice President, Energy Supply, Storage Development & Regulatory

Total Direct Compensation

	2010		2009	2008
	$	%	$	$
Cash				
Base salary	210,983	6.3	198,477	181,375
Short-term incentive	123,700	0.2	123,500	114,820
	334,683	**3.9**	**321,977**	**296,195**
Equity				
Performance stock units	47,230	52.5	30,968	-
Restricted stock units	-	-	-	15,508
Stock options	72,618	(7.8)	78,741	38,440
	119,848	**9.2**	**109,709**	**53,948**

Information on the values presented in this table is provided in the notes to the Summary Compensation Table found on page A20 of this Schedule.

Base Salary

Mr. Grant received an increase of 3.5% on April 1, 2010 and 5.2% on October 1, 2010 to maintain market competitiveness.

Short-Term Incentive

Enbridge corporate performance accounts measured in 2010 by ROE accounts for 40% of Mr. Grant's short-term incentive award. Corporate performance on this measure was determined to be 1.5 out of 2.0. See page A11 for information about the corporate performance multiplier.

As a business unit of Enbridge, the performance of EGD accounted for 30% of Mr. Grant's short-term incentive award calculation. Performance was determined by measures and targets established at the beginning of the year in the areas of financial, safety, governance, customer satisfaction and employee engagement. The performance multiplier for EGD was determined to be 1.45 out of 2.0. See page A11 for more information

Individual performance accounts for 30% of Mr. Grant's short-term incentive award where the performance multiplier was 1.45 out of 2.0. Key highlights of his 2010 accomplishments include:

- Ensured the continued safe and efficient operations of gas storage.
- Continued to develop EGD's gas supply strategy for the medium term.
- Ensured appropriate gas acquisition, transportation, and storage contracting to meet the needs of EGD and regulatory bodies.
- Set the strategy and implemented a second expansion of EGD's unregulated storage business.
- Set and implemented a Regulatory Affairs strategy to ensure that EGD's interests were fully represented with ratepayers and the Ontario Energy Board.

Mr. Grant's combined 2010 short-term incentive award, based on the performance described above, was $123,700.

Longer-Term Incentives

Mr. Grant was awarded 7,800 stock options and 1,000 performance stock units in early 2010. The performance stock unit grant included a discretionary top-up of units so that the total direct compensation for Mr. Grant was positioned at the top quartile of the market. The top-up was intended to reward outstanding Enbridge performance achieved by the senior management team in recent years, including Mr. Grant, which was evidenced by sustained top quartile earnings per share growth and total shareholder return of Enbridge on the TSX60 and the TSX Composite Indices.

2010 RESULTS

Summary Compensation Table

The table below shows the total Enbridge and its subsidiaries paid and granted to the named executives for the years ended December 31, 2010, 2009 and 2008.

Executive and principal position	Year	Salary ($)	Share-based awards[1] ($)	Option-based awards[2] ($)	Non-equity (annual incentive plan[3]) ($)	Sub-total (without pension) ($)	Pension value[4] ($)	All other compensation [5,6,7,8,9] ($)	Total compensation ($)
Janet Holder	2010	340,975	160,582	636,172	244,000	1,381,729	69,000	41,541	1,492,270
President	2009	315,000	89,033	223,436	254,050	881,519	37,000	44,924	963,443
	2008	311,083	65,909	163,060	224,720	764,772	195,000	89,458	1,049,230
Narin Kishinchandani	2010	173,289	23,615	54,929	100,800	352,633	89,000	12,911	454,544
Vice President, Finance	2009	153,286	23,226	56,532	69,270	302,314	36,000	11,318	349,632
(Current)	2008	146,288	19,385	39,680	68,250	273,603	37,000	11,492	322,095
William Ross[10]	2010	218,966	47,230	68,894	116,950	452,040	73,000	21,271	546,311
Vice President,	2009	212,302	34,839	85,471	130,330	462,942	14,000	20,746	497,688
Finance & Information	2008	208,371	38,770	78,740	125,960	451,841	70,000	21,377	543,218
Technology (Prior)									
Glenn Beaumont	2010	262,826	61,399	88,445	175,500	588,170	150,000	23,468	761,638
Senior Vice President,	2009	244,725	38,710	93,547	148,950	525,932	20,000	25,559	571,491
Operations	2008	236,919	38,770	86,180	145,200	507,069	138,000	25,525	670,594
Arunas Pleckaitis	2010	279,645	70,845	99,617	156,240	606,347	52,000	25,000	683,347
Vice President,	2009	274,500	42,581	100,277	172,840	590,198	-	25,000	615,198
Business Development	2008	267,375	38,770	92,380	165,750	564,275	155,000	25,000	744,275
& Customer Strategy									
James Grant	2010	210,983	47,230	72,618	123,700	454,531	77,000	23,966	555,497
Vice President,	2009	198,477	30,968	78,741	123,500	431,686	46,000	22,319	500,005
Energy Supply, Storage	2008	181,375	15,508	38,440	114,820	350,143	148,000	18,854	516,997
Development &									
Regulatory									

1 Amounts in this column reflect the number of performance stock units awarded multiplied by the unit value which is determined by the volume weighted average of an Enbridge share on the TSX for 20 trading days prior to the grant date. The unit value for the performance units awarded was $47.23 (2010), $38.71 (2009), $38.77 (2008). The unit value considers the notional dividends that are reinvested during the performance period. The unit value of the performance units varies from the accounting value which is based on a mark-to-market valuation of an Enbridge share at the end of each financial quarter, including notional dividends accrued. Particulars on performance stock units are set forth on page A8 of this Schedule.

2 Amounts in this column reflect the number of options awarded multiplied by the option value. The option value for all regular stock option grants is determined using the Black-Scholes method. In 2008 and 2009, the grant date fair value was consistent with the accounting value. In 2010, the volatility assumption for the accounting value was changed to address the instability in the financial markets and result impact on the volatility of the Enbridge shares. The volatility assumption was not adjusted however for stock option granting purposes therefore the grant date fair value is different than the accounting value. The following outlines the option value assumptions as well as the accounting value for the November 2010 (Ms. Holder only), February 2010, 2009 and 2008 stock option grants:

Assumptions	November 2010		February 2010		2009	2008
	Grant date fair value	Accounting value	Grant date fair value	Accounting value	Grant date fair value and accounting value	Grant date fair value and accounting value
Expected option term in years	6	6	6	6	6	6
Expected volatility	19.5%	19.1%	26.6%	19.1%	26.8%	18.1%
Expected dividend yield	3.11%	3.11%	3.64%	3.64%	3.88%	3.32%
Risk free interest rate	2.40%	2.40%	2.65%	2.65%	2.22%	3.61%
Exercise price	$55.68	$55.68	$46.59	$46.59	$39.61	$40.42
Regular option value	$7.92	$7.74	$9.31	$6.56	$6.73	$6.20

3 Amounts in this column reflect the short-term incentive plan awards earned in 2010 and payable on February 28, 2011. Awards are based on Enbridge, business unit and individual performance. Particulars on the short-term incentive awards calculations for each named executive are set forth on page A12 of this Schedule.

4 The pension value is equal to the compensatory change shown in the defined benefit plans table. The pension values reported in 2008 and 2009 for Ms. Holder include credited service with EGD only.

5 Amounts in this column include the flexible perquisite allowance, excess flexible benefit credits paid to the executive, the taxable benefit from loans by EGD (which were made prior to the enactment of the Sarbanes-Oxley Act), parking, relocation subsidies, financial counseling benefits and other incidental compensation.

6 In 2010, the executives were given a flexible perquisites allowance in the amount of $28,000 for Ms. Holder, $25,000 for Mr. Pleckaitis, $20,000

for each of Messrs. Ross, Beaumont and Grant, and $12,500 for Mr. Kishinchandani.

7 EGD has a flexible benefit program where employees receive flex credits with which they can purchase various health and insurance benefits; apply as contributions to the savings plan; or be paid as additional compensation. Flexible benefit credits directed to the savings plan or paid as additional compensation to the executives are reported in All Other Compensation.

8 For Ms. Holder, amount includes a taxable benefit from reimbursed mortgage interest of $5,925.

9 For Mr. Ross, amount includes a taxable benefit from a relocation subsidy of $1,271 paid by Enbridge Pipelines Inc.

10 Mr. Ross' compensation for 2010 reflects amounts from EGD, where he was employed until October 31, 2010, and from the Enbridge Liquids Pipelines business unit, which he joined on November 1, 2010.

Incentive Plan Awards

Outstanding option-based and share-based awards as of December 31, 2010

	Option Based Awards						Share-Based Awards			
Executive	**Option grant date**	**Number of securities underlying unexercised options (#)**	**Option exercise price ($)**	**Option expiration date**	**Value of unexercised in-the-money options[1, 2] ($)**		**Units grant date**	**Number of units that have not vested (#)**	**Unit maturity date**	**Market or payout value of units not vested[3, 4] ($)**
					Vested	**Unvested**				
Janet Holder	12-Nov-10	46,000	55.68	12-Nov-20	-	27,140	1-Jan-10	3,516	31-Dec-12	123,665
	16-Feb-10	29,200	46.59	16-Feb-20	-	282,656	1-Jan-09	2,467	31-Dec-11	86,769
	25-Feb-09	33,200	39.61	25-Feb-19	138,278	414,834				
	19-Feb-08	26,300	40.42	19-Feb-18	208,428	208,428				
	9-Feb-07	9,600	38.26	9-Feb-17	129,672	43,224				
	13-Feb-06	11,400	36.47	13-Feb-16	225,720	-				
	3-Feb-05	12,400	31.68	3-Feb-15	304,916	-				
	4-Feb-04	23,600	25.72	4-Feb-14	720,980	-				
	6-Feb-03	26,000	20.83	6-Feb-13	921,570	-				
	5-Feb-02	24,000	21.85	5-Feb-12	826,080	-				
	21-Feb-01	13,400	19.10	21-Feb-11	498,078	-				
Narin Kishinchandani[4]	16-Feb-10	5,900	46.59	16-Feb-20	-	57,112	1-Jan-10	517	01-Dec-12	29,098
	25-Feb-09	8,400	39.61	25-Feb-19	34,986	104,958	1-Jan-09	644	01-Dec-11	36,217
	19-Feb-08	6,400	40.42	19-Feb-18	50,720	50,720				
	9-Feb-07	5,100	38.26	9-Feb-17	68,888	22,963				
	13-Feb-06	1,600	36.47	13-Feb-16	31,680	-				
	3-Feb-05	1,600	31.68	3-Feb-15	39,344	-				
William Ross	16-Feb-10	7,400	46.59	16-Feb-20	-	71,632	1-Jan-10	1,034	31-Dec-12	36,372
	25-Feb-09	12,700	39.61	25-Feb-19	52,896	158,687	1-Jan-09	965	31-Dec-11	33,953
	19-Feb-08	12,700	40.42	19-Feb-18	100,648	100,648				
	9-Feb-07	6,700	38.26	9-Feb-17	90,500	30,167				
	13-Feb-06	7,100	36.47	13-Feb-16	140,580	-				
	3-Feb-05	7,800	31.68	3-Feb-15	191,802	-				
	4-Feb-04	4,000	25.72	4-Feb-14	122,200	-				
Glenn Beaumont	16-Feb-10	9,500	46.59	16-Feb-20	-	91,960	1-Jan-10	1,344	31-Dec-12	47,284
	25-Feb-09	13,900	39.61	25-Feb-19	57,894	173,681	1-Jan-09	1,073	31-Dec-11	37,726
	19-Feb-08	13,900	40.42	19-Feb-18	110,158	110,158				
	9-Feb-07	7,800	38.26	9-Feb-17	105,359	35,120				
	13-Feb-06	9,300	36.47	13-Feb-16	184,140	-				
	3-Feb-05	9,200	31.68	3-Feb-15	226,228	-				
	4-Feb-04	19,000	25.72	4-Feb-14	580,450	-				
	6-Feb-03	1,000	20.83	6-Feb-13	35,445	-				
Arunas Pleckaitis	16-Feb-10	10,700	46.59	16-Feb-20	-	103,576	1-Jan-10	1,551	31-Dec-12	54,558
	25-Feb-09	14,900	39.61	25-Feb-19	62,059	186,176	1-Jan-09	1,180	31-Dec-11	41,498
	19-Feb-08	14,900	40.42	19-Feb-18	118,083	118,083				
	9-Feb-07	8,700	38.26	9-Feb-17	117,515	39,172				
	13-Feb-06	9,800	36.47	13-Feb-16	194,040	-				
	3-Feb-05	11,200	31.68	3-Feb-15	275,408	-				
	4-Feb-04	22,600	25.72	4-Feb-14	690,430	-				
	6-Feb-03	25,000	20.83	6-Feb-13	886,125	-				
	5-Feb-02	25,000	21.85	5-Feb-12	860,500	-				

James Grant	16-Feb-10	7,800	46.59	16-Feb-20	-	75,504	1-Jan-10	1,034	31-Dec-12	38,372
	25-Feb-09	11,700	39.61	25-Feb-19	48,731	146,192	1-Jan-09	858	31-Dec-11	30,180
	19-Feb-08	6,200	40.42	19-Feb-18	49,135	49,135				
	9-Feb-07	5,800	38.26	9-Feb-17	78,344	26,115				
	13-Feb-06	4,400	36.47	13-Feb-16	87,120	-				
	3-Feb-05	2,200	31.68	3-Feb-15	54,098	-				
	4-Feb-04	2,400	25.72	4-Feb-14	73,320	-				
	6-Feb-03	2,800	20.83	6-Feb-13	99,246	-				
	5-Feb-02	2,800	21.85	5-Feb-12	96,376	-				

1 The value of the unexercised in-the-money stock options is based on the Enbridge share price on December 31, 2010 of $56.27.
2 The market value of the performance stock units that have not vested is calculated by the number of units granted plus the number of units credited in lieu of reinvested dividends multiplied by the threshold performance multiplier and the Enbridge share price on December 31, 2010 of $56.27.
3 We have assumed a threshold performance multiplier of 0.625, based on meeting minimum EPS threshold (50%) and a relative price to earnings ratio ranking of at least 50th percentile (50%). See page A8 for details.
4 Mr. Kishinchandani was granted restricted stock units in 2009 and 2010 and the market value of the units that have not vested is calculated by the number of units granted plus the number of units credited in lieu of reinvested dividends multiplied by the Enbridge share price on December 31, 2010 of $56.27.

Value Vested or Earned in 2010

Executive	Option-based awards – value vested during the year ($)	Share-based awards – value vested during the year[1, 2] ($)	Non-equity incentive plan compensation – value earned during the year[3] ($)
Janet Holder	148,785	210,446	244,000
Narin Kishinchandani	39,750	31,059	100,800
William Ross	74,563	123,791	116,950
Glenn Beaumont	86,602	123,791	175,500
Arunas Pleckaitis	93,132	123,791	156,240
James Grant	54,133	24,847	123,700

1 The performance units granted in 2008 matured on December 31, 2010. Awards are forecast. See page A13 for details.
2 Mr. Kishinchandani and Mr. Grant received a restricted unit payout on December 31, 2010.
3 Based on Enbridge and business unit performance at an "exceeds" rating, and varying individual performance. See executive profiles for more information.

The value of the option-based awards is based on the following:

Grant date	Grant price ($)	2010 vesting date	Market price on 2010 vesting date ($)
25-Feb-2009	39.61	25-Feb-2010	46.73
19-Feb-2008	40.42	19-Feb-2010	46.37
09-Feb-2007	38.26	09-Feb-2010	46.98
13-Feb-2006	36.47	13-Feb-2010	46.87

Enbridge Shares Used for Purposes of Equity Compensation

Enbridge grants options under its current stock options plan, which was approved by Enbridge shareholders in 2007. Before these plans were approved, Enbridge issued stock options and performance stocks options under its legacy incentive stock option plan (2002). While Enbridge no longer grant options under this plan, there are still some options outstanding.

Enbridge shares reserved for equity compensation as of December 31, 2010

Plan	Number of securities to be issued upon exercise of outstanding options, warrants and rights (#) (a)	Weighted-average exercise price of outstanding options, warrants and rights ($) (b)	Number of securities remaining available for future issue under equity compensation plans (excluding securities reflected in column (a)) (#) (c)
Current stock option plans	9,495,075	40.70	7,004,925
Legacy stock option plan	5,382,347	29.63	–

Plan Restrictions

Shares Enbridge can reserve for issue under all stock option plans	16,500,000 in total, or 4.3% of Enbridge's total issued and outstanding shares as at February 18, 2011 • for an employee – no more than 5% of the total shares issued and outstanding • for an executive or other insider – no more than 10% of the total shares issued and outstanding
Shares that can be issued in a one-year period	• for an insider or his or her associate – no more than 5% of the total shares issued and outstanding • for insiders as a group – no more than 10% of the total shares issued and outstanding
The number of shares that can be issued as incentive stock options (within the meaning of the US Internal Revenue Code) to designated employees of Enbridge's US subsidiaries	Up to 2,000,000 shares can be issued to these employees under each option plan unless, at the time of the grant: • the employee owns shares that give him or her more than 10% of the total combined voting power of all classes of shares in his or her employer, or of its parent or subsidiary, unless the grant price is at least 110% of the fair market value of the shares, and the options are to be exercised within five years of the grant date, *or* • the employee has options that can be exercised in a single calendar year for shares that have a total fair market value of more than US$100,000 (or the amount set out in the US Internal Revenue Code)
Options the President & CEO of Enbridge can grant to new executives when they join EGD	Up to 2% of the total shares outstanding at the time of the grant (undiluted) or the amount stated in the policies of the Committee (whichever is less)

Termination Provisions

The termination provisions for the Enbridge stock option plans are summarized below. Performance stock options have the same termination provisions as the regular stock options except for the following differences:

- for retirement, the entire grant of options is pro-rated;
- for death, unvested options are pro-rated and the plan assumes performance requirements have been met;
- for involuntary not for cause termination, unvested options are pro-rated; and,
- for change of control, the plan assumes the performance requirements have been met.

Pro-ration is based on active employment during the time vesting period (and any notice period on an involuntary not for cause termination will count as active employment), and pro-rated options are deemed to be time vested.

Reason for termination	Provision
Resignation	Can exercise vested options up to 30 days from the date of termination or until the option term expires (whichever is sooner).
Retirement	Options continue to vest and options that are vested or become vested can be exercised up to three years from retirement or until the option term expires (whichever is sooner).
Death	All options vest and can be exercised up to 12 months from the date of death or until the option term expires (whichever is sooner).
Disability	*Current stock option plans*: Options continue to vest based on the regular provisions of the plan. *Legacy stock option plan*: Options continue to vest. Vested options can be exercised up to three years from the date of disability or until the option term expires (whichever is sooner).
Termination - involuntary, not for cause	*Current stock option plans*: Unvested options continue to vest, and options that are vested or become vested can be exercised up to 30 days after the notice period expires or until the option term expires (whichever is sooner). *Legacy stock option plan*: Can exercise vested options up to 30 days from the date of termination or until the option term expires (whichever is sooner).
- involuntary, for cause	*Current stock option plans*: All options are cancelled on the date of termination. *Legacy stock option plan*: Can exercise vested options up to 30 days from the date of termination or until the option term expires (whichever is sooner).
- change of control or reorganization	*Current stock option plans*: For a change of control, options vest on a date determined by the Committee before the change of control. For any other kind of reorganization, options are to be assumed by the successor company. If they are not assumed, they will vest and the value will be paid in cash. *Legacy stock option plan*: Options will be assumed by the successor company. If they are not assumed, they will vest and the value will be paid in cash.

Retirement Benefits

The following table outlines estimated annual retirement benefits, accrued pension obligations and compensatory and non-compensatory changes for the executives under the defined benefit pension plans. All information is based on the assumptions and methods used for purposes of reporting financial statements.

Defined Benefit Plans

Executive	No. of years of credited service	Annual benefits payable ($) At year-end	At age 65	Accrued obligation at start of the year ($)	Compensatory change[1] ($)	Non-compensatory change[2] ($)	Accrued obligation at year-end ($)
Janet Holder[3]	16.33	136,000	216,000	1,179,000	69,000	333,000	1,581,000
Narin Kishinchandani[4]	7.58	23,000	117,000	151,000	89,000	55,000	295,000
William Ross[5]	7.83	43,000	103,000	361,000	73,000	77,000	511,000
Glenn Beaumont	24.50	106,000	218,000	990,000	150,000	378,000	1,518,000
Arunas Pleckaitis[6]	23.75	162,000	196,000	1,633,000	52,000	350,000	2,035,000
James Grant	27.58	96,000	159,000	1,062,000	77,000	293,000	1,432,000

1 The compensatory change includes current service cost, special arrangements and the difference between actual and estimated earnings.
2 The non-compensatory change includes interest on the accrued obligation at the start of the year, changes in actuarial assumptions and other experience gains and losses.
3 The accrued obligation at the start of the year for Ms. Holder has been adjusted from the value reported in the prior year due to including credited service with all Enbridge entities. Ms. Holder has 13.22 years of credited service with EGD. A portion of Ms. Holder's retirement benefit will be paid from other Enbridge entities based on her service with those entities. The final average earnings calculation for Ms. Holder will include bonuses for all service.
4 Mr. Kishinchandani joined the senior management pension plan on December 1, 2006.
5 Mr. Ross was employed by EGD until November 1, 2010. Mr. Ross has 7.66 years of credited service with EGD. A portion of Mr. Ross' retirement benefit will be paid from other Enbridge entities based on his service with those entities.
6 The final average earnings calculation for Mr. Pleckaitis will include bonuses for all service.

Other Retirement Benefits

In addition to pension plan and post retirement benefits, retirees are entitled to the following compensation:

- Annual incentive prorated for service in the last year of employment;
- Unvested options continue to vest. Options may be exercised up to, but no later than, the earlier of three years following retirement and the expiry of the option;

- Unvested performance stock unit grants are prorated for the period of active employment during the term of the grant and continue to vest in accordance with the terms of the plan.

Termination of Employment and Change of Control Arrangements

EGD does not have written employment agreements with its executives, other than with Ms. Holder and Mr. Pleckaitis. Upon resignation, retirement or termination without cause or constructive dismissal, each of the executives would be entitled to receive pension benefits under the senior management pension plan. The severance amounts payable to the executives upon termination without cause or constructive dismissal, except for Ms. Holder and Mr. Pleckaitis, would be individually determined based upon service, age, salary level and title. In the case of Ms. Holder and Mr.Pleckaitis, they would be entitled to the amounts described under “Executive Employment Agreement” below for termination without cause or constructive dismissal.

The following table discloses the lump sum value of pension benefits accrued under the senior management pension plan for the executives had they resigned, retired, been terminated involuntarily without cause or constructively dismissed as of December 31, 2010:

Executive	Pension ($)
Janet Holder	1,890,000
Narin Kishinchandani	179,000
William Ross	551,000
Glenn Beaumont	1,088,000
Arunas Pleckaitis	2,898,000
James Grant	1,103,000

Further information about the pension plan is set forth under the heading “Retirement Plan Benefits” of this Schedule.

Executive Employment Agreement

EGD has entered into executive employment agreements with Ms. Holder and Mr. Pleckaitis which provide that should they experience involuntary termination (other than for cause) or constructive dismissal (as defined in the agreement) they will be paid the amounts described in the agreement.

In the event of an involuntary termination, other than for cause, or a voluntary termination by Ms. Holder or Mr. Pleckaitis within 60 days following constructive dismissal, as at December 31, 2010, Ms. Holder and Mr. Pleckaitis would be entitled to the following estimated incremental benefits:

	Base salary[1] ($)	Short-term incentive[2] ($)	Longer-term incentive[3] ($)	Benefits[4] ($)	Pension[5] ($)	Total payout ($)
Janet Holder	800,000	972,500	1,481,322	133,236	403,000	3,790,058
Arunas Pleckaitis	562,720	338,590	677,541	83,118	480,000	2,141,969

1 Amount in this column equals two times the annual salary.
2 Amount in this column equals two times an annual short-term incentive award. For Ms. Holder, the amount was calculated based on the average short-term incentive award paid to other executives of Enbridge in 2008 and 2009. For Mr. Pleckaitis, the amount was calculated based on his short-term incentive awards paid in 2008 and 2009.
3 Amount equals the in-the-money value of un-exercisable stock options as at December 31, 2010 that equals $976,282 for Ms. Holder and $447,007 for Mr. Pleckaitis. It also includes the amounts of $505,040 for Ms. Holder and $230,534 for Mr. Pleckaitis for the performance stock units outstanding at December 31, 2010 assuming they mature and the Enbridge earnings per share multiplier was 1.5 and the price to earnings ratio multiplier was 1.5. For the purposes of these calculations, the closing price of an Enbridge share on December 31, 2010 was $56.27.
4 Amount in this column equals two times the flexible perquisite, employee benefits including health care, dental care and insurance coverage and the value that EGD would have contributed to the savings plan on their behalf. For Ms. Holder, the amount includes $20,000 for financial counseling.
5 This includes the value of two additional years of credited service and age at the assumed date of termination of December 31, 2010.

Change of Control

On a change of control of Enbridge, entitlement to short-term incentive, vesting of stock options, and maturing of performance units is accelerated as set forth below:

Plan	Result
Short-Term Incentive	Pro-rated short-term incentive payment based on service prior to the change of control assuming Corporate Performance at target, business unit performance as determined by Enbridge's President & Chief Executive Officer and individual performance meets requirements.
Stock Options	Unvested stock options conditionally vest not more than 30 days and not less than five days prior to the change of control.
Performance Units	All outstanding units mature 30 days prior to the change of control based on applicable performance measures achieved.

The following outlines the estimated incremental payment of longer-term incentive value in the event of a change of control on December 31, 2010:

Executive	Incremental Longer-Term Incentive Value ($)[1]
Janet Holder	1,481,322
Narin Kishinchandani[2]	301,068
William Ross	529,913
Glenn Beaumont	614,939
Arunas Pleckaitis	677,540
James Grant	456,671

1 Amount equals the in-the-money value of un-exercisable stock options as at December 31, 2010 and the value of the performance stock units outstanding at December 31, 2010. For the purpose of this calculation, a multiplier of 1.5 was applied. The closing price of an Enbridge share on December 31, 2010 was $56.27.

2 Mr. Kishinchandani received restricted stock units in 2010 and 2009 therefore no multiplier was applied for his calculation.

Directors' Compensation

Directors' Compensation Table

The following table sets forth the compensation elements and total compensation earned by each of EGD's directors in consideration for their service on EGD's Board of Directors during the financial year ended December 31, 2010.

Director[1]	Fees Earned[2] ($)	All Other Compensation[3] ($)	Total ($)
J. R. Bird	24,000	-	24,000
J. L. Braithwaite	24,000	2,000	26,000
P. D. Daniel	16,000	-	16,000
D. A. Leslie	27,000	2,000	29,000
S.J.J. Letwin[4]	13,500	500	14,000
D.T. Robottom[5]	2,500	-	2,500

1 Ms. Holder does not receive any compensation for acting as a director of EGD. She is compensated solely for holding the office of President.

2 Fees earned include annual retainers and meeting fees and is discussed in greater detail below. Directors' fees payable to employees of Enbridge who are directors of EGD are paid directly to Enbridge.

3 All other compensation includes an amount for meetings attended outside the director's Province or State of residence and is discussed below.

4 Mr. Letwin was a director of EGD until his resignation on November 1, 2010.

5 Mr. Robottom was appointed as a director of EGD on November 1, 2010.

Directors' Compensation Plan

Directors of EGD other than Ms. Holder are compensated in accordance with a Directors' Compensation policy which became effective in 1997 and was revised in 1998. EGD's Board of Directors is responsible for the development and implementation of the Directors' Compensation policy.

With the exception of the director who serves as EGD's President (currently Ms. Holder) each director receives $15,000 per annum for his services as a director as well as $3,000 per annum for serving as a member of any committee of the Board of Directors and an attendance fee of $1,000 for each board and committee meeting. Directors are also entitled to receive reimbursement for their out-of-pocket travel expenses incurred in connection with board and committee meetings. Directors are also entitled to $500 for meetings attended where the meeting is held outside of the Province or State of residence of such director. In addition, the chair of the Audit, Finance & Risk Committee receives $3,000 per annum for serving as Chair of such committee. The President of EGD does not receive any additional compensation for acting as a director of EGD.

Unlike compensation for the executives, the Directors' Compensation policy is not designed to pay for performance. Rather, directors receive retainers for their services in order to help ensure unbiased decision-making.

BOMA INTERROGATORY #1

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 1

a) Please confirm that the escalation factor approved in EB-2009-0172 for 2010 was 1.50% based on a GDP IPI FDD of 2.73% and an inflation coefficient of 55%.

b) What level would the escalation factor have had to been in 2010 to reduce the normalized return on equity from 11.075% to the benchmark ROE of 8.37%?

RESPONSE

a) The Company confirms that the escalation factor approved in EB-2009-0179 for 2010 was 1.50% based on a GDP IPI FDD of 2.73% and an inflation coefficient of 55%.

b) When the Company uses an ROE of 8.37% in its Revenue Sufficiency Calculation (Exhibit B, Tab 5, Schedule 1), as opposed to 9.37%, the gross revenue sufficiency becomes $54.18 million. To reduce the Approved 2010 Total Revenue of $2,434.26 million (EB-2009-0172, Final Rate Order, Appendix A) by $54.18 million, an escalation factor of (5.23%) would have had to have been used in the 2010 IR formula.

Witnesses: K. Culbert
R. Small

BOMA INTERROGATORY #2

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 1

With the exception of the HST, has EGD made any changes to the way that the earnings sharing amount has been calculated for 2010 from the methodology used for 2009 in EB-2010-0042? If yes, please describe the change(s) and why the change(s) was (were) made.

RESPONSE

EGD has not made any changes and has followed the same calculation process each year to determine the earnings sharing amount, using the prescribed methodology as identified within the EB-2007-0615 Board Approved Settlement Agreement (Exhibit N1, Tab 1, Schedule 1, p. 27).

Witnesses: K. Culbert
R. Small

BOMA INTERROGATORY #3

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 5

Please identify the type of expenses noted in paragraph 14 that total approximately $0.1 million. Is this amount the provincial component of the HST that is not eligible for the tax credit?

RESPONSE

The type of expenses included within the estimated amount are any energy related electricity, gas, fuel or steam operational costs incurred formerly as PST, or now as the provincial component of the HST, that are not eligible for tax credits.

Witnesses: K. Culbert
R. Small

BOMA INTERROGATORY #4

INTERROGATORY

Ref: Exhibit B, Tab 4, Schedule 1, page 8

a) Please explain the positive numbers shown in column 4 for CCA classes 1 and 41.

b) Please confirm that the opening CCA balances shown in column 2 are the actual final ending 2009 utility UCC balances from the 2009 tax return. If this cannot be confirmed, please explain the difference between the opening CCA balances shown here and the UCC Carry Forward figures for 2009 shown in Exhibit B, Tab 4, Schedule 1, page 8 of EB-2010-0042.

RESPONSE

a) The amounts are the result of estimates of the cost of the disposition of assets in the category exceeding any estimated proceeds.

b) The opening UCC balances shown in Column 2 are the actual final utility related 2009 UCC balances resident in the 2009 tax return.

Witnesses: K. Culbert
R. Small

BOMA INTERROGATORY #5

INTERROGATORY

Ref: Exhibit C, Tab 2, Schedule 2, pages 3-4

a) Has EGD made any changes to the allocations of the various deferral and variance accounts to the rate classes from what has been approved by the Board in the past?

b) If the response to part (a) is yes, please explain the allocation change, the rationale for the change and the impact of the change on the various rate classes.

RESPONSE

a) & b) No, EGD has not made any changes to the allocations that have been approved by the Board. However, although the allocation methodology is unchanged, the Company has chosen to present its evidence in the form of two sets of exhibits in order to separately derive unit rates for accounts where GST is applicable and for accounts where HST is applicable.

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

VECC INTERROGATORY #1

INTERROGATORY

References:

Exhibit B Tab 1Schedule 1Appendix A para. 1;
Exhibit C, Tab 1, Schedule 4

a) Provide the original and revised calculations of th impact of HST on Working capital.
b) Provide the details of how an increase of $1.0 million became a reduction of $3.2 million.
c) Show the original and revised calculations of the entries to the TRRCA.
d) Provide the original and revised Impacts on Earnings and Earnings sharing.

RESPONSE

a) & b) The table below shows the GST/HST working cash impacts used within the HST analysis at the time of year end and the completed HST analysis within evidence. In the year end analysis, as stated in Exhibit B, Tab 1, Schedule 1, Appendix A evidence, it was estimated that the annual working cash impact had increased by $2 million, the difference between a $1.8 million GST at 5%, working cash impact within the July 1, 2010 QRAM shown in Column 1 and a $3.8 million recalculation of that amount using an HST rate of 13% shown in Column 2. The analysis assumed an increase in working cash of $1 million in 2010 due to the implementation of HST half way through the year, and $2 million in each of 2011 and 2012 for a full year. That analysis was in error in assuming that HST would be applicable to all gas purchases. Upon completing the analysis, filed in evidence at Exhibit B, Tab 1, Schedule 5, Appendix A, it was determined that some gas purchases would require GST and others would require HST. The impact from this determination on working cash as shown in Column 3, resulted in an annual GST/HST working cash requirement of $(4.6) million. The GST/HST annual working cash impact had decreased by $(6.4) million from the Column 1 GST requirement of $1.8 million. Again, as the $(6.4) million decrease is an annual amount and as a result of HST being implemented half way through the 2010 year, the estimated 2010 GST/HST working cash impact was updated to $(3.2) million and $(6.4) million in each of 2011 and 2012.

Witnesses: K. Culbert
R. Small

Working Cash Requirement	Col. 1 July 1, 2010 QRAM GST $ Millions	Col. 2 Year end Anal. July 1, 2010 QRAM HST for all Items and for all Gas Purchases $ Millions	Col. 3 Revised Anal. July 1, 2010 QRAM HST for all Items and GST/HST for Gas Purchases $ Millions
Revenue	(8.4)	(21.9)	(21.9)
Gas purchases @ GST	8.3	-	7.9
Gas purchases @ HST	-	21.6	5.3
O & M	0.5	1.0	1.0
Capital	1.4	3.1	3.1
Total	1.8	3.8	(4.6)

c) The original calculations of the impact to revenue requirement using the year end analysis results are provided in Appendix A to this response where it is seen on page 1, Column 1, Line 12, that the revenue requirement impact for 2010 was $532 thousand. The original calculated amount to go into the TRRCVA was 50% of that amount, $266 thousand or $0.3 million as quoted in evidence at Exhibit B, Tab 1, Schedule 1, Appendix A, page 1, paragraph1, Line 12. The updated calculation at Ex.B, T1, S5, App.A, pg.1, col.1, line 12, shows the updated revenue requirement impact for 2010 as $907 thousand. The ratepayer 50% share of that amount is $450 thousand or $0.5 million as quoted in evidence at Exhibit B, Tab 1, Schedule 1, Appendix A, page 1, paragraph 1, Line 15, and is what the adjusted entry into the TRRCVA became, Ehibit C, Tab 1, Schedule 4, page 3, Column 3, Line 64.

d) The original before sharing, earnings and earnings sharing calculations were $367 thousand and $532 thousand, shown in Appendix A to this response, at page 1, Column 1,Lines 11 and 12. The revised before sharing, earnings and earnings sharing calculations became $626 thousand and $907 thousand, shown in evidence at Exhibit B, Tab 1, Schedule 5, Appendix A, page 1, Column 1, Lines 11 and 12.

Witnesses: K. Culbert
R. Small

Ontario Utility Capital Structure
HST Implementation/PST Elimination Analysis

		Col. 1	Col. 2	Col. 3
Line No.		Component	Indicated Cost Rate	Return Component
		%	%	%
1.	Long-term debt	59.65	7.31	4.36
2.	Short-term debt	1.68	4.12	0.07
3.		61.33		4.43
4.	Preference shares	2.67	5.00	0.13
5.	Common equity	36.00	8.39	3.02
6.		100.00		7.58

	($000's)	2010	2011	2012
7.	Ontario Utility Income	387.2	902.0	1,032.5
8.	Rate base	264.6	(3,653.2)	(8,889.2)
9.	Indicated rate of return	146.30 %	(24.69)%	(11.62)%
10.	(Def.) / suff. in rate of return	138.72 %	(32.27)%	(19.20)%
11.	Net (def.) / suff.	367.1	1,178.9	1,706.7
12.	Gross (def.) / suff.	532.0	1,643.1	2,314.2

Ontario Utility Rate Base
HST Implementation/PST Elimination Analysis

($000's)

Line No.		2010	2011	2012
	Property, plant, and equipment			
1.	Cost or redetermined value	(713.0)	(5,703.7)	(11,407.4)
2.	Accumulated depreciation	5.1	160.5	628.2
3.		(707.9)	(5,543.2)	(10,779.2)
	Allowance for working capital			
4.	Accounts receivable merchandise finance plan	-	-	-
5.	Accounts receivable rebillable projects	-	-	-
6.	Materials and supplies	-	-	-
7.	Mortgages receivable	-	-	-
8.	Customer security deposits	-	-	-
9.	Prepaid expenses	(27.5)	(110.0)	(110.0)
10.	Gas in storage	-	-	-
11.	Working cash allowance	1,000.0	2,000.0	2,000.0
12.		972.5	1,890.0	1,890.0
13.	Ontario utility rate base	264.6	(3,653.2)	(8,889.2)

Ontario Utility Income
HST Implementation/PST Elimination Analysis

Line No.	($000's)	2010	2011	2012
	Revenue			
1.	Gas sales	-	-	-
2.	Transportation of gas	-	-	-
3.	Transmission and compression	-	-	-
4.	Other operating revenue	-	-	-
5.	Other income	-	-	-
6.	Total revenue	-	-	-
	Costs and expenses			
7.	Gas costs	-	-	-
8.	Operation and Maintenance	(601.8)	(1,203.5)	(1,203.5)
9.	Depreciation and amortization	(33.4)	(307.3)	(628.0)
10.	Municipal and other taxes	-	-	-
11.	Total costs and expenses	(635.2)	(1,510.8)	(1,831.5)
12.	**Utility income before inc. taxes**	635.2	1,510.8	1,831.5
	Income taxes			
13.	Excluding interest shield	251.6	563.1	695.6
14.	Tax shield on interest expense	(3.6)	45.7	103.4
15.	Total income taxes	248.0	608.8	799.0
16.	**Ontario utility net income**	387.2	902.0	1,032.5

Ontario Utility Taxable Income and Income Tax Expense
HST Implementation/PST Elimination Analysis

($000's)

Line No.		2010	2011	2012
1.	Utility income before income taxes	635.2	1,510.8	1,831.5
	Add Backs			
2.	Depreciation and amortization	(33.4)	(307.3)	(628.0)
3.	Large corporation tax	-	-	-
4.	Other non-deductible items	-	-	-
5.	Any other add back(s)	-	-	-
6.	Total added back	(33.4)	(307.3)	(628.0)
7.	Sub total - pre-tax income plus add backs	601.8	1,203.5	1,203.5
	Deductions			
8.	Capital cost allowance - Federal	(209.8)	(790.0)	(1,446.4)
9.	Capital cost allowance - Provincial	(209.8)	(790.0)	(1,446.4)
10.	Items capitalized for regulatory purposes	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-
12.	Amortization of share and debt issue expense	-	-	-
13.	Amortization of cumulative eligible capital	-	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-
15.	Any other deduction(s)	-	-	-
16.	Total Deductions - Federal	(209.8)	(790.0)	(1,446.4)
17.	Total Deductions - Provincial	(209.8)	(790.0)	(1,446.4)
18.	Taxable income - Federal	811.5	1,993.5	2,649.9
19.	Taxable income - Provincial	811.5	1,993.5	2,649.9
20.	Income tax provision - Federal	146.1	328.9	397.5
21.	Income tax provision - Provincial	105.5	234.2	298.1
22.	Income tax provision - combined	251.6	563.1	695.6
23.	Part V1.1 tax	-	-	-
24.	Investment tax credit	-	-	-
25.	Total taxes excluding tax shield on interest expense	251.6	563.1	695.6
	Tax shield on interest expense			
26.	Rate base as adjusted	264.6	(3,653.2)	(8,889.2)
27.	Return component of debt	4.43%	4.43%	4.43%
28.	Interest expense	11.7	(161.8)	(393.8)
29.	Combined tax rate	31.000%	28.250%	26.250%
30.	Income tax credit	(3.6)	45.7	103.4
31.	**Total income taxes**	248.0	608.8	799.0

Ontario Utility Revenue Requirement
HST Implementation/PST Elimination Analysis

($000's)

Line No.		2010	2011	2012
	Cost of capital			
1.	Rate base	264.6	(3,653.2)	(8,889.2)
2.	Required rate of return	7.58%	7.58%	7.58%
3.	Cost of capital	20.1	(276.9)	(673.8)
	Cost of service			
4.	Gas costs	-	-	-
5.	Operation and Maintenance	(601.8)	(1,203.5)	(1,203.5)
6.	Depreciation and amortization	(33.4)	(307.3)	(628.0)
7.	Municipal and other taxes	-	-	-
8.	Cost of service	(635.2)	(1,510.8)	(1,831.5)
	Misc. & Non-Op. Rev			
9.	Other operating revenue	-	-	-
10.	Other income	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-
	Income taxes on earnings			
12.	Excluding tax shield	251.6	563.1	695.6
13.	Tax shield provided by interest expense	(3.6)	45.7	103.4
14.	Income taxes on earnings	248.0	608.8	799.0
	Taxes on (def) / suff.			
15.	Gross (def.) / suff.	532.0	1,643.1	2,314.2
16.	Net (def.) / suff.	367.1	1,178.9	1,706.7
17.	Taxes on (def.) / suff.	(164.9)	(464.2)	(607.5)
18.	**Revenue requirement**	(532.0)	(1,643.1)	(2,313.8)
	Revenue at existing Rates			
19.	Gas sales	0.0	0.0	0.0
20.	Transportation service	0.0	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0	0.0
22.	Rounding adjustment	0.0	0.0	0.4
23.	Revenue at existing rates	0.0	0.0	0.4
24.	**Gross revenue (def.) / suff.**	532.0	1,643.1	2,314.2

VECC INTERROGATORY #2

INTERROGATORY

References:

Exhibit B Tab 1Schedule 1Appendix A para. 2;
Exhibit B, Tab 1, Schedule 7

a) Provide the CAM amounts for 2007-2010.
b) Explain the process used in setting CAM amounts/.budgets. Confirm the agreed 2010 amount between EGDI and Enbridge Inc was $36.7 million (para 2).
c) Explain why the extracted CAM amounts did not reconcile with the $36.7 m amount agreed to in the 2010 Budget Process.(para 2).
d) How can EGDI and intervenors be sure that the revised 2010 CAM amount is correct? Provide a summary of the documentation between EGDI and Enbridge regarding setting of the 2010 CAM amount.

RESPONSE

a)

(000's)	2010	2009	2008	2007
CAM	$36.7M	$34.2M	$32.2M	$27.7M

b) The setting of Corporate Cost allocations is undertaken by Enbridge Inc. ("EI"). EI goes through a rigorous budget process to set CAM and after multiple levels of review CAM is allocated to the Company by EI. The amount of CAM in 2010 was $36.7M.

c) Please refer to EB-2011-0008, Exhibit B, Tab 1, Schedule 7, page 2, #4.

d) The Company reviewed its accounts on a detailed basis after 2010 year-end to confirm all amounts paid in respect of CAM. In particular, the Company did a full reconciliation between the general ledger and the budgeted amounts by cost center and natural account to ensure all CAM amounts were extracted from the financial systems. The Company received a forecast of the CAM amount from EI before the 2010 year began, and then received periodic updated forecasts as to amounts actually charged.

Witnesses: K. Culbert
R. Lei
L. Liauw

VECC INTERROGATORY #3

INTERROGATORY

References:

Exhibit B Tab 1 Schedule 3 Page 2 Paragraph 1b)
Exhibit B Tab 2 Schedule 2 Page 1Line 8

a) Provide actual LPP revenue for 2007-2010.
b) Provide an explanation for the 2010 LPP variance, including any changes in policy.
c) Provide an explanation of the increase in customer security deposits 2009-2010
d) Discuss proposed changes to customer service rules and the potential impact on LPP revenue and Security Deposits 2011-2012.

RESPONSE

a) Actual LPP

	2010 Historical Over/(Under) 2009 Historical ($Millions)	2010 Historical ($Millions)	2009 Historical ($Millions)	2008 Historical	2007 Historical
Late Payment Penalties	(0.9)	13.1	14.0	12.0	11.1

b) LPP revenue has declined with improvements in the economy.

c) The increase is predominantly due to an enhanced level of enforcement of the Mass Market security deposit policy starting in early 2009. Security deposits are held until the customer has demonstrated two years of good payment history with EGD. Therefore, an increased level of security deposit amounts was collected during 2009 and 2010, of which none would be eligible for refund to the customer until early 2011, at the earliest. This led to an increase in the security deposits 2009-2010.

Witnesses: K. Culbert
R. Small

Also in 2009, EGD began to identify credit risk with respect to several of its Large Volume customers given the economic downturn experienced in late 2008. In some cases, the risk mitigation strategy required collection of a cash security deposit that had not previously been provided.

d) EGD has filed comments and material related to the Board's Consultation on Customer Service Standards for Natural Gas Distributors, proceeding, EB-2010-0280. As this remains an open docket before the Board, it would be presumptuous for the Company to speculate on any impact that may result on the LPP revenue or the level of security deposits in future periods.

Witnesses: K. Culbert
R. Small

VECC INTERROGATORY #4

INTERROGATORY

References:

Exhibit B Tab 1 Schedule 6 Appendix I Storage Activities:
Exhibit B Tab 1 Schedule 6 Appendix II Allocation of Storage O&M Costs

a) Provide a list of the cost drivers/allocators used to allocate costs between unregulated and regulated storage.
b) Compare to Unions cost allocators.
c) Provide the physical amounts of capacity and volumes associated with regulated and unregulated storage.
d) Describe how the O&M amounts shown in Appendix I for unregulated storage are calculated and show how the percentage of O&M allocated to regulated and unregulated storage is estimated relative to the physical attributes of each.
e) Is there a Board Approved methodology for storage cost allocation? If so point to the Board Decision(s).

RESPONSE

a) The driver behind the allocation of O&M costs between the regulated and unregulated gas storage operations is the proportional share of the total storage capacity that is required by each operation. Costs have been allocated using a combination of an effective demand charge and a commodity charge. The proportion of any particular cost that is allocated by each of these is based upon the degree to which the cost varies with injection/withdrawal activity. Appendix II is an example of this and shows the classification of the various costs elements of the gas storage maintenance costs for the month of January 2011.

The demand portions are shared based upon the relative levels of Annual Turnover Capacity ("ATV") of the two operations and the commodity portion is shared based upon actual injection/withdrawal activity for each particular month.

b) The Company has reviewed Union's cost allocation materials but, not being involved in their operation, EGD does not feel qualified to comment on them in detail. Union's situation was different from EGD's at the time of the NGEIR

Witnesses: K. Culbert
B. Pilon

Decision and their methodology seems to address a number of things not pertinent to Enbridge.

c) Currently Enbridge is operating a total of 110 Bcf of Annual Turnover Capacity to service both its regulated and unregulated storage operations. Of this amount, 98 Bcf, or about 89 percent of the total, is committed to the utility with the balance available, and/or contracted, to the unregulated storage market.

d) There are several components to the O&M costs of the unregulated storage activity. The first line identified in Appendix I is the direct cost of Unregulated Storage O&M and is composed of the staff and other direct costs that are charged to a cost centre that is specific to the unregulated storage business. This includes the management and administration costs that are required for, and dedicated to, the unregulated activity.

The next three lines show amounts that make up the costs that are allocated from the total storage operation to the unregulated storage business. Appendix II is intended to illustrate some of the detail behind that allocation process. Again, this example is based on the January 2011 costs for storage maintenance.

The Labour and Overheads line in Appendix I is the amount of labour cost that has been allocated based upon the relative shares of both ATV and withdrawal capacity that are available to the unregulated storage operations. The costs include corporate A&G overhead amounts.

The second and third lines show the amounts of non-labour operating, maintenance and administration costs that have been allocated to the unregulated storage activity from the total storage operation.

e) Enbridge's allocation of storage costs as agreed to within Fiscal 2009 or EB-2010-0042 used a similar methodology as Enbridge has used and explained in the current proceeding. There has been no explicit Board approval of this methodology but the resulting costs were approved for 2010.

Enbridge has developed the allocation methodology that it is using based upon a review of the costs and cost drivers that underlie storage operations. Costs have been classified as annual or commodity based on an understanding of the specific cost behaviours. Most costs are relatively fixed however there are some such as overtime labour, hydro usage, and some maintenance activities, that are more activity driven and so they are shared based upon the relative shares of actual activity levels of the regulated and unregulated storage operations in each month.

Witnesses: K. Culbert
B. Pilon

VECC INTERROGATORY #5

INTERROGATORY

Reference: Exhibit B Tab 4 Schedule 2 Page 1

a) Provide (more) explanations for the following material changes:
   i. Customer Care Service Charges (line 3)
   ii. Information Technology (line 9)
   iii. Public and Government Affairs (line 14)
   iv. Corporate Allocations (line 16)

   For each variance indicate the 2011 estimate and indicate whether the 2011 level of expense will continued in 2012.

b) Confirm the Corporate Allocations figure shown in the 2007 column is the RCAM amount. Provide the actual 2007 CAM amount.

RESPONSE

a)
i. Costs related to the old customer information system (old CIS) were housed in the Customer Care department in 2009. However with the implementation of a new customer information system (new CIS) in September 2009, there were no old CIS fees incurred in the Customer Care department after this date. New CIS fees were moved to the Information Technology department.

ii. New CIS costs are housed in the Information Technology department. In 2009 there was three months worth of costs compared to a full year of costs in 2010.

iii. The Ombudsman Office was previously located in the Customer Care department, however, to elevate the profile of the Ombudsman function it was relocated to the Public and Government Affairs department. The Customer Relationship Study was conducted by the Business Development and Customer Strategy department in 2009, however, was transferred to the Public and Government Affairs department in 2010 resulting in increased costs to this group (equally offset by a decrease in the Business Strategy and Customer Strategy department). These

Witnesses: R. Lei
A. Patel

reorganizations also resulted in additional administration staff and a resulting increase in costs.

iv. Primarily due to increases related to the following:
- Stock Based Compensation
- Human Resource Information System (HRIS) Service Allocations
- Corporate HR Allocations
- Corporate Secretarial Legal Fee Allocations

The Company cannot provide an estimate for 2011or 2012 as this information is not available at this time.

b) The 2007 amount of $18.1M is RCAM. Actual 2007 CAM was $27.7M.

Witnesses: R. Lei
A. Patel

VECC INTERROGATORY #6

INTERROGATORY

Reference: Exhibit B Tab 4 Schedule 2 Page 3 para. 16

a) Provide a breakdown and explanation of the $2.9 m compensation-related Increase in CAM for 2010. Include Stock Based Compensation amounts, both the Performance Stock Unit (PSU) Plan and the Restricted Stock Unit (RSU) Plan, and number(s) of participants and average payments.
b) Compare to 2007 and 2008 and 2009 including relevant explanations regarding stock/strike price changes.
c) Provide the estimates for SBC costs for 2011 and 2012.

RESPONSE

The $2.9M increase in compensation-related CAM costs is driven by an increase in Stock Based Compensation ("SBC") costs, and other items. Specifically the increase related to SBC was $1.0M. Other variances were due to an increase in Human Resource Information System ("HRIS") Service allocations, an increase in Corporate HR allocations, and an increase in Corporate Secretarial Legal Fee allocations.

a)

(000's)	2010	2009	Variance
ISOs	1.0	1.3	(0.3)
PSUs	1.0	2.6	(1.6)
RSUs	3.6	1.1	2.5
Indirect	4.7	4.3	0.4
Total	10.3	9.3	1.0

Witnesses: R. Lei
A. Patel

b)

(000's)	2009	2008	2007
ISOs	1.3	1.1	1.1
PSUs	2.6	2.3	1.0
RSUs	1.1	1.0	0.3
Indirect	4.3	3.4	1.5
Total	9.3	7.6	3.9

Strike Price

	2010	2009	2008	2007
ISOs	46.59	39.61	40.42	38.26

Note: Strike Price is only applicable to ISOs.

The strike price is based on the fair market value as detailed below.

The 2007 strike price of the stock option grant was based on the last board lot sale price of common shares of the Corporation on the Toronto Stock Exchange on the last trading day immediately prior to the grant date.

The strike price of the 2008, 2009, and 2010 stock option grants were based on the weighted average trading price of an Enbridge share on the Toronto Stock Exchange for the last five trading days before the grant date. If the grant date was during a trading blackout period, Enbridge adjusted the grant date to no earlier than the sixth trading day after the trading blackout period ended. Enbridge does not backdate stock options.

c) The Company is unable to provide a projection of 2011 and 2012 SBC costs as there are a number of determinants required for such projections which cannot be reasonably estimated.

Witnesses: R. Lei
A. Patel

VECC INTERROGATORY #7

INTERROGATORY

Reference: Exhibit A Tab 2 Schedule1 Appendix A

a) Provide a list of the accounts and associated balances that have already undergone a formal Board review process and have obtained Board approval. Include references.

RESPONSE

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

Witnesses: K. Culbert
R. Small

VECC INTERROGATORY #8

INTERROGATORY

Reference: :Exhibit A, Tab 2,Schedule 1, Appendix A, Page 1 lines 9 and 10

a) Provide details of the calculation of the amounts and balances in the 2009/2010 OBSDA and OBAVA.
b) Relate the balances to be disposed of to the EB-2009-0043 Settlement Agreement.

RESPONSE

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

Witnesses: K. Culbert
R. Small

VECC INTERROGATORY #9

INTERROGATORY

References:

Exhibit A, Tab 2 Schedule 1, Appendix A, Page 1
Exhibit C Tab 2 Schedule 2 Page 2 of 6;

a) For non-PGVA accounts (lines 2-19) indicate the Year(s) for which the balances were accumulated.
b) Provide a version that shows the 2009 opening and closing balances, interest and total for each account.

RESPONSE

a) In reference to Exhibit C, Tab 2, Schedule 2, page 2, which details the amounts being requested for clearance, all lines relate to 2010 approved deferral accounts and represent balances accumulated for 2010, with the following noted exceptions:

- Lines 5, 6, and 7, the 2009 DSMVA, LRAM, and SSMVA, represent balances related to 2009 DSM activities. The 2009 DSMVA, LRAM and SSMVA amounts were recorded in 2010 once it was determined that required conditions were met and or following the annual DSM audit and settlement negotiations with the DSM consultative.

- Line 8 represents the 2011 installment of the approved CASDA recovery. CASDA costs incurred between 2005 and 2007 were approved for recovery over five years, 2008 through 2012, in EB-2007-0731.

- Line 10 represents the 2011 revenue requirement that results from amounts recorded in the 2007, 2008, 2009 and 2010 GDARCDA accounts.

- Line 14 represents the 2011 revenue requirement that results from amounts recorded in the 2008, 2009 and 2010 MPFDA accounts.

Witnesses: K. Culbert
J. Collier
A. Kacicnik
M. Suarez-Sharma

- Line 15 represents the requested recovery of the 2011 ratepayer share of the 2009 OBSDA balance. As approved in the EB-2009-0043 proceeding. plus incremental costs incurred in 2009 and approved in EB-2010-0042, would be shared equally between the Company and ratepayers and be cleared over a three year period beginning in 2010.

- Line 16 represents the requested recovery of the 2011 ratepayer share of the 2009 OBAVA balance. As approved in the EB-2009-0043 proceeding, the 2008 OBAVA balance (transferred to the 2009 account) would be shared equally between the Company and ratepayers and be cleared over a three year period beginning in 2010.

b) The table on the following page provides the requested account balance information (assuming 2010 information was requested not 2009 information which was provided last year). As noted in the response to part a), in some instances the account balances shown in the table are not the amounts requested for clearance as explained in the notes in Exhibit A, Tab 2, Schedule 1, Appendix A, page.1.

Witnesses: K. Culbert
J. Collier
A. Kacicnik
M. Suarez-Sharma

ENBRIDGE GAS DISTRIBUTION INC. DEFERRAL & VARIANCE ACCOUNT ACTUAL BALANCES

Line No.	Account Description	Account Acronym	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
			Actual at January 1, 2010			Actual at December 31, 2010			Actual at February 28, 2011		
			Principal ($000's)	Interest ($000's)	Total ($000's)	Principal ($000's)	Interest ($000's)	Total ($000's)	Principal[3] ($000's)	Interest ($000's)	Total ($000's)
	Non Commodity Related Accounts										
1.	Demand Side Management V/A	2009 DSMVA	-	-	-	1,165.1	4.4	1,169.5	1,165.1	7.2	1,172.3
2.	Lost Revenue Adjustment Mechanism	2009 LRAM	-	-	-	(45.7)	-	(45.7)	(45.7)	(0.1)	(45.8)
3.	Shared Savings Mechanism V/A	2009 SSMVA	-	-	-	5,364.2	-	5,364.2	5,364.2	13.1	5,377.3
4.	Class Action Suit D/A	2011 CASDA	18,838.2	1,517.1	20,355.3	14,128.6	1,227.6	15,356.2	9,419.1	806.4	10,225.5 [1, 2]
5.	Deferred Rebate Account	2010 DRA	-	-	-	2,176.8	12.7	2,189.5	(2,387.1)	12.4	(2,374.7) [3]
6.	Gas Distribution Access Rule Costs D/A	2010 GDARCDA	-	-	-	132.7	0.6	133.3	132.7	0.9	133.6
7.	Ontario Hearing Costs V/A	2010 OHCVA	-	-	-	92.6	-	92.6	92.1	0.2	92.3 [4]
8.	Unbundled Rate Implementation Cost D/A	2010 URICDA	-	-	-	144.1	0.2	144.3	144.1	0.6	144.7
9.	Open Bill Service D/A	2011 OBSDA	539.4	15.4	554.8	438.5	16.2	454.7	336.2	14.2	350.4 [1, 5]
10.	Open Bill Access V/A	2011 OBAVA	476.7	5.4	482.1	397.2	7.7	404.9	304.5	7.3	311.8 [1, 5]
11.	Municipal Permit Fees D/A	2010 MPFDA	-	-	-	901.6	-	901.6	901.6	-	901.6
12.	Average Use True-Up V/A	2010 AUTUVA	-	-	-	(2,145.2)	-	(2,145.2)	(2,145.2)	(5.3)	(2,150.5)
13.	Tax Rate and Rule Change V/A	2010 TRRCVA	-	-	-	704.0	-	704.0	704.0	1.7	705.7
14.	Earnings Sharing Mechanism D/A	2010 ESMDA	-	-	-	(18,500.0)	-	(18,500.0)	(18,500.0)	(45.3)	(18,545.3)
15.	IFRS Transition Costs D/A	2010 IFRSTCDA	-	-	-	2,080.6	10.1	2,090.7	2,080.6	15.2	2,095.8
16.	Ex-Franchise Third Party Billing Services D/A	2010 EFTPBSDA	-	-	-	(251.9)	-	(251.9)	(251.9)	(0.6)	(252.5)
17.	Total non commodity related accounts		19,854.3	1,537.9	21,392.2	6,783.2	1,279.5	8,062.7	(2,685.7)	827.9	(1,857.8)
	Commodity Related Accounts										
18.	Transactional Services D/A	2010 TSDA	-	-	-	(7,264.5)	(10.9)	(7,275.4)	(7,264.5)	(28.7)	(7,293.2)
19.	Unaccounted for Gas V/A	2010 UAFVA	-	-	-	8,729.4	-	8,729.4	8,729.4	21.4	8,750.8
20.	Storage and Transportation D/A	2010 S&TDA	-	-	-	(531.8)	(0.4)	(532.2)	(531.8)	(1.7)	(533.5)
21.	Total commodity related accounts		-	-	-	933.1	(11.3)	921.8	933.1	(9.0)	924.1
22.	Total Deferral and Variance Accounts		19,854.3	1,537.9	21,392.2	7,716.3	1,268.2	8,984.5	(1,752.6)	818.9	(933.7)

Notes:

1. The actual balances shown at January 1 and December 31, 2010 for the 2011 CASDA, OBSDA, and OBAVA accounts are shown to illustrate the continuity of account balances. However, within the Company's financial records, the January 1, 2010 balances were recorded in 2009 CASDA, OBSDA, and OBAVA accounts while the December 31, 2010 balances were recorded in 2010 CASDA, OBSDA, and OBAVA accounts. This is in accordance with Board Orders which have required uncleared balances to be rolled forward into corresponding accounts for the following year.
2. The February 28, 2011 principal balance, and to a large extent the interest balance, in the 2011 CASDA differs from December 31, 2010 balances as a result of the clearance of the 2010 (or 3rd) installment which occurred in January 2011. The CASDA balance is being cleared over five years as approved in EB-2007-0731.
3. The February 28, 2011 principal balance in the 2010 DRA differs from December 31, 2010 balance as a result of the clearance of the 2009 deferral and variance accounts which occurred in January 2011.
4. The February 28, 2011 principal balance in the 2010 OHCVA differs from December 31, 2010 balance as a result of the true-up of year end accruals..

VECC INTERROGATORY #10

INTERROGATORY

Reference: Exhibit B Tab 3 Schedule1 pages 3 and 4

a) What is EGDs Plan for review of the details of the transactions and revenue related to the 2010 TSDA?
b) Provide the composition of the TS and TSDA amounts and the basis for the adjustment to utility revenue.
c) Compare/contrast to 2009.

RESPONSE

a) The planned review of details of the transactions and revenue related to the 2010 TSDA is through interrogatories to be asked and responded to throughout this EB-2011-0008 process which follows the same process used within each of the previous 2008 and 2009 deferral account review proceedings.

b) The composition of the amounts within the TSDA and the determination of adjustment required to utility revenue are provided on page 2 of this response.

c) The amount of transactional service activity and revenue generated each year is a function of various market conditions specific to that year.

Witnesses: K. Culbert
D. Small
R. Small

2010	Storage Optimization	Transportation Optimization	Total Revenue
	$(000's)	$(000's)	$(000's)
Net Revenue	8,960.6	9,599.9	18,560.5
Rate Payer - %	90.00%	75.00%	
Rate Payer - $(000's)	8,064.5	7,199.9	15,264.5
Amount Included in Rates			(8,000.0)
Amount Transferred to TSDA			7,264.5
Utility Revenue (EB-2011-0008 Exhibit B, T3, S1, pg 3, line 11)			11,296.0
Transactional Service Elimination - EGD Incentive (EB-2011-0008 Exh. B, T3, S1, pg 4, line 11)			3,296.0

Witnesses: K. Culbert
D. Small
R. Small

VECC INTERROGATORY #11

INTERROGATORY

Reference: Exhibit C, Tab 1 Schedule 5 Page 3 of 3 plus Appendix A

a) Provide details of the 2010 Weather.
b) Provide the calculation of normalized volumes for Residential Rate 1 and Rate 6.
c) Compare to Budget/forecast.
d) Reconcile to 2010 Rate 1 AUTVA calculation.

RESPONSE

a) The 2010 Budget volumes reflect the meter reading heating degree days forecast for the Central Region of 3,546.[1] Meter reading heating degree days are acquired by amalgamating Gas Supply heating degree days with the billing schedules. The 2010 actual meter reading heating degree days for the Central Region were 3,454, or 92 degree days lower than budget. The majority of the decrease in degree days was attributable to significantly warmer than normal weather during the major heating and shoulder months.[2] In particular, 2010 experienced the third lowest degree days during the major heating and shoulder months since 1983 as shown in Figure 1. The 2010 actual meter reading heating degree days for both Eastern and Niagara Regions were 3,979 and 3,316, respectively. They were all lower than their corresponding budget degree days of 4,390 and 3,433, respectively.

b) The General Service normalization[3] is conducted on customer groups known as revenue class; that is, within the six regions of the Company's franchise area, by thirteen revenue classes, and three gas service types. These customer grouping numbers are then aggregated and consolidated into the reported Rate 1 and Rate 6 normalized volumes. Therefore, it would be difficult to display 234 calculations (i.e., 234 =13 revenue classes x 3 gas service types x 6 regions). As a result, in order to demonstrate the calculation for as many customers as clearly and as simple as possible, Tables 1 and 2 illustrate a calculation for revenue classes 20 and 48 within the Central Weather Zone by consolidating four Greater Toronto Area regions which

[1] Please refer to EB-2009-0172, Exhibit B, Tab 1, Schedule 6, Page 1.
[2] Major heating months are usually referred to the coldest months of the year, i.e. November-March. Major shoulder months are typically indicated to the first month right after the heating season and the light-up season, i.e. April and October.
[3] Please refer to the 2010 Gas Volume Budget Evidence at EB-2009-0172, Exhibit B, Tab 1, Schedule 5, Pages 42-45 for the detailed description of the normalization methodology.

account for 67% and 70% of the total 2010 actual Rate 1 and Rate 6 customers, respectively. Table 3 provides a description of the revenue class grouping. Tables 4 and 5 present a reconciliation of the normalized volumes between the customers grouping level and rate classes.

Figure 1: Historical Actual Meter Reading Degree Days - Major Heating and Shoulder Months

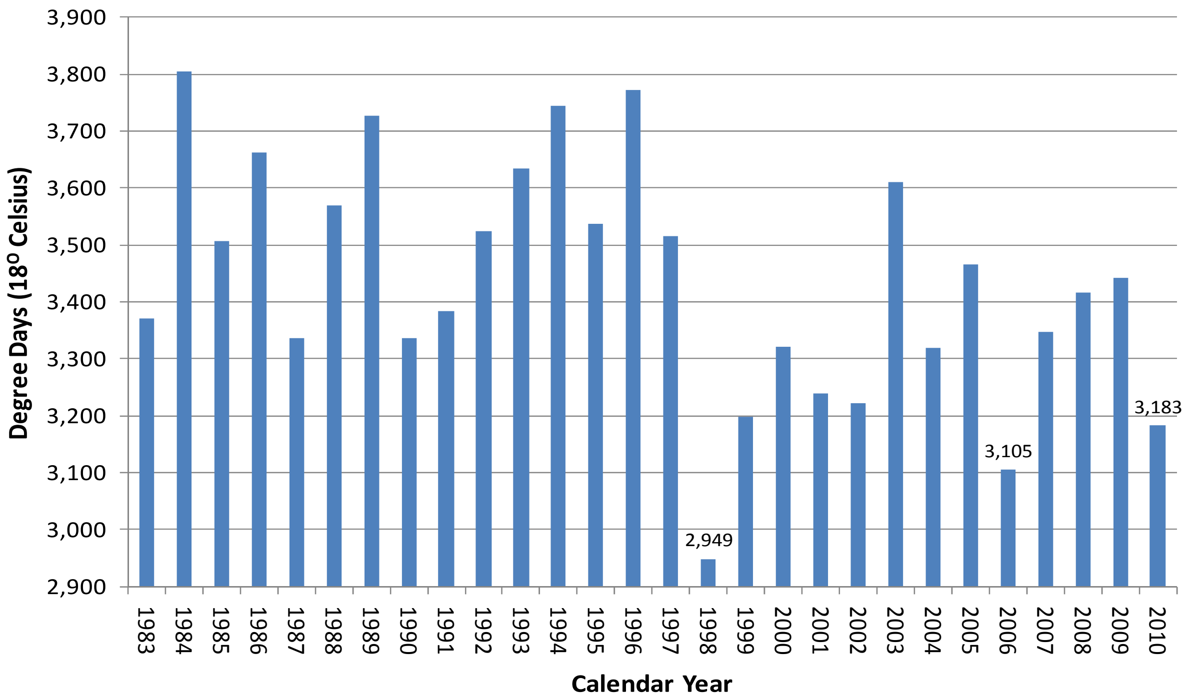


TABLE 1 - NORMALIZATION VOLUMES CALCULATION FOR CENTRAL ZONE, REVENUE CLASS 20, AND SALES

	Col. 1	Col. 2	Col. 3 = Col. 1*1000000/Col. 2	Col. 4	Col. 5 = Col. 4 * Col. 2/1000000	Col. 6 = Col. 3 - Col. 4	Col. 7	Col. 8	Col. 9 = Col. 6/Col. 7 * Col. 8	Col. 10 = Col. 9 *Col. 2/1000000	Col. 11 = Col. 10 + Col. 5
	Actual Volumes (10^6m^3)	Unlocks	Total Actual Use per Unlocks (m^3)	Actual Baseload Use Per Customer (m^3)	Baseload Volumes (10^6m^3)	Actual Heatload Use Per Customer (m^3)	Actual Balanced Point Degree Days	Budget Balanced Point Degree Days	Normalized Heatload Use per Customer (m^3)	Normalized Heatload Volumes (10^6m^3)	Total Normalized Volumes (10^6m^3)
Jan	381.1	808,278	471	201	162	271	594	546	249	201	363.3
Feb	376.8	812,225	464	160	130	304	568	553	296	241	370.5
Mar	283.4	817,731	347	87	71	259	398	464	303	248	319.0
Apr	182.4	824,802	221	59	49	162	214	282	213	176	224.9
May	121.5	823,321	148	80	66	68	109	127	79	65	130.8
Jun	62.5	827,488	76	76	63	0	21	11	0	0	62.5
Jul	41.8	834,648	50	50	42	0	1	0	0	0	41.8
Aug	44.7	839,893	53	53	45	0	0	0	0	0	44.7
Sep	50.3	846,494	59	59	50	0	5	0	0	0	50.3
Oct	88.4	849,999	104	73	62	31	75	62	26	22	83.6
Nov	174.2	858,233	203	164	141	39	227	215	37	31	172.5
Dec	322.4	865,697	372	194	168	179	449	404	161	139	306.9
Total	2,129.5	834,067			87		2,659	2,663		1,123	2,170.8

Reconciled to Table 4 Aggregate Sum of Items 1.19+1.22 +1.25+1.28

TABLE 2 - NORMALIZATION VOLUMES CALCULATION FOR CENTRAL ZONE, REVENUE CLASS 48, AND SALES

	Col. 1	Col. 2	Col. 3 = Col. 1*1000000/Col. 2	Col. 4	Col. 5 = Col. 4 * Col. 2/1000000	Col. 6 = Col. 3 - Col. 4	Col. 7	Col. 8	Col. 9 = Col. 6/Col. 7 * Col. 8	Col. 10 = Col. 9 *Col. 2/1000000	Col. 11 = Col. 10 + Col. 5
	Actual Volumes (10^6m^3)	Unlocks	Total Actual Use per Unlocks (m^3)	Actual Baseload Use Per Customer (m^3)	Baseload Volumes (10^6m^3)	Actual Heatload Use Per Customer (m^3)	Actual Balanced Point Degree Days	Budget Balanced Point Degree Days	Normalized Heatload Use per Customer (m^3)	Normalized Heatload Volumes (10^6m^3)	Total Normalized Volumes (10^6m^3)
Jan	185.9	79,253	2,346	523	41	1,823	594	546	1,674	133	174.2
Feb	204.9	80,682	2,540	407	33	2,133	568	553	2,079	168	200.6
Mar	156.1	81,445	1,917	234	19	1,683	398	464	1,965	160	179.1
Apr	100.2	81,892	1,223	239	20	984	214	282	1,297	106	125.8
May	32.2	81,394	396	117	10	279	109	127	325	26	36.0
Jun	29.5	81,835	361	361	30	0	21	11	0	0	29.5
Jul	19.3	81,171	238	238	19	0	1	0	0	0	19.3
Aug	21.3	80,358	265	265	21	0	0	0	0	0	21.3
Sep	28.6	79,530	359	359	29	0	5	0	0	0	28.6
Oct	41.9	79,096	529	319	25	210	75	62	172	14	38.9
Nov	85.6	79,511	1,076	388	31	689	227	215	654	52	82.8
Dec	191.9	80,233	2,392	509	41	1,883	449	404	1,694	136	176.8
Total	1,097.5	80,533			27		2,659	2,663		795	1,112.8

Reconciled to Table 5 Aggregate Sum of Items 2.19+2.22 +2.25+2.28

TABLE 3 - REVENUE CLASS DESCRIPTION

Revenue Class Group	Revenue Class Description	Rate Class
10	Residential Space Heating And Other Uses	1
12	Apartment Space Heating And Other Uses	6
20	Residential Space Heating, Water Heating And Other Uses	1
48	Commercial Space Heating, Water Heating And Other Uses	6
50	Residential Space Heating, Water Heatnig, Pool Heating, And Other Uses	1
60	Residential Non Heating And Other Uses	1
61	Residential Water Heating And Other Uses	1
73	Industrial Space Heating, Water Heating And Other Uses	6
79	Commerical Non Heating And Other Uses	6
83	Industrial Non Heating And Other Uses	6
86	Apartment Non Heating, Water Heating, Pool Heating, And Other Uses	6
90	Commerical Space Heating, Pool Heating, Water Heating, And Other Uses	6
97	Natural Gas Vehicle Retail Stations	9

TABLE 4 - RECONCILIATION BETWEEN CUSTOMER GROUPING LEVEL AND RATE CLASS VOLUMES AND METERS - RATE 1

Item No.	Revenue Class*	Region	Gas Service Type	Normalized Volumes (10^6m^3)	Customer Meters
1.1	10	Metro	Sales	44.4	24,457
1.2	10	Metro	Ontario Transportation	7.8	2,985
1.3	10	Metro	Western Transportation	4.7	2,408
1.4	10	Western	Sales	28.4	11,769
1.5	10	Western	Ontario Transportation	5.4	2,194
1.6	10	Western	Western Transportation	4.7	1,953
1.7	10	Central	Sales	32.2	16,122
1.8	10	Central	Ontario Transportation	5.9	3,035
1.9	10	Central	Western Transportation	4.5	2,427
1.10	10	Northern	Sales	63.0	25,875
1.11	10	Northern	Ontario Transportation	10.4	4,410
1.12	10	Northern	Western Transportation	8.1	3,653
1.13	10	Eastern	Sales	51.0	22,888
1.14	10	Eastern	Ontario Transportation	9.7	4,541
1.15	10	Eastern	Western Transportation	3.7	1,706
1.16	10	Niagara	Sales	12.0	6,411
1.17	10	Niagara	Ontario Transportation	2.5	1,208
1.18	10	Niagara	Western Transportation	1.3	698
1.19	20	Metro	Sales	811.6	290,850
1.20	20	Metro	Ontario Transportation	261.0	87,134
1.21	20	Metro	Western Transportation	107.9	38,473
1.22	20	Western	Sales	470.0	186,446
1.23	20	Western	Ontario Transportation	149.5	54,827
1.24	20	Western	Western Transportation	89.2	34,794
1.25	20	Central	Sales	254.4	111,593
1.26	20	Central	Ontario Transportation	80.1	32,290
1.27	20	Central	Western Transportation	42.3	18,202
1.28	20	Northern	Sales	634.8	245,178
1.29	20	Northern	Ontario Transportation	163.4	57,577
1.30	20	Northern	Western Transportation	92.7	35,059
1.31	20	Eastern	Sales	388.2	172,170
1.32	20	Eastern	Ontario Transportation	107.2	44,414
1.33	20	Eastern	Western Transportation	39.7	17,416
1.34	20	Niagara	Sales	193.6	89,885
1.35	20	Niagara	Ontario Transportation	63.6	27,465
1.36	20	Niagara	Western Transportation	27.8	12,652
1.37	50	Metro	Sales	61.5	11,124
1.38	50	Metro	Ontario Transportation	13.9	2,795
1.39	50	Metro	Western Transportation	5.8	1,143
1.40	50	Western	Sales	34.8	8,233
1.41	50	Western	Ontario Transportation	8.5	2,000
1.42	50	Western	Western Transportation	3.9	970
1.43	50	Central	Sales	19.7	5,412
1.44	50	Central	Ontario Transportation	6.3	1,727
1.45	50	Central	Western Transportation	2.7	764
1.46	50	Northern	Sales	55.3	11,286
1.47	50	Northern	Ontario Transportation	12.5	2,595
1.48	50	Northern	Western Transportation	6.6	1,306
1.49	50	Eastern	Sales	20.6	4,939
1.50	50	Eastern	Ontario Transportation	4.6	1,133
1.51	50	Eastern	Western Transportation	1.8	409
1.52	50	Niagara	Sales	8.8	2,547
1.53	50	Niagara	Ontario Transportation	2.4	687
1.54	50	Niagara	Western Transportation	0.9	257
1.55	60	Metro	Sales	0.9	2,692
1.56	60	Metro	Ontario Transportation	0.1	399
1.57	60	Metro	Western Transportation	0.4	312
1.58	60	Western	Sales	0.1	92
1.59	60	Western	Ontario Transportation	0.0	2
1.60	60	Western	Western Transportation	0.0	8
1.61	60	Central	Sales	0.2	152
1.62	60	Central	Ontario Transportation	0.0	6
1.63	60	Central	Western Transportation	0.0	15

TABLE 4 - RECONCILIATION BETWEEN CUSTOMER GROUPING LEVEL AND RATE CLASS VOLUMES AND METERS - RATE 1

Item No.	Revenue Class*	Region	Gas Service Type	Normalized Volumes (10^6m^3)	Customer Meters
1.64	60	Northern	Sales	0.3	255
1.65	60	Northern	Ontario Transportation	0.0	16
1.66	60	Northern	Western Transportation	0.0	22
1.67	60	Eastern	Sales	0.3	334
1.68	60	Eastern	Ontario Transportation	0.0	12
1.69	60	Eastern	Western Transportation	0.0	7
1.70	60	Niagara	Sales	0.2	272
1.71	60	Niagara	Ontario Transportation	0.0	34
1.72	60	Niagara	Western Transportation	0.0	18
1.73	61	Metro	Sales	11.8	4,666
1.74	61	Metro	Ontario Transportation	2.7	922
1.75	61	Metro	Western Transportation	1.4	524
1.76	61	Western	Sales	0.8	868
1.77	61	Western	Ontario Transportation	0.3	304
1.78	61	Western	Western Transportation	0.1	176
1.79	61	Central	Sales	0.9	890
1.80	61	Central	Ontario Transportation	0.3	256
1.81	61	Central	Western Transportation	0.1	142
1.82	61	Northern	Sales	1.1	970
1.83	61	Northern	Ontario Transportation	0.4	281
1.84	61	Northern	Western Transportation	0.1	127
1.85	61	Eastern	Sales	1.4	1,436
1.86	61	Eastern	Ontario Transportation	0.3	384
1.87	61	Eastern	Western Transportation	0.1	128
1.88	61	Niagara	Sales	0.7	997
1.89	61	Niagara	Ontario Transportation	0.2	196
1.90	61	Niagara	Western Transportation	0.1	96
1	Total Rate 1 Normalized Volumes			4,572.6	1,772,503
				reconciled to	reconciled to
				Exhibit C, Tab 1, Schedule 5, Appendix A, Page 4, Col. 13, Item 1.1	Exhibit C, Tab 1, Schedule 5, Appendix A, Page 4, Col. 13, Item 1.2

*Note: Please refer to Table 3 for definition.

Witness: I. Chan

TABLE 5 - RECONCILIATION BETWEEN CUSTOMER GROUPING LEVEL AND RATE CLASS VOLUMES AND METERS - RATE 6

Item No.	Revenue Class*	Region	Gas Service Type	Normalized Volumes (10^6m^3)	Customer Meters
2.1	12	Metro	Sales	196.3	1,672
2.2	12	Metro	Ontario Transportation	104.6	860
2.3	12	Metro	Western Transportation	185.1	672
2.4	12	Western	Sales	32.3	206
2.5	12	Western	Ontario Transportation	14.9	82
2.6	12	Western	Western Transportation	28.9	118
2.7	12	Central	Sales	7.8	120
2.8	12	Central	Ontario Transportation	3.5	30
2.9	12	Central	Western Transportation	8.9	45
2.10	12	Northern	Sales	16.9	187
2.11	12	Northern	Ontario Transportation	7.7	64
2.12	12	Northern	Western Transportation	14.0	56
2.13	12	Eastern	Sales	38.4	684
2.14	12	Eastern	Ontario Transportation	10.2	153
2.15	12	Eastern	Western Transportation	37.4	324
2.16	12	Niagara	Sales	11.1	334
2.17	12	Niagara	Ontario Transportation	4.6	68
2.18	12	Niagara	Western Transportation	3.9	48
2.19	48	Metro	Sales	434.1	27,928
2.20	48	Metro	Ontario Transportation	338.4	7,352
2.21	48	Metro	Western Transportation	154.9	3,793
2.22	48	Western	Sales	291.8	19,437
2.23	48	Western	Ontario Transportation	133.7	3,660
2.24	48	Western	Western Transportation	86.0	2,460
2.25	48	Central	Sales	98.1	8,672
2.26	48	Central	Ontario Transportation	42.1	1,606
2.27	48	Central	Western Transportation	30.1	1,049
2.28	48	Northern	Sales	288.8	24,496
2.29	48	Northern	Ontario Transportation	103.8	4,243
2.30	48	Northern	Western Transportation	80.5	2,856
2.31	48	Eastern	Sales	231.8	13,340
2.32	48	Eastern	Ontario Transportation	75.9	2,737
2.33	48	Eastern	Western Transportation	87.1	1,857
2.34	48	Niagara	Sales	89.6	7,859
2.35	48	Niagara	Ontario Transportation	57.8	1,577
2.36	48	Niagara	Western Transportation	20.7	739
2.37	73	Metro	Sales	90.5	2,374
2.38	73	Metro	Ontario Transportation	69.3	654
2.39	73	Metro	Western Transportation	33.4	380
2.40	73	Western	Sales	50.2	747
2.41	73	Western	Ontario Transportation	93.1	251
2.42	73	Western	Western Transportation	24.7	143
2.43	73	Central	Sales	12.8	166
2.44	73	Central	Ontario Transportation	50.5	58
2.45	73	Central	Western Transportation	2.9	27
2.46	73	Northern	Sales	36.5	414
2.47	73	Northern	Ontario Transportation	51.2	156
2.48	73	Northern	Western Transportation	19.1	81
2.49	73	Eastern	Sales	13.0	103
2.50	73	Eastern	Ontario Transportation	20.6	43
2.51	73	Eastern	Western Transportation	5.5	25
2.52	73	Niagara	Sales	23.0	165
2.53	73	Niagara	Ontario Transportation	26.6	79
2.54	73	Niagara	Western Transportation	7.9	38
2.55	79	Metro	Sales	20.6	1,805
2.56	79	Metro	Ontario Transportation	11.6	545
2.57	79	Metro	Western Transportation	3.8	261
2.58	79	Western	Sales	3.4	219
2.59	79	Western	Ontario Transportation	4.5	65
2.60	79	Western	Western Transportation	0.9	42
2.61	79	Central	Sales	1.9	209
2.62	79	Central	Ontario Transportation	4.9	68
2.63	79	Central	Western Transportation	0.2	19
2.64	79	Northern	Sales	2.6	269

TABLE 5 - RECONCILIATION BETWEEN CUSTOMER GROUPING LEVEL AND RATE CLASS VOLUMES AND METERS - RATE 6

Item No.	Revenue Class*	Region	Gas Service Type	Normalized Volumes (10^6m^3)	Customer Meters
2.65	79	Northern	Ontario Transportation	2.4	60
2.66	79	Northern	Western Transportation	0.5	33
2.67	79	Eastern	Sales	6.1	493
2.68	79	Eastern	Ontario Transportation	4.5	138
2.69	79	Eastern	Western Transportation	0.8	65
2.70	79	Niagara	Sales	1.1	169
2.71	79	Niagara	Ontario Transportation	1.6	50
2.72	79	Niagara	Western Transportation	0.3	24
2.73	83	Metro	Sales	1.4	41
2.74	83	Metro	Ontario Transportation	1.6	14
2.75	83	Metro	Western Transportation	0.5	4
2.76	83	Western	Sales	0.2	5
2.77	83	Western	Ontario Transportation	0.3	1
2.78	83	Western	Western Transportation	0.5	2
2.79	83	Central	Sales	0.1	1
2.80	83	Central	Ontario Transportation	0.1	1
2.81	83	Central	Western Transportation	0.5	4
2.82	83	Northern	Sales	0.4	6
2.83	83	Northern	Ontario Transportation	0.8	4
2.84	83	Northern	Western Transportation	0.0	0
2.85	83	Eastern	Sales	0.0	1
2.86	83	Eastern	Ontario Transportation	0.5	4
2.87	83	Eastern	Western Transportation	0.0	0
2.88	83	Niagara	Sales	0.1	3
2.89	83	Niagara	Ontario Transportation	0.6	2
2.90	86	Metro	Sales	1.9	50
2.91	86	Metro	Ontario Transportation	294.0	713
2.92	86	Metro	Western Transportation	2.0	12
2.93	86	Western	Sales	0.2	12
2.94	86	Western	Ontario Transportation	38.7	109
2.95	86	Western	Western Transportation	0.0	1
2.96	86	Central	Sales	0.4	37
2.97	86	Central	Ontario Transportation	2.8	17
2.98	86	Central	Western Transportation	0.1	4
2.99	86	Northern	Sales	0.4	13
2.100	86	Northern	Ontario Transportation	10.7	51
2.101	86	Northern	Western Transportation	0.3	3
2.102	86	Eastern	Sales	1.1	46
2.103	86	Eastern	Ontario Transportation	17.5	58
2.104	86	Eastern	Western Transportation	1.0	10
2.105	86	Niagara	Sales	0.1	16
2.106	86	Niagara	Ontario Transportation	0.9	5
2.107	86	Niagara	Western Transportation	0.0	4
2.108	90	Metro	Sales	1.2	46
2.109	90	Metro	Ontario Transportation	1.3	20
2.110	90	Metro	Western Transportation	0.4	10
2.111	90	Western	Sales	0.2	5
2.112	90	Western	Ontario Transportation	0.0	2
2.113	90	Western	Western Transportation	0.0	1
2.114	90	Central	Sales	0.0	2
2.115	90	Central	Ontario Transportation	0.6	2
2.116	90	Central	Western Transportation	0.2	1
2.117	90	Northern	Sales	0.6	11
2.118	90	Northern	Ontario Transportation	0.6	5
2.119	90	Northern	Western Transportation	0.0	1
2.120	90	Eastern	Sales	0.4	4
2.121	90	Eastern	Ontario Transportation	0.6	2
2.122	90	Eastern	Western Transportation	0.2	1
2.123	90	Niagara	Sales	0.4	13
2.124	90	Niagara	Ontario Transportation	0.1	5
2.125	90	Niagara	Western Transportation	0.1	2
2	Total Rate 6 Normalized Volumes			4,460.8	153,209
				reconciled to	reconciled to
				Exhibit C, Tab 1, Schedule 5, Appendix A, Page 5, Col. 13, Item 1.1	Exhibit C, Tab 1, Schedule 5, Appendix A, Page 5, Col. 13, Item 1.2

*Note: Please refer to Table 3 for definition.

Witness: I. Chan

c) Exhibit B, Tab 3 Schedule 2, pages 2 and 3 provides the comparison between weather normalized volumes for Rate 1 and Rate 6 and the 2010 Board Approved Volume Budget, along with commentary.

d) Total Rate 1 and Rate 6 normalized volumes and customer meters reported in Tables 4 and 5 in section (b) above are reconciled to items 1.1 and 1.2 from Tables 4 and 5 of Exhibit C, Tab 1, Schedule 5, Appendix A, pages 4 and 5. Item 1.3 from Tables 4 and 5 of Exhibit C, Tab 1, Schedule 5, Appendix A, pages 4 and 5 are then reconciled to the Col. 2 of the AUTUVA calculation at Exhibit C, Tab 1, Schedule 5, Appendix A, Table 1.

Witness: I. Chan

VECC INTERROGATORY #12

INTERROGATORY

References:

Exhibit A Tab 2 Schedule 1 Appendix A line 15;
Exhibit C Tab 2 Schedule 1Page 2 line 12

a) Provide a summary report of the Activities and Costs incurred related to the 2009 International Financial Reporting Standards Transition Costs Deferral Account (IFRSTCDA).

RESPONSE

a) Please see the chart below for a breakdown of the amounts in the 2010 IFRSTCDA:

Summary of 2010 IFRSTCDA charges

Service Provider	**Activities**	**Amount ('000's)**
Enbridge Inc.	Project Leadership, People Readiness, Process Changes, System Changes, Technical Accounting, External Audit Reviews, expenses	483
Deloitte	Project Management	242
Incremental Internal Labour	Accounting policies analysis and preparation	424
Ernst & Young	Capitalization Study	704
PWC	Review of Draft policies	181
Gannett Fleming	Depreciation consultation	46
Total		**2,080**

Witnesses: J. Jozsa
K. Culbert

CME INTERROGATORY #1

INTERROGATORY

Reference: Exhibit S, Tab 1, Schedule 3, page 2 of 4

EGD states that the other income charge of $13.1 M is mainly due to revenue from the "Management of Fee for Service, External Third Party Energy Efficiency Initiatives". Please describe the Management of Fee for Service, External Third Party Energy Efficiency Initiatives that have been conducted by EGD. If the Energy Efficiency Initiatives were subject to a contract or other form of performance agreement or Memorandum of Understanding, please produce those documents.

RESPONSE

The High Performance New Construction Program ("HPNC") Initiative with Ontario Power Authority ("OPA") accounts for $11.7 million on the other income change. Due to the confidential nature of the agreement Enbridge declines to file this document.

Witnesses: K. Culbert
R. Small

CME INTERROGATORY #2

INTERROGATORY

Reference: Exhibit S, Tab 4, Schedule 2, page 3 of 3

EGD states that the costs for Business Development and Customer Strategy increased $4.3M due to higher conservation service costs. CME wishes to better understand this cost increase. To this end:

(a) Please provide an explanation of the "Conservation Service Costs" which lead to the $4.3M increase;

(b) Please provide a description of Business Development and Customer Strategy's role conservation; and

(c) Please provide copies of any PowerPoints, memoranda, and/or other written communications from Business Development and Customer Strategy to senior management which addresses, in part or in whole, conservation services.

RESPONSE

(a) The increase is mainly due to higher than budgeted incentive costs paid to market participants for applications received and completed for electricity savings. These higher costs are offset by higher revenues as described in response to Board Staff Interrogatory #3 at Exhibit I, Tab 1, Schedule 3.

(b) The Business Development and Customer Strategy group is involved in conservation through programs and services provided to non-rate regulated entities (such as the OPA and municipalities) and to rate-regulated electric LDCs. Enbridge's DSM group is also part of the Business Development and Customer Strategy group, however, the DSM O&M budget is included separately at Exhibit B, Tab 4, Schedule 2.

(c) All known material pertaining to the Company's conservation services business contains sensitive financial information that relates, in whole or in part, to its business partners, eg. OPA. Consent from these business partners would need to be obtained prior to releasing any information that may disclose their interests and no such consent has been obtained.

Witnesses: R. Lei
A. Patel

CME INTERROGATORY #3

INTERROGATORY

Reference: Exhibit S, Tab 4, Schedule 2, page 3 of 3

EGD states that engineering costs increased $3.2M due to increased requirements for the technical training department, and increased employee health and safety costs. Have there been changes to relevant legislation and/or regulations relating to employee health and safety and/or mandatory technical training which caused the increase in engineering costs? If so, please identify those changes. If not, please explain why there were increased requirements for technical training and increased employee health and safety costs in 2010.

RESPONSE

No, there have not been any changes to legislation and/or regulations requiring increased technical training or health and safety costs. Rather the Company undertook a project in 2010 to implement a Technical Training Model to keep employees up to a certain level of safety standards. Costs included a needs assessment, a competency model, enhancement of the Learning Management System, development of technical training policies, development of processes and procedures, and governance over the entire Technical Training Module. Health and safety costs increased as operator qualification re-certifications came due in 2010.

Witnesses R. Lei
A. Patel

CME INTERROGATORY #4

INTERROGATORY

Reference: Exhibit S, Tab 4, Schedule 2, page 3 of 3

EGD states that Public and Government Affairs increased $2.4M primarily due to the transfer of the Ombudsman's Office from Customer Care and incremental costs incurred from a Customer Relationship Study conducted in 2010. To this end:

(a) Please explain the role of the Ombudsman's Office;

(b) Please explain why the Ombudsman's Office was transferred from Customer Care to Public and Government Affairs;

(c) How of the $2.4M is attributable to the Ombudsman's Office being moved?

(d) Was there a cost decrease in Customer Care as a result of the removal of the Ombudsman's Office? If not, why not? If so, did the decrease in costs correspond to the increase in Public and Government Affairs? If not, why not?

(e) Was the Customer Relationship Study internally conducted by EGO, or alternatively, was it outsourced to external consultants? If it was conducted by external consultants, please provide the identity of the consultants; and

(f) Please provide a copy of the Customer Relationship Study.

RESPONSE

a) The role of the Ombudsman Office is to oversee customer satisfaction. It was established to manage escalated calls after a customer remains unsatisfied with a Customer Service Representative (“CSR”), to manage walk-in customers to the Enbridge Gas Distribution building, and to take an in-depth look at issues, and trends in billing and service to identify and improve processes across the system.

b) The Ombudsman Office was moved from Customer Care to Public & Government Affairs to enhance the governance process. This new structure allows the Ombudsman Office to operate independently from that of the role and responsibilities of the customer care and call centre.

Witnesses: R. Lei
A. Patel

c) Of the total $2.4M variance, $1M is related to the Ombudsman Office being moved.

d) Customer Care costs did decrease as a result of the removal of the Ombudsman Office, however, the increase to Public and Government Affairs was greater than the decrease to Customer Care as additional staff was needed for this function in addition to an increase in associated administration costs. While in the Customer Care department the Ombudsman Office was operated in conjunction with the call center when transferred to Public and Government Affairs costs were incurred to establish it as its own function.

e) The Customer Relationship Study was conducted externally by Ipsos-Reid, a market research firm.

f) Due to its confidential content and proprietary material, the Company declines to file the report.

Witnesses: R. Lei
A. Patel

FRPO INTERROGATORY #1

INTERROGATORY

REF: Ex. B, Tab 1, Schedule 6

Preamble: As this is the first substantial submission on Cost Allocation and EGD has varied from Union in its approach, understandably because of their different situations, we would like to understand some general aspects about the evolution of Storage Operations and its impact on costs to ratepayers.

1) Studies Performed to Create the Unregulated Storage
   a) Our understanding is that these storage projects took many years to develop. While it unnecessary to provide the entire feasibility study, please provide all of the Enbridge Gas Distribution, Enbridge Inc. and Tecumseh Gas studies that lead to the development of the unregulated storage. To avoid a burdensome task, the following information from each study should be sufficient:
      i) The name of the organization who commissioned the study.
      ii) The date the study was initially completed.
      iii) An executive summary or a list of recommendations from the study.
      iv) The cost/benefit analysis or profitability analysis done in the study.
      v) How were the studies paid for by Enbridge Gas Distribution?
      vi) What portion of the costs did ratepayers fund through their rates including any reductions in Earnings Sharing Mechanism.

RESPONSE

1.

a) Enbridge conducted both market and feasibility analysis prior to commencing with any of the unregulated storage growth projects and the unregulated storage business generally. The Company's analysis and understanding of the storage market is confidential and the Company is not prepared to provide the requested information.

   The cost of this analysis work, however, was not charged to any account of regulated operations and so has not been funded by ratepayers of Enbridge Gas Distribution Inc.

Witnesses: K. Culbert
B. Pilon

FRPO INTERROGATORY #2

INTERROGATORY

REF: Ex. B, Tab 1, Schedule 6

Preamble: As this is the first substantial submission on Cost Allocation and EGD has varied from Union in its approach, understandably because of their different situations, we would like to understand some general aspects about the evolution of Storage Operations and its impact on costs to ratepayers.

2) Use of Assets
   a) What is the level of deliverability associated with resulting 7.5 Bcf of storage that was developed?
   b) What is the deliverability of the 98 Bcf of the regulated storage?
   c) For each of the last 3 years, please provide the maximum throughput on any day from the combination of regulated and unregulated storage and the actual amount of unregulated gas that was delivered from storage for the unregulated business on that specific day.
   d) What transmission assets of EGD does the unregulated business use to move the gas to:
      i) Dawn?
      ii) Parkway?
      iii) Michigan?
   e) In each of the above 3 cases, how is EGD compensated for use of any EGD assets and where do the revenues flow?

RESPONSE

a) The deliverability available to unregulated storage customers based upon a storage capacity of 7.5 Bcf was 373 MMcfd.

Witnesses: K. Culbert
B. Pilon

b) The deliverability that is attached to the 98 Bcf of utility storage, and that was available prior to the NGEIR Decision, is 1,850 MMcfd.

c) The following table shows both the total amounts of gas withdrawn on the maximum gas storage withdrawal days and the portion of that total that was withdrawn on behalf of the unregulated customers.

	2008	2009	2010
Total Peak Day Withdrawals (MMcfd)	1,640	1,642	1,582
Unregulated Storage Withdrawal (MMcfd)	0	255	109

d) Enbridge does not have true transmission assets although there are lengths of pipe that tie the Enbridge storage hub to the Union transmission facilities at Dawn.

Enbridge Storage can move gas to Dawn in a number of ways. It can be transported through the twin 30” lines that connect the Tecumseh Compressor station with Dawn, and/or the 16” line that connects the Sombra Compressor station with Dawn. At that point custody is transferred to Union. It can also be delivered to an interconnect point with the Vector pipeline and carried by Vector to Dawn.

e) There is no compensation paid by the unregulated business to the regulated business for the use of the pipes described above.

Witnesses: K. Culbert
B. Pilon

FRPO INTERROGATORY #3

INTERROGATORY

REF: Ex. B, Tab 1, Schedule 6

Preamble: As this is the first substantial submission on Cost Allocation and EGD has varied from Union in its approach, understandably because of their different situations, we would like to understand some general aspects about the evolution of Storage Operations and its impact on costs to ratepayers.

3) For each gas year (April-March), how does EGD determine how much:
    a) space available is needed for in-franchise requirements?
    b) deliverability needed for in-franchise needs?
    c) What was the amount of space and deliverability on the initial run for each gas year for the years 2008, 2009, 2010?
    d) Do those figures change throughout the year?
    e) Is there a specific process that deems whether excess in-franchise space or deliverability can be sold Short-term as space or through some other storage deal mechanisms? If so, please describe the process and how often it is performed.
    f) How are the revenues for these services treated?
    g) How are they kept separate from unregulated revenues?
    h) If the revenues move to deferral or variance accounts, do the embedded Board - approved costs move with the revenues?
        i) If not, what costs if any are transferred?
        ii) What is the practical effect of this treatment of revenue and costs from an Earnings Sharing point of view?

Witnesses: K. Culbert
B. Pilon

RESPONSE

a) For each gas year the Company develops a gas supply plan, of which storage requirements are a component, using a model known as "SENDOUT". The model determines an optimal monthly supply portfolio comprised of supply, transportation and storage. This optimal supply portfolio is generated using contract parameters, for example tolls and storage deliverability, in existence at the time the Gas Cost budget is set.

Storage requirements for in-franchise customers exceed those available from regulated storage operations at Tecumseh. Consequently, for each gas year it is assumed that all available storage capacity at Tecumseh is needed to meet the load balancing needs of in-franchise customers. As the regulated storage space available at Tecumseh is not sufficient to cover the load balancing needs of in-franchise customers the Company supplements this with third party storage contracts.

b) The maximum deliverability needed to meet in-franchise demand is part of the supply plan derived in part a) above. Storage deliverability is a function of the amount of gas in storage. Therefore the Company sets storage targets within the gas supply budget to ensure the required level of deliverability from storage is available to meet the design demand profile of its in-franchise customers.

c) The amount of storage space and deliverability available for in-franchise customers at Tecumseh has not changed over the time period identified. The table below shows the amount of storage available at Tecumseh for in-franchise customers over the period requested:

Year	Space	Peak Deliverability
2008	91Bcf	1.7Bcf/day
2009	91Bcf	1.7Bcf/day
2010	91Bcf	1.7Bcf/day

Witnesses: K. Culbert
B. Pilon

d) Physical balances within Tecumseh storage will change throughout the year however the total amount of space available for in-franchise customer's load balancing requirements will not change. As mentioned in part b) above the Company's gas supply budget includes the establishment of storage targets. Throughout the year the Company's personnel meet to discuss and develop the short term supply strategy, i.e,. the 7 day ahead forecast, and are mindful while developing this strategy of the storage targets established as part of the budget process.

e) When the Company is approached by a third party seeking to utilize the Company's regulated utility storage assets each deal is evaluated on a case by case basis based on information available at the time. Since transactional service deals can in no way impede the Company's ability to meet the needs of its in-franchise customers, the Company first ensures that supply can meet demand. If it is determined that the proposed deal will not impede the Company's ability to meet the needs of its in-franchise customers, and the terms of the deal are acceptable to all parties, the Company will typically proceed with the deal. From time to time and depending on market conditions the Company may also market utility storage assets provided any deals offered by the Company do not impede the Company's ability to match supply with demand in order to meet the needs of its in-franchise customers.

f) Revenues derived from storage related transactional service activities are shared with ratepayers. As per the NGEIR decision, 90% of the net revenue derived from storage related transactional service activities, is shared with ratepayers with the remaining 10% going to the account of EGD.

g) The unregulated storage group and the group responsible for conducting transactional services are separate and independent within the utility, each with their own set of books.

h) i), ii) Costs associated with the storage services (i.e., Company owned and contracted Third Party Storage) that are required to meet the needs of its utility customers are borne by the ratepayers. Any revenue collected by the Company from marketing these utility assets is shared net 90:10 between the ratepayer and the shareholder as per the NGEIR decision. This is a separate sharing mechanism from the earnings sharing calculation, as noted in the IR Settlement Agreement.

FRPO INTERROGATORY #4

INTERROGATORY

REF: Ex. B, Tab 1, Schedule 6, page 3, para. 9 and 10

Preamble: In paragraph 9, EGD uses "total turnover capacity" for the criteria for allocating costs that do not vary with day to day activity. In paragraph 10, EGD discusses the "injection/withdrawal activity characteristics" of the two operations.

4) Please differentiate total turnover capacity from actual injection and withdrawals.
   a) Please provide a simple numeric example to provide clarity for how these metric work for regulated and unregulated.

RESPONSE

Total Turnover Capacity is the term that is used to describe the total amount of underground storage space that is available to utility and unregulated customers. Conversely the injection and withdrawal activity is simply a measure of the amount of gas that has been handled during a period of time.

a) Appendix II of the evidence is intended to be an illustration of how these metrics are used for the purpose of cost allocations for Enbridge Gas Storage.

   Appendix II indicated the allocation of '"61601" Contract Service' towards the middle of the page. The '"Actual"' column shows the cost actual for the month of January 2011 at $34,429.

   Moving to the right one can see that it has been determined that 40% of this cost will be allocated based upon the pro-rata shares of the Annual Turnover Capacity held by each of regulated and unregulated storage. The calculation of those shares is shown above the cost section with the heading '"Annual Capacity"'.

   And then moving further to the right the balance of the cost is then allocated based upon the actual shares of total injection/withdrawal activity for that month. For January 2011 those shares are shown under the "'Commodity"' heading, again, above the cost section.

   The total of these allocations is then accumulated towards the bottom of the page.

Witnesses: K. Culbert
B. Pilon

FRPO INTERROGATORY #5

INTERROGATORY

REF: Ex. B, Tab 1, Schedule 6, page 4, para. 11

5) What are the cost drivers or metrics that are used to allocate the overhead costs from the respective EDGI and EI offices?

RESPONSE

Enbridge's overhead costs (A&G) are determined on a company-wide basis and then divided by total FTE headcount to determine annual overhead amounts per FTE. Those annual overhead amounts per FTE are multiplied by the number of FTEs associated with the unregulated storage business to determine the allocation of overhead costs to the unregulated storage business.

Witnesses: K. Culbert
B. Pilon

FRPO INTERROGATORY #6

INTERROGATORY

REF: Ex. B, Tab 1, Schedule 6, page 4, para. 12

6) What is the level of business development costs for EGD in 2010 for:

   a) the regulated storage business??

   b) what are the drivers or metrics used to do this allocation?

   c) if not allocated proportionately, what mechanism is used to assign the costs?

RESPONSE

a) – c) All of the costs of managing, operating and maintaining the regulated storage business are included in the O&M Regulated Storage numbers shown on Appendix I. As no regulated storage is being developed, there is no business development cost.

Witnesses: K. Culbert
B. Pilon

FRPO INTERROGATORY #7

INTERROGATORY

REF: Ex. B, Tab 1, Schedule 6, page 4-5, para. 13

7) Please provide a more specific definition of the FTE's used.
   a) Are the estimates of FTE to be allocated done on a fully allocated or incremental basis?
   b) What is used for return on equity for:
      i) the regulated storage business?
      ii) the unregulated storage business?
   c) What is the resulting proportionate breakdown on a percentage basis between the regulated and unregulated businesses?

RESPONSE

a) The reference to FTEs in paragraph 13 is simply to describe how the Company allocates costs in its fully allocated cost study. Time spent on unregulated activities by gas storage will be charged on a fully allocated basis.

b) The cost of capital and embedded return on equity included in the fully allocated cost determination is the most recent Board Approved level for rate setting, 2007 Board Approved. No return on equity of the “unregulated” storage business return is used

c) The proportionate split of FTE’s in gas storage are as determined by the capacity and activity driven allocators underlying the O&M cost allocations. They will be very close to the effective splits as shown in the example shown on Appendix II found at Exhibit B, Tab 1, Schedule 6.

Witnesses: K. Culbert
B. Pilon

FRPO INTERROGATORY #8

INTERROGATORY

REF: Ex. B, Tab 1, Schedule 6, page 5, para. 15

8) Please provide a rationale as to why the October QRAM price is used?
   a) Would cost causality principles be better followed if the QRAM price used was the one in effect in the month of the allocation? If not, why not?

RESPONSE

For purposes of determining the Company's gas cost budget an amount is included for Tecumseh fuel cost. That forecasted cost is based upon the estimated injection/ withdrawal fuel volume requirement multiplied by the October QRAM Reference Price. The derivation of EGD's rates include the recovery of that forecasted cost therefore, to ensure a matching of costs and revenues, the actual fuel volume charge is priced using the October QRAM Reference Price. This has been EGDI's practice for some time, for both regulated and unregulated fuel requirements.

Cost causality principles may be better served by using a more current QRAM price but the cost difference would not be material.

Witnesses: K. Culbert
B. Pilon

FRPO INTERROGATORY #9

INTERROGATORY

REF: Ex. B, Tab 1, Schedule 6, page 5-6, para. 18 and Appendix I

9) To ensure that we are understanding the numbers provided:
   a) What is Total Regulated Storage O&M as compared to the Unregulated?
   b) Does the O&M Regulated Storage include Direct Regulated Storage O&M?
   c) If not, please provide the appropriate figures to compare Regulated to Unregulated over the last 3 years.

RESPONSE

a) On the bottom of Appendix I the Company has shown the amounts of Storage Operations O&M that have been allocated to each of the unregulated and the regulated storage businesses. The two components of that total, O&M Allocated to Unregulated and O&M Regulated Storage, make up all of the O&M from Storage Operations.

   To understand the total amount of Unregulated Storage O&M the line titled 'Direct Unregulated Storage O&M' must be added to the O&M Allocated to Unregulated from Storage Operations. Looking at Appendix I the 2010 amount of Total Unregulated Storage O&M is $1.46 million as compared with the Regulated Storage O&M figure of $9.26 million.

b) and c) The amount shown on Appendix I as O&M Regulated Storage includes all O&M costs from Storage Operations.

Witnesses: K. Culbert
B. Pilon

APPRO INTERROGATORY #1

INTERROGATORY

Reference: Exh A, T2, S1, App A – Re: Unbundled Rate Implementation Cost D/A (2010 URICDA)

(a) Please confirm that EGD first requested approval for the establishment of the URICDA in the Board's NGEIR proceeding. If not, please indicate when approval for the establishment of the URICDA was first sought.

(b) Please provide a copy of the OEB approval of the establishment of the URICDA along with any documentation associated with it (including the Decision with Reasons in EB-2005-0551 dated November 7, 2006, with Appendices).

RESPONSE

(a) Yes, the URICDA was first requested and approved via EGD's Settlement Proposal (EB-2005-0551, Exhibit S, Tab 1, Schedule 1, p. 32) dated June 13, 2006 and approved by the Board on June 14, 2006 as part of the Board's NGEIR proceeding.

(b) Attached please find: (1) the Board's Rate Order for EGD arising from the NGEIR Decision with Reasons (EB-2005-0551), and (2) the Board's Final Rate Order for the 2010 IRM Adjustment (EB-2009-0172) and the accompanying Appendix D.

Witnesses: K. Culbert
A. Kacicnik
R. Small

Ontario Energy Board | Commission de l'Énergie de l'Ontario

Ontario

EB-2005-0551

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

AND IN THE MATTER OF a proceeding initiated by the Ontario Energy Board to determine whether it should order new rates for the provision of natural gas, transmission, distribution and storage services to gas-fired generators (and other qualified customers) and whether the Board should refrain from regulating the rates for storage of gas

BEFORE: Gordon Kaiser
Presiding Member and Vice Chair

Cynthia Chaplin
Member

Bill Rupert
Member

RATE ORDER FOR ENBRIDGE GAS DISTRIBUTION INC. ARISING FROM THE NATURAL GAS ELECTRICITY INTERFACE REVIEW DECISION WITH REASONS: EB-2005-0551

The Natural Gas Electricity Interface Review ("NGEIR") proceeding was commenced pursuant to sections 19, 29 and 36 of the *Ontario Energy Board Act, 1998*. On December 29, 2005, the Board issued a Notice of Proceeding on its own motion to determine: (a) whether it should order new rates for the provision of natural gas transmission, distribution and storage services to gas-fired generators (and other qualified customers); and (b) whether to refrain, in whole or part, from exercising its power to regulate the rates charged for the storage of gas in Ontario by considering whether, as a question of fact, the storage of gas in Ontario is subject to competition sufficient to protect the public interest.

Pursuant to Procedural Order No. 2, the proceeding also addressed the proposed unbundled rates for conventional large volume customers of Enbridge Gas Distribution Inc. ("Enbridge").

The hearing participants, which included gas-fired generators and consumer groups, reached settlements with Enbridge and Union Gas Limited on most of the issues related to services to gas-fired generators, including an amended Rate 125 distribution service for extra large customers. The Enbridge Settlement Proposal also contained agreements about the unbundled rates to be offered to other large volume customers (Rates 300 and 315). The Settlement Proposal indicated that these unbundled rates would be offered to customers, on a limited basis, beginning January 1, 2007. The Settlement Proposal also contained the agreement of all parties that Enbridge would establish an Unbundled Rate Implementation Cost Deferral Account to collect Enbridge's costs associated with preparing to offer unbundled rates as of January 1, 2007, as well as an Unbundled Rates Customer Migration Variance Account to capture the revenue consequences of the actual migration to the new unbundled rates being different from the forecast.

On July 14, 2006, the Board approved the Settlement Proposal related to Enbridge.

On November 7, 2006, the Board issued its EB-2005-0551 Decision with Reasons which addressed the balance of the issues in the proceeding.

In its Decision, the Board stated that:

> "As part of this proceeding, new unbundled rates have been approved for Enbridge and they are to be implemented as soon as possible. The Board therefore directs Enbridge to file a draft Rate Order within 15 days of this decision. The draft Rate Order should reflect the findings in this decision" (p. 119).

On November 22, 2006, Enbridge filed draft Rate Schedules for Rates 125, 300, 315 and 316, which are the unbundled rates that were approved in this proceeding. The Company also filed a draft Rate Rider for Enhanced Title Transfer Service and for Gas in Storage Title Transfer.

The draft Rate Schedules for Rates 125, 300, 315 and 316 all reflect a Monthly Customer Charge that has been reduced by $50 from the amount previously indicated. This reduction reflects the fact that the earlier versions of these Rate Schedules assumed that the Company would immediately proceed with an automated solution to process unbundled rate transactions. Now that parties have agreed to delay the implementation of the automated solution, the associated cost recovery of $50 per customer per month is not needed at this time.

The draft Rate Schedule for Rate 125 reflects the Board's decision that "the only aspect of Rate 125 that will be restricted to new customers is the billing contract demand feature" (EB-2005-0551 Decision with Reasons, p. 116). The amended version of Rate 125 will be available as of July 1, 2007.

The draft Rate Schedules for Rates 300 and 315 are essentially the same as agreed to in the Enbridge Settlement Proposal, and approved by the Board. Apart from the change to the Monthly Customer Charge, two other changes have been made to Rate 300 to address matters that were inadvertently omitted by Enbridge. A Direct Purchase Administration Charge of $50 has been added, to make Rate 300 consistent with Rate 125. References to Curtailment Delivered Supply, a service that bundled customers can currently receive with Rate 300, have also been added. Rates 300 and 315 will be available as of January 1, 2007.

The draft Rate Schedule for Rate 316 reflects the Board's decision that the Board will refrain from regulating the rates for new storage services, including Enbridge's high deliverability Rate 316 (EB-2005-0551 Decision with Reasons, p. 70). As a result, the draft Rate Schedule for Rate 316 reflects the fact that this regulated storage rate and service will be standard 1.2% deliverability storage, delivered at Dawn, Ontario. Rate 316 will be available as of July 1, 2007.

All customers taking service under Rate 315 or 316 are entitled to an allocation of cost-based standard 1.2% deliverability storage to be calculated in accordance with the Company's Board-approved excess over average methodology. Gas-fired generation customers also have the option to determine their allocation of cost-based standard 1.2% deliverability storage based upon the allocation methodology described at

Appendix G. In accordance with section 6.2.2 of the Board's decision, Enbridge will circulate to all parties in this proceeding and file the methodology or methodologies that it proposes to use to allocate cost based standard 1.2% deliverability storage to other unbundled customers. This will be completed by February 5, 2007.

Upon reviewing the materials, the Board finds it appropriate to issue a Rate Order in this proceeding approving the Rate Schedules for Enbridge's Rates 125, 300, 315 and 316, as well as the Rate Rider for Enhanced Title Transfer Service and for Gas in Storage Title Transfer. The Board also finds it appropriate to approve the establishment of Enbridge's 2006 and 2007 Unbundled Rate Implementation Cost Deferral Accounts, as well as Enbridge's 2007 Unbundled Rates Customer Migration Variance Account.

THE BOARD THEREFORE ORDERS THAT:

1. The Rate Schedules for Enbridge's Rates 125, 300, 315 and 316, attached as Appendices A, B, C and D to this Order are approved.

2. The Rate Rider for Enbridge's Enhanced Title Transfer Service and for Gas in Storage Title Transfer shall be in accordance with Appendix E to this Order.

3. Enbridge shall establish the 2006 and 2007 Unbundled Rate Implementation Cost Deferral Accounts and the Unbundled Rates Customer Migration Variance Account. The accounting treatment for these accounts shall be in accordance with the descriptions contained in the attached Appendix F. Enbridge shall refer to the Board directive issued in EB-2006-0117 to determine the interest rates for these accounts.

4. The storage allocation methodology for gas-fired generators is approved as described in Appendix G to this Order.

5. Enbridge shall circulate to all parties in this proceeding the methodology or methodologies that it will use to allocate cost-based standard 1.2% deliverability storage to other unbundled customers. Enbridge is directed

to circulate and file this methodology or methodologies with the Board by February 5, 2007.

ISSUED at Toronto, December 20, 2006

ONTARIO ENERGY BOARD

Original signed by

Peter H. O’Dell
Assistant Board Secretary

EB-2005-0551

NATURAL GAS ELECTRICITY INTERFACE REVIEW

ENBRIDGE GAS DISTRIBUTION INC.

RATE ORDER

DECEMBER 20, 2006

APPENDIX “F”

ACCOUNTING TREATMENT FOR AN UNBUNDLED RATE IMPLEMENTATION COST DEFERRAL ACCOUNT ("2006 URICDA")

For the 2006 Fiscal Year
(January 1, 2006 to December 31, 2006)

The purpose of the 2006 URICDA is to record the costs associated with preparing to offer unbundled rates as of January 1, 2007. The account will collect the costs relating to a manual solution which will allow the establishment of rates 300 and 315 initially on a limited basis. Costs to be included in the account are those related to the development of spreadsheets and procedures necessary to process transactions by unbundled customers, as well as staff hiring and training costs for the personnel who will actually run the manual solution. The account will also include costs related to customer education and EnTrac changes required for a manual solution, along with necessary implementation costs.

Simple interest is to be calculated on the opening monthly balances within the account at the Board approved short-term interest rate. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

Accounting Entries

1. To record costs related to the Unbundling Rate Implementation manual solution:

Debit:	Other Income	(Account 179. 636)
Credit:	Accounts Payable	(Account 251.010)

To record the costs associated with implementing Rates 300 and 315 through a manual solution on an interim basis.

2. Interest accrual:

Debit:	Interest on 2006 URICDA	(Account 179. 646)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balances of the 2006 URICDA at the Board approved short-term interest rate.

ACCOUNTING TREATMENT FOR AN UNBUNDLED RATE IMPLEMENTATION COST DEFERRAL ACCOUNT ("2007 URICDA")

For the 2007 Fiscal Year
(January 1, 2007 to December 31, 2007)

The purpose of the 2007 URICDA is to record any additional costs, if required, of continuing with a manual solution or the costs required of an automated solution for offering Unbundled Rates 125, 300, 315 and 316. Costs to be collected in the account are administrative, staffing and all reasonably incurred costs associated with offering these rates and the additional nomination windows required for such rates.

Simple interest is to be calculated on the opening monthly balances within the account at the Board approved short-term interest rate. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

Accounting Entries

1. To record costs related to the Unbundling Rate Implementation solution:

Debit:	Other Income	(Account 179. 637)
Credit:	Accounts Payable	(Account 251.010)

To record the costs associated with implementing Rates 300, 315 and 316 through a continuing manual solution or an automated solution.

2. Interest accrual:

Debit:	Interest on 2006 URICDA	(Account 179. 647)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balances of the 2007 URICDA at the Board approved short-term interest rate.

ACCOUNTING TREATMENT FOR AN UNBUNDLED RATES CUSTOMER MIGRATION VARIANCE ACCOUNT ("2007 URCMVA")

For the 2007 Fiscal Year
(January 1, 2007 to December 31, 2007)

The purpose of the 2007 URCMVA is to record the revenue consequences of actual customer migration variance from forecast migration for the new NGEIR unbundled rates 125, 300, 315 and 316. The pivot point or threshold for the variance account will be the revenue related to forecast migration to new rates such that if actual migration revenue is lower or higher than forecast, there would be an associated entry to the variance account to refund or collect from customers in all applicable rate classes.

Simple interest is to be calculated on the opening monthly balances within the account at the Board approved short-term interest rate. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

Accounting Entries

1. To record the impact of customer migration to unbundled rates versus forecast:

Debit/Credit:	2007 URCMVA	(Account 179. 677)
Credit/Debit:	Revenue	(Account 300. 000)

To record the revenue variance associated with actual versus forecast migration of customers to unbundled rates.

2. Interest accrual:

Debit/Credit:	Interest on 2007 URCMVA	(Account 179. 687)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balances of the 2007 URCMVA at the Board approved short-term interest rate.

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2009-0172

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, 2010.

BEFORE: Gordon Kaiser
Vice Chair and Presiding Member

Paul Sommerville
Member

Cathy Spoel
Member

FINAL RATE ORDER
2010 IRM Adjustment

Enbridge Gas Distribution Inc. ("Enbridge" or the "Applicant") filed an Application on September 1, 2009 (as amended on September 14, 2009) with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Sched. B, as amended, for an order of the Board approving or fixing rates for the distribution, transmission and storage of natural gas, effective January 1, 2010. The Board assigned file number EB-2009-0172 to the Application and has issued a Notice of Application dated September 18, 2009 (the "Notice").

On February 18, 2010, the Board issued a corrected Final Issues List for this proceeding. A copy of the Final Issues List is attached as Appendix "E" to this Order.

On March 4, 2010 the Board approved a Settlement Agreement having a complete settlement of all the issues on the Final Issues List that are associated with the annual rate adjustment under the 5-year incentive ratemaking process ("IRM") that was approved by the Board in the EB-2007-0615 proceeding. 2008 is the base year and 2010 is the second year that rates are adjusted under the IRM. A copy of the Settlement Agreement is attached as Appendix "F" to this Order.

Enbridge prepared a Draft Rate Order and circulated it to interested parties for comment. No party indicated any concerns to the Board with the Draft Rate Order.

The rates in the Draft Rate Order are designed to be effective January 1, 2010 but will be implemented on April 1, 2010. The Board notes that there will be a natural gas commodity rate adjustment effective April 1, 2010 under the Quarterly Rate Adjustment Mechanism ("QRAM") process. The QRAM draft order is expected to be filed March 12, 2010 under docket EB-2010-0048. For rate implementation purposes, it is anticipated that the rates approved under this Order will be immediately superceded by the April 1, 2010 QRAM rates.

A one-time adjustment, a Rider "E", is included with the Draft Rate Order under Appendix "C". Rider "E" will capture the difference in revenue between interim and final rates for the period between January 1, 2010 and March 31, 2010. Enbridge has proposed to clear the Rider "E" on a one-month prospective basis over the month of April 2010 using actual April volumes. The total rider amount is a customer refund of $10.8 million.

The Board notes that Enbridge intends to file the customer rate notices describing the rate impacts as part of the April 1, 2010 QRAM process.

Having reviewed all of the materials, the Board considers it appropriate to proceed with its Final Rate Order as proposed by Enbridge.

THE BOARD ORDERS THAT:

1. The following Deferral and Variance accounts shall be established for Enbridge's fiscal 2010 year:

Gas Related Accounts
Purchased Gas V/A ("2010 PGVA")
Transactional Services D/A ("2010 TSDA")
Unaccounted for Gas V/A ("2010 UAFVA")
Storage and Transportation D/A ("2010 S&TDA")
Change in Purchased Gas Variance Disposition Methodology D/A ("2010 CPGVDMDA")

Non-Gas related Accounts
Carbon Dioxide Offset Credits D/A ("2010 CDOCDA")
Class Action Suit D/A ("2010 CASDA")
Deferred Rebate Account ("2010 DRA")
Electric Program Earnings Sharing D/A ("2010 EPESDA")
Gas Distribution Access Rule Costs D/A ("2010 GDARCDA")
Manufactured Gas Plant D/A ("2010 MGPDA")
Municipal Permit Fees D/A ("2010 MPFDA")
Ontario Hearing Costs V/A ("2010 OHCVA")
Unbundled Rate Implementation Cost D/A ("2010 URICDA")
Unbundled Rates Customer Migration V/A ("2010 URCMVA")
Average Use True-Up V/A ("2010 AUTUVA")
Tax Rate and Rule Change V/A ("2010 TRRCVA")
Earnings Sharing Mechanism D/A ("2010 ESMDA")
International Financial Reporting Standards Transition Costs D/A ("2010 IFRSTCDA")

Open Bill Service D/A ("2010 OBSDA")
Open Bill Access V/A ("2010 OBAVA)
Open Bill Revenue V/A ("2010 OBRVA")
Ex-Franchise Third Party Billing Services D/A ("2010 EFTPBSDA")

Mean Daily Volume Mechanism D/A (“2010 MDVMDA”)

<u>DSM Related Accounts</u>
Demand Side Management V/A (“2010 DSMVA”)
Lost Revenue Adjustment Mechanism (“2010 LRAM”)
Shared Savings Mechanism V/A (“2010 SSMVA”)

2. The accounting treatment for Enbridge’s fiscal 2010 deferral and variance accounts, including the applicable interest rate, shall be in accordance with the descriptions contained in the attached Appendix “D”.

3. The Financial Statements, attached as Appendix “A” to this order, are accepted as the basis for the rates in this order.

4. The rates in the Rate Handbook, attached as Appendix “B” to this order, are hereby effective January 1, 2010. These rates will be immediately superceded by the rates resulting from the April 2010 QRAM, docket EB-2010-0048.

5. The adjustment applicable to customer’s April 2010 volumes shall be calculated using the unit rates included in Rider E, attached as Appendix “C”.

DATED at Toronto, March 8, 2010

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX “D”

2010 Deferral Accounts

ACCOUNTING TREATMENT FOR A PURCHASED GAS VARIANCE ACCOUNT ("2010 PGVA")

For the 2010 Fiscal Year (January 1, 2010 to December 31, 2010)

The purpose of the 2010 PGVA is to record the effect of price variances between actual 2010 gas purchase prices and the forecast prices that underpin the revenue rates to be charged in 2010. Without this deferral account, the ratepayers and the Company are exposed to the risk of purchased gas price variances, which could unduly penalize or benefit one party at the benefit or expense of the other. Lower than forecast gas purchase prices would result in an over recovery from the customers and higher prices would result in an under recovery to the Company. This deferral account ensures that such effects are eliminated.

Methodology

The actual unit cost is determined by dividing the total commodity and transportation costs (less the demand charges related to unutilized TransCanada firm service transportation capacity, if any) plus any other costs associated with emerging gas pricing mechanisms incurred in the month by the actual volumes purchased in the month. The rate differential between the PGVA reference price and the actual unit cost of the purchases, multiplied by the actual volumes purchased, is recorded in the PGVA monthly.

The fixed cost component of the TransCanada firm service transportation costs (i.e., Transportation Demand Charge) is included in the determination of the reference price. However, any demand charges relating to unutilized transportation capacity, either forecast or actual, are excluded. This treatment of forecast and actual Transportation Demand Charges for unutilized transportation capacity is consistent with the Board's concerns that these amounts be excluded from the PGVA.

Since all transportation costs on volumes purchased by the Company related to forecast utilized capacity are included in the determination of the PGVA reference price, any changes in the TransCanada tolls will be recorded in the PGVA. Any toll changes related to the cost of forecast unutilized capacity will not be recorded in the PGVA and therefore, requires separate adjustment. The inclusion of changes in TransCanada tolls in the PGVA is consistent with past practice.

Since the transportation tolls for the Alliance and Vector pipelines that were used in the determination of the PGVA reference price were based upon an estimate, any variation between the actual transportation costs (including associated fuel costs) and the estimated transportation costs will be recorded in the PGVA.

Since transportation costs related to the transport of Western Canada Bundled T-service volumes are not included in the derivation of the PGVA reference price, changes in TransCanada tolls will be recorded in the PGVA as a separate adjustment.

For the period January 1, 2010 to December 31, 2010 expenditures related to TransCanada's Storage Transportation Services, including balancing fees related to TransCanada's Limited Balancing Agreement, will be recorded in the 2010 PGVA. The 2010 PGVA will also record amounts related to a Limited Balancing Agreement with Union Gas.

The PGVA will record adjustments related to transactional services activities which are designed to record the impact of direct and avoided costs between the PGVA and the TSDA. These adjustments are required to ensure appropriate allocation of costs and benefits to the underlying transactions and appropriate recording of amounts in the 2010 PGVA and 2010 TSDA for purposes of deferral account dispositions.

In addition, the 2010 PGVA will record the amounts related to unforecast penalty revenues received from interruptible customers who do not comply with the Company's curtailment requirements, unauthorized overrun gas revenues, the use of electronic bulletin boards, and the unforecast Unabsorbed Demand Charge ("UDC") that arises as a consequence of the Company voluntarily leaving transportation capacity unutilized in order to gain a net benefit for the customer by purchasing lower priced unforecast discretionary delivered supplies.

The 2010 PGVA will also record an inventory valuation adjustment every time a recalculated “Utility Price” or PGVA Reference Price comes into effect at the beginning of a quarter. The adjustment consists of the storage inventory valuation adjustment necessary to price actual opening inventory volumes at a rate equal to the Board approved quarterly PGVA reference price.

The 2010 PGVA will also record any refund/collection associated with Board approved Gas Cost Adjustment Riders.

The Company will record, at the time a Banked Gas Account Balance is purchased from a customer, the difference in the amount payable to the customer and the amount included in the PGVA (the Ontario T-Service credit). This amount would be credited to a sub-account of the PGVA. In the event the Company incurs unforecast UDC costs as a result of having to purchase Banked Gas Account Balances then the amount in such sub-account will be used to offset corresponding UDC costs. All amounts remaining in this sub-account, after offsetting these UDC costs, will be rolled up into the PGVA.

The commodity sale price on the disposition of Banked Gas Account Balances, the incentive sale price, is set at 120% of an average Empress price over the 12 months of the contractual year. Any amount in excess of 100% of the gas supply charge stated in the applicable rate schedule, net of the commodity related bad debt, will be included in the PGVA.

Simple interest is to be calculated on the opening monthly balance of the 2010 PGVA using the Board Approved EB-2006-0117 interest rate methodology. The balance of the 2010 PGVA, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the monthly gas purchase variance:

Debit:	2010 PGVA	(Account 179.700)
Credit:	Gas in Storage	(Account 152.000)
	or	
Debit:	Gas in Storage	(Account 152.000)
Credit:	2010 PGVA	(Account 179.700)

To record the total rate variance on the current month's gas purchases.

2. TransCanada Toll changes related to forecast un-utilized transportation capacity:

Debit:	2010 PGVA	(Account 179.700)
Credit:	Accounts Payable	(Account 259.000)
	or	
Debit:	Sundry Accounts Receivable	(Account 141.030)
Credit:	2010 PGVA	(Account 179.700)

To record the amounts related to TransCanada toll changes on forecast unutilized transportation capacity.

3. TransCanada Toll changes related to Western Canada Bundled T-Service transportation capacity:

Debit:	2010 PGVA	(Account 179. 700)
Credit:	Accounts Payable	(Account 259. 000)
	or	
Debit:	Sundry Accounts Receivable	(Account 141. 030)
Credit:	2010 PGVA	(Account 179. 700)

To record the amounts related to TransCanada toll changes on Western Canada Bundled T-Service transportation capacity.

4. Transactional services activities:

Debit/Credit:	2010 TSDA	(Account 179. 800)
Debit/Credit:	Various accounts	(Account ___. ___)
Credit/Debit:	2010 PGVA	(Account 179. 700)

To record adjustments for direct and avoided costs related to Transactional Services activities between the 2010 PGVA and 2010 TSDA, and other accounts such as Gas Costs, Gas Stored Underground and Storage Demand Charges.

5. Electronic bulletin boards:

Debit:	2010 PGVA	(Account 179. 700)
Credit:	Accounts Payable	(Account 259. 000)

To record the amounts related to the Company's use of electronic bulletin boards.

6. Unforecast penalty revenues:

Debit:	Accounts Receivable	(Account 140. 010)
Credit:	2010 PGVA	(Account 179. 700)

To record unforecast penalty revenues received from interruptible customers who do not comply with the Company's curtailment requirements.

7. Voluntary UDC:

Debit:	2010 PGVA	(Account 179. 700)
Credit:	Accounts Payable	(Account 259. 000)

To record voluntary UDC as a result of purchasing lower priced unforecast discretionary delivered supplies.

8. Inventory valuation adjustment:

Credit/Debit:	Gas In Storage	(Account 152. 000)
Debit/Credit:	2010 PGVA	(Account 179. 700)

To record the adjustment necessary to value actual inventory volumes at a rate equal to the 2010 PGVA reference price.

9. Refund or collection of the Gas Cost Adjustment Rider:

Debit/Credit:	2010 PGVA	(Account 179. 700)
Credit/Debit:	Accounts Receivable	(Account 140. 010)

To record the amounts refunded or collected from customers through the Gas Cost Adjustment Rider.

10. Purchase of banked gas account balance:

Debit:	Gas In Storage	(Account 152. 000)
Credit:	2010 PGVA	(Account 179. 700)

To record the purchase of the Banked Gas Account Balance less the Ontario T-Service credit.

11. Unforecast UDC:

Debit:	2010 PGVA	(Account 179. 700)
Credit:	Accounts Payable	(Account 259. 000)

To record unforecast UDC costs resulting from the purchase of Banked Gas Account Balances from T-Service customers.

12. Sales in excess of 100% of the applicable gas supply charge:

Debit:	Other Income	(Account 319. 010)
Credit:	2010 PGVA	(Account 179. 700)

To record the amount of sales in excess of 100% of the gas supply charge stated in the applicable rate schedule, net of the commodity related bad debt amount.

13. Interest accrual:

Debit:	2010 PGVA - Interest Receivable	(Account 179. 710)
Credit:	Interest Expense	(Account 323.000)
	or	
Debit:	Interest Expense	(Account 323.000)
Credit:	2010 PGVA - Interest Payable	(Account 179. 710)

To record simple interest on the opening monthly balance of the 2010 PGVA using the Board Approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A TRANSACTIONAL SERVICES DEFERRAL ACCOUNT ("2010 TSDA")

For the 2010 Fiscal Year (January 1, 2010 to December 31, 2010)

The purpose of the 2010 TSDA is to record the ratepayer share of the net revenue, from transportation and storage related transactional services, in excess of the $8.0 million ratepayer guarantee and the operation and maintenance costs associated with storage related transactional services.

As determined in the NGEIR Decision with Reasons (EB-2005-0551), there is a distinction, and differing sharing mechanisms, associated with transportation related and storage related transactional services. Net transportation related transactional services revenue will employ a 75:25 sharing mechanism between the Company's ratepayers and shareholders, but net storage related transactional services revenue will employ a 90:10 sharing mechanism between ratepayers and shareholders.

Net revenue is defined as gross revenues for providing these services less any direct incremental costs incurred, plus, any avoided costs. Direct incremental costs represent those direct costs incurred as a result of a transactional service activity and avoided costs are those costs that have been avoided as a result of a transactional service activity. Typical direct incremental costs and avoided costs would include transportation costs, fuel costs, charges for name changes, re-direct charges, etc.

In EB-2005-0001, the Board determined that the operating and maintenance expenses (O&M) such as salaries, benefits, promotion, legal fees, etc. are properly recovered from ratepayers through rates outside of the TS sharing mechanism. This methodology remains in effect for O&M related to transportation related transactional services, but no longer applies to O&M related to storage related transactional services. The NGEIR Decision with Reasons (EB-2005-0551) determined that incremental O&M related to providing storage related transactional services will now be applied against the corresponding net revenues.

Simple interest is to be calculated on the opening monthly balance of the 2010 TSDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of the 2010 TSDA, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record Transactional Services revenues and costs:

Debit/Credit:	Other Income	(Account 319. 010)
Credit/Debit:	2010 TSDA	(Account 179. 800)

To record the ratepayer portion of net revenues generated from transactional services activities in excess of the guaranteed amount, inclusive of O&M costs related to TS storage activities.

2. Allocation of costs and benefits to Transactional Services activities:

Debit/Credit:	2010 TSDA	(Account 179. 800)
Debit/Credit:	Various accounts	(Account ___. ___)
Credit/Debit:	2010 PGVA	(Account 179. 700)

To record adjustments for direct and avoided costs related to transactional services activities between the 2010 PGVA and 2010 TSDA, and other accounts such as Gas Costs, Gas Stored Underground and Storage Demand Charges.

3. Interest accrual:

Debit:	Interest Expense	(Account 323. 000)
Credit:	2010 TSDA - Interest Payable	(Account 179. 810)

To record simple interest on the opening monthly balance of the 2010 TSDA using the Board Approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN UNACCOUNTED FOR GAS VARIANCE ACCOUNT ("2010 UAFVA")

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 UAFVA is to record the cost of gas that is associated with volumetric variances between the actual volume of unaccounted for gas ("UAF") and the 2010 Board approved UAF volumetric forecast.

The gas costs associated with the UAF variance account will be calculated at the end of calendar 2010 based on the estimated volumetric variance between the 2010 Board approved level and the estimate of the 2010 actual UAF. An adjustment will be made to the UAFVA in the subsequent year to record any differences between the estimated UAF and actual UAF.

The UAF annual variance will be allocated on a monthly basis in proportion to actual sales and costed at the monthly PGVA reference price.

Carrying costs for the UAFVA will be calculated on the allocated monthly balances using the Board Approved EB-2006-0117 interest rate methodology. The balance of the UAFVA, together with the carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the estimated volumetric variance between the December 31, 2010 actual UAF and the Board Approved level:

Debit/Credit:	2010 UAFVA	(Account 179. 850)
Credit/Debit:	Gas Costs	(Account 623. 010)

To record the costs associated with the volumetric variance related to unaccounted for gas.

2. Interest accrual:

Debit/Credit:	Interest on 2010 UAFVA	(Account 179. 860)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2010 UAFVA using the Board Approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A STORAGE AND TRANSPORTATION DEFERRAL ACCOUNT (“2010 S&TDA”)

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 S&TDA is to record the difference between the forecast of Storage and Transportation rates (both cost of service and market based pricing) included in the Company’s approved rates and the final Storage and Transportation rates (both cost of service and market based pricing) incurred by the company. It will also be used to record variances between the forecast Storage and Transportation rebate programs and the final rebates received by the company. The accounting treatment for the S&TDA is in line with that established for the 2008 S&TDA, which recognized that storage and transportation services may be provided to the Company by suppliers other than Union Gas and at market based rates.

The 2010 S&TDA will also record the variance between the forecast Storage and Transportation demand levels and the actual Storage and Transportation demand levels. In addition, this account will be used to record amounts related to deferral account dispositions received or invoiced from Storage and Transportation suppliers.

The 2010 S&TDA will also record the variance between the forecasted commodity cost for fuel and the updated QRAM Reference Price.

Simple interest is to be calculated on the opening monthly balance of the 2010 S&TDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. Storage and Transportation rate variance:

   [(Final Storage and Transportation rates) – (Storage and Transportation rates underpinning the Company’s 2010 rates)] **X** Actual storage and/or transportation volumes

Debit/Credit:	2010 S&TDA	(Account 179. 880)
Credit/Debit:	Gas in Storage	(Account 152. 000)
	or	
Credit/Debit:	Gas Costs	(Account 623. 010)

   To record the difference between the Storage and Transportation rates included in the Company’s 2010 rates and the final Storage and Transportation rates.

2. To record variances in the Storage and Transportation rebate programs:

Debit:	Sundry Accounts Receivable	(Account 141. 030)
Credit:	2010 S&TDA	(Account 179. 880)
	or	
Debit:	2010 S&TDA	(Account 179. 880)
Credit:	Accounts Payable	(Account 259. 000)

To record the difference between the Storage and Transportation rebate programs included in the Company's 2010 rates and the final rebates received by the Company.

3. To record Storage and Transportation deferral account disposition:

Debit:	Sundry Accounts Receivable	(Account 141. 030)
Credit:	2010 S&TDA	(Account 179. 880)
	or	
Debit:	2010 S&TDA	(Account 179. 880)
Credit:	Accounts Payable	(Account 259. 000)

To record amounts related to deferral account dispositions received or invoiced from Storage and Transportation.

4. Inventory valuation adjustment:

Debit/Credit:	2010 S&TDA	(Account 179. 880)
Credit/Debit:	Gas In Storage	(Account 152. 000)

To record adjustments to storage and transmission fuel costs associated with quarterly price changes.

5. Interest accrual:

Debit/Credit:	Interest on 2010 S&TDA	(Account 179. 890)
Credit/Debit:	Interest Income/Expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2010 S&TDA using the Board Approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A CHANGE IN PURCHASED GAS VARIANCE DISPOSITION METHODOLOGY DEFERRAL ACCOUNT ("2010 CPGVDMDA")

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 CPGVDMDA is to record the one-time implementation costs in relation to changing the methodology by which the Company disposes of the PGVA. The change in methodology is a result of the Board's Decision and Order in the Commodity, Load Balancing and Cost Allocation proceeding (EB-2008-0106).

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record one-time implementation costs:

Debit:	2010 CPGVDMDA	(Account 179. 720)
Credit:	Accounts payable	(Account 251. 010)

To record the one-time implementation costs in relation to changing the methodology by which the Company disposes of the PGVA.

2. Interest accrual:

Debit:	Interest on 2010 CPGVDMDA	(Account 179. 730)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2010 CPGVDMDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A CARBON DIOXIDE OFFSET CREDITS DEFERRAL ACCOUNT ("2010 CDOCDA")

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 CDOCDA is to record amounts which represent proceeds resulting from the sale of or other dealings in earned carbon dioxide offset credits. This deferral account was originally approved by the Board in its Natural Gas Generic DSM proceeding, docket EB-2006-0021.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the proceeds resulting from the sale of earned carbon dioxide offset credits:

Debit:	Various accounts	(Account ___. ___)
Credit:	2010 CDOCDA	(Account 179. 500)

Proceeds arising from carbon dioxide offset credits earned.

2. Interest accrual:

Debit:	Interest expense	(Account 323. 000)
Credit:	Interest on 2010 CDOCDA	(Account 179. 510)

To record simple interest on the opening monthly balance of the 2010 CDOCDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A CLASS ACTION SUIT DEFERRAL ACCOUNT (“2010 CASDA”)

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The Board, in it’s EB-2007-0731 Decision, approved the use of an ongoing or continuance of a CASDA account as an extension of the Board Approved 2007 CASDA in order to record amounts as allowed within the account and bring forward any un-cleared account balance for future disposition. In that decision, the Board approved the recovery of amounts in the CASDA along with interest, over the five year period of 2008 through 2012. The 2007 CASDA, which included amounts brought forward from 2006, recorded the Company’s legal costs, plaintiff costs, costs of actuarial advice, costs of historical records analysis incurred in defending the 5% late payment penalty lawsuit against the Company, and the eventual settlement amount.

Simple interest is to be calculated on the opening monthly balance of the 2010 CASDA using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record the costs associated with defending the Company's late payment penalty:

Debit:	2010 CASDA	(Account 179. 400)
Credit:	Accounts payable	(Account 251. 010)
Credit:	2009 CASDA	(Account 179. 069)

To record the third party incremental costs incurred to defend the late payment penalty class action lawsuit and to roll forward un-cleared amounts from the board approved 2009 CASDA.

2. Interest accrual:

Debit:	Interest on 2010 CASDA	(Account 179. 410)
Credit:	Interest expense	(Account 323. 000)
Credit:	Interest on 2009 CASDA	(Account 179. 079)

To record simple interest on the opening monthly balance of the 2010 CASDA using the Board approved EB-2006-0117 interest rate methodology and to roll forward un-cleared amounts from the board approved 2009 interest on CASDA account.

ACCOUNTING TREATMENT FOR A DEFERRED REBATE ACCOUNT ("2010 DRA")

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 DRA is to record any amounts payable to, or receivable from, customers of Enbridge Gas Distribution as a result of the clearing of deferral and variance accounts authorized by the Board which remain outstanding due to the Company's inability to locate such customers. The account will also include amounts arising from differences between actual and forecast volumes used for the purpose of clearing deferral account balances.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. Disposition of non-gas supply deferral accounts:

Debit:	2008 DSMVA	(Account 179. 028)
Debit:	2009 ESMDA	(Account 179. 589)
Debit:	2009 EFTPBSDA	(Account 179. 080)
Debit:	2009 TRRCVA	(Account 179. 409)
Credit:	2009 AUTUVA	(Account 179. 569)
Credit:	2008 LRAM	(Account 179. 108)
Credit:	2010 CASDA	(Account 179. 400)
Credit:	2009 GDARCDA	(Account 179. 209)
Credit:	2009 DRA	(Account 179. 009)
Credit:	2009 MPFDA	(Account 179. 549)
Credit:	2009 OBAVA	(Account 179. 449)
Credit:	2009 OBSDA	(Account 179. 429)
Credit:	2009 OHCVA	(Account 179. 189)
Credit:	2008 SSMVA	(Account 179. 128)
Credit:	2009 IFRSTCDA	(Account 179. 380)
Credit:	Interest on DA's & VA's – various	(Account 179. ___)
Debit:	2010 DRA	(Account 179. 000)

2. Disposition of gas supply deferral accounts:

Debit:	2009 TSDA	(Account 179. 729)
Debit:	2009 S&TDA	(Account 179. 749)
Debit:	2009 PGVA	(Account 179. 709)
Credit:	2009 UAFVA	(Account 179. 769)
Debit:	Interest on DA's & VA's –various	(Account 179. ___)
Credit:	2010 DRA	(Account 179. 000)

3. Refund or collection:

Debit:	2010 DRA	(Account 179. 000)
Credit:	Accounts Receivable	(Account 140. 010)
	or	
Debit:	Accounts Receivable	(Account 140. 010)
Credit:	2010 DRA	(Account 179. 000)

To record the actual amounts refunded to / recovered from customers.

4. Interest accrual:

Debit/Credit:	Interest expense	(Account 323. 000)
Debit/Credit:	Interest on the 2010 DRA	(Account 179. 010)

To record simple interest on the opening monthly balance of the 2010 DRA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
ELECTRIC PROGRAM EARNINGS SHARING DEFERRAL ACCOUNT
("2010 EPESDA")

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 EPESDA is to track and account for the ratepayer share of net revenues generated by providing DSM services under contract to electric LDCs. The ratepayer share is 50% of net revenues, using fully allocated costs, as was determined in the generic DSM proceeding EB-2006-0021.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record the ratepayer share of net revenues from electric DSM:

Debit:	Other income	(Account 319. 010)
Credit:	Operating & Maintenance	(Various accounts)
Credit:	2010 EPESDA	(Account 179. 600)

To record the ratepayer share of net revenues generated by providing DSM services to electric LDCs.

2. Interest accrual:

Debit:	Interest expense	(Account 323. 000)
Credit:	Interest on 2010 EPESDA	(Account 179. 610)

To record simple interest on the opening monthly balance of the 2010 EPESDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
GAS DISTRIBUTION ACCESS RULE COSTS DEFERRAL ACCOUNT
("2010 GDARCDA")

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 GDARCDA is to record all incremental unbudgeted capital and operating costs associated with the development, implementation, and operation of the Gas Distribution Access Rule. Such costs would include, but not be limited to, market restructuring oriented customer education and communication programs, legal or expert advice required, operating costs in relation to the establishment of contractual agreements and developing revised business processes and related computer hardware and software required to meet the requirements of the GDAR.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record costs related to Gas Distribution Access Rule requirements:

Debit:	2010 GDARCDA	(Account 179. 200)
Credit:	Accounts payable	(Account 251. 010)

To record the unbudgeted costs associated with GDAR development, implementation, and operation.

2. Interest accrual:

Debit:	Interest on 2010 GDARCDA	(Account 179. 210)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2010 GDARCDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A MANUFACTURED GAS PLANT DEFERRAL ACCOUNT (“2010 MGPDA”)

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 MGPDA is to capture all costs incurred in managing and resolving issues related to the Company’s manufactured gas plant (“MGP”) legacy operations. Amounts recorded in the 2009 MGPDA will also be transferred to the 2010 MGPDA. Costs charged to the account could include, but are not limited to:

- Responding to all enquiries, demands and court actions relating to former MGP sites;
- All oral and written communications with existing and former third party liability and property insurers of the Company;
- Conducting all necessary historical research and reviews to facilitate the Company’s responses to all enquiries, demands, court actions and communications with claimants, third parties and insurers;
- Engaging appropriate experts (for example, environmental, insurance archivists, engineers, etc.) for the purposes of evaluating any alleged contamination that may have resulted from former MGP operations and providing advice regarding the appropriate steps to remediate/contain/monitor such contamination, if any;
- Engaging legal counsel to respond to all demands and court actions by claimants, and to take appropriate steps in relation to the Company’s existing and former third party liability and property insurers; and
- Undertaking appropriate research into the regulatory treatment of costs resulting from former MGP operations in the United States.

The MGPDA would also be used to record any amounts which are payable to any claimant following settlement or trial, including any damages, interest, costs and disbursements and any recoveries from insurers or third parties.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record costs:

Debit:	2010 MGPDA	(Account 179. 300)
Credit:	Accounts Payable	(Account 251. 010)
Credit:	2009 MGPDA	(Account 179. 309)

To record the unbudgeted costs incurred in managing and resolving manufactured gas plants legal proceedings and litigation and to roll forward any un-cleared 2009 MGPDA amounts.

2. Interest accrual:

Debit:	Interest on 2010 MGPDA	(Account 179. 310)
Credit:	Interest expense	(Account 323. 000)
Credit:	Interest on 2009 MGPDA	(Account 179. 319)

To record simple interest on the opening monthly balance of the 2010 MGPDA using the Board approved EB-2006-0117 interest rate methodology and to roll forward any un-cleared interest amounts on the 2009 MGPDA.

ACCOUNTING TREATMENT FOR A MUNICIPAL PERMIT FEES DEFERRAL ACCOUNT ("2010 MPFDA")

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 MPFDA is to capture the revenue requirement impact from Municipal permit fees charged for certain activities, such as road cuts, related to the Company's construction and maintenance operations. These are unbudgeted new charges being incurred by the Company, imposed by Municipal governments in Ontario, resulting from changes to Ontario regulations made under the Municipal Act, 2001.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record Municipal permit fee costs:

Debit:	2010 MPFDA	(Account 179. 540)
Credit:	Accounts Payable	(Account 251. 010)

To record the permit fee costs incurred in construction and maintenance operations.

2. Interest accrual:

Debit:	Interest on 2010 MPFDA	(Account 179. 550)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2010 MPFDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN ONTARIO HEARING COSTS VARIANCE ACCOUNT ("2010 OHCVA")

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 OHCVA is to record the variance between the actual costs incurred by the Company in relation to 2010 regulatory proceedings, stakeholder consultatives, Board costs, and related expenses versus the $5,842,500 which is embedded within rates.

Simple interest is to be calculated on the opening monthly balance of the 2010 OHCVA using the Board approved EB-2006-0117 interest rate methodology. The balance of the OHCVA, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the variance in Ontario proceeding related costs:

Debit:	2010 OHCVA	(Account 179. 220)
Credit:	Accounts payable	(Account 251. 010)
	or	
Debit:	Operating revenue	(Account 300. 000)
Credit:	2010 OHCVA	(Account 179. 220)

To record variances between actual Ontario proceeding related costs and the amount embedded in rates.

2. Interest accrual:

Debit/Credit:	Interest on 2010 OHCVA	(Account 179. 230)
Debit/Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2010 OHCVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN UNBUNDLED RATE IMPLEMENTATION COST DEFERRAL ACCOUNT ("2010 URICDA")

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 URICDA is to record any costs, if required, of continuing with a manual solution or the costs required of an automated solution for offering Unbundled Rates 125, 300, 315 and 316. Costs to be recorded in the account include administrative, staffing, training, communication, customer education, and all other reasonably incurred costs associated with offering these rates and the additional nomination windows required for such rates.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record costs related to the Unbundled Rate Implementation solution:

Debit:	2010 URICDA	(Account 179. 630)
Credit:	Accounts Payable	(Account 251. 010)

To record the costs associated with implementing Rates 125, 300, 315 and 316 through a continuing manual solution or an automated solution.

2. Interest accrual:

Debit:	Interest on 2010 URICDA	(Account 179. 640)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2010 URICDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN UNBUNDLED RATES CUSTOMER MIGRATION VARIANCE ACCOUNT (“2010 URCMVA”)

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 URCMVA is to record the revenue consequences of actual customer migration versus forecast migration for the new Unbundled Rates, 125 and 300. The pivot point or threshold for the variance account will be the revenue related to forecast migration to new rates such that if actual migration revenue is lower or higher than forecast, there would be an associated entry to the variance account to refund or collect from customers in all applicable rate classes.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record the impact of customer migration to unbundled rates versus forecast:

Debit/Credit:	2010 URCMVA	(Account 179. 670)
Credit/Debit:	Operating revenue	(Account 300. 000)

To record the revenue variance associated with actual versus forecast migration of customers to unbundled rates.

2. Interest accrual:

Debit/Credit:	Interest on 2010 URCMVA	(Account 179. 680)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2010 URCMVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN AVERAGE USE TRUE-UP VARIANCE ACCOUNT (“2010 AUTUVA”)

For the 2010 Fiscal Year (January 1, 2010 to December 31, 2010)

The purpose of the 2010 AUTUVA is to record (“true-up”) the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer, for general service rate classes (Rate 1 and Rate 6), embedded in the volume forecast that underpins Rates 1 and 6 and the actual weather normalized average use experienced during the year. The calculation of the volume variance between forecast average use and actual normalized average use will exclude the volumetric impact of Demand Side Management programs in that year. The revenue impact will be calculated using a unit rate determined in the same manner as for the derivation of the Lost Revenue Adjustment Mechanism (LRAM), extended by the average use volume variance per customer and the number of customers.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record the revenue impact of forecast versus normalized average use:

Debit/Credit:	2010 AUTUVA	(Account 179. 650)
Credit/Debit:	Operating revenue	(Account 300. 000)

To record the revenue impact associated with the variance in forecast average use per customer versus actual normalized average use per customer.

2. Interest accrual:

Debit/Credit:	Interest on 2010 AUTUVA	(Account 179. 660)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2010 AUTUVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A TAX RATE AND RULE CHANGE VARIANCE ACCOUNT (“2010 TRRCVA”)

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 TRRCVA is to record the ratepayer portion of any variance relating to changes in actual tax rates and rules which differ from those proposed and embedded in rates. In the event that actual future tax rates and rules are not as currently expected, the Company will calculate the appropriate amounts which should be shared equally between ratepayers and the Company, based upon 2007 Board Approved base level benchmarks embedded in rates, and record the appropriate variance in the variance account to be returned to or collected from ratepayers. This true-up will occur annually, along with any associated required change to ongoing future rates.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the impact of actual tax rate and rule changes versus forecast:

Debit/Credit:	Operating revenue	(Account 300. 000)
Credit/Debit:	2010 TRRCVA	(Account 179. 440)

To record the ratepayer portion of any variance in taxes as a result of actual tax rates and rules differing from those proposed and embedded in rates.

2. Interest accrual:

Debit/Credit:	Interest expense	(Account 323. 000)
Credit/Debit:	Interest on 2010 TRRCVA	(Account 179. 450)

To record simple interest on the opening monthly balance of the 2010 TRRCVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN EARNINGS SHARING MECHANISM DEFERRAL ACCOUNT ("2010 ESMDA")

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 ESMDA is to record the ratepayer share of utility earnings that result from the application of the earnings sharing mechanism. If the 2010 actual utility return on equity, calculated on a weather normalized basis, is more than 100 basis points over the amount calculated by applying the Board's ROE Formula, the resultant amount will be shared equally (i.e., 50/50) between the Company's ratepayers and shareholders. The calculation of a utility return for earnings sharing determination purposes, will include all revenues that would otherwise be included in earnings and only those expenses (whether operating or capital) that would otherwise be allowable deductions from earnings as within a cost of service application. In addition, the following are examples of shareholder incentives and other amounts which are outside of the ambit of the earnings sharing mechanism: amounts related to the Shared Savings Mechanism ("SSM") and Lost Revenue Adjustment Mechanism ("LRAM"), amounts related to storage and transportation deferral accounts, and the Company's 50% share of tax savings calculated in association with expected tax rate and rule changes.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the ratepayers' share of earnings as a result of the earning sharing mechanism:

Debit:	Operating revenue	(Account 300. 000)
Credit:	2010 ESMDA	(Account 179. 580)

To record the ratepayers' share of utility earnings when the actual weather normalized ROE is greater than 100 basis points over the Board's formula ROE.

2. Interest accrual:

Debit:	Interest expense	(Account 323. 000)
Credit:	Interest on 2010 ESMDA	(Account 179. 590)

To record simple interest on the opening monthly balance of the 2010 ESMDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN INTERNATIONAL FINANCIAL REPORTING STANDARDS TRANSITION COSTS DEFERRAL ACCOUNT (“2010 IFRSTCDA”)

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 IFRSTCDA is to record the difference between the actual incremental one-time administrative costs incurred to convert accounting policies and processes from their current compliance with Canadian Generally Accepted Accounting Principles (CGAAP) to their future compliance with International Financial Reporting Standards (IFRS) and the costs included in rates as approved by the Board.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record incremental one-time administrative costs:

Debit:	2010 IFRSTCDA	(Account 179. 460)
Credit:	Other admin and general expense	(Account 728. ___)
Credit:	Depreciation	(Account 303. ___)

To record incremental one time administrative costs in relation to converting accounting policies and processes from compliance with CGAAP to IFRS.

2. Interest accrual:

Debit:	Interest on 2010 IFRSTCDA	(Account 179. 470)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2010 IFRSTCDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN OPEN BILL SERVICE DEFERRAL ACCOUNT ("2010 OBSDA")

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 OBSDA is to bring forward, track and clear a portion of balances from the previously un-cleared 2009 OBSDA. The account include amounts approved to be brought forward from the 2008 OBSDA and amounts incurred / recorded in 2009 for TMG consulting costs, OBA stakeholder costs and start up legal costs. An equal amount of the above total costs is to be shared equally by ratepayers and EGD over the years 2010 through 2012. As a result of the required timing of clearance of these accounts, the amount to be cleared to ratepayers for 2010 will be cleared through a 2009 account with the 2011 and 2012 amounts to be cleared through 2010 and 2011 accounts.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To track and record the amount of the OBSDA costs for clearance in 2010 through 2012:

Debit:	2010 OBSDA	(Account 179. 420)
Credit:	Other admin and general expense	(Account 728. ___)
Credit:	Depreciation	(Account 303. ___)

To track and record costs relating to Open Bill Services program.

2. Interest accrual:

Debit:	Interest on 2010 OBSDA	(Account 179. 430)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2010 OBSDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN OPEN BILL ACCESS VARIANCE ACCOUNT ("2010 OBAVA")

For the 2010 Fiscal Year
January 1, 2010 to December 31, 2010)

The purpose of the 2010 OBAVA is to bring forward, track and clear a portion of balances from the previously un-cleared 2009 OBAVA. An equal amount of the above total cost is to be shared equally by ratepayers and EGD over the years 2010 through 2012. As a result of the required timing of clearance of these accounts, the amount to be cleared to ratepayers for 2010 will be cleared through a 2009 account with the 2011 and 2012 amounts to be cleared through 2010 and 2011 accounts.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record incremental one-time administrative costs:

Debit:	2010 OBAVA	(Account 179. 520)
Credit:	Other admin and general expense	(Account 728. ___)
Credit:	Depreciation	(Account 303. ___)

To track and record costs relating to Open Bill Access program.

2. Interest accrual:

Debit:	Interest on 2010 OBAVA	(Account 179. 530)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2010 OBAVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN OPEN BILL REVENUE VARIANCE ACCOUNT ("2010 OBRVA")

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 OBRVA is to track and record the net revenue for Open Bill Services. The account allows for net revenue annual revenue amounts in excess of $7.389 million to be shared 50/50 with ratepayers, and allows for a credit to Enbridge in the event that net annual revenues are less than $4.889 million, equal to the shortfall between actual net revenues and $4.889 million. The net revenue amounts will be determined in accordance with the EB-2009-0043 Board Approved Open Bill Access Settlement Proposal dated October 15, 2009.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record incremental one-time administrative costs:

Debit:	2010 OBRVA	(Account 179. 480)
Credit:	Other admin and general expense	(Account 728. ___)
Credit:	Depreciation	(Account 303. ___)

To record net revenue associated with Open Bill Service programs.

2. Interest accrual:

Debit:	Interest on 2010 OBRVA	(Account 179. 490)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2010 OBRVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
EX-FRANCHISE THIRD PARTY BILLING SERVCIES DEFERRAL ACCOUNT
("2010 EFTPBSDA")

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 EFTPBSDA is to record and track revenues generated from third party billing services provided to ex-franchise parties net of incremental costs associated with the services. The net revenue is to be shared on a 50/50 basis with ratepayers. The net revenue amounts will be determined in accordance with the EB-2009-0043 Board Approved Open Bill Access Settlement Proposal dated October 15, 2009.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record incremental one-time administrative costs:

Debit:	2010 EFTPBSDA	(Account 179. 080)
Credit:	Other admin and general expense	(Account 728. ___)
Credit:	Depreciation	(Account 303. ___)

To record net revenue associated with Ex-Franchise third party Billing Services.

2. Interest accrual:

Debit:	Interest on 2010 EFTPBSDA	(Account 179. 090)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2010 EFTPBSDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A MEAN DAILY VOLUME MECHANISM DEFERRAL ACCOUNT ("2010 MDVMDA")

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 MDVMDA is to record the incremental costs of establishing and implementing the changes required to meet the Company's newly proposed Mean Daily Volume mechanism. The Company was ordered to bring forward a proposed mechanism for future adoption in the Board's Decision and Order in the Commodity, Load Balancing and Cost Allocation proceeding (EB-2008-0106).

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record incremental costs:

Debit:	2010 MDVMDA	(Account 179. 560)
Credit:	Accounts payable	(Account 251. 010)

To record the incremental costs of establishing and implementing the Company's proposed Mean Daily volume mechanism.

2. Interest accrual:

Debit:	Interest on 2010 MDVMDA	(Account 179. 570)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2010 MDVMDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
DEMAND SIDE MANAGEMENT VARIANCE ACCOUNT
("2010 DSMVA")

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 DSMVA is to record the difference between the actual 2010 DSM spending and the $26.7 million incorporated within 2010 rates. Any amount of under spending will be incorporated into the DSMVA, but overspending will be capped at 15% of the DSM budget dependent upon the Company achieving more than the 2010 DSM targeted TRC Net Benefits, on a pre-audited basis, as determined in the EB-2006-0021 proceeding. Furthermore, overspending charged to the 2010 DSMVA is limited to incremental program expenses only.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record variances in variable costs only:

Debit:	2010 DSMVA	(Account 179. 060)
Credit:	Operating & Maintenance	(Various accounts)
	or	
Debit:	Operating & Maintenance	(Various accounts)
Credit:	2010 DSMVA	(Account 179. 060)

To record the difference between actual and forecast Demand Side Management operating expenditures.

2. Interest accrual:

Debit:	Interest on 2010 DSMVA	(Account 179. 070)
Credit:	Interest expense	(Account 323. 000)
	or	
Debit:	Interest expense	(Account 323. 000)
Credit:	Interest on 2010 DSMVA	(Account 179. 070)

To record simple interest on the opening monthly balance of the 2010 DSMVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A LOST REVENUE ADJUSTMENT MECHANISM ("2010 LRAM")

For the 2010 Fiscal Year
(January 1, 2010 to December 31, 2010)

The purpose of the 2010 LRAM is to record the amount of distribution margin gained or lost when the Company's DSM programs are less or more successful than budgeted, for the period January 1, 2010 to December 31, 2010.

When the utility's DSM programs are less successful in the Test Year than budgeted, the utility gains distribution margin. Similarly, the utility loses distribution margin in the Test Year when its DSM programs are more successful than budgeted.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record LRAM amounts:

Debit:	Gas costs	(Account 623. 010)
Credit:	2010 LRAM	(Account 179. 100)
	or	
Debit:	2010 LRAM	(Account 179. 100)
Credit:	Gas costs	(Account 623. 010)

To record in the LRAM, the distribution margin impact of differences between actual and budget gas savings forecast in the Company's DSM programs.

2. Interest accrual:

Debit:	Interest expense	(Account 323. 000)
Credit:	Interest on 2010 LRAM	(Account 179. 110)
	or	
Debit:	Interest on 2010 LRAM	(Account 179. 110)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2010 LRAM using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A SHARED SAVINGS MECHANISM VARIANCE ACCOUNT ("2010 SSMVA")

For the 2010 Fiscal Year (January 1, 2010 to December 31, 2010)

The purpose of the 2010 SSMVA is to record the actual amount of the shareholder incentive earned by the Company as a result of its DSM programs. The criteria and formula used to determine the amount of any shareholder incentive, to be recorded in the SSMVA, will be in accordance with the guidelines established in the generic DSM proceeding EB-2006-0021.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. Shareholder incentive earned by the Company related to DSM programs:

Debit:	2010 SSMVA	(Account 179. 280)
Credit:	Other income	(Account 319. 010)

To record the shareholder incentive earned by the Company related to its DSM programs.

2. Interest accrual:

Debit/Credit:	Interest on 2010 SSMVA	(Account 179. 290)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2010 SSMVA using the Board approved EB-2006-0117 interest rate methodology.

APPRO INTERROGATORY #2

INTERROGATORY

Reference: Exh C, T2, S2, Page 8, Footnote **:
We note that there is the following description in the footnote on pg. 8 of Sch 2. "** The Company incurred $78.9 k in additional staffing costs in 2010 associated with the additional upstream (such as FT-SN) nomination windows for unbundled customers. As specified in the NGEIR Settlement Agreement (EB-2005-0551 Ex S T1 S1 p13), the costs are to be recovered from the parties who availed of the service. Three customers on Rate 125 utilized the additional nomination windows in 2010 and the costs were allocated equally among the three customers."

(a) Please provide the reference to any other information included in the application that is intended to explain the URICDA.

(b) Please provide a detailed description of the nature of the "additional staffing costs" referred to above. In particular:

(i) Are these costs associated with incremental staff hired to perform this function?

(ii) Please provide in detail the functions associated with the "additional staffing costs" & explain how they are incremental to the staffing costs included in EGD's overall rates.

(iii) Enbridge is also a significant FT-SN shipper on TCPL and the capacity is used for this system supply, and also makes additional nominations in order to effectively utilize the capacity. Please detail how the proportion of the additional costs incurred is related to and has been allocated to system supply.

(iv) What is the basis to pass on these additional costs incurred in the context of the IRM?

RESPONSE

(a) There is no separate explanation included in this application for URICDA. Please see the response and attachments to APPRO Interrogatory #1 at Exhibit 1, Tab 6,

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

Schedule 1, page 1. Page 22 of Appendix D of the EB-2009-0172 Final Rate Order contains a description of the accounting treatment for the 2010 URICDA.

(b)

(i) Confirmed. These costs are associated with one incremental FTE that was hired to facilitate the creation of the Volume Planner role. The Volume Planner is responsible for processing the additional nominations arising from short notice nomination windows as well as other activities for unbundled large power generators. The addition of the FTE and optimization of shift schedules allowed three senior staff to act in the capacity of either a Volume Planner or controller/scheduler. As a result incremental costs were kept to a minimum and were considerably less than the estimate ($250,000 - $750,000 per year, depending upon the number of customers) provided in the NGEIR generic proceeding. However, the optimization of shift schedules has reduced the flexibility of gas control to deal with unanticipated staff absences in its 24/7 operation. .

(ii) The functions of the Volume Planner are distinct from the traditional functions of gas control and gas management services. Gas controllers are responsible for forecasting daily demand, monitoring distribution system pressures and ensuring the system is balanced at the end of the gas day. Schedulers process nominations arising out of EGD's upstream supply, transport and storage contracts as well as direct purchase activities, excluding short notice services for unbundled customers. Volume Planner functions include the following activities for power generators:

- Processing additional nominations as a result of short notice nomination windows offered in unbundled rates
- Ensuring unbundled customer nominated volumes fall within contract allowances
- Answer customer inquiries related to operations
- Monitor hourly flows to ensure actual consumption is not out of tolerance with nominations (this is especially critical during peak operating days and during abnormal or emergency operating conditions).
- Provide reports which contribute to the invoicing process for unbundled customers
- Help Gas Control forecast overall daily system load based on expected Power Gen short notice service requirements.

(iii) Please see ii) above.

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

(iv) These costs are included in the application to clear 2010 deferral and variance account balances which were established by the Board as part of the Final Rate Order for 2010 IRM Adjustment. The Unbundled Rate Implementation Cost Deferral Account (URICDA) was established through the Board's Rate Order arising from the Natural Gas Electricity Interface Review (NGEIR) Decision with Reasons (EB-2005-0051) to recover incremental costs associated with unbundling implementation.

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

APPRO INTERROGATORY #3

INTERROGATORY

Reference: Exh C, T2, S2, Page 4

(a) Please provide the details behind the $145,500 cost shown in Item No. 7.

(b) Please explain how the amounts in column 9 are allocated to Rate 125.

RESPONSE

(a) The following provides the breakdown of the 2010 URICDA balance:

Incremental FTE to support unbundled services	$ 66,600
Incremental FTE for addt'l upstream nom windows	$ 78,900
Total 2010 URICDA balance	$145,500

(b) Rate 125 customers are allocated the entire $78,900 in additional staffing costs associated with supporting additional upstream nomination window, per the NGEIR Settlement Agreement. In addition, they are allocated their share of the $66,600 that supports the overall implementation of unbundled services. This cost is allocated to all large volume customers based on the number of customers in each rate class as specified in the NGEIR Settlement Agreement and consistent with Board-approved methodology. The amount allocated to Rate 125 is $500.

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

APPRO INTERROGATORY #4

INTERROGATORY

Reference: Exh C, T2, S2, Pages 7 & 8

(a) Please provide the details of the derivation of the rates for Rate 125 on each schedule.

(b) Footnote * on each page states that the "Unit Rates are derived based on 2010 actual volumes."

(i) Are the unit rates on these pages demand charges or commodity charges for Rate 125?

(ii) Please provide the total contract demand volumes and total throughput volumes for the Rate 125 customers.

RESPONSE

(a)

Rate 125 allocation of 2010 Deferral and Variance Account Balances:					
Method of Allocation	**($000)**	**Reference**	**Unit Rate determination**	**cents/m ^{3}**	**($000/user)**
GST-Applicable					
DRR	16.0	ExC T2 S2 p3 col 7 line 1.7	divided by R125 contract demand*	0.2373	
HST-Applicable					
DRR	(131.0)	ExC T2 S2 p4 col 7 line 1.7	divided by R125 contract demand*	(1.9422)	
Rate Base	6.3	ExC T2 S2 p4 col 10 line 1.7	divided by R125 contract demand*	0.0936	
Number of Customers	79.4	ExC T2 S2 p4 col 9 line 1.7	$0.5k divided by R125 contract demand*, $78.9 divided by 3 customers	0.0071	26.3
Total HST-applicable	(45.3)			(1.8415)	
TOTAL Rate 125	(108.7)		GST-Applicable	0.2373	
			HST-Applicable	(1.8415)	26.3
* Notes: Rate 125 contract demand = 6,746,281,000					

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

(b)

(i) Unit rates for Rate 125 are derived on the basis of contract demand and billing contract demand, if applicable. All costs for Rate 125 are recovered through demand charges in rates.

(ii) The total contract demand for Rate 125 in 2010 is 6,746,281,000 m^3.

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma