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May 18, 2012

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. ("Enbridge")
2013 Rate Adjustment Application
Ontario Energy Board ("Board") File Number EB-2011-0354

Attached please find the following new exhibits in Enbridge's 2013 Rates proceeding:

Exhibit A3, Tab 4, Schedule 2;
Exhibit A3, Tab 6, Schedule 2;
Exhibit B2, Tab 2, Schedule 1;
Exhibit D2, Tab 1, Schedule 1; and
Exhibit D2, Tab 5, Schedule 1.

This submission was filed through the Board's RESS and will be available on the Company's website at www.enbridgegas.com/ratecase .

Please contact the undersigned if you have any questions.

Yours truly,

[original signed by]

Lorraine Chiasson
Regulatory Coordinator

cc: Mr. F. Cass, Aird & Berlis LLP (via email)
All interested Parties in EB-2011-0354

ENBRIDGE GAS DISTRIBUTION INC.

2011 Annual Report

Enbridge Gas Distribution Inc.
500 Consumers Road
Toronto, ON M2J 1P8
Canada

Mailing Address
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Scarborough, ON M1K 5E3
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Consolidated Financial Statements 28 | Corporate Information 61 | Corporate Governance 62

This Management's Discussion and Analysis (MD&A) dated February 14, 2012 should be read in conjunction with the audited consolidated financial statements and notes thereto of Enbridge Gas Distribution Inc. (the Company) for the year ended December 31, 2011, which are prepared in accordance with Part V – Pre-changeover Accounting Standards of The Canadian Institute of Chartered Accountants (CICA) Handbook (Canadian GAAP or Part V). All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

OVERVIEW

The Company is a rate-regulated natural gas distribution utility that has been in operation for more than 160 years. The Company serves approximately 2 million residential, commercial and industrial customers in its franchise areas of central and eastern Ontario, including the City of Toronto and 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 areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence). The Company is a wholly owned subsidiary of Enbridge Inc. (Enbridge).

The Company also owns and operates unregulated facilities in Ontario, including two solar projects located in Amherstburg, Ontario, through its 99.9% limited partnership interest in Project AMBG2 LP (Project Amherstburg) and unregulated natural gas storage facilities.

PERFORMANCE OVERVIEW

Year ended December 31,	2011	2010	2009
(millions of Canadian dollars, except per share amounts)			
Earnings attributable to the common shareholder	**209**	191	218
Earnings excluding the effect of weather[1]	**208**	203	201
Cash Flow Data			
Cash provided by operating activities	**514**	512	953
Cash used by investing activities	**(464)**	(365)	(384)
Cash used by financing activities	**(54)**	(154)	(661)
Dividends			
Common share dividends declared	**220**	215	188
Dividends declared per common share	**1.56**	1.53	1.34
Preferred share dividends declared	**2**	2	3
Dividends declared per preferred share	**0.60**	0.52	0.84
Total revenues	**2,466**	2,475	2,903
Total assets	**7,315**	7,152	6,998
Total long-term liabilities	**4,054**	3,871	3,547

[1] *Earnings excluding the effect of weather is a non-GAAP measure that does not have any standardized meaning prescribed by GAAP. For more information on this non-GAAP measure see page 4.*

Earnings Attributable to the Common Shareholder

Earnings attributable to the common shareholder were $209 million for the year ended December 31, 2011 compared with $191 million for the year ended December 31, 2010. The increase was primarily due to colder weather, lower interest expense, lower income taxes, lower earnings sharing, customer growth and higher distribution charges. This was partially offset by higher operating and administrative expenses and higher depreciation and amortization expense.

Earnings attributable to the common shareholder were $191 million for the year ended December 31, 2010 compared with $218 million for the year ended December 31, 2009. The decrease primarily resulted from warmer weather and higher depreciation and amortization expense, partially offset by customer growth, higher distribution charges and lower income taxes. Depreciation and amortization expense was higher due to an increase in the overall asset base, including the implementation of a new customer billing system in late 2009.

Earnings Excluding the Effect of Weather

Year ended December 31,	2011	2010	2009
(millions of Canadian dollars)			
Earnings attributable to the common shareholder	209	191	218
(Colder)/warmer than normal weather	(1)	12	(17)
Earnings excluding the effect of weather	208	203	201

The effect of weather is measured by heating degree days and 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. Heating degree days is a key measure used by the Company to isolate the impact of weather, a factor beyond the control of management. This measure enables a meaningful analysis of the operational performance of the Company over different periods.

Normal weather is the weather forecast by the Company in its distribution franchise area, using the forecasting methodology approved by the Ontario Energy Board (OEB). Normal weather is a measure that is unique to the Company and does not have any standardized meaning. In addition, due to differing franchise areas, it is unlikely to be directly comparable to the impact of weather-normalized earnings that may be reported by other entities. Moreover, normal weather may not be comparable from year to year given that the forecasting models are updated annually to reflect the recent weather trend.

Earnings excluding the effect of weather were $208 million for the year ended December 31, 2011 compared with $203 million for the year ended December 31, 2010. The increase was primarily due to lower interest expense, lower income taxes, lower earnings sharing and customer growth. This was partially offset by higher operating and administrative expenses and higher depreciation and amortization expense.

Earnings excluding the effect of weather were $203 million for the year ended December 31, 2010 compared with $201 million for the year ended December 31, 2009. The increase was primarily due to customer growth, higher distribution charges and lower taxes, partially offset by higher depreciation and amortization expense.

Revenues

Revenues for the year ended December 31, 2011 were $2,466 million compared with $2,475 million for the year ended December 31, 2010. The decrease in revenues was primarily a result of lower natural gas prices and other revenue, partially offset by colder weather, customer growth and higher distribution charges.

Revenues for the year ended December 31, 2010 were $2,475 million compared with $2,903 million for the year ended December 31, 2009. The decrease in revenues was primarily a result of lower natural gas prices and warmer weather compared to the prior year, partially offset by customer growth and higher distribution charges.

Forward-looking Information

Forward-looking information, or forward-looking statements, have been included in this MD&A 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; 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 underlie 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 MD&A 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 MD&A 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.

Non-GAAP Measure

This MD&A contains references to earnings excluding the effect of weather, which represents earnings attributable to the common shareholder adjusted for weather. Management believes that the presentation of this measure provides useful information to investors and the shareholder as it provides increased transparency and predictive value. Management uses this measure to set targets and assess performance of the Company. Earnings excluding the effect of weather is not a measure that has a standardized meaning prescribed by GAAP and is not considered a GAAP measure; therefore, this measure may not be comparable with a similar measure presented by other issuers.

STRATEGY

The Company's vision is to become North America's leading energy distribution and services company. To achieve its vision, the Company has outlined the following strategic objectives:

- achieve and maintain top decile safety performance;
- deliver shareholder value;
- maintain and enhance customer and stakeholder relationships;
- maintain a healthy and productive work environment; and
- enhance governance, integrity and transparency in all business processes.

The Company's strategic initiatives are designed to protect and enhance its core business with a continued focus on optimizing performance during the Incentive Regulation (IR) term. The Company will target new growth opportunities, which complement its core business, by pursuing newly evolving business models and technologies. In addition, the Company will continue to grow its natural gas storage assets.

RECENT DEVELOPMENTS

Amherstburg Solar Projects

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company. Project Amherstburg holds two solar projects, consisting of separate 10 megawatt (MW) and 5-MW facilities, both located in Amherstburg, Ontario. The total consideration transferred for the two projects was approximately $66 million, and was primarily funded by the issuance of common shares. The remaining 0.1% limited partnership interest is owned by the general partner, Project AMBG2 Inc., a wholly-owned subsidiary of Enbridge. First Solar Inc. constructed both facilities under fixed price engineering, procurement and construction agreements, and is providing operating and maintenance services for a period of 10 years to both projects, with an optional 10-year renewal. Construction was completed and commercial operations commenced in August 2011. The combined facilities' power output is being sold to the Ontario Power Authority pursuant to 20-year fixed price power purchase agreements. The investment complies with the *Affiliate Relationships Code for Gas Utilities* issued by the OEB and the Company's Undertakings to the Lieutenant Governor in Council for the Province of Ontario.

Customer Care Agreement Extension

In February 2011, the Company's Board of Directors approved a five-year nine month extension to the Company's customer care services contract with a third party service provider for call centre, collections and billing services. This contract extension is effective April 1, 2012 and has been structured to provide enhanced levels of customer service and cost certainty. The total cost of the customer care services during the term of the extension is approximately $360 million. The Company filed an application with the OEB in June 2011 requesting that the OEB establish a procedure to facilitate the completion of a regulatory settlement agreement and subsequent approval of the rate recovery of the costs associated with the extended customer care services contract and other related costs. The OEB approved the Company's recovery of costs associated with the agreement in September 2011. Other elements of the customer care services also form part of the settlement agreement.

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 report's new policy guidelines forecasted a new base level return on equity (ROE) of 9.75% for the Company's 2010 rate year, which was higher than the 8.37% generated by the 1997 ROE formula. 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. The OEB issued a decision in May 2010 that the new ROE is not to be used for such earnings sharing determinations. The Company appealed the OEB's 2010 decision to the Ontario Divisional Court and the appeal was dismissed by the Divisional Court in March 2011. As a result, earnings sharing will continue to be calculated on the basis of the 1997 ROE formula for the balance of the IR term. The Company has applied for the new ROE to determine rates after the conclusion of the IR term, commencing with the 2013 rate year.

Unregulated Storage Services And Nexus Project

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, 2011, the Company had expanded its storage capacity by 12% (to total capacity of approximately 0.3 billion cubic metres or 12 billion cubic feet (bcf)), compared to pre-deregulation capacity, and sold unregulated storage services into the storage market.

The Nexus Project is a 4.5 bcf expansion of the Company's unregulated natural gas storage facility near Sarnia, Ontario. The project, which has received regulatory approval for construction, is secured by a long-term commercial contract. Construction began in the second quarter of 2011 and was completed in 2011 at an approximate capital cost of $34 million. Additional remediation and close-out activities are expected to be performed in 2012 to bring the total capital cost to approximately $38 million.

Appointment Of New President

Effective September 1, 2011, Mr. Guy Jarvis was appointed as President of the Company. At the same time, Ms. Janet Holder, the Company's previous President, was appointed Executive Vice President, Western Access, Enbridge.

RESULTS OF OPERATIONS

Year ended December 31,	2011	2010	2009
(millions of Canadian dollars)			
Gas distribution margin	1,021	995	1,025
Other revenue	104	108	108
Operating and administrative expenses	(419)	(393)	(385)
Depreciation and amortization	(281)	(270)	(254)
Municipal and other taxes	(41)	(44)	(49)
Earnings sharing	(13)	(19)	(19)
Affiliate financing income	63	63	63
Interest expense	(172)	(186)	(190)
Income taxes	(51)	(61)	(78)
Earnings	211	193	221
Earnings attributable to the common shareholder	209	191	218

Gas Distribution Margin

Gas distribution margin for the year ended December 31, 2011 increased by $26 million compared with the year ended December 31, 2010. The increase was primarily due to colder weather, customer growth and higher distribution charges.

The heating degree days reported in 2011 were 5 heating degree days warmer compared with forecast heating degree days. However, due to the relative effectiveness and monthly distribution of heating degree days in the year, on a weather-normalized basis, net gas distribution margin for the year ended December 31, 2011 would have been lower by $1 million (2010 - higher by $17 million). As experienced in 2010, there was significant variability in the 2011 heating degree day profiles of the geographical regions in which the Company operates. Heating degree days are fully effective, typically in the peak winter months, when their occurrence directly impacts the consumption pattern by a similar magnitude. Weather, measured in heating degree days, was 3,597 heating degree days for the year ended December 31, 2011 compared with 3,466 heating degree days for the year ended December 31, 2010.

Gas distribution margin for the year ended December 31, 2010 decreased by $30 million compared with the year ended December 31, 2009. The decrease was primarily due to warmer weather, partially offset by customer growth and higher distribution charges.

The heating degree days reported in 2010 were 80 heating degree days warmer compared with forecast heating degree days, with significant variability in the heating degree day profiles of the geographical regions in which the Company operates, unlike what was experienced in 2009. On a weather-normalized basis, net gas distribution margin in the year ended December 31, 2010 would have been higher by approximately $17 million (2009 - lower by $25 million). Weather, measured in heating degree days, was 3,466 degree days for the year ended December 31, 2010 compared with 3,767 heating degree days for the year ended December 31, 2009.

Other Revenue

Other revenue for the year ended December 31, 2011 decreased by $4 million compared with the year ended December 31, 2010. The decrease was primarily due to higher Shared Savings Mechanism revenue in the prior year which resulted from exceeding targets on delivery of energy efficiency programs for promotion of energy efficient use of natural gas to customers. Contributing to the decrease was lower revenue from the management of fee-for-service energy efficiency initiatives. This was partially offset by revenue from Project Amherstburg and higher unregulated storage revenue.

Other revenue for the year ended December 31, 2010 was consistent with that of the year ended December 31, 2009. Incremental revenues during the year were derived from the management of fee-for-service energy efficiency initiatives and from unregulated storage operations due to additional contracts for storage services; however, these were offset by the inclusion of interest income in fiscal 2009 relating to recovery of a GST overpayment.

Operating and Administrative

Operating and administrative expenses for the year ended December 31, 2011 increased by $26 million compared with the year ended December 31, 2010. The increase was primarily due to higher employee related costs, higher pipeline integrity and safety costs, and higher customer support related costs.

Operating and administrative expenses for the year ended December 31, 2010 increased by $8 million compared with the year ended December 31, 2009. The increase was primarily due to higher costs relating to the management of fee-for-service energy efficiency initiatives for external parties and higher employee related costs, partially offset by lower customer support related costs due to the implementation of a new customer billing system in late 2009.

Depreciation and Amortization

Depreciation and amortization charge for the year ended December 31, 2011 increased by $11 million compared with the year ended December 31, 2010. Depreciation was higher primarily due to an increase in the overall asset base resulting from customer growth projects and improvements to the distribution system.

Depreciation and amortization charge for the year ended December 31, 2010 increased by $16 million compared with the year ended December 31, 2009. Depreciation was higher primarily due to an increase in the overall asset base mainly resulting from the implementation of a new customer billing system in late 2009.

Municipal and Other Taxes

Municipal and other taxes for the year ended December 31, 2011 decreased by $3 million compared with the year ended December 31, 2010. The decrease was primarily due to the elimination of Ontario's capital tax in 2010.

Municipal and other taxes for the year ended December 31, 2010 decreased by $5 million compared with the year ended December 31, 2009. The decrease was primarily due to the elimination of Ontario's capital tax.

Earnings Sharing

Earnings sharing represents the estimated customer portion of regulated earnings in excess of 100 basis points above the ROE threshold currently applicable to the Company, relating to the approved IR formula for the current fiscal year and relating to the OEB's ROE policy guideline in effect prior to December 2009. The earnings sharing mechanism resulted in the return of revenue of $13 million to customers for the year ended December 31, 2011 (2010 - $19 million; 2009 - $19 million), subject to OEB approval in 2012. There was approximately $6 million in lower earnings sharing during 2011 as compared to 2010 even though there was no significant variance in regulated earnings. The lower earnings sharing is primary as a result of a higher rate base threshold in 2011 compared to the prior period.

Interest Expense

Interest expense for the year ended December 31, 2011 decreased by $14 million compared with the year ended December 31, 2010. The decrease was primarily due to the Company's redemption of its $150 million 10.80% debentures in April 2011, which were replaced with the issuance of $100 million medium term notes (MTNs) at 4.95% and additional draws on its credit facilities at lower interest rates.

Interest expense for the year ended December 31, 2010 decreased by $4 million compared with the year ended December 31, 2009. The decrease was primarily due to the Company's redemption of its $100 million 11.15% debentures in March 2009 and lower credit facility fees resulting from more favourable market conditions.

Income Taxes

Year ended December 31,	2011	2010	2009
(millions of Canadian dollars)			
Earnings before income taxes	262	254	299
Income taxes	51	61	78
Effective tax rate (%)	19.5	24.0	26.1

The effective tax rate for the year ended December 31, 2011 was lower compared with the year ended December 31, 2010. The decrease was due to temporary differences relating to property, plant and equipment and intangible assets, and an approximate 2.75% reduction in the combined federal and Ontario income tax rates.

The effective tax rate for the year ended December 31, 2010 was lower compared with the year ended December 31, 2009. The decrease was primarily due to a 1.0% reduction in each of the federal and Ontario income tax rates.

RATE REGULATION

The utility operations of the Company and St. Lawrence are regulated by the OEB and the New York State Public Service Commission (NYSPSC), respectively (collectively the Regulators).

Incentive Regulation

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 Settlement Agreement (the Settlement) with customer representatives.

In 2008, the Company moved to an IR methodology. The objectives of the IR Settlement are as follows:

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

In preparation for the conclusion of the current IR term at the end of 2012, the Company has recently filed a 2013 Cost of Service (COS) application. The Company expects the OEB to address the application in 2012.

2012 Rate Adjustment Application

In September 2011, the Company filed an application with the OEB to adjust rates for 2012 pursuant to the approved IR formula. The Company applied for distribution revenue of $1,024 million, and $1,004 million or 98%, was approved for recovery by the OEB, pursuant to a settlement agreement with the intervenors representing customers. The rate adjustment was effective January 1, 2012. A hearing with respect to the remaining $20 million applied for distribution revenue and related issues was held by the OEB in January 2012 with a decision expected by April 2012.

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.

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.

Impact of Rate Regulation

The Company follows GAAP, which may differ in their application to the Company's regulated operations, as compared to non-regulated businesses. These differences occur when the Regulators render their decisions on the Company's rate applications, and generally involve the timing of revenue and expense recognition to ensure that the actions of the Regulators, which create assets and liabilities, have been reflected in the consolidated financial statements.

Accounting Guideline 19 (AcG-19), *Disclosures by Entities Subject to Rate Regulation*, requires the disclosure of information to facilitate an understanding of the nature and economic effects of rate regulation, as well as additional information on how rate regulation has affected the Company's consolidated financial statements. Detailed disclosure on rate regulation is included in Note 3 to the 2011 Annual Consolidated Financial Statements.

The Company has several instances where the difference between the amount approved by the Regulators for inclusion in regulated rates and the Company's actual experience is deferred until the Regulators approve the refund to or recovery from customers.

The difference between the total natural gas distributed by the Company and the amount of natural gas billed or billable to customers for their recorded consumption, referred to as unaccounted for gas variance, is an example. To the extent the difference varies from the approved amount built into rates, the variance is deferred until the subsequent year, and upon refund or recovery, no earnings impact is recorded. Effectively, the consolidated statement of earnings captures only the approved estimate of this variance and the related revenue, rather than the actual variance and related revenue.

There are other areas where the determination of the amounts to be recovered in current rates is different from the determination that would be reported by a non-regulated business, and the Company records those items on the same basis as they are recovered in rates. Future removal and site restoration reserves, income taxes and employee future benefits are the most significant such examples.

The recognition or omission of these items is based on an expectation of the future actions of the Regulators. For example, the liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. However, the regulated utility operations of the Company recover income tax expense based on the taxes payable method as prescribed by the Regulators for rate-making purposes. As a result, rates do not include the recovery of future income taxes related to temporary differences. A corresponding future income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates.

To the extent that the Regulators' future actions are different from the Company's current expectations, the timing and amount of recovery or refund of amounts recorded on the consolidated statement of financial position, or that would have been recorded on the consolidated statement of financial position in absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded.

LIQUIDITY AND CAPITAL RESOURCES

The Company expects to utilize cash from operations and the issuance of replacement debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay dividends.

In 2010, the Company issued $200 million of new 10 year MTNs at an interest rate of 4.04% and $200 million of new 40 year MTNs at an interest rate of 4.95%. In 2011, the Company issued additional $100 million additional MTNs under the same terms as the $200 million 40 year MTN pricing supplement issued in 2010 at an interest rate of 4.95%. In 2011, the Company had total debenture maturities of $150 million (2010 - $150 million).

In July 2011, the Company extended the maturity date of the $700 million committed line of credit for an additional year to August 2012, with an additional one-year term out option.

The Company actively manages its bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of the Company's credit facilities at December 31, 2011.

	Total Facilities	Credit Facility Draws[1]	Available
(millions of Canadian dollars)			
Enbridge Gas Distribution Inc.	700	545	155
St. Lawrence Gas Company, Inc.	12	10	2
Total credit facilities	712	555	157

[1] *Includes facility draws and commercial paper issuances, net of discount, that are backstopped by the credit facility.*

Changes in natural gas prices impact accounts receivable and other, gas inventories and accounts payable and other, which may result in the working capital being negative on a temporary basis.

December 31,	2011	2010
(millions of Canadian dollars)		
Cash and cash equivalents	9	13
Accounts receivable and other	663	802
Gas inventories	380	400
Bank overdraft	(7)	(17)
Short-term borrowings	(556)	(332)
Accounts payable and other	(713)	(850)
Working capital	(224)	16

When issuing any new indebtedness with a maturity of over 18 months, covenants contained in the Company's trust indentures require that the pro forma long-term debt interest coverage ratio be at least 2.0 times for twelve consecutive months out of the previous 23 months. At December 31, 2011, this ratio was 2.65 (2010 - 2.64). The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test.

Operating Activities

Cash provided by operating activities was $514 million for the year ended December 31, 2011 compared with $512 million in 2010. The increase was due to a decrease in receivables from customers as a result of the impacts of weather, offset by an increase in the net settlement on purchase gas variances owing to customers.

Cash provided by operating activities was $512 million for the year ended December 31, 2010 compared with $953 million in 2009. The decrease was primarily due to insignificant increases in accounts receivable and gas inventories compared to significant decreases in 2009. These impacts were primarily the result of fluctuations in the market price of natural gas.

Investing Activities

Cash used for investing activities was $464 million for the year ended December 31, 2011 compared with $365 million in 2010. The increase was primarily due to higher comparative capital spending on unregulated natural gas storage projects, customer growth projects, improvements to the distribution system and construction of a technical training facility.

Cash used for investing activities was $365 million for the year ended December 31, 2010 compared with $384 million in 2009. The decrease was primarily due to spending in 2009 for a new customer billing system, which was implemented in late 2009, partially offset by higher comparative spending in 2010 for distribution system improvements.

Capital Expenditures

Year ended December 31,	2011	2010	2009
(millions of Canadian dollars)			
System improvements and upgrades	159	160	144
System expansion	140	107	107
Computers and communication equipment	38	32	73
Unregulated storage	32	7	12
Solar assets (Project Amherstburg)	68	-	-
Other	106	59	34
Total capital expenditures	543	365	370

The Company's existing distribution network consists of approximately 35,000 kilometres of underground natural gas mains and services. To support continuing customer growth, expansion of the network on an ongoing basis is required in addition to capital improvements.

The Company expects to spend approximately $440 million in 2012 on capital projects and maintenance. Annual capital expenditures in recent years have averaged approximately $415 million.

The 2012 capital projects include the cast iron replacement program, construction of the technical training facility, the Greater Toronto Area (GTA) reinforcement project and power generation projects. The Company expects to finance these expenditures through cash from operating activities and available liquidity.

Financing Activities

Cash used for financing activities was $54 million for the year ended December 31, 2011 compared with $154 million in 2010. The decrease was primarily due to issuances of short-term borrowings and the issuance of $100 million MTNs, partially offset by the repayment of the portion of long-term debt that became due.

In 2010, cash used for financing activities was $154 million compared with $661 million in 2009. The decrease was primarily due to $400 million of MTN issuances in 2010 and lower net repayments of short-term borrowings compared to the prior year as a result of decreased cash from operating activities, partially offset by a larger debenture maturity and an increase in common share dividends paid compared to the prior year.

Short-term borrowings are used primarily to finance working capital, including gas inventories.

Preferred Shares

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.

Outstanding Share Data[1]

	Number
Preferred Shares, Group 3, Series D, Fixed/Floating Cumulative Redeemable Convertible	4,000,000
Common Shares	142,345,114

[1] *Outstanding share data information is provided as at February 14, 2012.*

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

The following chart outlines significant changes in the consolidated statements of financial position between December 31, 2010 and December 31, 2011.

Consolidated Statements of Financial Position Category	Increase/ (Decrease)	Explanation
(millions of Canadian dollars)		
Accounts receivable and other	(139)	Primarily due to warmer weather in the fourth quarter and lower commodity prices.
Property, plant and equipment, net	312	Primarily due to an increase in the overall asset base resulting from the acquisition of Project Amherstburg assets and expenditures on unregulated natural gas storage projects, customer growth projects, improvements to the distribution system and construction of a technical training facility.
Short-term borrowings	224	Primarily to fund working capital needs.
Accounts payable and other	(137)	Primarily due to refunds of gas price variances to customers.
Current maturities of long-term debt	(150)	Repayment of the current portion of long-term debt.
Long-term debt	107	Primarily due to a $100 million MTN issue.
Other long-term liabilities	69	Primarily due to increased regulatory liabilities from future removal and site restoration reserves and pensions.
Share capital – common shares	66	Issuance of common shares to fund the Project Amherstburg acquisition.

OFF-BALANCE SHEET ARRANGEMENTS

Gas Held on Behalf of Transportation Service Customers

Transportation service customers source their natural gas supplies independently or through a broker and their estimated consumption is delivered into the Company's system evenly throughout the year. However, the consumption pattern varies from the even natural gas delivery pattern. Depending on the consumption/replenishment cycle, the Company borrows or loans natural gas from/to transportation service customers. Specific defined parameters are in place and are monitored carefully to ensure that the volume of natural gas loaned does not exceed certain threshold levels. Customer accounts beyond these defined threshold levels incur penalties. All loaned volumes are trued up annually. The Company also has strict credit policies in place to mitigate this risk. See CREDIT RISK.

Included in, or deducted from, gas inventories is an amount for natural gas to be received from, or returned to, direct purchase customers or agents (non-system supply customers). This amount represents the difference between natural gas received on behalf of non-system supply customers and natural gas delivered to such customers.

At December 31, 2011, $100 million of natural gas was held on behalf of transportation service customers (December 31, 2010 - $102 million). These transactions have no impact on the Company's consolidated earnings or financial position.

CONTINGENCIES AND COMMITMENTS

The Company is occasionally named as a party in various claims and legal proceedings which arise during the normal course of its business. The Company reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. Although there can be no assurance that any particular claim will be resolved in the Company's favour, the Company does not believe that the outcome of any claims or potential claims of which it is currently aware will have a material adverse effect on the Company, taken as a whole.

Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totalling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its Station A MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on the Company. It was and remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, the Company and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with the Company. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

On August 30, 1994, Wyndham Court Canada Inc. (Wyndham) commenced an action in the Ontario Court of Justice (General Division) against the Company and 20 other defendants claiming that coal tar originating from the Company's Station A MGP in Toronto migrated to lands owned by Wyndham. Wyndham claimed general damages in the amount of $70 million and punitive damages in the amount of $5 million. It is believed that this action was also commenced by Wyndham due to its concern about the running of limitation periods.

The Company entered into a Tolling Agreement with Wyndham pursuant to which Wyndham's action was discontinued, without prejudice to Wyndham's right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham sold the lands that were the subject of the action to Cityscape Holdings Inc., which directed that title to a portion of these lands be transferred to Cityscape Residential Inc. (jointly Cityscape). Cityscape served the Company with a Statement of Claim in February 2003, naming the Company and nine other defendants who own or have owned portions of the former Station A MGP site. Cityscape is claiming $50 million in damages and $5 million in punitive damages against the Company as a result of alleged coal tar contamination of the lands now owned by Cityscape. The Company responded with a Statement of Defence denying liability. In January 2004, Cityscape dismissed the action against each of the Company's co-defendants.

In February 2008, the Ontario Superior Court of Justice ordered that examinations for discovery of the plaintiff be completed by mid-June 2008. Examinations for discovery were completed by this date, but required steps in the discovery process have not yet been completed by the plaintiff. At present, it is unknown when the trial of the matter will be heard.

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2012 fiscal years, the OEB approved the establishment of deferral accounts. The issue of whether the possible claims and related costs are recoverable from customers has yet to be determined.

The Company remains of the view that it has a valid defence to the Cityscape lawsuit; however, it acknowledges that certain risks exist. Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation/isolation/containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. The Company expects that if it is found that it must contribute to any remediation costs (either as a result of a lawsuit or government order), it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company's financial position.

Bloor Street Incident

The Company was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred in April 2003 on Bloor Street West in Toronto. In December 2011, the Company pleaded guilty before the Ontario Court of Justice to one charge under OHSA and one charge under TSSA. The Court imposed a fine of $350,000 in connection with each charge. With the application of a required 25% Victim Fine Surcharge, the total amount payable by the Company was $875,000.

Other Litigation

The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

Contractual Obligations

Payments due for contractual obligations over the next five years and thereafter are as follows:

	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
(millions of Canadian dollars)					
Long-term debt[1]	2,387	-	400	-	1,987
Loans from affiliate company[1]	375	-	-	-	375
Services contract[2]	26	18	8	-	-
Customer care service contracts[3]	359	58	115	122	64
Gas transportation and storage contracts	927	628	193	90	16
Pension and OPEB obligations[4]	24	24	-	-	-
Total contractual obligations	4,098	728	716	212	2,442

1 *Excludes interest. Changes to the planned funding requirements dependent on the terms of any debt re-financing agreements.*

2 *Consists of fixed overhead payments to contractors and fees relating to services provided for work and asset management initiatives. The majority of the latter expenditures will be capitalized to gas mains under property, plant and equipment in accordance with regulatory treatment. At December 31, 2011, $133 million (2010 - $124 million) of such costs were included in gas mains, which are depreciated over the average service life of 25 years.*

3 *In 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. The total cost of the customer care services during the term of the extension is approximately $360 million. The OEB approved the Company's recovery of costs associated with the agreement in 2011.*

4 *Assumes only required payments will be made into the pension and OPEB plans in 2012. Contributions are made in accordance with the independent actuarial valuations as of December 31, 2011. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.*

QUARTERLY FINANCIAL INFORMATION

2011	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars)					
Revenues[1]	999	473	315	679	2,466
Earnings attributable to the common shareholder[1]	108	50	9	42	209
Colder/(warmer) than normal weather	11	2	-	(12)	1

2010	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars)					
Revenues[1]	1,002	423	297	753	2,475
Earnings attributable to the common shareholder[1]	86	28	8	69	191
(Warmer)/colder than normal weather	(8)	(10)	-	6	(12)

[1] *Quarterly financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.*

Revenues include amounts billed to customers for natural gas, which vary 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.

In addition, the Company operates in a seasonal industry. Earnings for interim periods in isolation are not indicative of results for the fiscal year since volumes delivered during the peak winter months are significantly higher.

Earnings for a given quarter 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.

Further, as a result of continued changes in customer billing to increase the fixed charge portion and decrease the per unit volumetric charge, a portion of revenues and earnings will shift from the colder winter quarters progressively to the warmer summer quarters, with no material impact on full year revenue and earnings. This change will also impact the comparability of a given quarter from year to year.

FOURTH QUARTER 2011 HIGHLIGHTS

Earnings attributable to the common shareholder were $42 million for the three months ended December 31, 2011 compared with $69 million for the same period in 2010. The decrease was primarily due to warmer weather, lower other revenue, higher operating and administrative expenses, and higher depreciation and amortization expense during the period. This was partially offset by lower income taxes and lower interest expense.

Earnings applicable to the common shareholder were $69 million for the three months ended December 31, 2010 compared with $72 million for the same period in 2009. The decrease of $3 million was primarily due to tax differences relating to intangible assets, partially offset by lower interest expense from lower credit facility fees.

RELATED PARTY TRANSACTIONS

The Company had transactions with related parties during the year. Amounts are invoiced on a monthly basis and are usually due and paid on a quarterly basis.

IPL System Inc. The Company has invested in Class D, non-voting redeemable, retractable preferred shares of IPL System Inc., an affiliated company under common control. At December 31, 2011, the investment of $825 million in these shares resulted in a weighted average dividend yield of 7.60%. For the year ended December 31, 2011, dividends received amounted to $63 million (2010 - $63 million) with an outstanding receivable balance of $5 million at December 31, 2011 (2010 - $5 million).

IPL System Inc. advanced the Company $375 million ($200 million at 6.85% and $175 million at 7.50%) repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in

either cash or non-retractable preferred shares of the Company. For the year ended December 31, 2011, interest paid amounted to $20 million (2010 - $27 million) with an outstanding payable balance of $9 million at December 31, 2011 (2010 - $2 million).

Enbridge (U.S.), an affiliated company under common control, advanced a subsidiary of the Company $8 million (2010 - $6 million) at the LIBOR rate plus 0.55%, payable on demand.

Enbridge, the ultimate parent company, provides treasury and other management services and charges the Company amounts designed to recover the costs of providing such services. Charges incurred for the year ended December 31, 2011 were $34 million (2010 - $32 million) with an outstanding payable balance of $1 million at December 31, 2011 (2010 - $1 million).

Gazifère Inc., an affiliated company under common control, purchases wholesale services from the Company. These services are pursuant to a contract negotiated between the two companies and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie. Total revenues for the year ended December 31, 2011 were $28 million (2010 - $30 million) with an outstanding receivable of $4 million at December 31, 2011 (2010 - $5 million).

Vector Pipeline Limited Partnership (U.S.), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2011 were $24 million (2010 - $27 million) with an outstanding payable of nil at December 31, 2011 (2010 - nil).

Vector Pipeline Limited Partnership (Canadian), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2011 were $2 million (2010 - $1 million) with an outstanding payable of nil at December 31, 2011 (2010 - nil).

Alliance Pipeline Limited Partnership (Canadian), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2011 were $25 million (2010 - $25 million) with an outstanding payable of nil at December 31, 2011 (2010 - nil).

Alliance Pipeline Limited Partnership (U.S.), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2011 were $18 million (2010 - $17 million) with an outstanding payable of nil at December 31, 2011 (2010 - nil).

Enbridge Commercial Services Inc., an affiliated company under common control, provides information services to the Company. Total charges for the year ended December 31, 2011 were nil (2010 - $2 million) with an outstanding payable of nil at December 31, 2011 (2010 - nil).

Other Transactions

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Company has formal risk management policies, procedures and systems designed to mitigate the risks described below. In addition, the Company performs an annual corporate risk assessment to scan its environment for all potential risks. Risks are ranked based on severity and likelihood and results are considered in the Company's strategic and operating plans. Through this process, a range of ongoing mitigants are identified and implemented.

Regulatory Risk

The Company's operations are regulated and are subject to regulatory risk. The Company retains dedicated professional staff and maintains strong relationships with customers, interveners and regulators to help minimize regulatory risk.

The formula currently approved by the OEB for determination of the ROE, which is embedded and escalated within rates over the IR period, is based on the OEB's risk assessment of the Company for the 2007 fiscal year (refer to RECENT DEVELOPMENTS – COST OF CAPITAL).

The Settlement allows certain Y and Z factors (which represent specific categories of expense from a COS view and uncontrollable external factors, respectively) in the IR formula, which will permit the Company to recover, with OEB approval, certain costs that are beyond management control, but are necessary for the maintenance of its services. The Settlement also includes a mechanism to reassess the IR plan and return to COS if there are significant and unanticipated developments that threaten the sustainability of the IR plan. The above noted terms set out in the Settlement mitigate the Company's risk to factors beyond management's control.

The Company does not profit from the sale of natural gas nor is it at risk for the difference between the actual cost of natural gas purchased and the price approved by the Regulators (including risk management costs for St. Lawrence). This difference is deferred

as a receivable from or payable to customers until the Regulators approve its refund or collection. The Company monitors the balance and its potential impact on customers and will request interim rate relief that will allow the Company to recover or refund the natural gas cost differential.

The Company, excluding St. Lawrence, has a quarterly rate adjustment mechanism in place that allows for the quarterly adjustment of rates to reflect changes in natural gas prices. Adjustments are subject to prior approval by the OEB.

Volume Risks

Since customers are billed on both a fixed charge and on a volumetric basis, the Company's ability to collect its total IR formula revenue depends on achieving the forecast distribution volume established in the rate-making process. Under IR, volume forecasts are reviewed and approved by the OEB annually. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers. Over the life of the current IR agreement, the portion of fixed charges will increase annually thereby reducing this risk.

Weather is a significant driver of delivery volumes, given that a significant portion of the Company's customer base uses natural gas for space heating. Weather, measured in terms of heating degree days, normally directly impacts earnings of the Company as noted below. Heating degree days is a measure of coldness, calculated as the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius.

Factor	Incremental change	Approximate incremental impact
Weather	18 heating degree days	1 billion cubic feet
Volume	1 billion cubic feet	$1.3 million (after-tax)

An unusual pattern of distribution of heating degree days during the year and their relative effectiveness may impact the above sensitivity. Heating degree days are fully effective, typically in the peak winter months, when their occurrence directly impacts the consumption pattern by a similar magnitude.

Distribution volume may also be impacted by the increased adoption of energy efficient technologies, along with more efficient building construction, that continues to place downward pressure on consumption. In addition, conservation efforts by customers further contribute to the decline in annual average consumption.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 80% (2010 - 80%) of total distribution volume. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions are important to all market sectors as continued expansion adds to the total consumption of natural gas.

Even in those circumstances where the Company attains its total forecast distribution volume, the Company may not earn the expected ROE due to other forecast variables such as the mix between the higher margin residential and commercial sectors and the lower margin industrial sector.

This distribution volume risk for customers other than large volume transportation customers is mitigated by the average use true-up variance account that was established under the IR Settlement Agreement. This variance account enables recovery from or repayment to customers amounts representing variances in the actual and forecast average use by general service customers. The Company remains at risk of distribution volume for large volume contract commercial and industrial customers.

Market Price Risk

The Company's earnings, cash flows and other comprehensive income are subject to movements in interest rates, foreign exchange rates and natural gas commodity prices (collectively, market price risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following section summarizes the primary types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them.

Interest Rate Risk

The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Floating to fixed interest rate swaps and options are used to hedge against the effect of future period interest rate movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2012 at an average rate of 1.8%.

Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. A portion of the Company's purchases of natural gas are denominated in United States dollars and as a result there is exposure to fluctuations of the United States dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the net exposure of the Company to movements in the foreign exchange rate on natural gas purchases is nil.

Natural Gas Price Risk

Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. Only St. Lawrence manages the exposure to natural gas price risk by entering into fixed price natural gas contracts. Other than St. Lawrence, the Company no longer manages natural gas price risk exposure, in compliance with the OEB's direction. Fluctuations in natural gas prices are borne by the customers.

Credit Risk

Exposure to credit risk is largely mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms, including obtaining additional security, to minimize the consequences of the risk of default on receivables.

The Company minimizes credit risk to derivative counterparties by entering into risk management transactions only with institutions that possess solid investment grade credit ratings or which have provided the Company with an acceptable form of credit protection. The Company has no significant concentration with any single counterparty.

Financing Risk

The Company's financing risk relates to the price volatility and availability of debt to finance capital expenditures and refinance existing debt maturities. This risk is directly influenced by market factors, as Canadian debt market conditions can change dramatically, affecting capital availability.

To address this risk, the Company maintains sufficient liquidity through committed credit facilities with its diversified banking groups designed to enable the Company to fund all anticipated requirements for one year without accessing the capital markets. In addition, the Company strives to ensure that it can readily access the Canadian public capital markets by maintaining a current shelf prospectus with the securities regulators.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments, as they become due. To manage this risk, the Company forecasts the cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of replacement debt, commercial paper and/or credit facility draws. The Company maintains a current shelf prospectus with the securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets.

Maturities of Derivative Financial Liabilities

Based on valuations at December 31, 2011, the Company's financial derivative instruments will give rise to $1 million undiscounted cash outflows in 2012.

Financial Instruments

December 31, 2011	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
(millions of Canadian dollars)								
Assets								
Cash and cash equivalents	9	-	-	-	-	-	9	9
Accounts receivable and other	-	-	614	-	-	49	663	614
Investment in affiliate company[2]	-	825	-	-	-	-	825	N/A
Liabilities								
Bank overdraft	7	-	-	-	-	-	7	7
Short-term borrowings	-	-	-	556	-	-	556	556
Accounts payable and other	-	-	-	654	1	58	713	655
Long-term debt	-	-	-	2,374	-	-	2,374	2,943
Loans from affiliate company[2]	-	-	-	375	-	-	375	N/A

December 31, 2010	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
(millions of Canadian dollars)								
Assets								
Cash and cash equivalents	13	-	-	-	-	-	13	13
Accounts receivable and other	-	-	722	-	-	80	802	722
Investment in affiliate company[2]	-	825	-	-	-	-	825	N/A
Liabilities								
Bank overdraft	17	-	-	-	-	-	17	17
Short-term borrowings	-	-	-	332	-	-	332	332
Accounts payable and other	-	-	-	611	1	238	850	612
Long-term debt	-	-	-	2,417	-	-	2,417	2,775
Loans from affiliate company[2]	-	-	-	375	-	-	375	N/A

[1] *Fair value does not include non-financial instruments and available for sale equity instruments held at cost that do not trade on an actively quoted market.*

[2] *Investment in affiliate company and loans from affiliate company resulted from related party transactions and are carried at historical cost; no fair value has been determined.*

Fair Value of Financial Instruments

The fair value of financial instruments reflects the Company's best estimates of fair value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such prices are not available, the Company uses discounted cash flow analysis from attributable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of cash and cash equivalents, bank overdraft, and short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates, natural gas prices and time value.

Derivative Instruments

The total notional principal or quantity outstanding related to the Company's derivative instruments at December 31, 2011 include $111 million of interest rate contracts and 6 million cubic metres of natural gas contracts, both maturing in 2012.

Additional information about the Company's Risk Management and Financial Instruments is included in Notes 14 and 15 of the 2011 Annual Consolidated Financial Statements.

General Business Risks

Distribution Network Operating Risk

The Company's distribution network is exposed to operational risks such as accidental damage to mains and service lines, corrosion leaks in mains and service lines, breaks in cast iron pipes, malfunction of compression and decompression equipment and other issues that can lead to outages. Leaks in the distribution system are an inherent risk of operations. A comprehensive surveillance, maintenance and repair program as well as the phased replacement of cast iron pipes significantly reduces the exposure.

Other operating risks include: the breakdown or failure of equipment, information systems or processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); failure to maintain adequate supplies of spare parts; operator error; labour disputes; disputes with interconnected facilities and carriers; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs, and other similar events, many of which are beyond the control of the distribution network. The occurrence or continuance of any of these events could increase the cost of operating the Company's distribution network or reduce revenues, thereby impacting earnings.

The Company has an extensive program to manage pipeline integrity, which includes the development and use of in-line inspection tools for pipelines. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as required. The Company also maintains comprehensive insurance coverage for significant pipeline leaks and has a comprehensive security program designed to reduce security-related risks. While the Company considers the level of insurance to be adequate, it may not be sufficient to cover all potential losses.

Environmental, Health and Safety Risk

The Company's operations and facilities are subject to extensive national, regional and local environmental, health and safety laws and regulations governing, among other things, discharges to air, land and water, the handling and storage of petroleum compounds and hazardous materials, waste disposal, the protection of employee health, safety and the environment, and the investigation and remediation of contamination. The Company's facilities, or facilities to which it provides operating services, could experience incidents, malfunctions or other unplanned events that could result in spills or emissions in excess of permitted levels and result in personal injury, fines, penalties or other sanctions and property damage. The Company could also incur liability in the future for environmental contamination associated with past and present activities and properties. The facilities and distribution network must maintain a number of environmental and other permits from various governmental authorities in order to operate and these facilities and the distribution network are subject to inspection from time to time. Failure to maintain compliance with these requirements could result in operational interruptions, fines or penalties, or the need to install potentially costly pollution control technology. Compliance with current and future environmental laws and regulations, which are likely to become more stringent over time, including those governing greenhouse gas (GHG) emissions, may impose additional capital costs and financial expenditures and affect the demand for the Company's services, which could adversely affect operating results and profitability. The Company could be targeted by environmental groups attempting to draw attention to GHG emissions.

The Company is committed to protecting the health and safety of employees, contractors and the general public, and to sound environmental stewardship. The Company believes that prevention of incidents and injuries, and protection of the environment, benefits everyone and delivers increased value to the shareholder, customers and employees. The Company has health and safety and environmental management systems and has established policies, programs and practices for conducting safe and environmentally sound operations. Ongoing training is provided to ensure employee and contractor competency as well as to enhance the safety culture in the Company. Regular reviews and audits are conducted to assess compliance with legislation and Company policy.

Climate Change Legislation

Federal and Provincial carbon regulations remain in development. With the withdrawal of Canada from the Kyoto protocol, sector specific carbon related regulations may develop. It is currently unclear how natural gas distributors will be specifically treated.

Ontario and Quebec, as members of the Western Climate Initiative, are implementing reporting and cap and trade programs respectively to meet their stated GHG reduction targets. GHG reporting in Ontario was implemented in 2011, with subsequent years requiring verification of the data submitted. Quebec has announced a pilot cap and trade program prior to proposed regulatory compliance requirements. The Company will continue to monitor provincial developments and respond accordingly.

The Company is on track to deploy a carbon data management system to ensure compliance with 2012 reporting requirements. The Company continues to publicly report its GHG emissions and will continue to develop internal procedures to identify operationally related GHG reductions.

Reputation Risk

The Company's reputation is one of its most valuable assets. Reputation risk is the risk of negative impacts on the Company's business, operations or financial condition resulting from changes in the Company's reputation with stakeholders and other entities. These potential impacts may include loss of business, legal action or increased regulatory oversight.

Reputation risk often arises as a consequence of some other risk event, such as operating, regulatory or legal risks. Therefore, reputation risk cannot be managed in isolation from other risks. The Company manages reputation risk by:

- having formal risk management policies, procedures and systems in place to identify, assess and mitigate risks to the Company;
- operating to the highest ethical standards, with integrity, honesty and transparency, and maintaining positive relationships with customers, investors, employees, partners, regulators and other stakeholders;
- having health, safety and environment management systems in place, as well as policies, programs and practices for conducting safe and environmentally sound operations;
- having strong corporate governance practices, including a Statement on Business Conduct, with which all employees are required to certify their compliance on an annual basis, and whistleblower procedures, which allow employees to report suspected ethical concerns on a confidential and anonymous basis; and
- pursuing socially responsible operations as a longer-term corporate strategy (implemented through the Company's Corporate Social Responsibility Policy, Climate Change Policy, Aboriginal and Native American Policy and initiatives such as the Neutral Footprint Initiative and the Company's commitment to Green Energy).

CRITICAL ACCOUNTING ESTIMATES

Revenue Recognition

The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced.

Depreciation

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2011 of $4,770 million (2010 - $4,458 million), or 65% of total assets (2010 - 62%), is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

These depreciation rates are reviewed through periodic depreciation studies conducted by an external consulting firm that makes an objective assessment of the useful lives of the Company's property, plant and equipment. The depreciation rates used by the Company are subject to approval by the OEB for rate setting purposes, which may not always reflect the recommendations of the latest depreciation study. The last such study was completed in 2011. The external consulting firm also provides a framework for the Company's calculation of the estimate of the net cumulative amount collected from customers for future site removal and restoration of property, plant and equipment.

Regulatory Assets and Liabilities

The Regulators exercise statutory authority over matters such as construction, rates and rate-making, and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in operations may differ from that otherwise expected under GAAP for non rate-regulated entities. Also, the Company records regulatory assets and liabilities to recognize the economic effects of the actions of the Regulators. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. On refund or recovery of this difference, no earnings impact is recorded. Effectively, the consolidated statement of earnings captures only the approved costs and the related revenue rather than the actual costs and related revenue. As of December 31, 2011, the Company's regulatory assets totaled $269 million (2010 - $296 million) and regulatory liabilities totaled $1,076 million (2010 - $1,171 million). To the extent that the Regulators' actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

Post-employment Benefits

The Company maintains pension plans, which provide non-contributory defined benefit and/or defined contribution pension benefits to the majority of its employees and post-employment benefits other than pensions (OPEB) to eligible retirees.

Pension costs and obligations for the defined benefit pension plans are determined using the projected benefit method. This method involves complex actuarial calculations using several assumptions including discount rates, expected rates of return on plan assets, health-care cost trend rates, projected salary increases, retirement age, mortality and termination rates. These assumptions are determined by management and are reviewed annually by the Company's actuaries. However, there is significant measurement uncertainty incorporated into the actuarial valuation process. For example, there is no assurance that the pension plan will be able to earn the assumed rate of return.

Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods. However, no earnings impact would result due to the continuity of the existing regulatory mechanism in place under which plan contributions and actual OPEB benefit costs are expensed as paid, consistent with the recovery of such costs in rates.

The difference between the actual and expected return on plan assets was a shortfall of $38 million for the year ended December 31, 2011 (2010 - $29 million) as disclosed in Note 18 to the 2011 Annual Consolidated Financial Statements. The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

Assuming no discretionary funding is made into the pension and OPEB plans, funding in 2012 will be $24 million.

The following sensitivity analysis identifies the impact on the December 31, 2011 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions.

	Pension Benefits		OPEB	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Decrease in discount rate	60	6	7	-
Decrease in expected return on assets	N/A	4	N/A	-
Decrease in rate of salary increase	(8)	(2)	-	-

Contingent Liabilities

Provisions for claims filed against the Company are determined on a case by case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on the financial results of the Company, are detailed in the Commitments and Contingencies section of this report and are disclosed in Note 21 of the 2011 Annual Consolidated Financial Statements.

REGULATORY GOVERNANCE

Undertakings

The Company, and its parent Enbridge, have entered into Undertakings with the Lieutenant Governor in Council for Ontario that commit Enbridge and the Company to certain obligations relating to the maintenance of common equity, as well as restrictions on diversification to the effect that the Company must not carry on, except through an affiliate or affiliates, any business activity other than the distribution, storage or transmission of natural gas without the OEB's prior approval. In compliance with these undertakings, the Company has obtained OEB approval to carry on the Natural Gas Vehicle Program, Agent Billing and Collection Program and Gas Sales and Oil Production activity.

In August 2006, the Government of Ontario approved changes to the Undertakings that allow the Company to provide services related to the promotion of electricity conservation, natural gas conservation and the efficient use of electricity, electricity load management, and the promotion of cleaner energy sources, including alternative energy sources and renewable energy sources. In addition, the Company is allowed to engage in activities and provide services related to the local distribution of steam, hot and cold water in an initiative with Markham District Energy Inc., and pursuit of a pilot project for the generation of electricity by means of large stationary fuel cells integrated with energy recovery from natural gas transmission and distribution pipelines.

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.

Affiliate Relationships Code

The Company is subject to the provisions of the OEB's Affiliate Relationships Code for Gas Utilities (the Code). The Code sets out the standards and conditions that govern the interaction between natural gas distributors, transmitters and storage companies in Ontario and their respective affiliated companies and is intended to:

- minimize the potential for a utility to cross-subsidize competitive or non-monopoly activities;
- protect the confidentiality of consumer information collected in the course of providing utility services; and
- ensure there is no preferential access to regulated utility services.

The Code specifically sets out standards of conduct including the degree of separation, sharing of services and resources, terms under which service agreements must be prepared and transfer pricing guidelines.

CHANGES IN ACCOUNTING POLICIES

Business Combinations

Effective January 1, 2011, the Company adopted Part V Section 1582, *Business Combinations*, which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be re-measured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. In accordance with the transitional provisions of this standard, Section 1582 was adopted prospectively and accordingly, assets and liabilities that arose from business combinations occurring before January 1, 2011 were not restated. The adoption of this standard has not impacted the Company's earnings, cash flows or financial position for the year ended December 31, 2011.

Consolidated Financial Statements and Noncontrolling Interests

Effective January 1, 2011, the Company adopted Part V Sections 1601, *Consolidated Financial Statements*, and 1602, *Noncontrolling Interests*, which together replace the former consolidated financial statements standard. Under the revised standards, noncontrolling interests are classified as a component of equity, and earnings and comprehensive income are attributed to both the parent and noncontrolling interest. In accordance with the transitional provisions of these standards, Section 1601 was adopted prospectively and Section 1602 was adopted retroactively with restatement of prior periods. As the adoption of these standards impacts presentation only, there has been no impact to the Company's earnings, cash flows, or financial position for the current or prior periods presented.

Future Accounting Policy Changes

United States Generally Accepted Accounting Principles (U.S. GAAP)

First-time adoption of Part I - International Financial Reporting Standards (Part I or IFRS) of The CICA Handbook was mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I applies to qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and has presented its consolidated financial statements in accordance with Part V of the CICA Handbook in the 2011 deferral period.

There continues to be uncertainty with respect to the application of IFRS to the rate regulated operations of the Company, which are pervasive and central to its business and performance measurement. A rate regulated accounting standard model was not finalized by the International Accounting Standards Board in advance of 2012. As a wholly-owned subsidiary of a United States Securities and Exchange Commission (SEC) registrant, the Company has received permission from the Canadian securities regulators to prepare its consolidated financial statements in accordance with U.S. GAAP and will adopt U.S. GAAP for interim and annual consolidated financial statements beginning on January 1, 2012.

In preparation for the U.S. GAAP conversion, Enbridge has formed a U.S. GAAP project team and developed a transition plan and governance structure to monitor the progress of the transition. The Company has engaged a public accounting firm to assist with the project and to provide technical accounting advice on the interpretation and application of U.S. GAAP to its primary consolidated financial statements. Management reports regularly to the Audit, Finance & Risk Committee of the Board of Directors on the advancement of the conversion to U.S. GAAP.

Accounting and Reporting

The Company is in the process of integrating known U.S. GAAP differences into its primary consolidated financial statements. The most significant differences impact the following areas:

- Push-down accounting as a result of a business combination;
- Pensions and other post-employment benefits; and
- Presentation of deferred financing costs.

The Company will commence reporting using U.S. GAAP as its primary basis of accounting in the first quarter of 2012. To facilitate users' understanding of the transition, subsequent to filing its Canadian GAAP consolidated financial statements for the year ended December 31, 2011 and before filing its first interim report under U.S. GAAP, the Company will be filing, for information purposes, its 2011 comparative consolidated financial statements restated under U.S. GAAP along with comparative periods and related note disclosures.

Training

The Company has provided U.S. GAAP training to internal personnel impacted by the conversion. U.S. GAAP training will continue into and beyond 2012 as a regular business activity.

Information Systems and Business Processes

The Company has completed testing system changes necessary to support the conversion to U.S GAAP and to sustain U.S. GAAP reporting in 2012 and beyond. Implementation of these changes will take place in the first quarter of 2012. Impacts to internal controls over financial reporting and disclosures have been evaluated and no significant impacts were noted.

Business Activities

The Company has reviewed the effect of the U.S. GAAP conversion on its debt covenants, compensation agreements and hedging activities, and does not expect the conversion to U.S. GAAP to significantly impact these activities or requirements.

The detailed project plan and the expected timing of key activities identified above may change prior to the U.S. GAAP conversion date due to economic conditions or other factors.

ENBRIDGE GAS DISTRIBUTION INC. HIGHLIGHTS

Year ended December 31,	2011	2010
Financial *(millions of Canadian dollars)*		
Gas commodity and distribution revenue	2,010	1,977
Transportation of gas for customers	352	390
Other revenue	104	108
Total revenue	2,466	2,475
Gas commodity and distribution costs	(1,341)	(1,372)
	1,125	1,103
Earnings	211	193
Earnings attributable to the common shareholder	209	191
Return on equity[1] (%)	11.3	10.3
Operating		
Volumetric Statistics *(millions of cubic metres)*		
Gas commodity sales	6,257	5,550
Transportation of gas for customers	5,370	5,584
Unbundled volumes[2]	434	460
Total volume	12,061	11,594
Number of active customers[3] *(thousands)*	1,997	1,963
Heating degree days[4]		
Actual	3,597	3,466
Forecast based on normal weather	3,602	3,546

[1] *Return on equity data relates to the consolidated entity.*

[2] *Unbundled customers deliver their own natural gas into the Company's distribution system and manage their load balancing independent of the Company.*

[3] *Number of active customers is the number of natural gas consuming customers at the end of the year.*

[4] *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 distribution 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 Greater Toronto Area.*

TO THE SHAREHOLDERS OF ENBRIDGE GAS DISTRIBUTION INC.

Financial Reporting

Management of Enbridge Gas Distribution Inc. (the Company) is responsible for the accompanying consolidated financial statements and all other information in this Annual Report. The consolidated financial statements have been prepared in accordance with Part V – Pre-changeover Accounting Standards of The Canadian Institute of Chartered Accountants Handbook and necessarily include amounts that reflect management's judgment and best estimates. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (AF&RC) of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The AF&RC meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AF&RC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with generally accepted accounting principles and provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.



D. Guy Jarvis
President



Narinder K. Kishinchandani
Vice President, Finance

February 14, 2012

Independent Auditor's Report

TO THE SHAREHOLDERS OF ENBRIDGE GAS DISTRIBUTION INC.

We have audited the accompanying consolidated financial statements of Enbridge Gas Distribution Inc. and its subsidiaries, which comprise the consolidated statements of financial position as at December 31, 2011 and 2010 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and its subsidiaries as at December 31, 2011 and 2010 and the results of its operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants,
Licensed Public Accountants

Toronto, Ontario

February 14, 2012

Consolidated Statements of Earnings

Year ended December 31,	2011	2010
(millions of Canadian dollars)		
Gas commodity and distribution revenue *(Note 20)*	2,010	1,977
Transportation of gas for customers	352	390
	2,362	2,367
Gas commodity and distribution costs excluding depreciation *(Note 20)*	(1,341)	(1,372)
Gas distribution margin	1,021	995
Other revenue	104	108
	1,125	1,103
Expenses		
Operating and administrative *(Note 20)*	419	393
Depreciation and amortization	281	270
Municipal and other taxes	41	44
Earnings sharing *(Note 3)*	13	19
	754	726
	371	377
Affiliate financing income *(Note 20)*	63	63
Interest expense *(Notes 10 and 20)*	(172)	(186)
	262	254
Income Taxes *(Note 17)*		
Current	(50)	(59)
Future	(1)	(2)
	(51)	(61)
Earnings	211	193
Preferred share dividends	(2)	(2)
Earnings attributable to the common shareholder	209	191

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Comprehensive Income

Year ended December 31,	2011	2010
(millions of Canadian dollars)		
Earnings	211	193
Other comprehensive income/(loss)		
Change in unrealized loss on cash flow hedges, net of tax	(1)	(17)
Reclassification to earnings of realized gains on cash flow hedges, net of tax	2	2
Change in foreign currency translation adjustment	-	(1)
Other comprehensive income/(loss)	1	(16)
Comprehensive income	212	177

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Shareholders' Equity

Year ended December 31,	2011	2010
(millions of Canadian dollars)		
Preferred shares *(Note 12)*	100	100
Common shares *(Note 12)*		
Balance at beginning of year	1,071	1,071
Common shares issued	66	-
Balance at end of year	1,137	1,071
Contributed surplus	202	202
Retained earnings		
Balance at beginning of year	572	596
Earnings attributable to the common shareholder	209	191
Common share dividends declared	(220)	(215)
Balance at end of year	561	572
Accumulated other comprehensive loss		
Balance at beginning of year	(18)	(2)
Other comprehensive income	1	(16)
Balance at end of year	(17)	(18)
Total shareholders' equity	1,983	1,927

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Cash Flows

Year ended December 31,	2011	2010
(millions of Canadian dollars)		
Operating activities		
Earnings	211	193
Depreciation and amortization	281	270
Future income taxes	1	2
Other	4	2
Changes in operating assets and liabilities *(Note 19)*	17	45
	514	512
Investing activities		
Additions to property, plant and equipment	(441)	(345)
Additions to intangible assets	(34)	(20)
Change in construction payable	5	-
Other	6	-
	(464)	(365)
Financing activities		
Change in bank overdraft	(10)	(11)
Net change in short-term borrowings	222	(182)
Issue of short-term note payable to affiliate company *(Note 20)*	5	2
Repayment of short-term note payable to affiliate company *(Note 20)*	(3)	(3)
Debenture and term note issues	100	402
Debenture and term note repayments	(150)	(150)
Preferred share dividends	(2)	(2)
Common share dividends	(218)	(208)
Other	2	(2)
	(54)	(154)
Decrease in cash and cash equivalents	(4)	(7)
Cash and cash equivalents at beginning of year	13	20
Cash and cash equivalents at end of year	9	13
Supplementary cash flow information		
Income taxes paid	62	59
Interest paid *(Note 10)*	169	185

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Financial Position

December 31,	2011	2010
(millions of Canadian dollars)		
Assets		
Current assets		
Cash and cash equivalents	9	13
Accounts receivable and other *(Notes 5 and 20)*	663	802
Gas inventories	380	400
	1,052	1,215
Property, plant and equipment, net *(Note 6)*	4,770	4,458
Investment in affiliate company *(Note 20)*	825	825
Deferred amounts and other assets *(Note 7)*	489	487
Intangible assets *(Note 8)*	179	167
	7,315	7,152
Liabilities and shareholders' equity		
Current Liabilities		
Bank overdraft	7	17
Short-term borrowings *(Note 10)*	556	332
Accounts payable and other *(Notes 9 and 20)*	713	850
Current maturities of long-term debt *(Note 10)*	-	150
Future income taxes *(Note 17)*	2	5
	1,278	1,354
Long-term debt *(Note 10)*	2,374	2,267
Other long-term liabilities *(Note 11)*	1,127	1,058
Future income taxes *(Note 17)*	178	171
Loans from affiliate company *(Notes 10 and 20)*	375	375
	5,332	5,225
Shareholders' Equity		
Share capital		
Preferred shares *(Note 12)*	100	100
Common shares *(Note 12)*	1,137	1,071
Contributed surplus	202	202
Retained earnings	561	572
Accumulated other comprehensive loss	(17)	(18)
	1,983	1,927
Commitments and contingencies *(Notes 20 and 21)*		
	7,315	7,152

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:



D. Guy Jarvis
President



David A. Leslie
Director

Enbridge Gas Distribution Inc. (the Company) is a rate-regulated natural gas distribution utility, serving residential, commercial and industrial customers in its franchise areas of central and eastern Ontario. The Company also serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence). The Company is a wholly owned subsidiary of Enbridge Inc. (Enbridge).

The Company also owns and operates unregulated facilities in Ontario, including two solar projects located in Amherstburg, Ontario, through its 99.9% limited partnership interest in Project AMBG2 LP (Project Amherstburg) and unregulated natural gas storage facilities.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company are prepared in accordance with Part V – Pre-changeover Accounting Standards of The Canadian Institute of Chartered Accountants (CICA) Handbook (Canadian GAAP or Part V). Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of the consolidated financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: estimates of revenue; carrying values of regulatory assets and liabilities *(Note 3)*; unbilled revenues *(Note 5)*; allowance for doubtful accounts *(Note 5)*; depreciation rates and carrying values of property, plant and equipment *(Note 6)*; amortization rates and carrying values of intangible assets *(Note 8)*; fair values of financial instruments *(Notes 14 and 15)*; income taxes *(Note 17)*; post-employment benefits *(Note 18)*; contingencies *(Note 21)*; and fair value of asset retirement obligations. Actual results could differ from those estimates.

Basis of Presentation

The consolidated financial statements include the accounts of the Company and its subsidiaries. Investments are accounted for according to their classification (see Financial Instruments). All significant intercompany accounts and transactions are eliminated upon consolidation.

Regulation

The utility operations of the Company, excluding St. Lawrence, are regulated by the Ontario Energy Board (OEB) and the utility operations of St. Lawrence are regulated by the New York State Public Service Commission (NYSPSC) (collectively the Regulators).

The Regulators exercise statutory authority over matters such as construction, rates and rate-making and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in the utility operations may differ from that otherwise expected under Canadian GAAP for non rate-regulated entities.

Revenue Recognition

The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas commodity and distribution revenue is recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. 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 distribution franchise area.

A significant portion of the Company's operations are subject to regulation and accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as mandated by the Regulators. This may give rise to regulatory deferral accounts pending disposition by decisions of the Regulators.

Financial Instruments

The Company classifies financial assets and financial liabilities as held for trading, available for sale, loans and receivables, other financial liabilities or derivatives in qualifying hedging relationships. The Company has not classified any financial assets or liabilities as held to maturity.

Held for Trading

Financial assets and liabilities that are classified as held for trading are measured at fair value with changes in fair value recognized in earnings. The Company has classified Cash and cash equivalents and Bank overdraft as held for trading.

Available for Sale

The Company classifies its investment in the preferred shares of IPL System Inc. as an available for sale financial asset. Available for sale instruments are periodically created by the Company and its affiliated companies to meet the current and future financing requirements of either the Company or its affiliated companies. This investment originated in a related party transaction. No external market for the instrument exists and no quoted market price is available in an active market. Therefore, the investment is carried at cost and a fair value has not been determined. Dividends received from this investment are recognized in earnings when the right to receive payment is established *(Note 20)*.

Loans and Receivables

Loans and receivables, which include Accounts receivable and other, are initially recognized at fair value and subsequently measured at amortized cost using the effective interest rate method, net of any impairment losses recognized.

Other Financial Liabilities

Other financial liabilities are measured at amortized cost using the effective interest rate method and include Short-term borrowings, Accounts payable and other, Long-term debt and Loans from affiliate company.

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage changes in natural gas prices and interest rates. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings and cash flow effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges. The Company did not have any fair value hedges or net investment hedges outstanding as at December 31, 2011 and 2010.

Cash Flow Hedges

The Company uses cash flow hedges to manage changes in interest rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income (OCI) and is reclassified to earnings when the hedged item impacts earnings or to the carrying value of the related nonfinancial asset. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss deferred in OCI up to that date will be recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from ineffective derivative instruments are recognized in earnings in the period in which they occur.

The majority of St. Lawrence's derivatives relate to the management of natural gas prices. Given that St. Lawrence is subject to rate regulation, the effective portion of changes in the fair value of these derivatives is deferred as an asset or liability until they are settled and an offsetting asset or liability is recorded on behalf of customers. Upon settlement, the recognized gain or loss is recorded as a regulatory asset or liability and is collected from or refunded to customers in subsequent period rates.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments are offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with the related debt. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

Income Taxes

The liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. Any interest and/or penalty incurred related to tax is reflected in income taxes.

The regulated utility operations of the Company recover income tax expense based on the taxes payable method as prescribed by the Regulators for rate-making purposes. As a result, rates do not include the recovery of future income taxes related to temporary differences. A corresponding future income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates.

Foreign Currency Translation

The functional currency of the Company's only foreign operation, St. Lawrence, is the United States dollar. This operation is self-sustaining and is translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates and revenues and expenses are translated using monthly average rates. Gains and losses arising on translation of this operation are included in the foreign currency translation adjustment component of Accumulated other comprehensive loss (AOCL).

Gas Inventories

Gas inventories are primarily comprised of natural gas in storage and also include costs such as storage injection and demand costs. Natural gas in storage is recorded at the prices approved by the Regulators in the determination of distribution rates. The actual price of natural gas purchased may differ from the Regulators' approved price. The difference between the approved price and the actual cost of the natural gas purchased is deferred as a liability for future refund or as an asset for collection by the Company to/from customers, as approved by the Regulators. Actual cost of natural gas for St. Lawrence includes the effect of natural gas price risk management activities.

Included in, or deducted from, gas inventories is an amount for natural gas to be received from, or returned to, direct purchase customers or agents (non-system supply customers). This amount represents the difference between natural gas received on behalf of non-system supply customers and natural gas delivered to such customers.

At December 31, 2011, $100 million of natural gas was held on behalf of transportation service customers (December 31, 2010 - $102 million). These transactions have no impact on the Company's consolidated earnings or financial position.

Property, Plant and Equipment

Property, plant and equipment are recorded at historical cost, including associated operating costs and an allowance for interest during construction at rates approved by the Regulators.

The Regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are booked as an adjustment to accumulated depreciation. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

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Deferred Amounts and Other Assets

Deferred amounts and other assets include costs the Regulators have permitted, or are expected to permit, to be recovered through future rates, derivative financial instruments and pension assets. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges.

Intangible Assets

Intangible assets consist primarily of the Customer Information System (CIS), software costs and the Project Amherstburg contracts, which are amortized on a straight-line basis over their expected useful lives, commencing when the asset is available for use.

Asset Retirement Obligations

Asset retirement obligations (AROs) associated with the retirement of long-lived assets would be measured at fair value and recognized as Other Long-Term Liabilities in the period in which they could be reasonably determined. The fair value would approximate the cost a third party would charge to perform the tasks necessary to retire such assets and would be recognized at the present value of expected future cash flows. AROs would be added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability would be accreted over time through charges to earnings and would be reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

It is not possible to make a reasonable estimate of AROs for the Company due to the indeterminate timing of the asset retirements.

Post-employment Benefits

The Company maintains non-contributory pension plans that provide defined benefit and/or defined contribution pension benefits to the majority of its employees. The Company also provides post-employment benefits other than pensions (OPEB), including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants.

The Company's post-employment costs are determined as follows:

- The cost of pensions and OPEB earned by employees are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimate of future salary levels, other cost escalations, retirement ages of employees and expected health-care and insurance costs. Adjustments arising from plan amendments, actuarial gains and losses, and changes to assumptions are amortized over the expected average remaining service lives of the employees.
- Pension plan assets are measured at fair value.
- The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.
- The excess of the cumulative unrecognized net actuarial gain or loss over 10% of the greater of the accrued benefit obligation and the fair value of plan assets is amortized over the expected average remaining service lives of the active employee group covered by the plans.
- The transitional asset and obligation is amortized over the expected average remaining service period of the active employee group covered by the plans at the date of transition. The transitional asset relates to the pension plans and is the fair value of the plan assets less the accrued benefit obligation at October 1, 2000, amortized over 13 years. The transitional obligation relates to OPEB and is equal to the accrued benefit obligation at October 1, 2000, amortized over 15 years.

The regulated utility operations of the Company recover pension and OPEB expense based on the amounts paid. This is in accordance with the methodology accepted by the Regulators for rate-making purposes. As a result, rates typically only include the recovery of required contributions. A corresponding pension regulatory liability and OPEB regulatory asset have been recorded to the extent that they are expected to be included in regulator approved future rates and recovered from, or refunded to, future customers.

Comparative Amounts

Certain comparative amounts have been reclassified to conform with the current year's consolidated financial statement presentation.

2. CHANGES IN ACCOUNTING POLICIES

Business Combinations

Effective January 1, 2011, the Company adopted Part V Section 1582, *Business Combinations*, which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be remeasured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. In accordance with the transitional provisions of this standard, Section 1582 was adopted prospectively and accordingly, assets and liabilities that arose from business combinations occurring before January 1, 2011 were not restated. The adoption of this standard has not impacted the Company's earnings, cash flows, or financial position for the year ended December 31, 2011.

Consolidated Financial Statements and Noncontrolling Interests

Effective January 1, 2011, the Company adopted Part V Sections 1601, *Consolidated Financial Statements*, and 1602, *Noncontrolling Interests*, which together replace the former consolidated financial statements standard. Under the revised standards, noncontrolling interests are classified as a component of equity, and earnings and comprehensive income are attributed to both the parent and non controlling interest. In accordance with the transitional provisions of these standards, Section 1601 was adopted prospectively and Section 1602 was adopted retroactively with restatement of prior periods. As the adoption of these standards impacts presentation only, there has been no impact to the Company's earnings, cash flows, or financial position for the current or prior periods presented.

United States Generally Accepted Accounting Principles (U.S. GAAP)

First-time adoption of Part I - International Financial Reporting Standards (Part I or IFRS) of The CICA Handbook was mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I applies to qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and has presented its consolidated financial statements in accordance with Part V of The CICA Handbook in the 2011 deferral period.

There continues to be uncertainty with respect to the application of IFRS to the rate regulated operations of the Company, which are pervasive and central to its business and performance measurement. The Company believes U.S. GAAP, which articulates specific guidance for entities subject to rate regulation, provides a more relevant basis on which to evaluate and present its regulated businesses. As a wholly-owned subsidiary of a United States Securities and Exchange Commission (SEC) registrant, the Company has received permission from the Canadian securities regulators to prepare its consolidated financial statements in accordance with U.S. GAAP and will adopt U.S. GAAP for interim and annual consolidated financial statements beginning on January 1, 2012.

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

For the purposes of this note, "Enbridge Gas Distribution" refers specifically to Enbridge Gas Distribution Inc. excluding St. Lawrence, whereas "St. Lawrence" refers specifically to St. Lawrence Gas Company, Inc.

Rate Approval

Enbridge Gas Distribution's annual rates are currently set using a revenue per customer cap Incentive Regulation (IR) methodology. This IR methodology adjusts revenues, and consequently rates, annually and relies on an annual process to forecast volume and customer additions. Under IR, the Company has the opportunity to benefit from productivity enhancements and incremental revenues. The cost of natural gas is passed on to customers as a flow-through.

St. Lawrence's rates for each year are set using a Cost of Service (COS) methodology that allows the revenues to be set to recover forecast costs and to earn a rate of return on common equity. Forecast costs include natural gas commodity and transportation, operating and administrative, depreciation and amortization, municipal taxes, interest and income taxes. The rate base is the average level of investment in all recoverable assets used in natural gas distribution, storage and transmission and an allowance for working capital. Under COS, it is the responsibility of St. Lawrence to demonstrate to the NYSPSC the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken. The cost of natural gas is passed on to customers as a flowthrough.

Approved Rates

Enbridge Gas Distribution

Enbridge Gas Distribution's after-tax rate of return on common equity embedded in rates was 8.39% for the year ended December 31, 2011 (2010 - 8.39%) based on a 36% (2010 - 36%) deemed common equity component of capital for regulatory purposes.

To align the interests of customers with the Company's common shareholder, an earnings sharing mechanism forms part of the Settlement Agreement (the Settlement) with customer representatives approved by the OEB in February 2008. The Settlement encompasses all major financial aspects of the IR methodology that will operate for 2008 to 2012 (inclusive). 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 common shareholder retains the first 100 basis points of ROE above the NROE, while earnings represented by the ROE in excess of 100 basis points above the NROE are shared equally with customers.

St. Lawrence

St. Lawrence's approved after-tax rate of return on common equity embedded in rates was 10.5% for the year ended December 31, 2011 (2010 - 10.5%) based on a 50% (2010 - 50%) deemed common equity component of capital for regulatory purposes. Any earnings above a return on equity of 11% (2010 - 11%) are shared equally with customers. The calculation of such earnings is cumulative over the three-year period commencing January 1, 2010 and ending December 31, 2012, and resulted in no sharing impact for the years ended December 31, 2011 and December 31, 2010.

Impacts Of Rate Regulation

Regulatory Assets and Liabilities

As a result of rate regulation, the Company has recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are recorded in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

Regulatory Risk and Uncertainties Affecting Recovery or Settlement

The recognition of regulatory assets and liabilities is based on the actions, or an expectation of the future actions, of the Regulators. To the extent that the Regulators' future actions are different from the Company's current expectations, the timing and amount of recovery or settlement of regulatory balances could differ from those recorded.

Financial Statement Effects

As a result of rate regulation, the following regulatory assets and liabilities have been recognized:

December 31,	2011	2010	Consolidated Statements of Financial Position Classification**	Estimated Recovery/ Settlement Period *(years)*	Earnings Impact[1] 2011	Earnings Impact[1] 2010
(millions of Canadian dollars)						
Regulatory Assets/(Liabilities)						
Enbridge Gas Distribution						
Future income taxes[2]	164	164	DA/OLTL	*	-	(7)
OPEB[3]	74	68	DA	*	4	4
Unaccounted for gas variance[4]	9	18	AR	1	(7)	5
Settlement recoverable[5]	5	15	AR	1	(7)	(3)
Deferred rate hearing costs[6]	3	3	AR/DA	2	-	(2)
Future removal and site restoration reserves[7]	(815)	(753)	OLTL	*	-	-
Pension plans[8]	(231)	(222)	OLTL	*	(6)	(6)
Transactional services deferral[9]	(7)	(14)	AP	1	-	-
Earnings sharing deferral[10]	(14)	(38)	AP	1	-	-
Average use true-up variance[11]	(3)	4	AP/AR	*	(5)	1
Purchased gas variance[12]	-	(144)	AP	1	-	-
Shared Savings Mechanism[13]	-	11	AR	*	-	-
Other regulatory assets and liabilities	2	10	***	*	(4)	-
	(813)	(878)			(25)	(8)
St. Lawrence						
Other regulatory assets and liabilities	6	3	***	*	2	3
	6	3			2	3
	(807)	(875)			(23)	(5)

* *Refer to the footnote for details.*

** *AR – Accounts receivable and other*
AP – Accounts payable and other
DA – Deferred amounts and other assets
OLTL – Other long-term liabilities

****Dependent on the nature of the item.*

[1] *The earnings impact represents the increase/(decrease) in the Company's after-tax reported earnings as a result of the rate regulated recognition of the item, excluding any additional earnings sharing impact. This includes the impact of items outstanding at the end of the prior year being recovered or refunded in the current year.*

[2] *The future income taxes balance represents the regulatory offset to future income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from future customers. The recovery period depends on the timing of the reversal of temporary differences. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.*

[3] *The OPEB balance represents the regulatory offset to the OPEB liability to the extent that the amounts are to be collected from customers in future rates. The settlement period for this balance is not determinable. Enbridge Gas Distribution continues to record and recover OPEB expenditures through rates on a cash basis. In the absence of rate regulation, this regulatory balance would not be recorded and OPEB expense would be charged to earnings based on the accrual basis of accounting.*

[4] *Unaccounted for gas variance represents the difference between the total natural gas distributed by Enbridge Gas Distribution and the amount of natural gas billed or billable to customers for their recorded consumption, to the extent it is different from the approved amount built into rates. Enbridge Gas Distribution has deferred unaccounted for gas variance and has historically been granted OEB approval for recovery or required refund of this amount in the subsequent year. In the absence of rate regulation, this variance would be included in earnings in the year incurred.*

[5] *Settlement recoverable deferral represents amounts paid towards the settlement of a class action lawsuit related to late payment penalties. Pursuant to an OEB decision in February 2008, these amounts are being recovered from customers over a five-year period, which commenced in 2008. In the absence of rate regulation, these costs would be expensed as incurred.*

[6] *Deferred rate hearing costs are incurred by Enbridge Gas Distribution for the regulatory process. Enbridge Gas Distribution has been granted OEB approval for recovery of such hearing costs, generally within two years. In the absence of rate regulation, these costs would be expensed as incurred.*

[7] *Future removal and site restoration reserves result from amounts collected from customers by Enbridge Gas Distribution, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that Enbridge Gas Distribution has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

[8] *The pension plans' balance represents the regulatory offset to the pension asset to the extent that the amounts are to be refunded to customers in future rates. The settlement period for this balance is not determinable. Enbridge Gas Distribution continues to record and recover pension expenditures through rates on a cash basis. In the absence of rate regulation, this regulatory balance would not be recorded and pension expense would be charged to earnings based on the accrual basis of accounting.*

[9] *Transactional services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. Enbridge Gas Distribution has historically been required to refund the amount to customers in the following year. There would be no change in the treatment of this item in the absence of rate regulation.*

[10] *Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the IR Settlement. The earnings sharing is payable to customers and represents 50% of normalized earnings (i.e., excluding the effects of weather) represented by the ROE in excess of 100 basis points above the NROE. The December 31, 2011 balance relates to the years ended December 31, 2011 and 2010. The December 31, 2010 balance relates to the years ended December 31, 2010 and 2009. There would be no change in the treatment of this item in the absence of rate regulation.*

[11] *Average use true-up variance represents the net revenue impact to be recovered from or refunded to customers, associated with any variance between forecast average use and actual normalized average use for general service customers. The amount will be recovered from or refunded to customers in future periods in accordance with the OEB's approval. In the absence of rate regulation, the variance would be included in earnings in the year incurred.*

[12] *Purchased gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to, or to collect this balance from, customers in the following quarter via the Quarterly Rate Adjustment Mechanism (QRAM) process. In the absence of rate regulation, the actual cost of natural gas would be included in gas commodity and distribution costs and revenues or costs would be adjusted by an equal and offsetting amount as the right to collect or refund the revenue or costs has been established.*

[13] *Shared Savings Mechanism (SSM) deferral represents the benefit derived by Enbridge Gas Distribution as a result of its energy efficiency programs. Enbridge Gas Distribution has historically been granted OEB approval to recover the SSM amount through rates after a detailed review by the OEB. The process of review and subsequent recovery may extend over a few years. There would be no change in the treatment of this item in the absence of rate regulation.*

Other Items Affected by Rate Regulation

Revenue

To recognize the actions or expected actions of the Regulators, the timing and recognition of certain revenues and expenses may differ from that otherwise expected for non rate-regulated entities.

Operating Cost Capitalization

With the approval of the Regulators, the Company capitalizes a percentage of certain operating costs. The Company is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs may be charged to earnings in the year incurred.

The Company entered into a service contract relating to asset management initiatives. The majority of the costs are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2011, costs relating to this service contract of $133 million (2010 - $124 million) were included in gas mains and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

Property, Plant and Equipment

In the absence of rate regulation, property, plant and equipment would not include some operating costs since these costs would have been charged to earnings in the period incurred. Further, on the retirement of utility assets, the excess of the book value net of proceeds would be recorded as a loss on the sale of assets in earnings in the period of retirement. Any removal costs incurred would be booked against the future removal and site restoration balance (described above).

Intangible Assets

The Company entered into contracts relating to CIS integration services, software maintenance and support. At December 31, 2011, the net book value of these costs was $99 million (2010 - $111 million). In the absence of rate regulation, a portion of the original cost of these assets would have been expensed in the period incurred.

Gas Inventories

Natural gas in storage is recorded in inventory at the prices approved by the Regulators in the determination of customers' system supply rates. In the absence of rate regulation, the actual price of natural gas purchased would be recorded in gas inventories.

Included in gas inventories at December 31, 2011 is $42 million (2010 - $43 million) of storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during the off-peak months and charged to gas costs during the peak winter months. In the absence of rate regulation, these costs would be expensed as incurred.

Depreciation

In the absence of rate regulation, depreciation rates would not have included a provision for future removal and site restoration costs.

4. ACQUISITION

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company. Project Amherstburg holds two solar projects, consisting of separate 10 megawatt (MW) and 5-MW facilities, both located in Amherstburg, Ontario. The total consideration transferred for the two projects was approximately $66 million, and was primarily funded by the issuance of common shares (1,612,367 shares). The remaining 0.1% limited partnership interest is owned by the general partner, Project AMBG2 Inc., a wholly-owned subsidiary of Enbridge Inc.

The transaction, which is a related party transaction, has been accounted for at carrying value. The Company consolidates its interest in Project Amherstburg.

Since the acquisition date, Project Amherstburg's revenue and earnings before tax for the year ended December 31, 2011 were $3 million and $2 million, respectively.

December 31,	2011
(millions of Canadian dollars)	
Carrying value of assets acquired:	
Property, plant and equipment	59
Intangible assets	9
Future income tax liability	(2)
	66
Consideration:	
Common shares	66

5. ACCOUNTS RECEIVABLE AND OTHER

December 31,	2011	2010
(millions of Canadian dollars)		
Trade receivables	378	422
Unbilled revenues	175	231
Agent billing and collection receivable	69	86
Regulatory assets *(Note 3)*	24	61
Due from affiliates *(Note 20)*	12	11
Taxes receivable	22	14
Prepaid expenses	3	5
Other	25	23
Allowance for doubtful accounts	(45)	(51)
	663	802

6. PROPERTY, PLANT AND EQUIPMENT

December 31, 2011	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Regulated property, plant and equipment				
Gas mains	4.2%	2,641	528	2,113
Gas services	4.5%	2,120	667	1,453
Regulating and metering equipment	3.7%	719	236	483
Gas storage	3.0%	275	89	186
Land and right-of-way	2.5%	79	30	49
Computer technology	19.8%	35	5	30
Under construction	-	92	-	92
Construction materials inventory	-	39	-	39
Other	3.5%	259	76	183
		6,259	1,631	4,628
Unregulated property, plant and equipment				
Gas storage	3.0%	88	4	84
Solar assets	4.0%	59	1	58
		147	5	142
		6,406	1,636	4,770

December 31, 2010	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Regulated property, plant and equipment				
Gas mains	4.2%	2,505	484	2,021
Gas services	4.6%	2,036	628	1,408
Regulating and metering equipment	3.8%	691	224	467
Gas storage	2.8%	240	79	161
Land and right-of-way	2.6%	77	29	48
Computer technology	19.8%	33	4	29
Under construction	-	66	-	66
Construction materials inventory	-	25	-	25
Other	3.5%	259	76	183
		5,932	1,524	4,408
Unregulated property, plant and equipment				
Gas storage	3.0%	52	2	50
		52	2	50
		5,984	1,526	4,458

Total depreciation expense, including amounts collected for future removal and site restoration costs, for property, plant and equipment was $250 million for the year ended December 31, 2011 (2010 - $238 million).

7. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	2011	2010
(millions of Canadian dollars)		
Regulatory assets *(Note 3)*	248	252
Pension asset *(Note 18)*	231	222
Other	10	13
	489	487

8. INTANGIBLE ASSETS

December 31, 2011	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Regulated intangible assets				
Software	20.0%	111	40	71
CIS	10.1%	127	28	99
		238	68	170
Unregulated intangible assets				
Power purchase contract	5.0%	9	-	9
		9	-	9
		247	68	179

December 31, 2010	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Regulated intangible assets				
Software	20.1%	100	44	56
CIS	10.0%	127	16	111
		227	60	167

Intangible assets include $21 million of work-in-progress for the year ended December 31, 2011 (2010 - $9 million). Total amortization expense for intangible assets was $31 million for the year ended December 31, 2011 (2010 - $32 million).

9. ACCOUNTS PAYABLE AND OTHER

December 31,	2011	2010
(millions of Canadian dollars)		
Operating accrued liabilities	250	282
Regulatory liabilities *(Note 3)*	32	204
Budget billing plan payable	136	92
Security deposits	79	73
Dividends payable	56	54
Trade payables	67	57
Taxes payable	26	34
Interest payable	26	29
Due to affiliates *(Note 20)*	10	3
Current derivative liabilities *(Note 15)*	1	1
Other	30	21
	713	850

10. DEBT

December 31,	Weighted Average Interest Rate	Maturity	2011	2010
(millions of Canadian dollars)				
Debenture	9.85%	2024	85	235
Medium term notes	5.51%	2014-2050	2,295	2,195
Commercial paper and credit facility draws, net			555	333
Other			8	6
Deferred debt issue costs			(13)	(20)
Total debt			2,930	2,749
Current maturities			-	(150)
Short-term borrowings	1.07%		(556)	(332)
Long-term debt			2,374	2,267
Loans from affiliate company			375	375

Medium term note maturities for the years ending December 31, 2012 through 2016 are nil, nil, $400 million, nil, and nil, respectively. The Company's debenture and medium term notes bear interest at fixed rates and the interest obligations for the years ending December 31, 2012 through 2016 are $135 million, $135 million, $129 million, $114 million and $114 million, respectively.

Interest Expense

Year ended December 31,	2011	2010
(millions of Canadian dollars)		
Debenture and medium term notes	140	149
Loans from affiliate company *(Note 20)*	27	27
Commercial paper and credit facility draws	3	2
Other interest and finance costs	8	11
Capitalized	(6)	(3)
	172	186

In 2011, total interest paid to third parties was $149 million (2010 - $158 million) and total interest paid to affiliated companies was $20 million (2010 - $27 million).

Credit Facilities

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, 2011	Total Facilities	Credit Facility Draws[1]	Available
(millions of Canadian dollars)			
Enbridge Gas Distribution Inc.	700	545	155
St. Lawrence Gas Company, Inc.	12	10	2
Total credit facilities	712	555	157

[1] *Includes facility draws and commercial paper issuances, net of discount, that are backstopped by the credit facility.*

Credit facilities carried a weighted average standby fee of 0.38% per annum from January to July 2011 and 0.22% per annum from August to December 2011 on the unused portion and draws bear interest at market rates.

11. OTHER LONG-TERM LIABILITIES

December 31,	2011	2010
(millions of Canadian dollars)		
Regulatory liabilities *(Note 3)*	1,047	984
OPEB liabilities *(Note 18)*	75	71
Pension liability *(Note 18)*	5	3
	1,127	1,058

12. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and a limited number of preferred shares.

Common Shares

December 31,	2011		2010	
	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of common shares in millions)				
Balance at beginning of year	140.7	1,071	140.7	1,071
Common shares issued	1.6	66	-	-
Balance at end of year	142.3	1,137	140.7	1,071

Preferred Shares

December 31, 2011 and 2010	Authorized	Issued and Outstanding	Amount
(millions of Canadian dollars, number of preferred shares in millions)			
Group 1	0.2	nil	-
Group 2, Series A - C, Cumulative Redeemable Retractable	6	nil	-
Group 2, Series D, Cumulative Redeemable Convertible	4	nil	-
Group 3, Series A - C, Cumulative Redeemable Retractable	6	nil	-
Group 3, Series D, Fixed/Floating Cumulative Redeemable Convertible	4	4	100
Group 4	10	nil	-
Group 5	10	nil	-
			100

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.

13. STOCK OPTION AND STOCK UNIT PLANS

Certain employees and senior officers of the Company are granted stock-based compensation from Enbridge through its three long-term incentive compensation plans: the Incentive Stock Option (ISO) Plan, the Performance Stock Unit (PSU) Plan and the Restricted Stock Unit (RSU) Plan. The PSU and RSU plans grant notional units as if a unit were one Enbridge common share and are payable in cash.

Incentive Stock Options

Key employees are granted ISOs to purchase common shares of Enbridge at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

During the year ended December 31, 2011, 663,800 stock options (2010 - 361,000 stock options) were issued to employees of the Company. The stock options were issued at a weighted average exercise price of $28.78 in 2011 (2010 - $23.30) and a grant date fair value of $4.00 (2010 - $3.28).

Performance Stock Units

Enbridge has a PSU Plan that includes the Company's senior officers where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average common share price and by a performance multiplier. The performance multiplier ranges from zero, if Enbridge's performance fails to meet threshold performance levels, to a maximum of two, if Enbridge performs within the highest range of its performance targets. The 2009, 2010, and 2011 grants derive the performance multiplier through a calculation of Enbridge's price/earnings ratio relative to a specified peer group of companies and Enbridge's growth in earnings per share, adjusted for non-operating or non-recurring items, relative to targets established at the time of grant.

During the year ended December 31, 2011, 25,200 PSUs (2010 - 18,200) were issued to employees of the Company.

Restricted Stock Units

Enbridge has an RSU plan where cash awards are paid to certain non-executive employees of the Company following a 35 month maturity period. RSU holders receive cash equal to Enbridge's weighted average share price multiplied by the units outstanding on the maturity date.

During the year ended December 31, 2011, Enbridge granted 111,300 RSUs (2010 - 124,000) to certain employees of the Company.

Stock-based Compensation Expense

The Company is charged an expense for stock-based compensation which includes a direct charge for ISOs, PSUs and RSUs issued to employees of the Company and an allocation of such costs with respect to employees of Enbridge who provide services to the Company. For the year ended December 31, 2011, the total amount of direct charge was $8 million (2010 - $6 million) and the total amount of allocation was $6 million (2010 - $5 million). These costs are included in operating and administrative expenses.

14. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Market Price Risk

The Company's earnings, cash flows and OCI are subject to movements in interest rates, foreign exchange rates and natural gas prices (collectively, market price risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them.

Interest Rate Risk

The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Floating to fixed interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2012 at an average rate of 1.8%.

At December 31, 2011, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would have resulted in no change (2010 - nil) in earnings and would have caused a $1 million increase (2010 - $3 million) in OCI in the year due to the revaluation of interest rate derivatives outstanding at December 31, 2011, and a $6 million decrease (2010 - $3 million) in earnings due to increased interest expense related to the Company's variable rate debt outstanding at December 31, 2011 assuming the variable rate debt outstanding had been outstanding for the entire period.

Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. A portion of the Company's purchases of natural gas are denominated in United States dollars and as a result there is exposure to fluctuations of the United States dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the net exposure of the Company to movements in the foreign exchange rate on natural gas purchases is nil (2010 - nil).

Natural Gas Price Risk

Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. Only St. Lawrence manages the exposure to natural gas price risk by entering into fixed price natural gas contracts. Other than St. Lawrence, the Company no longer manages natural gas price risk exposure, in compliance with the directive of the OEB. Fluctuations in natural gas prices are borne by the customers.

Total Derivative Instruments

The total notional principal or quantity outstanding related to the Company's derivative instruments at December 31, 2011 include $111 million of interest rate contracts and 6 million cubic metres of natural gas contracts, both maturing in 2012.

The Company does not have any credit-risk related contingent features associated with its derivative instruments.

The Company estimates that $1 million of AOCL related to cash flow hedges from interest rate contracts will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest rates in effect when derivative contracts that are currently outstanding mature. Any gains or losses from natural gas derivatives are borne by customers. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 24 months at December 31, 2011.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments *(Notes 20 and 21)*, as they become due. In order to manage this risk, the Company forecasts cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations and the issuance of commercial paper and/or credit facility draws. The Company maintains a current shelf prospectus with the securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities *(Note 10)* with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2011. As a result, all credit facilities are available to the Company and the banks are obligated to fund, and have been funding, the Company under the terms of the facilities.

Maturities of Financial Instruments

The Company generally has no financial instruments, other than derivative instruments, maturing beyond one year with the exception of its long-term debt and loans from affiliate company *(Notes 10 and 20)*.

Based on valuations at December 31, 2011, the Company's financial derivative instruments will give rise to $1 million undiscounted cash outflows in 2012.

Credit Risk

The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is largely mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms including obtaining additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value, as disclosed in Note 15, *Fair Value of Financial Instruments*.

The change in the allowance for doubtful accounts with respect to accounts receivable is detailed below.

Year ended December 31,	2011	2010
(millions of Canadian dollars)		
Balance at beginning of year	(51)	(57)
Additional allowance	(25)	(23)
Amounts used and reversed	31	29
Balance at end of year	(45)	(51)

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 21 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts.

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

Estimated costs associated with uncollectible accounts receivable are recovered through regulated distribution rates, which largely limits the Company's exposure to credit risk related to accounts receivable, to the extent such estimates are accurate. Under IR, these estimated costs recovered through distribution rates relate to the base year of the IR plan (2007) and are escalated by the approved formula during the IR term.

Entering into derivative financial instruments can also result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company only enters into risk management transactions with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

The Company generally has a policy of entering into individual International Securities Dealers Association agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with those specific counterparties in the event of bankruptcy or other significant credit event, and would reduce our credit risk exposure on derivative asset positions outstanding with these counterparties in these particular circumstances.

At December 31, 2011, the Company has a maximum exposure to credit risk of nil (2010 - nil) related to its derivative counterparties.

15. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following table summarizes the Company's financial instrument carrying and fair values and provides a reconciliation to the Consolidated Statements of Financial Position.

December 31, 2011	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
(millions of Canadian dollars)								
Assets								
Cash and cash equivalents	9	-	-	-	-	-	9	9
Accounts receivable and other	-	-	614	-	-	49	663	614
Investment in affiliate company[2]	-	825	-	-	-	-	825	N/A
Liabilities								
Bank overdraft	7	-	-	-	-	-	7	7
Short-term borrowings	-	-	-	556	-	-	556	556
Accounts payable and other	-	-	-	654	1	58	713	655
Long-term debt	-	-	-	2,374	-	-	2,374	2,943
Loans from affiliate company[2]	-	-	-	375	-	-	375	N/A

December 31, 2010	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
(millions of Canadian dollars)								
Assets								
Cash and cash equivalents	13	-	-	-	-	-	13	13
Accounts receivable and other	-	-	722	-	-	80	802	722
Investment in affiliate company[2]	-	825	-	-	-	-	825	N/A
Liabilities								
Bank overdraft	17	-	-	-	-	-	17	17
Short-term borrowings	-	-	-	332	-	-	332	332
Accounts payable and other	-	-	-	611	1	238	850	612
Long-term debt	-	-	-	2,417	-	-	2,417	2,775
Loans from affiliate company[2]	-	-	-	375	-	-	375	N/A

[1] *Fair value does not include non-financial instruments and available for sale equity instruments held at cost that do not trade on an actively quoted market (Note 20).*

[2] *Investment in affiliate company and loans from affiliate company resulted from related party transactions and are carried at historical cost; no fair value has been determined (Note 20).*

The fair value of financial instruments reflects the Company's best estimates of fair value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments other than derivatives represents the amounts estimated to be received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of Cash and cash equivalents and Short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates, natural gas prices and time value.

Fair Value of Derivatives

The Company categorizes its derivative assets and liabilities, measured at fair value, into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps and natural gas swaps for which observable inputs can be obtained.

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates.

When possible the estimated fair value is based on quoted market prices, and, if not available, estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes pricing models for options. Depending on the type of derivative and the nature of the underlying risk, primary inputs to these techniques include observable market prices (interest, foreign exchange and natural gas) and volatility. The Company uses inputs and data used by willing market participants when valuing derivatives and considers its own credit default swap spread as well as those of its counterparties in its determination of fair value. Where possible, the Company uses observable inputs.

At December 31, 2011, the Company has current Level 2 derivative liabilities with fair value of $1 million (2010 - $1 million).

16. CAPITAL DISCLOSURES

The Company defines capital as shareholders' equity (excluding AOCL), long-term debt (including intercompany debt, excluding transaction costs), short-term borrowings, cash and cash equivalents and bank overdraft.

The Company's capital is calculated as follows:

December 31,	2011	2010
(millions of Canadian dollars)		
Cash and cash equivalents	(9)	(13)
Bank overdraft	7	17
Short-term borrowings	556	332
Long-term debt (includes current portion)	2,387	2,437
Loans from affiliate company	375	375
Shareholders' equity	2,000	1,945
	5,316	5,093

The Company's objectives when managing capital are to maintain flexibility among: enabling the business to operate at the highest efficiency while maintaining safety and reliability; providing liquidity for growth opportunities; maintaining a capital structure that is in alignment with the deemed equity ratio of 36%; and providing acceptable returns to the common shareholder. These objectives are primarily met through maintenance of an investment grade credit rating, which provides access to lower cost capital. Capital is available generally through the issuance of both short and long-term debt and equity.

The Company manages its capital in light of changes in the economic and regulatory environment and the underlying assets. In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends paid to the common shareholder, issue new shares or issue new debt. Dividend payments are determined with the objective of maintaining a capital structure that is in alignment with the deemed equity ratio of 36%.

Due to the seasonal nature of the Company's business and continuing growth in the asset base, cash receipts do not typically match the Company's requirements for capital expenditures, dividends, long-term debt retirement and inventory replenishment. Generally, cash shortfalls are financed initially through the issuance of short-term debt. The Company maintains a balanced capital structure by periodically refinancing short-term debt with long-term debt.

The Company's borrowings, whether debentures or medium term notes, are unsecured. When issuing any new indebtedness with a maturity of over 18 months, covenants contained in the Company's trust indentures require that the pro forma long-term debt interest coverage ratio be at least 2.0 times for twelve consecutive months out of the previous 23 months. The pro forma long-term debt interest coverage ratio is calculated as Canadian GAAP earnings adjusted for income taxes, long-term debt interest expense, amortization of debt issue costs and intercompany interest expense, less gains on asset dispositions divided by the annual interest requirements. The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test. As at December 31, 2011, the Company was in compliance with these covenants.

17. INCOME TAXES

Income Tax Rate Reconciliation

Year ended December 31,	2011	2010
(millions of Canadian dollars)		
Earnings before income taxes	262	254
Combined statutory income tax rate	28.3%	31.0%
Income taxes at statutory rate	74	79
Increase/(decrease) resulting from:		
Non-taxable dividend income from affiliated companies	(18)	(19)
Future income taxes related to regulated operations	-	7
Other	(5)	(6)
Income taxes	51	61
Effective income tax rate	19.5%	24.0%

The future income taxes recorded in current liabilities of $2 million (2010 - $5 million) arise primarily from temporary differences relating to regulatory deferral accounts.

At December 31, 2011, the Company had a future income tax liability of $164 million (2010 - $164 million) related to regulatory assets, primarily property, plant and equipment, with an offsetting long-term regulatory asset *(Note 3)* to the extent that the future income tax liability is expected to be included in regulator-approved future rates and recovered from future customers.

18. POST-EMPLOYMENT BENEFITS

Pension Plans

The Company provides a non-contributory basic pension plan that provides either defined benefit and/or defined contribution pension benefits to the majority of its employees. The Company has two supplemental non-contributory defined benefit pension plans which provide pension benefits in excess of the basic plan for certain employees. A measurement date of December 31, 2011 was used to determine the plan assets and the accrued benefit obligation.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publiclytraded equity and fixed income securities. The effective date of the most recent actuarial valuation was December 31, 2009, and the effective date of the next required actuarial valuation is December 31, 2012.

The defined benefit pension plan costs have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages.

Defined Contribution Plans

Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

Post-employment Benefits Other than Pensions

OPEB primarily include supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

Defined Benefit Plans

The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plan using the accrual method.

	Pension Benefits		OPEB	
December 31,	**2011**	2010	**2011**	2010
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**702**	588	**87**	81
Service cost	**16**	12	**1**	1
Interest cost	**39**	39	**5**	5
Actuarial loss	**127**	79	**13**	5
Benefits paid	**(33)**	(31)	**(3)**	(3)
Other	**1**	15	**-**	(2)
Benefit obligation at end of year	**852**	702	**103**	87
Change in plan assets				
Fair value of plan assets at beginning of year	**759**	695	**4**	-
Transfer to the defined contribution component	**(1)**	(2)	**-**	-
Actual return on plan assets	**15**	78	**-**	-
Employer's contributions	**4**	4	**6**	7
Benefits paid	**(33)**	(31)	**(3)**	(3)
Other	**-**	15	**(1)**	-
Fair value of plan assets at end of year	**744**	759	**6**	4
Funded status				
Benefit obligation	**(852)**	(702)	**(103)**	(87)
Fair value of plan assets	**744**	759	**6**	4
Overfunded/(underfunded) status at end of year	**(108)**	57	**(97)**	(83)
Unamortized prior service cost	**2**	4	**-**	-
Unamortized transitional (asset)/obligation	**(44)**	(70)	**13**	16
Unamortized net actuarial loss/(gain)	**376**	228	**9**	(4)
Net amount recognized in the Consolidated Statements of Financial Position at end of year	**226**	219	**(75)**	(71)
Included in the following accounts:				
Deferred amounts and other assets *(Note 7)*	**231**	222	**-**	-
Other long-term liabilities *(Note 11)*	**(5)**	(3)	**(75)**	(71)

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension Benefits		OPEB	
Year ended December 31,	**2011**	2010	**2011**	2010
Discount rate	**4.50%**	5.70%	**4.50%**	5.70%
Average rate of salary increases	**3.50%**	3.50%	**5.00%**	5.00%

Net Benefit Costs Recognized

	Pension Benefits		OPEB	
Year ended December 31,	**2011**	2010	**2011**	2010
(millions of Canadian dollars)				
Benefits earned during the year	**16**	12	**1**	1
Interest cost on projected benefit obligations	**39**	39	**5**	5
Actual return on plan assets	**(15)**	(78)	**-**	-
Actuarial loss	**127**	79	**13**	5
Differences between costs arising in the year and costs recognized in the year:				
Return on plan assets	**(38)**	29	**-**	-
Prior service costs	**2**	1	**-**	-
Transitional (asset)/obligation	**(26)**	(24)	**3**	3
Actuarial loss	**(110)**	(64)	**(13)**	(5)
Net defined benefit costs on an accrual basis	**(5)**	(6)	**9**	9
Defined contribution benefit costs	**1**	2	**-**	-
(Credits)/costs on an accrual basis	**(4)**	(4)	**9**	9

Costs related to the period on an accrual basis are presented above and are initially expensed. However, there is a partially offsetting adjustment due to the regulatory mechanism in place. As a result, the net expense, which is consistent with the recovery of such costs in rates, was $4 million for pension benefits and $4 million for OPEB for the year ended December 31, 2011 (2010 - $4 million and $4 million, respectively).

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	Pension Benefits		OPEB	
Year ended December 31,	**2011**	2010	**2011**	2010
Discount rate	**5.70%**	6.60%	**5.70%**	6.60%
Average rate of return on pension plan assets	**7.25%**	7.14%	**-**	-
Average rate of salary increases	**3.50%**	3.50%	**5.00%**	5.00%

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Medical Cost Trends

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in Which Ultimate Medical Cost Trend Rate Assumption is Achieved
Drugs	8.40%	4.50%	2029
Other Medical and Dental	4.50%	4.50%	2029

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $15 million in the accumulated post-employment benefit obligations and an increase of $1 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $12 million in the accumulated post-employment benefit obligations and a decrease of $1 million in benefit and interest costs.

Plan Assets

Major Categories of Plan Assets

	Pension Benefits		
	2011		2010
As at December 31,	Allocation	Amount	Allocation
(millions of Canadian dollars)			
Equity securities	55%	410	58%
Fixed income securities	44%	328	41%
Other	1%	7	1%
Total assets	100%	745	100%

The Company manages the investment risk of its defined benefit pension plans by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long term expectations.

Target Mix for Plan Assets

Equity securities	52.5%
Fixed income securities	42.5%
Other	5.0%

Plan Contributions by the Company

	Pension Benefits		OPEB	
Year ended December 31,	2011	2010	2011	2010
(millions of Canadian dollars)				
Total contributions	4	4	6	7
Contributions expected to be paid in 2012	20		4	

Benefits Expected to be Paid by the Company

Year ended December 31,	2012	2013	2014	2015	2016	2017-2021
(millions of Canadian dollars)						
Expected future benefit payments	39	41	43	45	47	255

19. CASH FLOW INFORMATION

Changes In Operating Assets And Liabilities

Year ended December 31,	2011	2010
(millions of Canadian dollars)		
Accounts receivable and other	139	8
Gas inventories	20	(4)
Accounts payable and other	(142)	41
	17	45

Significant Non-cash Items

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company for non-cash consideration of $66 million, primarily funded by the issuance of common shares.

20. RELATED PARTY TRANSACTIONS

Year ended December 31,	2011	2010
(millions of Canadian dollars)		
IPL System Inc.		
Dividend income	63	63
Interest expense	27	27
Enbridge Inc.		
Purchase of treasury and other management services	34	32
Gazifère Inc.		
Revenue from wholesale service, including gas sales	28	30
Vector Pipeline Limited Partnership (U.S.)		
Purchase of gas transportation services	24	27
Vector Pipeline Limited Partnership (Canadian)		
Purchase of gas transportation services	2	1
Alliance Pipeline Limited Partnership (Canadian)		
Purchase of gas transportation services	25	25
Alliance Pipeline Limited Partnership (U.S.)		
Purchase of gas transportation services	18	17
Enbridge Commercial Services Inc.		
Purchase of information services	-	2

The Company had related party balances as follows:

December 31,	2011	2010
(millions of Canadian dollars)		
Investment in affiliate company		
IPL System Inc.	825	825
Dividend receivable	5	5
Loans from affiliate company		
IPL System Inc.	375	375
Interest payable	9	2
Note payable to affiliate company		
Enbridge (U.S.) Inc.	8	6
Accounts receivables/(payables)		
Enbridge Inc.	(1)	(1)
Gazifère Inc.	4	5
Niagara Gas Transmission Ltd.	2	-

Financing Transactions

The Company has invested in Class D, non-voting redeemable, retractable preferred shares of IPL System Inc., an affiliate under common control. At December 31, 2011, the investment of $825 million (2010 - $825 million) in these shares, at cost, resulted in a weighted average dividend yield of 7.60%.

At December 31, 2011, the borrowing from IPL System Inc. stood at $375 million ($200 million at 6.85% and $175 million at 7.50%). These loans are repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in either cash or non-retractable preferred shares of the Company. For the year ended December 31, 2011, interest paid amounted to $20 million (2010 - $27 million).

The note payable to Enbridge (U.S.) Inc. bears interest at the LIBOR rate plus 0.55% and is payable on demand.

Treasury and Other Management Services

Enbridge provides treasury and other management services and charges the Company amounts designed to recover the costs of providing such services.

Wholesale Service

These services are pursuant to a contract negotiated between the Company and Gazifère Inc., an affiliate under common control, and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie.

Gas Transportation Services

The Company has contracted for natural gas transportation services from Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian), Alliance Pipeline Limited Partnership (Canadian) and Alliance Pipeline Limited Partnership (U.S.), related entities partially owned by an affiliated company under common control. Contractual obligations under these contracts are 2012 - $69 million, 2013 to 2014 - $131 million, 2015 to 2016 - $70 million and thereafter - nil.

Information Services

The Company purchases access to a few of its customer care information systems from Enbridge Commercial Services Inc. (ECS), an affiliate under common control. ECS charges the Company amounts under a service level agreement designed to recover the cost of providing the service.

Trade Receivables and Payables

The cash balances of the Company and its subsidiaries are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

The Company provides consulting and other services to affiliates. Market prices are charged for these services where they are reasonably determinable. Where no market price exists, a cost-based price is charged. The Company may also purchase consulting and other services from affiliates with prices determined on the same basis as services provided by the Company. The trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates.

Other Transactions

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company for non-cash consideration of $66 million, primarily funded by the issuance of common shares *(Note 4)*.

The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

21. COMMITMENTS AND CONTINGENCIES

Commitments

The Company has entered into long-term contracts and future payments under the contracts are as follows:

	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
(millions of Canadian dollars)					
Services contract[1]	15	7	8	-	-
Customer care service contracts[2]	359	58	115	122	64
Total	374	65	123	122	64

[1] *Primarily fees relating to services provided with respect to work and asset management initiatives. The majority of these expenditures will be capitalized to gas mains under property, plant and equipment in accordance with regulatory treatment. At December 31, 2011, $133 million (2010 - $124 million) of such costs were included in gas mains, which are depreciated over the average service life of 25 years.*

[2] *In 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. The total cost of the customer care services during the term of the extension is approximately $360 million. The OEB approved the Company's recovery of costs associated with the agreement in 2011.*

Contingencies

Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its Station A MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on the Company. It was and remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, the Company and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with the Company. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

On August 30, 1994, Wyndham Court Canada Inc. (Wyndham) commenced an action in the Ontario Court of Justice (General Division) against the Company and 20 other defendants claiming that coal tar originating from the Company's Station A MGP in Toronto migrated to lands owned by Wyndham. Wyndham claimed general damages in the amount of $70 million and punitive damages in the amount of $5 million. It is believed that this action was also commenced by Wyndham due to its concern about the running of limitation periods.

The Company entered into a Tolling Agreement with Wyndham pursuant to which Wyndham's action was discontinued, without prejudice to Wyndham's right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham sold the lands that were the subject of the action to Cityscape Holdings Inc., which directed that title to a portion of these lands be transferred to Cityscape Residential Inc. (jointly Cityscape). Cityscape served the Company with a Statement of Claim in February 2003, naming the Company and nine other defendants who own or have owned portions of the former Station A MGP site. Cityscape is claiming $50 million in damages and $5 million in punitive damages against the Company as a result of alleged coal tar contamination of the lands now owned by Cityscape. The Company responded with a Statement of Defence denying liability. In January 2004, Cityscape dismissed the action against each of the Company's co-defendants.

In February 2008, the Ontario Superior Court of Justice ordered that examinations for discovery of the plaintiff be completed by mid-June 2008. Examinations for discovery were completed by this date, but required steps in the discovery process have not yet been completed by the plaintiff. At present, it is unknown when the trial of the matter will be heard.

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2012 fiscal years, the OEB approved the establishment of deferral accounts. The issue of whether the possible claims and related costs are recoverable from customers has yet to be determined.

The Company remains of the view that it has a valid defence to the Cityscape lawsuit; however, it acknowledges that certain risks exist. Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation/isolation/containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. The Company expects that if it is found that it must contribute to any remediation costs (either as a result of a lawsuit or government order), it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company's financial position.

Bloor Street Incident

The Company was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred in April 2003 on Bloor Street West in Toronto. In December 2011, the Company pleaded guilty before the Ontario Court of Justice to one charge under OHSA and one charge under TSSA. The Court imposed a fine of $350,000 in connection with each charge. With the application of a required 25% Victim Fine Surcharge, the total amount payable by the Company was $875,000.

Other Litigation

The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

TRUSTEE AND REGISTRARS

Debenture

9.85% debenture

CIBC Mellon Trust Company of Canada
c/o BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, 11th Floor
Toronto, Ontario, M5H 4A6
and in Montreal, Calgary and Vancouver

For the above debenture, CIBC Mellon Trust Company of Canada is the Interest Dispersing Agent.

REGISTRAR AND PAYING AGENT

Medium Term Notes

Canadian Imperial Bank of Commerce
Debt Management Service
22 Front Street West, 5th Floor
Toronto, Ontario, M5J 2W5

TRUSTEE

Medium Term Notes

CIBC Mellon Trust Company of Canada
c/o BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, 11th Floor
Toronto, Ontario, M5H 4A6

REGISTRAR AND TRANSFER AGENT

Group 3 Preferred Shares

Computershare Investor Services Inc.
100 University Avenue
Toronto, Ontario, M5J 2Y1

The size of the Board of Directors of the Company is currently set at six (6) members, two (2) of whom are considered to be independent directors.

The Board has an Audit, Finance & Risk Committee comprised of the following directors:

J. L. Braithwaite

D.A. Leslie

J. R. Bird

The Audit, Finance & Risk Committee's key responsibilities include the review of the consolidated financial statements, systems of internal financial and compliance control.

The governance of the Company is the responsibility of the Board of Directors and the Audit, Finance & Risk Committee of the Board, who are also responsible under law for the supervision of the management of the Company's businesses and affairs and have the statutory authority and obligation to act honestly and in good faith with a view to the best interests of the Company.

The Board makes independent decisions and also receives recommendations from the following committees of the Enbridge Inc. Board of Directors, who act in an advisory capacity to the Board of Directors of the Company:

- Governance Committee
- Human Resources & Compensation Committee
- Corporate Social Responsibility Committee

In addition to the committee structure and mandate of the Board of Directors outlined above, the Board of Directors has adopted and governs itself in accordance with Enbridge Inc.'s corporate governance practices as expressed in the *Corporate Governance Practices* of Enbridge annually disclosed in its *Management Information Circular* (last dated March 2, 2011), which is incorporated herein by reference.

ENBRIDGE



ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2011

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Inc.

Financial Reporting
Management of Enbridge Inc. (the Company) is responsible for the accompanying consolidated financial statements. The consolidated financial statements have been prepared in accordance with Part V – Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants Handbook and necessarily include amounts that reflect management's judgment and best estimates

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (AF&RC) of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The AF&RC meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AF&RC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with generally accepted accounting principles and provide reasonable assurance that assets are safeguarded.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2011, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2011.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States).

"signed"

Patrick D. Daniel
President & Chief Executive Officer

"signed"

J. Richard Bird
Executive Vice President &
Chief Financial Officer

February 21, 2012



Independent Auditor's Report

To the Shareholders of Enbridge Inc.

We have completed integrated audits of Enbridge Inc.'s 2011, 2010 and 2009 consolidated financial statements and its internal control over financial reporting as at December 31, 2011. Our opinions, based on our audits, are presented below.

Report on the consolidated financial statements
We have audited the accompanying consolidated financial statements of Enbridge Inc., which comprise the consolidated statements of financial position as at December 31, 2011 and December 31, 2010 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2011, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the consolidated financial statements.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Inc. as at December 31, 2011 and December 31, 2010 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011 in accordance with Canadian generally accepted accounting principles.

Report on internal control over financial reporting
We have also audited Enbridge Inc.'s internal control over financial reporting as at December 31, 2011, based on the criteria established in Internal Control - Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

PricewaterhouseCoopers LLP, Chartered Accountants
111 5 Avenue SW, Suite 3100, Calgary, Alberta, Canada T2P 5L3
T: +1 403 509 7500, F: +1 403 781 1825, www.pwc.com/ca

"PwC" refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership.

Management's responsibility for internal control over financial reporting
Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying management's report on internal control over financial reporting.

Auditor's responsibility
Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on the company's internal control over financial reporting.

Definition of internal control over financial reporting
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Inherent limitations
Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Opinion
In our opinion, Enbridge Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2011 based on criteria established in Internal Control – Integrated Framework, issued by COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada

February 21, 2012

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars, except per share amounts)			
Revenues			
Commodity sales	**15,676**	11,990	9,720
Transportation and other services	**3,726**	3,137	2,746
	19,402	15,127	12,466
Expenses			
Commodity costs	**14,854**	11,291	9,011
Operating and administrative	**1,720**	1,466	1,430
Depreciation and amortization	**937**	864	764
	17,511	13,621	11,205
	1,891	1,506	1,261
Income from equity investments	**336**	38	198
Other income *(Note 28)*	**112**	374	678
Interest expense *(Note 16)*	**(711)**	(687)	(597)
Gain on sale of investments *(Note 6)*	**-**	-	365
	1,628	1,231	1,905
Income taxes *(Note 26)*	**(568)**	(251)	(306)
Earnings	**1,060**	980	1,599
Earnings attributable to noncontrolling interests	**(56)**	(10)	(37)
Earnings attributable to Enbridge Inc.	**1,004**	970	1,562
Preference share dividends	**(13)**	(7)	(7)
Earnings attributable to Enbridge Inc. common shareholders	**991**	963	1,555
Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 20)*	**1.32**	1.30	2.14
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 20)*	**1.30**	1.29	2.12

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings	**1,060**	980	1,599
Other comprehensive income/(loss)			
Change in unrealized loss on cash flow hedges, net of tax	**(427)**	(113)	(54)
Change in unrealized gain/(loss) on net investment hedges, net of tax	**(19)**	51	151
Reclassification to earnings of realized cash flow hedges, net of tax	**32**	(25)	114
Reclassification to earnings of unrealized cash flow hedges, net of tax *(Note 23)*	**8**	-	(20)
Other comprehensive loss from equity investees, net of tax	**(61)**	(11)	(24)
Change in foreign currency translation adjustment	**242**	(274)	(815)
Other comprehensive loss	**(225)**	(372)	(648)
Comprehensive income	**835**	608	951
Comprehensive (income)/loss attributable to noncontrolling interests	**(43)**	23	35
Comprehensive income attributable to Enbridge Inc.	**792**	631	986
Preference share dividends	**(13)**	(7)	(7)
Comprehensive income attributable to Enbridge Inc. common shareholders	**779**	624	979

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 20)*			
Balance at beginning of year	**125**	125	125
Preference shares issued	**931**	-	-
Balance at end of year	**1,056**	125	125
Common shares *(Note 20)*			
Balance at beginning of year	**3,683**	3,379	3,194
Common shares issued	**-**	-	4
Dividend reinvestment and share purchase plan	**229**	224	143
Shares issued on exercise of stock options	**57**	80	38
Balance at end of year	**3,969**	3,683	3,379
Contributed surplus			
Balance at beginning of year	**59**	54	38
Stock-based compensation	**18**	13	19
Options exercised	**(7)**	(8)	(3)
Dilution gains and other *(Note 19)*	**36**	-	-
Balance at end of year	**106**	59	54
Retained earnings			
Balance at beginning of year	**4,734**	4,400	3,383
Earnings attributable to Enbridge Inc. common shareholders	**991**	963	1,555
Common share dividends declared	**(759)**	(648)	(555)
Dividends paid to reciprocal shareholder	**25**	19	17
Balance at end of year	**4,991**	4,734	4,400
Accumulated other comprehensive income/(loss) *(Note 22)*			
Balance at beginning of year	**(882)**	(543)	33
Other comprehensive loss	**(212)**	(339)	(576)
Balance at end of year	**(1,094)**	(882)	(543)
Reciprocal shareholding *(Note 11)*			
Balance at beginning of year	**(154)**	(154)	(154)
Acquisition of equity investment	**(33)**	-	-
Balance at end of year	**(187)**	(154)	(154)
Total Enbridge Inc. shareholders' equity	**8,841**	7,565	7,261
Noncontrolling interests			
Balance at beginning of year	**658**	727	797
Earnings attributable to noncontrolling interests	**56**	10	37
Other comprehensive income/(loss) attributable to noncontrolling interests			
Change in unrealized income/(loss) on cash flow hedges, net of tax	**(7)**	(9)	4
Other comprehensive loss from equity investees, net of tax	**(15)**	(3)	(5)
Change in foreign currency translation adjustment	**9**	(21)	(71)
	(13)	(33)	(72)
Comprehensive income/(loss) attributable to noncontrolling interests	**43**	(23)	(35)
Distributions	**(37)**	(30)	(33)
Contributions *(Note 19)*	**208**	29	-
Acquisitions *(Notes 10 and 19)*	**(27)**	(45)	-
Other	**1**	-	(2)
Balance at end of year	**846**	658	727
Total shareholders' equity	**9,687**	8,223	7,988
Dividends paid per common share	**0.98**	0.85	0.74

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Operating activities			
Earnings attributable to Enbridge Inc.	**1,004**	970	1,562
Depreciation and amortization	**937**	864	764
Unrealized gains on derivative instruments	**(13)**	(10)	(204)
Allowance for equity funds used during construction	**(3)**	(80)	(135)
Cash distributions (less than)/in excess of equity earnings	**(42)**	214	(9)
Gain on reduction of ownership interest	**(141)**	(81)	-
Gain on sale of investments *(Note 6)*	**-**	-	(365)
Future income taxes *(Note 26)*	**415**	238	218
Goodwill and asset impairment losses	**11**	-	11
Noncontrolling interests	**56**	10	37
Other	**150**	(11)	(105)
Changes in regulatory assets and liabilities	**78**	30	11
Changes in operating assets and liabilities *(Note 29)*	**251**	(293)	232
	2,703	1,851	2,017
Investing activities			
Additions to property, plant and equipment	**(2,516)**	(2,357)	(3,225)
Government grant	**145**	-	-
Additions to intangible assets	**(165)**	(50)	(95)
Change in construction payable	**(66)**	27	(110)
Long-term investments	**(217)**	(121)	(359)
Affiliate loans, net	**10**	(80)	(145)
Acquisitions *(Notes 6 and 19)*	**(1,208)**	(116)	-
Proceeds on sale of investments *(Note 6)*	**-**	23	535
Sale of property, plant and equipment	**-**	-	87
Settlement of hedges *(Note 6)*	**-**	-	6
	(4,017)	(2,674)	(3,306)
Financing activities			
Net change in bank indebtedness and short-term borrowings	**224**	(165)	(393)
Net change in commercial paper and credit facility draws	**11**	(347)	736
Debenture and term note issues	**825**	2,300	1,500
Debenture and term note repayments	**(203)**	(600)	(616)
Net change in Southern Lights project financing	**(62)**	14	343
Non-recourse debt issues	**17**	5	60
Non-recourse debt repayments	**(81)**	(73)	(130)
Contributions from/(distributions) to noncontrolling interests, net	**214**	(1)	(33)
Preference shares issued	**926**	-	-
Common shares issued	**46**	66	36
Preference share dividends	**(7)**	(7)	(7)
Common share dividends	**(530)**	(426)	(414)
	1,380	766	1,082
Effect of translation of foreign denominated cash and cash equivalents	**12**	(11)	(35)
Increase/(decrease) in cash and cash equivalents	**78**	(68)	(242)
Cash and cash equivalents at beginning of year	**342**	410	652
Cash and cash equivalents at end of year[1]	**420**	342	410
Supplementary cash flow information			
Income taxes paid/(received) *(Note 26)*	**(35)**	108	205
Interest paid *(Note 16)*	**749**	711	656

The accompanying notes are an integral part of these consolidated financial statements.

1 *Cash and cash equivalents consists of $343 million (2010 - $243 million; 2009 - $267 million) of cash and $77 million (2010 - $99 million; 2009 - $143 million) of short-term investments and includes restricted cash of $17 million (2010 - $12 million; 2009 - $7 million), and joint-venture cash which is not readily accessible by the Company of $224 million (2010 - $48 million; 2009 - $52 million).*

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2011**	2010
(millions of Canadian dollars)		
Assets		
Current assets		
Cash and cash equivalents	**420**	342
Accounts receivable and other *(Note 7)*	**3,136**	2,706
Inventory *(Note 8)*	**739**	813
	4,295	3,861
Property, plant and equipment, net *(Note 9)*	**22,623**	20,332
Long-term investments *(Note 11)*	**2,540**	2,198
Deferred amounts and other assets *(Note 12)*	**3,220**	2,886
Intangible assets *(Note 13)*	**600**	478
Goodwill *(Note 14)*	**1,024**	385
Future income taxes *(Note 26)*	**41**	80
	34,343	30,220
Liabilities and shareholders' equity		
Current liabilities		
Bank indebtedness	**102**	100
Short-term borrowings *(Note 16)*	**548**	326
Accounts payable and other *(Note 15)*	**3,722**	2,688
Interest payable	**114**	117
Current maturities of long-term debt *(Note 16)*	**252**	154
Current maturities of non-recourse long-term debt *(Note 17)*	**122**	70
	4,860	3,455
Long-term debt *(Note 16)*	**14,257**	13,561
Non-recourse long-term debt *(Note 17)*	**951**	1,061
Other long-term liabilities *(Note 18)*	**1,892**	1,473
Future income taxes *(Note 26)*	**2,696**	2,447
	24,656	21,997
Equity		
Share capital		
Preference shares *(Note 20)*	**1,056**	125
Common shares *(Note 20)*	**3,969**	3,683
Contributed surplus	**106**	59
Retained earnings	**4,991**	4,734
Accumulated other comprehensive loss *(Note 22)*	**(1,094)**	(882)
Reciprocal shareholding *(Note 11)*	**(187)**	(154)
Total Enbridge Inc. shareholders' equity	**8,841**	7,565
Noncontrolling interests *(Note 19)*	**846**	658
	9,687	8,223
Commitments and contingencies *(Note 31)*		
	34,343	30,220

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

"signed"	"signed"
David A. Arledge	**David A. Leslie**
Chair	Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

Enbridge Inc. (Enbridge or the Company) is a publicly traded energy transportation and distribution company. Enbridge conducts its business through five operating segments: Liquids Pipelines, Gas Distribution, Gas Pipelines, Processing and Energy Services, Sponsored Investments and Corporate. These operating segments are strategic business units established by senior management to facilitate the achievement of the Company's long-term objectives, to aid in resource allocation decisions and to assess operational performance.

LIQUIDS PIPELINES
Liquids Pipelines consists of common carrier and contract crude oil, natural gas liquids (NGL) and refined products pipelines and terminals in Canada and the United States, including the Canadian Mainline, Regional Oil Sands System, Southern Lights Pipeline, Spearhead Pipeline, Seaway Crude Pipeline (Seaway Pipeline) interest and other feeder pipelines.

GAS DISTRIBUTION
Gas Distribution consists of the Company's natural gas utility operations, the core of which is Enbridge Gas Distribution Inc. (EGD) which serves residential, commercial and industrial customers, primarily in central and eastern Ontario as well as northern New York State. This business segment also includes natural gas distribution activities in Quebec and New Brunswick.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES
Gas Pipelines, Processing and Energy Services consists of investments in natural gas pipelines and processing facilities, green energy projects, Canadian midstream businesses, the Company's energy services businesses and international activities.

Investments in natural gas pipelines include the Company's interests in the United States portion of Alliance Pipeline (Alliance Pipeline US), the Vector Pipeline and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include the Company's interest in Aux Sable, a natural gas fractionation and extraction business, an interest in the development of Cabin Gas Plant in northeastern British Columbia, and processing facilities connected to the Gulf of Mexico System. The energy services businesses manage the Company's volume commitments on Alliance and Vector Pipelines, as well as perform natural gas, NGL and crude oil storage, transport and supply management services, as principal and agent.

SPONSORED INVESTMENTS
Sponsored Investments includes the Company's 23.0% ownership interest in Enbridge Energy Partners, L.P. (EEP), Enbridge's 66.7% investment in the United States segment of the Alberta Clipper Project through EEP and Enbridge Energy, Limited Partnership (EELP) and an overall 69.2% economic interest in Enbridge Income Fund (the Fund), held both directly, and indirectly through Enbridge Income Fund Holdings Inc. Enbridge manages the day-to-day operations of, and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

EEP transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and NGLs. The primary operations of the Fund include a crude oil and liquids pipeline and gathering system, a 50% interest in the Canadian portion of Alliance Pipeline (Alliance Pipeline Canada) and interests in renewable power generation projects.

CORPORATE
Corporate consists of the Company's investment in Noverco Inc. (Noverco), new business development activities, corporate investments and financing costs not allocated to the business segments.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company are prepared in accordance with Part V – Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants (CICA) Handbook (Canadian GAAP or Part V). These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP) and the significant differences that impact the Company's consolidated financial statements are described in Note 33. Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities *(Note 5)*; unbilled revenues *(Note 7)*; allowance for doubtful accounts *(Note 7)*; depreciation rates and carrying value of property, plant and equipment *(Note 9)*; amortization rates of intangible assets *(Note 13)*; measurement of goodwill *(Note 14)*; valuation of share based compensation *(Note 21)*; fair value of financial instruments *(Notes 23 and 24)*; income taxes *(Note 26)*; post-employment benefits *(Note 27)*; commitments and contingencies *(Note 31);* and fair value of asset retirement obligations (AROs). Actual results could differ from these estimates.

BASIS OF PRESENTATION

The consolidated financial statements include the accounts of Enbridge, its subsidiaries and its proportionate share of the accounts of various joint ventures. The Fund is consolidated in the accounts of the Company because it is a variable interest entity. The Company is the primary beneficiary of the Fund through the combination of a total direct and indirect 35.4% equity interest and a preferred unit investment. Investments in entities which are not subsidiaries or joint ventures, but over which the Company exercises significant influence, are accounted for using the equity method. Other investments are accounted for according to their classification as Held to maturity, Loans and receivables or Available for sale (see *Financial Instruments*).

REGULATION

Certain of the Company's businesses are subject to regulation by various authorities including, but not limited to, the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Energy Resources Conservation Board in Alberta, the New Brunswick Energy and Utilities Board (EUB) and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under Canadian GAAP for non rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are included in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions of the regulator. To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component which are both capitalized based on rates set out in a regulatory agreement. In the absence of rate regulation, the Company would capitalize interest using a capitalization rate based on its cost of borrowing and the

capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation would not be recognized.

Certain regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation. Entities not subject to rate regulation write off the net book value of the retired asset and include any resulting gain or loss in earnings.

With the approval of the regulator, EGD and certain distribution operations capitalize a percentage of certain operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of capitalized costs could differ significantly from those recorded. In the absence of rate regulation, a portion of such costs may be charged to current period earnings.

REVENUE RECOGNITION

For businesses which are not rate-regulated, revenues are recorded when products have been delivered or services have been performed and the amount of revenue can be reliably measured. Customer credit worthiness is assessed prior to agreement signing as well as throughout the contract duration. Certain Liquids Pipelines revenues are recognized under the terms of committed delivery contracts rather than the cash tolls received.

For the rate-regulated portion of the Company's main Canadian crude oil pipeline system, revenue was recognized in a manner that is consistent with the underlying agreements as approved by the regulator. Effective July 1, 2011, Canadian Mainline earnings are governed by the Competitive Toll Settlement (CTS), under which revenues are recorded when services are performed. Effective July 1, 2011, the Company discontinued the application of rate-regulated accounting for its Canadian Mainline (excluding Lines 8 and 9) on a prospective basis, with the exception of flow-through income taxes covered by a specific rate order.

For natural gas utility rate-regulated operations in Gas Distribution, revenue is recognized in a manner consistent with the underlying rate-setting mechanism as mandated by the regulator. Natural gas utilities revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period.

For rate-regulated operations in Sponsored Investments and rate-regulated operations in natural gas pipelines included in Gas Pipelines, Processing and Energy Services, transportation revenues include amounts related to expenses recognized that are expected to be recovered from shippers in future tolls. Revenue is recognized in a given period for tolls received to the extent that expenses are incurred. Differences between the recorded transportation revenue and actual toll receipts give rise to a regulatory asset or liability.

FINANCIAL INSTRUMENTS

The Company classifies financial assets and financial liabilities as held for trading, available for sale, loans and receivables, held to maturity, other financial liabilities or derivatives in qualifying hedging relationships. All financial instruments are initially recorded at fair value on the Consolidated Statements of Financial Position. Subsequent measurement of the financial instrument is based on its classification.

Held for Trading

Financial assets and liabilities that are classified as held for trading are measured at fair value with changes in fair value recognized in earnings in Transportation and other services revenue, Commodity costs, Other income and Interest expense. The Company has classified Cash and cash equivalents, bank indebtedness and its non-qualifying derivative instruments as held for trading.

Available for Sale
Financial assets that are available for sale are measured at fair value, with changes in those fair values recorded in Other comprehensive income/(loss) (OCI) unless actively quoted prices are not available for fair value measurement, in which case available for sale assets are measured at cost. Generally, the Company classifies equity investments in other entities that do not trade on an actively quoted market as available for sale. Dividends received from available for sale financial assets are recognized in earnings when the right to receive payment is established.

Loans and Receivables
Loans and receivables, which include Accounts receivable and other and affiliate long-term notes receivable, are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized.

Held to Maturity
The Company has classified certain investments which are non-derivative financial assets as held to maturity. Held to maturity investments are measured at amortized cost using the effective interest rate method.

Other Financial Liabilities
Other financial liabilities are recorded at amortized cost using the effective interest rate method and include Short-term borrowings, Accounts payable and other, Interest payable, Long-term debt and Non-recourse long-term debt.

Derivatives in Qualifying Hedging Relationships
The Company uses derivative financial instruments to manage changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings and cash flow effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges.

Cash Flow Hedges
The Company uses cash flow hedges to manage changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in OCI and is reclassified to earnings when the hedged item impacts earnings or to the carrying value of the related non-financial asset. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss deferred in OCI up to that date will be recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from ineffective derivative instruments are recognized in earnings in the period in which they occur.

Fair Value Hedges
The Company may use fair value hedges to hedge the fair value of debt instruments or commodity positions. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged asset or liability, otherwise required to be carried at cost or amortized cost, ceases to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item. The Company did not have any fair value hedges outstanding at December 31, 2011 or December 31, 2010.

Net Investment Hedges
The Company uses net investment hedges to manage the carrying values of United States dollar denominated foreign operations. The effective portion of the change in the fair value of the hedging instrument is recorded in OCI. Any ineffectiveness is recorded in current period earnings. Amounts recorded in Accumulated other comprehensive income/(loss) (AOCI) are recognized in earnings when there is a reduction of the hedged net investment.

Classification of Derivatives
The Company recognizes the fair market value of derivative instruments on the Consolidated Statements of Financial Position as current or long-term depending on the timing of the settlements and the resulting cash flows associated with the instruments. The fair value related to cash flows occurring beyond one year are classified as non-current.

Balance Sheet Offset
Assets and liabilities arising from derivative instruments are offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

Transaction Costs
Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with the related debt. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

EQUITY INVESTMENTS
Equity investments over which the Company exercises significant influence, but does not have controlling financial interests, are accounted for using the equity method. Equity investments are initially measured at cost and are adjusted for the Company's proportionate share of undistributed equity earnings or loss. Equity investments are increased for contributions made to and decreased for distributions received from the investees.

NONCONTROLLING INTERESTS
Noncontrolling interests represent the outstanding ownership interests attributable to third parties in certain consolidated subsidiaries, limited partnerships and variable interest entities. The portion of the entities not owned by the Company is reflected as noncontrolling interests within the equity section of the Consolidated Statements of Financial Position.

INCOME TAXES
The liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For the Company's regulated operations, a future income tax liability is recognized with a corresponding regulatory asset. Any interest and/or penalty incurred related to tax is reflected in income taxes.

FOREIGN CURRENCY TRANSLATION
Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates. Transactions denominated in foreign currencies are translated into Canadian dollars using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period that they arise.

The Company's foreign operations are primarily self-sustaining. The financial statements of self-sustaining foreign operations are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates and revenues and expenses are translated using monthly average rates. Gains and losses arising on translation of these

operations are included in the cumulative translation adjustment component of AOCI and are recognized in earnings when there is a disposal of all or part of the foreign operation.

CASH AND CASH EQUIVALENTS
Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased. Cash and cash equivalents include restricted cash of amounts in trust and proportionately consolidated cash from joint ventures.

ALLOWANCE FOR DOUBTFUL ACCOUNTS
The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

INVENTORY
Inventory is primarily comprised of natural gas in storage held in EGD. Natural gas in storage is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of the gas purchased is deferred as a liability for future refund or as an asset for collection as approved by the OEB. Other inventory, consisting primarily of commodities held in storage, is recorded at fair value as measured at the spot price less costs to sell.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment is recorded at historical cost. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit. The Company capitalizes interest incurred during construction for non rate-regulated assets. For rate-regulated assets, AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component.

The Company uses the group method of depreciation for all property, plant and equipment, except for the non rate-regulated assets in Canada, which are depreciated on a single asset basis. Depreciation is provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. Under the group method, upon the disposition of property, plant and equipment, the net book value less net proceeds is typically charged to accumulated depreciation and no gain or loss on disposal is recognized. However, when a separately identifiable group of assets, such as a stand-alone pipeline system, is sold, a gain or loss is recognized in the Consolidated Statements of Earnings for the difference between the cash received and the net book value of the assets sold.

DEFERRED AMOUNTS AND OTHER ASSETS
Deferred amounts and other assets include costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, including future income taxes, contractual receivables under the terms of long-term delivery contracts, derivative financial instruments and pension assets. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges.

INTANGIBLE ASSETS
Intangible assets consist primarily of acquired long-term transportation contracts, long-term power purchase agreements and certain software costs. The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangibles are amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

GOODWILL
Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually in the fourth quarter of each year, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. For the purposes of impairment testing, reporting units are identified as business operations within an operating segment.

Potential impairment is identified when the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value. Goodwill impairment is measured as the excess of the carrying amount of the reporting unit's allocated goodwill over the implied fair value of the goodwill based on the fair value of the assets and liabilities of the reporting unit.

IMPAIRMENT

The Company reviews the carrying values of its long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, the asset is written down to fair value.

With respect to investments in debt and equity securities, the Company assesses at each balance sheet date whether there is objective evidence that a financial asset is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is determined to be objective evidence of impairment, the Company internally values the expected discounted cash flows using observable market inputs and determines whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

With respect to other financial assets, the Company assesses the assets for impairment when it no longer has reasonable assurance of timely collection. If evidence of impairment is noted, the Company reduces the value of the financial asset to its estimated realizable amount, determined using discounted expected future cash flows.

ASSET RETIREMENT OBLIGATIONS

AROs associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For the majority of the Company's assets it is not possible to make a reasonable estimate of AROs due to the indeterminate timing and scope of the asset retirements.

POST-EMPLOYMENT BENEFITS

The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimate of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors. Pension cost is charged to earnings as services are rendered and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of the initial net transitional asset, prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans;
- Interest cost of pension plan obligations;
- Expected return on pension fund assets; and
- Amortization of cumulative unrecognized net actuarial gains and losses, in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate or salary inflation experience.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contribution occurs.

The Company also provides post-employment benefits other than pensions (OPEB), including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants. The cost of such benefits is accrued during the years in which employees render service.

Certain regulated operations of the Company recover pension and OPEB expense based on amounts paid in accordance with the methodology accepted by the regulators for rate-making purposes. As a result, rates typically only include the recovery of required contributions. A corresponding pension regulatory liability and OPEB regulatory asset have been recorded to the extent that they are expected to be included in regulator-approved future rates and recovered from or refunded to future customers. In the absence of rate regulation, these balances would not be recorded and pension and OPEB expense would be charged to earnings based on the accrual basis of accounting.

STOCK BASED COMPENSATION
Incentive Stock Options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility, with a corresponding credit to Contributed surplus. Balances in Contributed surplus are transferred to share capital when the options are exercised.

Performance based stock options (PBSOs) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated by the Bloomberg barrier option valuation model and is recognized on a straight-line basis with a corresponding credit to Contributed surplus. The options become exercisable when both performance targets and time vesting requirements have been met. Balances in Contributed surplus are transferred to share capital when the options are exercised.

Performance Stock Units (PSUs) and Restricted Stock Units (RSUs) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest at the completion of a 35-month term. During the vesting term, an expense is recorded based on the number of units outstanding and the current market price of the Company's shares with an offset to Accounts payable and other or Other long-term liabilities. The value of the PSUs is also dependent on the Company's performance relative to performance targets set out under the plan.

COMPARATIVE AMOUNTS
Certain comparative amounts have been reclassified to conform with the current year's financial statement presentation.

3. CHANGES IN ACCOUNTING POLICIES

Business Combinations
Effective January 1, 2011, the Company adopted Part V Section 1582, *Business Combinations*, which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be re-measured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect

a business combination be expensed in the period in which they are incurred. In accordance with the transitional provisions of this standard, Section 1582 was adopted prospectively and accordingly, assets and liabilities that arose from business combinations occurring before January 1, 2011 were not restated. The application of this standard decreased Earnings attributable to Enbridge Inc. by $37 million, net of income taxes of $5 million for dilution gains for subsidiaries, which are now recognized in equity for the year ended December 31, 2011. The application of this standard had no material impact to the Company's cash flows for the year ended December 31, 2011.

Consolidated Financial Statements and Noncontrolling Interests
Effective January 1, 2011, the Company adopted Part V Sections 1601, *Consolidated Financial Statements* and 1602, *Noncontrolling Interests,* which together replace the former consolidated financial statements standard. Under the revised standards, noncontrolling interests are classified as a component of equity, and earnings and comprehensive income are attributed to both the parent and noncontrolling interest. In accordance with the transitional provisions of these standards, Section 1601 was adopted prospectively and Section 1602 was adopted retroactively with restatement of prior periods. As the adoption of these standards impacts presentation only, there was no impact to the Company's earnings or cash flow for the current or prior periods presented.

United States Generally Accepted Accounting Principles
First-time adoption of Part I - International Financial Reporting Standards (Part I or IFRS) of the CICA Handbook was mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I is mandatory for qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and presented its financial statements in accordance with Part V of the CICA Handbook during the 2011 deferral period.

As a rate regulated accounting standard model has not been finalized by the International Accounting Standards Board, the Company does not intend to adopt IFRS in 2012 but rather U.S. GAAP. As a United States Securities and Exchange Commission (SEC) registrant, Enbridge is permitted by Canadian securities regulation to prepare its financial statements in accordance with U.S. GAAP and will adopt U.S. GAAP for interim and annual financial statements beginning on January 1, 2012.

4. SEGMENTED INFORMATION

Year ended December 31, 2011	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	**1,959**	**2,574**	**14,476**	**393**	**-**	**19,402**
Commodity costs	**-**	**(1,354)**	**(13,500)**	**-**	**-**	**(14,854)**
Operating and administrative	**(760)**	**(492)**	**(295)**	**(137)**	**(36)**	**(1,720)**
Depreciation and amortization	**(327)**	**(320)**	**(167)**	**(111)**	**(12)**	**(937)**
	872	**408**	**514**	**145**	**(48)**	**1,891**
Income/(loss) from equity investments	**-**	**-**	**-**	**342**	**(6)**	**336**
Other income/(expense)	**31**	**(11)**	**38**	**202**	**(148)**	**112**
Interest expense	**(256)**	**(166)**	**(97)**	**(74)**	**(118)**	**(711)**
Income taxes recovery/(expense)	**(139)**	**(55)**	**(161)**	**(219)**	**6**	**(568)**
Earnings/(loss)	**508**	**176**	**294**	**396**	**(314)**	**1,060**
Earnings attributable to noncontrolling interests	**(3)**	**-**	**(1)**	**(52)**	**-**	**(56)**
Preference share dividends	**-**	**-**	**-**	**-**	**(13)**	**(13)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**505**	**176**	**293**	**344**	**(327)**	**991**
Additions to property, plant and equipment[1]	**977**	**483**	**953**	**73**	**33**	**2,519**
Total assets	**12,366**	**7,713**	**4,968**	**5,245**	**4,051**	**34,343**

Year ended December 31, 2010	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	1,672	2,611	10,518	326	-	15,127
Commodity costs	-	(1,384)	(9,907)	-	-	(11,291)
Operating and administrative	(603)	(497)	(215)	(120)	(31)	(1,466)
Depreciation and amortization	(312)	(310)	(144)	(88)	(10)	(864)
	757	420	252	118	(41)	1,506
Income from equity investments	-	-	-	32	6	38
Other income/(expense)	115	(17)	30	114	132	374
Interest expense	(223)	(179)	(96)	(58)	(131)	(687)
Income taxes recovery/(expense)	(135)	(64)	(65)	(66)	79	(251)
Earnings	514	160	121	140	45	980
Earnings attributable to noncontrolling interests	(2)	(5)	-	(3)	-	(10)
Preference share dividends	-	-	-	-	(7)	(7)
Earnings attributable to Enbridge Inc. common shareholders	512	155	121	137	38	963
Additions to property, plant and equipment[1]	765	387	1,153	132	-	2,437
Total assets	11,508	7,594	5,536	3,833	1,749	30,220

Year ended December 31, 2009	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	1,333	2,992	7,823	313	5	12,466
Commodity costs	-	(1,757)	(7,254)	-	-	(9,011)
Operating and administrative	(565)	(495)	(226)	(113)	(31)	(1,430)
Depreciation and amortization	(230)	(298)	(140)	(88)	(8)	(764)
	538	442	203	112	(34)	1,261
Income from equity investments	-	-	-	188	10	198
Other income/(expense) and gain on sale of investments	161	(12)	366	13	515	1,043
Interest expense	(144)	(188)	(87)	(56)	(122)	(597)
Income taxes	(108)	(50)	(54)	(88)	(6)	(306)
Earnings	447	192	428	169	363	1,599
Earnings attributable to noncontrolling interests	(2)	(6)	-	(28)	(1)	(37)
Preference share dividends	-	-	-	-	(7)	(7)
Earnings attributable to Enbridge Inc. common shareholders	445	186	428	141	355	1,555
Additions to property, plant and equipment[1]	2,662	326	321	41	10	3,360

1 Includes allowance for equity funds used during construction (AEDC).

The measurement basis for preparation of segmented information is consistent with the significant accounting policies described in Note 2.

GEOGRAPHIC INFORMATION

Revenues[1]

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Canada	**12,591**	9,876	9,503
United States	**6,811**	5,251	2,963
	19,402	15,127	12,466

1 Revenues are based on the country of origin of the product or services sold.

Property, Plant and Equipment

December 31,	**2011**	2010
(millions of Canadian dollars)		
Canada	**17,843**	16,095
United States	**4,780**	4,237
	22,623	20,332

5. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS

A number of businesses within the Company are subject to regulation whereby the rates approved by the regulator are designed to recover the costs of providing products and services to customers, referred to as the cost of service toll methodology. The Company's significant regulated businesses and related accounting impacts are described below.

Canadian Mainline

The Canadian Mainline includes the Canadian portion of the mainline system. The primary business activities of the Canadian Mainline are subject to regulation by the NEB. Prior to July 1, 2011, the incentive tolling settlement (ITS) defined the methodology for calculation of tolls and the revenue requirement on the core component of the Canadian Mainline. Toll adjustments, for variances from requirements defined in the ITS, were filed annually with the regulator for approval. Surcharges were also determined for a number of system expansion components and were added to the base toll determined for the core system.

Effective July 1, 2011, Canadian Mainline earnings (excluding Lines 8 and 9) were governed by the CTS. The CTS covers local tolls to be charged for service on the Canadian Mainline and supersedes all existing toll agreements on the Canadian Mainline during the ten year term of the CTS. As a result, the Company discontinued the application of rate-regulated accounting to its Canadian Mainline on a prospective basis commencing July 1, 2011. While the CTS is based on previous tolling settlements and cost of service principles, the Company retains some risk associated with volume throughput and capital and operating costs, subject to various protection mechanisms. As a result, the Canadian Mainline operations (excluding Lines 8 and 9) no longer meet all of the criteria required for the continued application of rate-regulated accounting treatment.

The regulatory asset of approximately $470 million related to future income taxes recorded at the date of discontinuance will continue to be recognized as the Company retains the ability to recover future income taxes under an NEB order governing flow-through income tax treatment. In the same manner, the rate order provides for the recovery of future income taxes incurred subsequent to the discontinuance of rate-regulated accounting, and, as such, regulatory assets related to future income taxes will continue to be recognized as incurred. The regulatory asset of approximately $70 million related to tolling deferrals recorded at the date of discontinuance is being recovered through a toll surcharge over a period of two years.

Southern Lights
The United States portion of the Southern Lights Pipeline is regulated by the FERC and the Canadian portion of the pipeline is regulated by the NEB. Shippers on the Southern Lights Pipeline are subject to 15-year transportation contracts under a cost of service toll methodology. Toll adjustments are filed annually with the regulators. Tariffs provide for recovery of all operating and debt financing costs, plus a pre-determined after tax rate of return on equity (ROE) of 10%. Southern Lights Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

Enbridge Gas Distribution
EGD's gas distribution operations are regulated by the OEB. EGD's rates are based on a revenue per customer cap incentive regulation methodology that expires in December 2012, which adjusts revenues, and consequently rates, annually and relies on an annual process to forecast volume and customer additions.

EGD's after-tax rate of return on common equity embedded in rates was 8.39% for the years ended December 31, 2011, 2010 and 2009 based on a 36% deemed common equity component of capital for regulatory purposes for each of those years.

Enbridge Gas New Brunswick
Enbridge Gas New Brunswick (EGNB) is regulated by the EUB and an application for rate adjustments is filed annually for EUB approval. EGNB's after-tax ROE for the year ended December 31, 2011 was 10.90% (2010 - 13.00%; 2009 - 13.00%) based on equity which is capped at 45%.

On December 9, 2011, the Government of New Brunswick tabled and subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. The legislation permits the government to implement new regulations which could affect the franchise agreement between EGNB and the province, impact prior decisions by the province's independent regulator and influence the regulator's future decisions. Significant details of the rate setting process were left to be established in the new regulations which have yet to be published.

Vector Pipeline
Vector Pipeline is an interstate natural gas pipeline in the United States with a FERC approved tariff that establishes rates, terms and conditions governing its service to customers. Rates are determined using a cost of service methodology. Tariff changes may only be implemented upon approval by the FERC. Tolls for the year ended December 31, 2011 included an after-tax ROE component of 11.18% (2010 - 11.18%; 2009 - 11.07%).

Alliance Pipeline

The Alliance Pipeline US is regulated by the FERC and Alliance Pipeline Canada is regulated by the NEB. Transportation service agreements with shippers are in place for substantially all of the pipeline capacity until December 2015 under a cost of service methodology. Toll adjustments are filed annually with the regulators. Tolls for the years ended December 31, 2011, 2010 and 2009 included an after-tax ROE component of 10.88% for Alliance Pipeline US and 11.26% (2010 - 11.26%; 2009 - 11.26%) for Alliance Pipeline Canada. Alliance Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following significant regulatory assets and liabilities:

December 31,	**2011**	2010	Estimated Settlement Period *(years)*	Earnings Impact[1] **2011**	2010	2009
(millions of Canadian dollars)						
Regulatory assets/(liabilities)						
Liquids Pipelines						
Future income taxes[2]	**527**	479	-	**36**	55	49
Tolling deferrals[3]	**14**	132	1	**(3)**	19	(16)
Deferred transportation revenue[8]	**84**	32	29	**34**	21	-
Gas Distribution						
Future income taxes[2]	**224**	211	-	**9**	(12)	(11)
EGNB regulatory deferral[4]	**180**	171	30	**9**	18	15
Future removal and site restoration reserves[5]	**(836)**	(773)	-	**-**	-	6
Purchased gas variance[6]	**-**	(144)	1	**-**	-	-
Pension plans and OPEB, net[7]	**(95)**	(97)	-	**(2)**	-	(2)
Gas Pipelines, Processing and Energy Services						
Future income taxes[2]	**1**	1	-	**-**	-	-
Deferred transportation revenue[8]	**124**	150	13-15	**(18)**	(17)	(6)
Sponsored Investments						
Future income taxes[2]	**83**	94	-	**(8)**	(3)	(11)
Deferred transportation revenue[8]	**100**	98	15	**1**	5	5

1 *The effect of a number of the Company's businesses being subject to rate regulation increased/(decreased) after-tax reported earnings by the identified amounts.*

2 *The asset represents the regulatory offset to future income tax liabilities to the extent that future income taxes are expected to be included in regulator-approved future rates and recovered from or refunded to future customers. The recovery period depends on future temporary differences. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.*

3 *Tolls for regulated pipelines under a cost of service methodology are established each year based on capacity and the allowed revenue requirement. Where actual volumes shipped on the pipeline result in an under or over collection of the annual revenue requirement, a regulatory asset or liability is recognized and incorporated into tolls in the subsequent year or in accordance with the related agreement.*

4 *A regulatory deferral account captures the cumulative difference between EGNB's distribution revenues and its cost of service revenue requirement during the development period. The regulatory deferral account balance is expected to be amortized over a recovery period approved by the EUB expected to commence at the end of the development period in 2013 and end no sooner than 2040. The impact of legislative changes passed by the Government of New Brunswick in December 2011 (the specific details of which remain dependent upon regulations which have not yet been published) is not determinable as of February 21, 2012.*

5 *The future removal and site restoration reserves balance results from amounts collected from customers by certain of the Company's businesses, with the approval of the regulator, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that has been collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

6 *Purchased gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. EGD has been granted OEB approval to refund this balance to customers in the following year. In the absence of rate regulation the actual cost of natural gas would be included in commodity costs and commodity revenue would be adjusted by an equal and offsetting amount as the right to collect the revenue has been established.*

7 *The pension plan balance represents the regulatory offset to the pension asset to the extent that the amounts are to be refunded to customers in future rates. The OPEB balance represents the regulatory offset to the OPEB liability to the extent that the amounts are to be collected from customers in future rates. The settlement periods for these balances are not determinable. EGD continues to record and recover pension and OPEB expenditures through rates on a cash basis. In the absence of rate regulation, these regulatory balances would not be recorded and pension and OPEB expense would be charged to earnings based on the accrual basis of accounting.*

8 *Deferred transportation revenue is related to the cumulative difference between Canadian GAAP depreciation expense for Southern Lights, Alliance and Vector Pipelines and the negotiated depreciation rates included in the regulated transportation tolls. The Company expects to recover this difference over a number of years when depreciation rates in the transportation agreements are expected to exceed Canadian GAAP depreciation rates: for Southern Lights after 2020, for Alliance Pipeline US beginning in 2009, for Alliance Pipeline Canada beginning in 2012 and for Vector Pipeline beginning in 2008. This regulatory asset is not included in the rate base.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Allowance for Funds Used During Construction and Other Capitalized Costs

Under the pool method prescribed by certain regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains or losses on the retirement of certain specific fixed assets in any given year cannot be identified or quantified.

Operating Cost Capitalization

With the approval of regulators, EGD and certain distribution operations capitalize a percentage of certain operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

EGD entered into a consulting contract relating to asset management initiatives. The majority of the costs, primarily consulting fees, are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2011, cumulative costs relating to this consulting contract of $133 million (2010 - $124 million) were included in property plant and equipment and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

6. ACQUISITIONS AND DISPOSITIONS

ACQUISITIONS

Seaway Crude Pipeline Company

On December 20, 2011, Enbridge acquired 50% of the outstanding common units in Seaway Pipeline, a partnership engaged in the crude oil pipeline business in Texas, for cash consideration of $1.2 billion (US$1.2 billion). The Company's investment in Seaway Pipeline is accounted for as a joint venture interest *(Note 10)*.

December 20,	**2011**
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets	**5**
Property, plant and equipment	**536**
Goodwill	**638**
Current liabilities	**(4)**
	1,175
Purchase Price:	
Cash (net of $9 million cash acquired)	**1,175**

A net loss of $1 million related to transaction costs was recognized in Earnings for the year ended December 31, 2011. Had the acquisition occurred on January 1, 2011, an unaudited proforma net loss of $2 million, including $1 million of transaction costs, would have been recognized as earnings. The entire amount of acquired goodwill is expected to be tax deductible for United States income tax purposes.

Tonbridge Power Inc.
On October 13, 2011, Enbridge acquired 100% of the 36 million outstanding common shares of Tonbridge Power Inc. (Tonbridge), an independent company engaged in constructing an electric transmission line between Montana and Alberta, for $20 million in cash at a price of $0.54 per share.

October 13,	**2011**
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Working capital deficiency	**(5)**
Property, plant and equipment	**196**
Intangible assets	**17**
Long-term debt	**(182)**
Other long-term liabilities	**(21)**
	5
Purchase Price:	
Cash (net of $15 million cash acquired)	**5**

No revenue from Tonbridge was recognized in 2011 as the transmission line is not yet in service. A net loss of $1 million was recognized in income for the period from October 13, 2011 to December 31, 2011 related to operating and administrative expenses. An unaudited proforma net loss of $38 million, including $6 million of transaction costs, would have been recognized in income in 2011 had the acquisition occurred on January 1, 2011.

DISPOSITIONS
Gain on Sale of Investments

December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
NetThruPut (NTP)	-	**-**	29
Oleoducto Central S.A. (OCENSA)	-	**-**	336
	-	**-**	365

NTP
On May 1, 2009, the Company sold its investment in NTP, an internet-based exchange facility for physical crude oil products, for proceeds of $32 million. Earnings generated by the NTP investment for the year ended December 31, 2009 were $1 million and were included in the Corporate operating segment.

OCENSA
On March 17, 2009, the Company sold its investment in OCENSA, a crude oil pipeline in Colombia, for proceeds of $512 million (US$402 million). Earnings and cash flows from operating activities generated by this investment for the year ended December 31, 2009 were $7 million. Earnings from the OCENSA investment were included in the Gas Pipelines, Processing and Energy Services operating segment. As a result of the sale of OCENSA, the Company reclassified $20 million of after-tax gains on unrealized cash flow hedges from OCI to earnings in the year ended December 31, 2009.

7. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2011**	2010
(millions of Canadian dollars)		
Unbilled revenues	**1,535**	1,284
Trade receivables	**699**	740
Taxes receivable	**157**	205
Regulatory assets	**80**	182
Current derivative assets *(Note 23)*	**465**	170
Due from affiliates *(Note 30)*	**69**	63
Prepaid expenses and deposits	**42**	36
Dividends receivable	**32**	16
Other	**113**	72
Allowance for doubtful accounts *(Note 23)*	**(56)**	(62)
	3,136	2,706

8. INVENTORY

December 31,	**2011**	2010
(millions of Canadian dollars)		
Natural gas	**488**	537
Other commodities	**251**	276
	739	813

9. PROPERTY, PLANT AND EQUIPMENT

December 31, 2011 *(millions of Canadian dollars)*	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
Liquids Pipelines				
Pipeline	2.8%	**7,482**	**1,811**	**5,671**
Pumping equipment, buildings, tanks and other	3.5%	**5,098**	**1,367**	**3,731**
Land and right-of-way	3.0%	**232**	**38**	**194**
Under construction	-	**1,718**	**-**	**1,718**
		14,530	**3,216**	**11,314**
Gas Distribution				
Gas mains, services and other	4.0%	**6,961**	**1,401**	**5,560**
Land and right-of-way	2.5%	**79**	**30**	**49**
Under construction	-	**137**	**-**	**137**
		7,177	**1,431**	**5,746**
Gas Pipelines, Processing and Energy Services				
Pipeline	3.6%	**2,171**	**814**	**1,357**
Wind turbines, solar panels and other[1]	5.8%	**1,208**	**125**	**1,083**
Land and right-of-way	2.6%	**50**	**14**	**36**
Under construction	-	**567**	**-**	**567**
		3,996	**953**	**3,043**
Sponsored Investments				
Pipeline	4.0%	**1,105**	**398**	**707**
Wind turbines, solar panels and other[1]	3.4%	**1,744**	**225**	**1,519**
Under construction	-	**23**	**-**	**23**
		2,872	**623**	**2,249**
Corporate				
Other	2.9%	**270**	**30**	**240**
Under construction	-	**31**	**-**	**31**
		301	**30**	**271**
		28,876	**6,253**	**22,623**

December 31, 2010	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Liquids Pipelines				
Pipeline	2.7%	7,295	1,618	5,677
Pumping equipment, buildings, tanks and other	3.6%	4,728	1,221	3,507
Land and right-of-way	1.8%	232	29	203
Under construction	-	728	-	728
		12,983	2,868	10,115
Gas Distribution				
Gas mains, services and other	3.6%	6,605	1,272	5,333
Land and right-of-way	2.6%	68	15	53
Under construction	-	103	-	103
		6,776	1,287	5,489
Gas Pipelines, Processing and Energy Services				
Pipeline	3.4%	2,121	706	1,415
Wind turbines, solar panels and other[1]	3.1%	1,527	142	1,385
Land and right-of-way	2.4%	62	13	49
Under construction	-	622	-	622
		4,332	861	3,471
Sponsored Investments				
Pipeline	4.0%	1,598	484	1,114
Wind turbines, solar panels and other[1]	8.5%	108	29	79
Under construction	-	17	-	17
		1,723	513	1,210
Corporate				
Other	11.3%	67	20	47
		67	20	47
		25,881	5,549	20,332

1 *In October 2011, Enbridge Pipelines Inc. (EPI) sold three renewable energy assets to the Fund. As a result, at December 31, 2011, $1,087 million of property, plant and equipment was reclassified from Gas Pipelines, Processing and Energy Services to Sponsored Investments. The December 31, 2010 balance of $1,103 million has not been reclassified for presentation purposes.*

10. JOINT VENTURES

The impact of the Company's joint venture interests on net assets, earnings, cash flows and financial position is summarized below.

December 31,	Ownership Interest	Net Assets **2011**	2010
(millions of Canadian dollars)			
Liquids Pipelines			
Chicap Pipeline	43.8%	**27**	27
Mustang Pipeline	30.0%	**27**	26
Woodland Pipeline	50.0%	**79**	23
Seaway Pipeline *(Note 6)*	50.0%	**1,186**	-
Gas Pipelines, Processing and Energy Services			
Enbridge Offshore Pipelines - various joint ventures	22.0%-74.3%	**420**	433
Alliance Pipeline US	50.0%	**293**	318
Vector Pipeline	60.0%	**347**	349
Aux Sable[1]	42.7%-50.0%	**217**	86
Lac Alfred Wind Project (Lac Alfred)[2]	50.0%	**130**	-
Other	33.3%-70.0%	**21**	27
Sponsored Investments			
Alliance Pipeline Canada	50.0%	**642**	660
Other	33.0%-50.0%	**58**	56
		3,447	2,005

1 In July 2011, the Company, through its affiliate Aux Sable, acquired a 42.7% interest in the Palermo Conditioning Plant and the Prairie Rose Pipeline for $76 million.

2 In December 2011, the Company acquired a 50% interest in the Lac Alfred for $128 million.

The following table summarizes the impact of proportionately consolidating the joint ventures to the consolidated financial statements of the Company.

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings			
Revenues	**804**	771	781
Commodity costs	**(138)**	(92)	(74)
Operating and administrative	**(200)**	(203)	(226)
Depreciation and amortization	**(163)**	(163)	(171)
Interest expense	**(75)**	(82)	(99)
Other income/(expense)	**(2)**	(1)	10
Proportionate share of earnings	**226**	230	221
Cash flows			
Cash provided by operating activities	**392**	349	342
Cash used in investing activities	**(196)**	(57)	(49)
Cash used in financing activities	**(71)**	(78)	(133)
Proportionate share of increase in cash and cash equivalents	**125**	214	160

December 31,	2011	2010
(millions of Canadian dollars)		
Financial position		
Current assets	**229**	171
Property, plant and equipment, net	**3,019**	2,331
Intangible assets	**210**	166
Goodwill	**959**	321
Deferred amounts and other assets	**267**	270
Current liabilities	**(239)**	(150)
Non-recourse long-term debt	**(951)**	(1,061)
Other long-term liabilities	**(47)**	(43)
Proportionate share of net assets	**3,447**	2,005

During the year ended December 31, 2010, the Company acquired an additional 20% interest in Olympic Pipe Line Company (Olympic Pipeline), a refined products pipeline, for $12 million, increasing its ownership interest to 85%. As the Company now controls the entity, it has consolidated its interest in Olympic Pipeline. Prior to August 9, 2010, the entity was accounted for as a joint venture.

During the year ended December 31, 2010, the Company acquired the remaining 50% interest in Hardisty Caverns Limited Partnership (Hardisty Caverns), an oil storage facility, for $52 million, increasing its ownership interest to 100%. As the Company now controls the entity, it has consolidated its interest in Hardisty Caverns. Prior to June 16, 2010, the entity was accounted for as a joint venture.

During the year ended December 31, 2009, the Company purchased the additional 50% interest in Starfish Pipeline Company, LLC (Starfish Pipeline) for $28 million (US$27 million), increasing its ownership percentage to 100%. As the Company established control over the entity effective December 31, 2009, it has consolidated its interest in Starfish Pipeline from that date forward. Prior to December 31, 2009, the entity was classified as a joint venture.

11. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	2011	2010
(millions of Canadian dollars)			
Equity investments			
Sponsored Investments			
The Partnership	23.0%	**1,711**	1,473
Enbridge Energy, Limited Partnership - Series AC	66.7%	**453**	463
Corporate			
Noverco Common Shares	38.9%	**-**	14
Other	5.0%-20.0%	**35**	13
Other investments			
Corporate			
Noverco Preferred Shares		**285**	181
Value Creation Inc.		**29**	29
Fuel Cell Energy Ltd.		**11**	25
Other		**16**	-
		2,540	2,198

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investee's assets at the purchase date of $120 million at December 31, 2011 (2010 - $123 million). The excess is attributable to the value of property, plant and equipment within the investees based on estimated fair values at the purchase date and is amortized over the economic life of the assets.

The Partnership

The Partnership includes the Company's investments in EEP and Enbridge Energy Management, L.L.C. (EEM). The Company has a combined 23.0% ownership in EEP, through a 2.0% general partner interest, a 16.0% interest in Class A units, a 2.7% interest in Class B units and a 2.3% interest in EEP as a result of a 16.8% investment in EEM, which owns 13.3% of EEP through its 100% interest in EEP's i-units.

The Company recorded investment income inclusive of incentive earnings, before tax, of $296 million (2010 - $51 million; 2009 - $175 million) for the year ended December 31, 2011.

During the year ended December 31, 2011, EEP issued Class A units and, because Enbridge did not fully participate in this issuance, a dilution gain of $66 million net of income taxes of $53 million and noncontrolling interests of $22 million, was recognized in earnings. As a result, Enbridge's ownership interest in EEP decreased from 25.5% to 23.0%.

During the year ended December 31, 2010, EEP issued Class A units and, because Enbridge did not fully participate in this issuance, a dilution gain of $81 million before tax and noncontrolling interest, was recognized in earnings. As a result, Enbridge's ownership interest in EEP decreased from 27.0% to 25.5%.

Although 83.2% of EEM is widely held, the Company has voting control and therefore consolidates its investment in EEM.

Enbridge Energy, Limited Partnership

The Company has a 66.7% interest in the series AC units of EELP, which constructed the United States segment of the Alberta Clipper project (*Note 30*). The Company recorded investment income from EELP of $53 million for the year ended December 31, 2011 (2010 - $63 million; 2009 - $12 million).

During 2011, the Board of Directors of EEM declared distributions of $74 million (US$76 million) (2010 - $40 million (US$39 million)) payable to the Company relating to its series AC interest in the Alberta Clipper project.

Noverco

During the year ended December 31, 2011, the Company invested $144 million in cash and $255 million in a dividend received from Noverco to increase its common share investment from 32.1% to 38.9%. In addition, the Company received $399 million of preferred shares which are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus 4.40%. There has been no change in the accounting for the Company's common or preferred share investments in Noverco as a result of the restructuring. The Company's interest in Noverco continues to be accounted for as a long-term investment and is included in the Corporate segment.

The Company adjusted its preferred share investments in Noverco which are entitled to cumulative preferred dividends based on the average yield of Government of Canada bonds maturing in greater than 10 years plus a range of 4.34% to 4.40% to $285 million at December 31, 2011 (2010 - $181 million) due to the restructure of Noverco in 2011.

The Company also reduced its equity investment in Noverco common shares to nil at December 31, 2011 (2010 - $14 million) due to the restructure. Noverco owns an approximate 8.9% (2010 - 9.0%) reciprocal shareholding in the shares of the Company. As a result, the Company has an indirect pro-rata interest of 3.5% (2010 - 2.9%) in its own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $187 million at December 31, 2011 (2010 - $154 million). Noverco records dividends paid by the Company as dividend income and the Company eliminates these dividends from its equity earnings of Noverco. The Company records its pro-rata share of dividends paid by the Company to Noverco as a reduction of dividends paid and an increase in the Company's investment in Noverco. In 2011, the Company recorded equity investment loss of $6 million (2010 - $6 million of earnings; 2009 - $10 million of earnings) related to its interest in Noverco.

12. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2011**	2010
(millions of Canadian dollars)		
Regulatory assets	**1,434**	1,419
Long-term portion of derivative assets *(Note 23)*	**549**	462
Affiliate long-term note receivable *(Note 30)*	**336**	334
Pension asset *(Note 27)*	**320**	301
Contractual receivables	**288**	277
Other	**293**	93
	3,220	2,886

At December 31, 2011, deferred amounts of $63 million (2010 - $66 million) were subject to amortization and are presented net of accumulated amortization of $43 million (2010 - $39 million). Amortization expense in 2011 was $6 million (2010 - $9 million; 2009 - $7 million).

13. INTANGIBLE ASSETS

December 31, 2011	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	**13.4%**	**521**	**199**	**322**
Transportation agreements	**4.2%**	**241**	**79**	**162**
Power purchase agreements and other	**10.4%**	**122**	**6**	**116**
		884	**284**	**600**

December 31, 2010	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	13.4%	457	172	285
Transportation agreements	4.2%	231	66	165
Power purchase agreements and other	5.0%	33	5	28
		721	243	478

Total amortization expense for intangible assets was $61 million for the year ended December 31, 2011 (2010 - $60 million; 2009 - $44 million). Assuming no asset additions or impairments, the Company expects aggregate amortization expense for the years ending December 31, 2012 through 2016 of $62 million, $55 million, $48 million, $43 million and $38 million, respectively.

14. GOODWILL

	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Balance at December 31, 2009	19	-	45	308	-	372
Foreign exchange and other	(1)	-	(3)	-	-	(4)
Business acquisition	17	-	-	-	-	17
Balance at December 31, 2010	35	-	42	308	-	385
Foreign exchange and other	**-**	**-**	**1**	**-**	**-**	**1**
Acquired *(Note 6)*	**638**	**-**	**-**	**-**	**-**	**638**
Balance at December 31, 2011	**673**	**-**	**43**	**308**	**-**	**1,024**

In 2011, the Company recognized $638 million of goodwill on the acquisition of a 50% interest in Seaway Pipeline. In 2010, the Company recognized $17 million of goodwill on the acquisition of the remaining 50% interest in Hardisty Caverns.

15. ACCOUNTS PAYABLE AND OTHER

December 31,	**2011**	2010
(millions of Canadian dollars)		
Operating accrued liabilities	**2,068**	1,677
Trade payables	**153**	232
Construction payables	**224**	253
Taxes payable	**283**	156
Current derivative liabilities *(Note 23)*	**711**	138
Security deposits	**84**	78
Contractor holdbacks	**40**	78
Other	**159**	76
	3,722	2,688

16. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2011**	2010
(millions of Canadian dollars)				
Liquids Pipelines				
Debentures	8.20%	2024	**200**	200
Medium-term notes	5.05%	2012-2040	**2,435**	2,435
Southern Lights project financing[1]	2.52%	2013-2014	**1,449**	1,488
Commercial paper and credit facility draws, net			**26**	26
Other[2]			**13**	15
Gas Distribution				
Debentures	9.85%	2024	**85**	235
Medium-term notes	5.51%	2014-2050	**2,295**	2,195
Commercial paper and credit facility draws, net			**556**	334
Sponsored Investments				
Medium-term notes	4.72%	2014-2020	**415**	290
Credit facility draws, net			**260**	130
Corporate				
U.S. dollar term notes[3]	5.48%	2014-2017	**1,119**	1,094
Medium-term notes	4.74%	2013-2040	**3,518**	2,918
Commercial paper and credit facility draws, net[4]			**2,785**	2,776
Deferred debt issue costs and other			**(99)**	(95)
Total debt			**15,057**	14,041
Current maturities			**(252)**	(154)
Short-term borrowings	1.07%		**(548)**	(326)
Long-term debt			**14,257**	13,561

1 2011 - $360 million and US$1,071 million (2010 - $388 million and US$1,106 million).
2 Primarily capital lease obligations.
3 2011 - US$1,100 million (2010 - US$1,100 million).
4 2011 - $987 million and US$1,780 million (2010 - $2,515 million and US$265 million).

Debenture and term note maturities for the years ending December 31, 2012 through 2016 are $252 million, $451 million, $898 million, $916 million and $701 million, respectively. The Company's debentures and term notes bear interest at fixed rates and the interest obligations for the years ending December 31, 2012 through 2016 are $557 million, $536 million, $515 million, $475 million and $450 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Debentures and medium-term notes	**598**	578	494
Non-recourse long-term debt *(Note 17)*	**65**	75	83
Commercial paper and credit facility draws	**71**	63	71
Southern Lights project financing	**38**	37	45
Capitalized	**(61)**	(66)	(96)
	711	687	597

CREDIT FACILITIES

December 31, 2011	Maturity Dates[2]	Total Facilities	Credit Facility Draws[3]	Available
(millions of Canadian dollars)				
Liquids Pipelines	2013	**300**	**26**	**274**
Gas Distribution	2012-2013	**717**	**556**	**161**
Sponsored Investments	2013	**500**	**268**	**232**
Corporate	2012-2016	**5,653**	**2,832**	**2,821**
		7,170	**3,682**	**3,488**
Southern Lights project financing[1]	2013-2014	**1,576**	**1,466**	**110**
Total credit facilities		**8,746**	**5,148**	**3,598**

1 Total facilities inclusive of $61 million for debt service reserve letters of credit.
2 Total facilities include $30 million in demand facilities with no maturity date.
3 Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.

Credit facilities carry a weighted average standby fee of 0.17% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a backstop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2012 to 2016.

Commercial paper and credit facility draws, net of short-term borrowings, of $3,079 million (2010 - $2,940 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

17. NON-RECOURSE DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2011**	2010
(millions of Canadian dollars)				
Gas Pipelines, Processing and Energy Services				
Long-term credit facilities[1]		2015	**5**	1
Senior notes[2]	6.78%	2015-2025	**325**	347
Term debt[3]	3.54%	2012-2019	**31**	29
Capital lease obligations	10.60%	2020	**31**	32
Sponsored Investments				
Credit facilities		2012-2015	**23**	23
Senior notes	6.67%	2015-2025	**638**	675
Fair value increment on senior notes acquired			**25**	29
Deferred debt issue costs and other			**(5)**	(5)
Total non-recourse debt			**1,073**	1,131
Current maturities			**(122)**	(70)
Non-recourse long-term debt			**951**	1,061

1 2011 - US$5 million (2010 - US$1 million).
2 2011 - US$319 million (2010 - US$349 million).
3 2011 - US$26 million (2010 - US$24 million).

Maturities on non-recourse borrowings for the years ending December 31, 2012 through 2016 are $122 million, $78 million, $81 million, $86 million and $64 million, respectively. The medium-term notes and senior notes bear interest at fixed rates. Interest obligations on non-recourse borrowings for the years ending December 31, 2012 through 2016 are $67 million, $62 million, $56 million, $51 million and $46 million, respectively.

Certain assets of Alliance Pipeline Canada and Alliance Pipeline US, with a carrying value of $959 million and $693 million, respectively, are pledged as collateral to Alliance Pipeline Canada and to Alliance Pipeline US lenders.

18. OTHER LONG-TERM LIABILITIES

December 31,	**2011**	2010
(millions of Canadian dollars)		
Future removal and site restoration reserves *(Note 5)*	**836**	773
Regulatory liabilities	**189**	198
Derivative liabilities *(Note 23)*	**433**	133
OPEB liabilities *(Note 27)*	**127**	118
Other	**307**	251
	1,892	1,473

19. NONCONTROLLING INTERESTS

December 31,	**2011**	2010
(millions of Canadian dollars)		
Enbridge Energy Management, L.L.C. (EEM)	**475**	394
Enbridge Income Fund (the Fund)	**227**	109
Enbridge Gas Distribution Inc. (EGD) Preferred Shares	**100**	100
Talbot Windfarm, LP (Talbot)	**-**	26
Greenwich Windfarm, LP (Greenwich)	**26**	12
Other	**18**	17
	846	658

Noncontrolling interests in EEM represents the 83.2% of the listed shares of EEM not held by the Company. During the year ended December 31, 2011, EEM completed a listed share issuance, in which the Company did not participate, resulting in an increase in the noncontrolling interests.

Noncontrolling interests in the Fund at December 31, 2011 represents 64.6% of interests that are held by third parties. During the year ended December 31, 2011, the Fund acquired the Ontario Wind, Sarnia Solar and Talbot Wind energy projects from a wholly owned subsidiary of Enbridge for proceeds of $1.2 billion. Ordinary trust units were issued by the Fund to partially finance the acquisition, resulting in an increase in interests held by third parties. Contributions from noncontrolling interests for the year ended December 31, 2011 included $168 million attributable to the Fund's common trust unit issuance.

The Company owns 100% of the outstanding common shares of EGD; however, the four million Cumulative Redeemable EGD Preferred Shares held by third parties are entitled to a claim on the assets of EGD prior to the common shareholder. The fixed yield rate on these preferred shares was 4.93% per annum until July 1, 2009, after which floating adjustable cumulative cash dividends are payable at 80% of the prime rate. The preferred shares have no fixed maturity date. EGD may, at its option, redeem all or a portion of the outstanding shares for $25 per share plus all accrued and unpaid dividends to the redemption date. As at December 31, 2011, no preferred shares have been redeemed.

Noncontrolling interests in both Talbot and Greenwich represent 10% of partnership units held by a third party. During the year ended December 31, 2011, the Company acquired the remaining 10% interest in Talbot for $28 million, increasing its ownership interest to 100%. Effective October 21, 2011, ownership of Talbot was transferred to the Fund.

20. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and an unlimited number of preference shares.

COMMON SHARES

	2011		2010		2009	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of common shares in millions)						
Balance at beginning of year	**770**	**3,683**	756	3,379	746	3,194
Common shares issued	**-**	**-**	-	-	-	4
Shares issued on exercise of stock options	**4**	**57**	6	80	2	38
Dividend Reinvestment and Share Purchase Plan (DRIP)	**7**	**229**	8	224	8	143
Balance at end of year	**781**	**3,969**	770	3,683	756	3,379

PREFERENCE SHARES

	2011		2010		2009	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of preference shares in millions)						
Preference shares, Series A	**5**	**125**	5	125	5	125
Preference shares, Series B issued[1]	**20**	**490**	-	-	-	-
Preference shares, Series D issued[2]	**18**	**441**	-	-	-	-
Balance at end of year		**1,056**		125		125

1 Gross proceeds - $500 million; net issuance costs - $10 million.
2 Gross proceeds - $450 million; net issuance costs - $9 million.

Characteristics of the preference shares are as follows:

	Initial Yield	Dividend[1]	Per Share Cash Dividend Declared	Per share Base Redemption Value[2]	Redemption and Conversion Option Date [2,3]	Right to Convert[3,4]
(Canadian dollars unless otherwise stated)						
Preference shares, Series A	5.5%	1.3750	1.3750	25	-	-
Preference shares, Series B	4.0%	1.0000	0.4192	25	June 1, 2017	Series C
Preference shares, Series D	4.0%	1.0000	0.2705	25	March1, 2018	Series E

1 Fixed, cumulative, quarterly preferential dividend per share per year.
2 The Company may at its option, redeem all or a portion of the outstanding preference shares for the base redemption value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.
3 The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified Series on the Conversion Option Date and every fifth anniversary thereafter.
4 Holders will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x (90-day Government of Canada treasury bill rate + 2.40% (Series C) or 2.37% (Series E)).

Subsequent to year end, on January 18, 2012, the Company issued 20 million Series F Preference Shares for gross proceeds of $500 million. The 4.0% Cumulative Redeemable Preference Shares, Series F are entitled to the same dividends, redemption and conversion terms as the Series B and Series D Preference Shares. Redemption of Series F Preference Shares by the Company or conversion by holders into Cumulative Redeemable Preference Shares, Series G can occur on June 1, 2018 and on June 1 of every fifth year thereafter. The holders of Series G Preference Shares will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to $25 multiplied by the number of days in the

quarter divided by 365 and multiplying that product by the sum of the then 90-day Government of Canada treasury bill rate plus 2.51%.

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 25 million (2010 - 22 million; 2009 - 22 million), resulting from the Company's reciprocal investment in Noverco.

The treasury stock method is used to determine the dilutive impact of stock options. This method assumes any proceeds from the exercise of stock options would be used to purchase common shares at the average market price during the period.

December 31,	**2011**	2010	2009
(number of common shares in millions)			
Weighted average shares outstanding	**751**	741	728
Effect of dilutive options	**10**	7	5
Diluted weighted average shares outstanding	**761**	748	733

For the year ended December 31, 2011, 48,000 anti-dilutive stock options (2010 - 92,000; 2009 - 1,113,000) with a weighted average exercise price of $32.02 (2010 - $27.84; 2009 - $20.49) were excluded from the diluted earnings per share calculation.

STOCK SPLIT

Effective May 25, 2011, a two-for-one split of the common shares of the Company was completed. All references to the number of shares outstanding, earnings per common share, diluted earnings per common share, dividends per common share and outstanding option information have been retroactively restated to reflect the impact of the stock split.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Under the DRIP, registered shareholders may reinvest dividends in common shares of the Company and make additional optional cash payments to purchase common shares, free of brokerage or other charges. Participants in the Company's DRIP receive a 2% discount on the purchase of common shares with reinvested dividends.

SHAREHOLDER RIGHTS PLAN

The Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Rights issued under the plan become exercisable when a person and any related parties, acquires or announces its intention to acquire 20% or more of the Company's outstanding common shares without complying with certain provisions set out in the plan or without approval of the Company's Board of Directors. Should such an acquisition occur, each rights holder, other than the acquiring person and related parties, will have the right to purchase common shares of the Company at a 50% discount to the market price at that time.

21. STOCK OPTION AND STOCK UNIT PLANS

The Company maintains four long-term incentive compensation plans: the ISO Plan, the PBSO Plan, the PSU Plan and the RSU Plan. A maximum of 60 million common shares were reserved for issuance under the 2002 ISO plan, of which 43 million have been issued to date. In 2007, a new reserve of 33 million common shares was approved and established and in 2011 an increase of 19 million to the reserved common shares was approved, resulting in a total of 52 million shares being available for the 2007 ISO and PBSO plans, of which 1 million have been issued to date. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

INCENTIVE STOCK OPTIONS

Key employees are granted ISOs to purchase common shares at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date. Compensation expense recorded for the year ended December 31, 2011 for ISOs is $16 million (2010 - $11 million; 2009 - $17 million).

Outstanding Incentive Stock Options

December 31,	**2011**		2010		2009	
	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
Options at beginning of year	**25,460**	**18.34**	24,932	17.01	21,300	15.53
Options granted	**6,041**	**28.78**	4,000	22.70	6,056	19.81
Options exercised	**(3,926)**	**14.23**	(3,436)	14.52	(2,374)	11.01
Options cancelled or expired	**(110)**	**25.87**	(36)	12.45	(50)	20.33
Options at end of year	**27,465**	**21.19**	25,460	18.34	24,932	17.01
Options vested	**14,214**	**17.93**	13,764	16.01	13,100	14.48

The total intrinsic value of ISOs exercised during the year ended December 31, 2011 was $68 million (2010 - $38 million; 2009 - $22 million) and cash received on exercise was $56 million (2010 - $50 million; 2009 - $26 million). Intrinsic value represents the difference between the Company's share price and the exercise price, multiplied by the number of options. The total intrinsic value of ISOs outstanding and vested at December 31, 2011 was $285 million (2010 - $182 million) and $194 million (2010 - $131 million), respectively.

Incentive Stock Option Characteristics

December 31, 2011	Options Outstanding			Options Vested		
Exercise Price Range	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
10.00-12.49	**1,195**	**1.0**	**10.45**	**1,195**	**1.0**	**10.45**
12.50-14.99	**1,440**	**2.1**	**12.86**	**1,440**	**2.1**	**12.86**
15.00-17.49	**2,578**	**4.7**	**15.99**	**1,963**	**4.0**	**15.94**
17.50-19.99	**7,877**	**6.0**	**19.30**	**5,486**	**5.5**	**19.08**
20.00-22.49	**5,202**	**6.4**	**20.55**	**3,390**	**6.2**	**20.37**
22.50-24.99	**3,102**	**8.1**	**23.30**	**717**	**8.1**	**23.30**
27.50-29.99	**6,023**	**9.1**	**28.90**	**23**	**8.9**	**27.84**
30.00-32.49	**48**	**9.7**	**32.02**	**-**	**-**	**-**
	27,465	**6.5**	**21.08**	**14,214**	**4.9**	**17.83**

The total fair value of options vested under the ISO Plan during the year ended December 31, 2011 was $17 million (2010 - $14 million; 2009 - $13 million).

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes option pricing model are as follows:

Year ended December 31,	**2011**	2010	2009
Fair value per option *(Canadian dollars)*[1]	**4.19**	3.44	3.56
Valuation assumptions			
Expected option term *(years)*[2]	**6**	6	6
Expected volatility[3]	**18.63%**	19.72%	28.08%
Expected dividend yield[4]	**3.40%**	3.64%	3.87%
Risk-free interest rate[5]	**2.85%**	2.70%	2.24%

1 *Options granted to United States employees are based on New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the United States options and the Canadian options. The fair value per option were $4.01 (2010 - $3.28; 2009 - $3.37) for Canadian employees and US$5.11 (2010 - US$4.00; 2009 - US$3.43) for United States employees.*
2 *The expected option term is based on historical exercise practice.*
3 *Expected volatility is determined with reference to historic daily share price volatility. Beginning in 2010, implied volatility observable in call option values near the grant date is also considered in determining the expected volatility.*
4 *The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.*
5 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and United States Treasury Bond Yields.*

As of December 31, 2011, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO plan was $24 million. The cost is expected to be fully recognized by December 31, 2014.

PERFORMANCE BASED STOCK OPTIONS

PBSOs are granted to executive officers and become exercisable when both performance targets and time vesting requirements have been met. PBSOs were granted on September 16, 2002 under the 2002 plan and on August 15, 2007 and February 19, 2008 under the 2007 plan. All performance and time vesting conditions on the 2002 grant were met prior to the term of the options expiring on September 16, 2010. All performance targets for the 2007 and 2008 grants have been met. The time vesting requirements will be fulfilled evenly over a five year period ending on August 15, 2012 with the options being exercisable until August 15, 2015. Compensation expense recorded for the year ended December 31, 2011 for PBSOs was $2 million (2010 - $2 million; 2009 - $2 million).

Outstanding Performance Based Stock Options

December 31,	**2011**		2010		2009	
	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
Options at beginning of year	**4,294**	**18.51**	6,790	16.85	7,476	16.36
Options exercised	**(167)**	**18.29**	(2,078)	13.12	(686)	11.58
Options cancelled	**-**	**-**	(418)	18.29	-	-
Options at end of year	**4,127**	**18.52**	4,294	18.51	6,790	16.85
Options vested	**3,191**	**18.47**	2,524	18.44	1,600	11.58

The total intrinsic value of PBSOs exercised during the year ended December 31, 2011 was $2 million (2010 - $26 million; 2009 - $6 million) and cash received on exercise was $3 million (2010 - $27 million; 2009 - $8 million). The total intrinsic value of PBSOs outstanding and vested at December 31, 2011 is $54 million (2010 - $30 million) and $42 million (2010 - $18 million), respectively.

Performance Based Stock Option Characteristics

December 31, 2011	Options Outstanding			Options Vested		
Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
18.29	**3,627**	**3.6**	**18.29**	**2,891**	**3.6**	**18.29**
20.21	**500**	**3.6**	**20.21**	**300**	**3.6**	**20.21**
	4,127	**3.6**	**18.52**	**3,191**	**3.6**	**18.47**

The total fair value of options vested under the PBSO Plan during the year ended December 31, 2011 was $2 million (2010 - $2 million; 2009 - $2 million).

As of December 31, 2011, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the PBSO plan was $1 million. The cost is expected to be fully recognized by December 31, 2012.

PERFORMANCE STOCK UNITS

The Company has a PSU Plan for senior officers where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if the Company's performance fails to meet threshold performance levels, to a maximum of two, if the Company performs within the highest range of its performance targets. The 2009, 2010 and 2011 grants derive the performance multiplier through a calculation of the Company's price/earnings ratio relative to a specified peer group of companies and the Company's earnings per share, adjusted for non-operating or non-recurring items, relative to targets established at the time of grant.

Compensation expense recorded for the year ended December 31, 2011 for PSUs was $42 million (2010 - $27 million; 2009 - $20 million). To calculate the 2011 expense, multipliers of two, based upon multiplier estimates at December 31, 2011, were used for each of the 2009, 2010 and 2011 PSU grants.

Outstanding Performance Stock Units

December 31,	**2011**	2010	2009
Units at beginning of year	**955,894**	660,832	590,856
Units granted	**317,000**	572,400	339,200
Units matured	**(375,190)**	(319,634)	(303,764)
Dividend reinvestment	**39,453**	42,296	34,540
Units at end of year	**937,157**	955,894	660,832

Of the PSUs outstanding at December 31, 2011, 610,459 units have a performance period ending December 31, 2012 and 326,698 have a performance period ending December 31, 2013. The total intrinsic value of PSUs outstanding at December 31, 2011 is $71 million (2010 - $54 million; 2009 - $31 million). The total amount paid during the year ended December 31, 2011 for PSUs was $17 million (2010 - $14 million; 2009 - $9 million).

RESTRICTED STOCK UNITS

Enbridge has an RSU plan where cash awards are paid to certain non-executive employees of the Company following a 35 month maturity period. RSU holders receive cash equal to the Company's weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date. Compensation expense recorded for the year ended December 31, 2011 for RSUs was $31 million (2010 - $29 million; 2009 - $23 million).

Outstanding Restricted Stock Units

December 31,	**2011**	2010	2009
Units at beginning of year	**2,095,970**	1,975,754	1,400,068
Units granted	**938,100**	937,200	1,087,000
Units cancelled	**(92,276)**	(60,908)	(36,858)
Units matured	**(1,132,674)**	(855,504)	(565,312)
Notional dividend reinvestment	**92,865**	99,428	90,856
Units at end of year	**1,901,985**	2,095,970	1,975,754

The total intrinsic value of RSUs outstanding at December 31, 2011 is $72 million (2010 - $59 million; 2009 - $47 million). The total liability paid during the year ended December 31, 2011 for RSUs was $39 million (2010 - $24 million; 2009 - $12 million).

As of December 31, 2011, unrecognized compensation expense related to non-vested units granted under the PSU and RSU plans was $68 million and is expected to be fully recognized by December 31, 2013.

22. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Noncontrolling Interests	Cash Flow Hedges	Total
(millions of Canadian dollars)						
Balance at January 1, 2009	278	(275)	(8)	17	21	33
Changes during the year	181	(815)	(38)	72	71	(529)
Tax impact	(30)	-	14	-	(31)	(47)
	151	(815)	(24)	72	40	(576)
Balance at December 31, 2009	429	(1,090)	(32)	89	61	(543)
Changes during the year	61	(274)	(18)	33	(133)	(331)
Tax impact	(10)	-	7	-	(5)	(8)
	51	(274)	(11)	33	(138)	(339)
Balance at December 31, 2010	480	(1,364)	(43)	122	(77)	(882)
Changes during the year	**(21)**	**242**[1]	**(91)**	**13**	**(513)**	**(370)**
Tax impact	**2**	**-**	**30**	**-**	**126**	**158**
	(19)	**242**	**(61)**	**13**	**(387)**	**(212)**
Balance at December 31, 2011	**461**	**(1,122)**	**(104)**	**135**	**(464)**	**(1,094)**

1 Changes in the Cumulative Translation Adjustment balance during the year included the release of a $155 million loss to earnings following the partial liquidation of an investment in a foreign subsidiary.

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET PRICE RISK

The Company's earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company's share price (collectively, market price risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

Earnings at Risk (EaR), a variant of Value at Risk, is the principal risk management metric used to quantify market price risk at Enbridge. EaR is an objective, statistically derived risk metric that measures the maximum adverse change in projected 12-month earnings that could result from market price risk over a one-month period within a 97.5% confidence interval. The Company's policy is to operate within a maximum EaR of 5% of earnings. Earnings exposure from market price risk is managed within the overall consolidated EaR limits of the Company. Further, commodity price risk is managed within

business unit EaR sub-limits. The Company's Corporate Financial Risk Management Committee (CFRMC) establishes and monitors the EaR limits on a monthly basis. Compliance with EaR limits is reported to the CFRMC and variances, if any, are remediated as necessary.

The Company calculates EaR using Monte Carlo simulation to produce projections of earnings using a randomly generated series of forecasted market prices and Enbridge's current market exposures. Historical statistical distributions of market prices and the correlation among those market prices are used to generate an entire probability distribution of possible deviations from forecast earnings.

There is currently no uniform industry methodology for estimating EaR. The use of this metric has limitations because it is based on historical correlations and volatilities in commodity prices and assumes future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated EaR on 97.5% of occasions, losses on the other 2.5% of occasions could be substantially greater than the estimated EaR.

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Foreign Exchange Risk

The Company's earnings, cash flows and OCI are subject to foreign exchange rate variability, primarily arising from its United States dollar denominated investments and subsidiaries, and certain revenues and expenses denominated in United States dollars. The Company has implemented a policy where it economically hedges a minimum level of foreign currency denominated earnings exposures identified over the next five year period. The Company may also hedge anticipated foreign currency denominated purchases or sales, foreign currency denominated debt, as well as certain equity investment balances and net investments in foreign denominated subsidiaries. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage variability in cash flows arising from its United States dollar investments and subsidiaries, and primarily non-qualifying derivative instruments to manage variability arising from certain revenues and expenses denominated in United States dollars.

The impact of a $0.05 strengthening of the Canadian dollar across the forward curve relative to the United States dollar at December 31, 2011, would have resulted in a $310 million increase (2010 - $81 million) to earnings. The foreign exchange sensitivity analysis is limited to changes in the fair value of financial instruments, external debt and loans to non-consolidated foreign operations within the Company that are not denominated in the Company's functional currency and are not considered a net investment. A sensitivity analysis excludes financial instruments that are not monetary items and the impact of translating the Company's United States dollar denominated self-sustaining subsidiaries on OCI; therefore, a sensitivity analysis on the impacts to OCI is considered unrepresentative of the inherent risk to OCI.

Interest Rate Risk

The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2016 at an average swap rate of 2.27%

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long term interest rate variability on select forecast term debt issuances through 2015. A total of $5,200 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.86%. Further, many of the Company's existing commercial arrangements and certain construction projects provide for the full recovery of financing costs through tolls.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to maintain a consolidated portfolio of debt which stays within its Board of Directors approved policy limit band of a maximum of 25% floating rate debt as a percentage of total debt outstanding. The Company uses primarily qualifying derivative instruments to manage interest rate risk.

At December 31, 2011, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would have resulted in no change (2010 - nil) in earnings and a $457 million increase (2010 - $178 million) in OCI in the year due to the revaluation of interest rate derivatives outstanding at December 31, 2011. A 1% increase across the interest rate yield curve, with all other variables constant, would have caused a $23 million decrease (2010 - $22 million) in earnings due to increased interest expense related to the Company's variable rate debt outstanding at December 31, 2011 assuming the variable rate debt outstanding had been outstanding for the entire period.

Commodity Price Risk

The Company's earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, power, crude oil and NGLs. The Company employs financial derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. The Company uses primarily non-qualifying derivative instruments to manage commodity price risk.

The Company has implemented a program to mitigate the volatility from fractionation spreads (natural gas/NGLs) that impact earnings from its ownership interest in the Aux Sable natural gas processing plant and its indirect ownership of the gathering and process business held by EEP.

The Company uses EaR as a metric to monitor certain commodity price risk exposures, principally those associated with its ownership of Aux Sable, its ownership of EEP and the activities of its energy services subsidiaries. The EaR metric measures the price exposures, net of the impact of financial derivatives used to manage such exposures. The Company has estimated the following maximum adverse change in projected 12 month earnings that has a maximum 2.5% chance of resulting from such commodity price risk over a one month period.

	2011	2010
(millions of Canadian dollars)		
Average EaR during the year	**23**	22
High EaR during the year	**27**	29
Low EaR during the year	**18**	16
Closing EaR at year end	**20**	25

Equity Price Risk

Equity price risk is the risk of earnings fluctuations due to changes in the Company's share price. The Company has exposure to its own common share price through the issuance of various forms of stock based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to manage the earnings volatility derived from one form of stock based compensation, RSUs (*Note 21*).

Due to revaluation of the equity derivative contracts at December 31, 2011, the impact of a $4 increase in the Company's share price would have been a $3 million increase in earnings (2010 - $2 million) and a $2 million increase in OCI (2010 - $1 million). The earnings impact of non-qualifying equity derivatives partially offsets earnings impacts due to the revaluation of liabilities associated with the Company's RSUs.

TOTAL DERIVATIVE INSTRUMENTS

The following tables summarize the balance sheet location and fair value of the Company's derivative instruments. The Company had no outstanding fair value hedges as at December 31, 2011 or 2010.

December 31, 2011	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments
(millions of Canadian dollars)				
Accounts receivable and other *(Note 7)*				
Foreign exchange contracts	**4**	**15**	**315**	**334**
Interest rate contracts	**-**	**-**	**7**	**7**
Commodity contracts	**-**	**-**	**114**	**114**
Equity contracts	**3**	**-**	**7**	**10**
	7	**15**	**443**	**465**
Deferred amounts and other *(Note 12)*				
Foreign exchange contracts	**15**	**79**	**203**	**297**
Interest rate contracts	**1**	**-**	**22**	**23**
Commodity contracts	**1**	**-**	**223**	**224**
Equity contracts	**3**	**-**	**2**	**5**
	20	**79**	**450**	**549**
Accounts payable and other *(Note 15)*				
Foreign exchange contracts	**(4)**	**-**	**(275)**	**(279)**
Interest rate contracts	**(341)**	**-**	**(3)**	**(344)**
Commodity contracts	**(1)**	**-**	**(87)**	**(88)**
	(346)	**-**	**(365)**	**(711)**
Other long-term liabilities *(Note 18)*				
Foreign exchange contracts	**(35)**	**(5)**	**(51)**	**(91)**
Interest rate contracts	**(303)**	**-**	**(18)**	**(321)**
Commodity contracts	**(2)**	**-**	**(19)**	**(21)**
	(340)	**(5)**	**(88)**	**(433)**
Total net derivative asset/(liability)				
Foreign exchange contracts	**(20)**	**89**	**192**	**261**
Interest rate contracts	**(643)**	**-**	**8**	**(635)**
Commodity contracts	**(2)**	**-**	**231**	**229**
Equity contracts	**6**	**-**	**9**	**15**
	(659)	**89**	**440**	**(130)**

December 31, 2010	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments
(millions of Canadian dollars)				
Accounts receivable and other *(Note 7)*				
Foreign exchange contracts	4	15	111	130
Interest rate contracts	6	-	-	6
Commodity contracts	-	-	33	33
Equity contracts	-	-	1	1
	10	15	145	170
Deferred amounts and other *(Note 12)*				
Foreign exchange contracts	18	100	275	393
Interest rate contracts	67	-	-	67
Commodity contracts	-	-	2	2
	85	100	277	462
Accounts payable and other *(Note 15)*				
Foreign exchange contracts	(4)	-	(11)	(15)
Interest rate contracts	(72)	-	-	(72)
Commodity contracts	-	-	(51)	(51)
	(76)	-	(62)	(138)
Other long-term liabilities *(Note 18)*				
Foreign exchange contracts	(47)	-	(3)	(50)
Interest rate contracts	(80)	-	-	(80)
Commodity contracts	-	-	(3)	(3)
	(127)	-	(6)	(133)
Total net derivative asset/(liability)				
Foreign exchange contracts	(29)	115	372	458
Interest rate contracts	(79)	-	-	(79)
Commodity contracts	-	-	(19)	(19)
Equity contracts	-	-	1	1
	(108)	115	354	361

The following table summarizes the maturity and total notional principal or quantity outstanding related to the Company's derivative instruments.

	2011		2010	
December 31,	Maturity	Notional Principal or Quantity Outstanding	Maturity	Notional Principal or Quantity Outstanding
U.S. dollar forwards - purchase *(millions of United States dollars)*	**2012-2020**	**1,281**	2011-2020	1,185
U.S. dollar forwards - sell *(millions of United States dollars)*	**2012-2020**	**10,866**	2011-2020	3,516
Interest rate contracts *(millions of Canadian dollars)*	**2012-2029**	**16,540**	2011-2029	10,772
Commodity contracts - energy *(billions of cubic feet equivalent)*	**2012-2013**	**2**	2011-2013	41
Commodity contracts - power *(megawatts per hour)*	**2012-2024**	**53**	2011-2024	2
Equity contracts *(millions of shares)*	**2011-2013**	**2**	2011-2012	1

The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income
The following table presents the effect of cash flow hedges and net investment hedges on the Company's consolidated earnings and consolidated comprehensive income.

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Amount of unrealized gain/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**(22)**	(25)
Interest rate contracts	**(545)**	(172)
Commodity contracts	**(6)**	97
Equity contracts	**6**	(1)
Net investment hedges		
Foreign exchange contracts	**(26)**	19
Total unrealized loss recognized in OCI	**(593)**	(82)
Amount of gain/(loss) reclassified from AOCI to earnings *(effective portion)*		
Cash flow hedges		
Foreign exchange contracts[1]	**1**	(7)
Interest rate contracts[2]	**18**	68
Commodity contracts[3]	**5**	(95)
Equity contracts[4]	**(2)**	1
Total gain/(loss) reclassified from AOCI to earnings *(effective portion)*	**22**	(33)
Amount of ineffectiveness reclassified from AOCI to earnings		
Cash flow hedges		
Interest rate contracts[2]	**11**	-
Total ineffectiveness reclassified from AOCI to earnings	**11**	-

1 (Gain)/loss reported within Other income in the Consolidated Statements of Earnings.
2 (Gain)/loss reported within Interest expense in the Consolidated Statements of Earnings.
3 (Gain)/loss reported within Operating and administrative expense in the Consolidated Statements of Earnings.
4 (Gain)/loss reported within Operating and administrative expense in the Consolidated Statements of Earnings.

The Company estimates that $33 million of AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all significant forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 48 months at December 31, 2011.

Non-Qualifying Derivatives
The following table presents the unrealized gains and losses associated with changes in the fair value of the Company's non-qualifying derivatives.

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Foreign exchange contracts[1]	**(179)**	33	232
Interest rate contracts[2]	**9**	(2)	2
Commodity contracts[3]	**244**	(5)	(88)
Equity contracts[4]	**4**	-	-
Total unrealized derivative fair value gain	**78**	26	146

1 Gain/(loss) reported within Transportation and other services revenues and Other income in the Consolidated Statements of Earnings.
2 Gain/(loss) reported within Interest expense in the Consolidated Statements of Earnings.
3 Gain/(loss) reported within Transportation and other services revenue, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.
4 Gain reported within Operating and administrative expense in the Consolidated Statements of Earnings.

Additional information regarding the Company's derivative instruments is included in Note 24, *Fair Value of Financial Instruments.*

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees *(Notes 31 and 32)*, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities, as well as access to capital markets. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities *(Note 16)* with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2011. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

Maturities of Financial Instruments

The Company generally has no financial instruments, other than derivative instruments, maturing beyond one year with the exception of its long-term debt *(Notes 16 and 17).*

For the years ending December 31, 2012 through 2016, and thereafter, the Company has estimated the following undiscounted cash flows will arise from its financial derivative instruments based on valuations at the balance sheet date:

	2012	2013	2014	2015	2016	Thereafter
(millions of Canadian dollars)						
Cash inflows	440	213	180	69	74	105
Cash outflows	(401)	(133)	(124)	(77)	(65)	(610)
Net cash flows	39	80	56	(8)	9	(505)

CREDIT RISK

Entering into derivative financial instruments can result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company only enters into risk management transactions with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and industry standard netting arrangements.

The Company generally has a policy of entering into individual International Securities Dealers Association agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with these counterparties in these particular circumstances.

At December 31, 2011 and 2010, the Company had group credit concentrations and maximum credit exposure, with respect to derivative instruments, in the following counterparty segments.

December 31,	2011	2010
(millions of Canadian dollars)		
Canadian financial institutions	**426**	451
Non-Canadian financial institutions	**509**	125
Other	**73**	50
	1,008	626

Credit risk also arises from trade and other long-term receivables and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Credit risk in the Gas Distribution segment is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value, as disclosed in Note 24, *Fair Value of Financial Instruments*.

The change in allowance for doubtful accounts in respect of accounts receivable is detailed below.

Year ended December 31,	2011	2010
(millions of Canadian dollars)		
Balance at beginning of year	**(62)**	(74)
Additional allowance	**(26)**	(23)
Amounts used	**32**	35
Balance at end of year	**(56)**	(62)

24. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following table summarizes the Company's financial instrument carrying and fair values and provides a reconciliation to the Consolidated Statements of Financial Position.

December 31, 2011	Held for Trading	Available for Sale[1]	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value[2]
(millions of Canadian dollars)									
Assets									
Cash and cash equivalents	**420**	**-**	**-**	**-**	**-**	**-**	**-**	**420**	**420**
Accounts receivable and other	**443**	**-**	**2,392**	**-**	**-**	**22**	**279**	**3,136**	**2,857**
Long-term investments	**-**	**56**	**-**	**285**	**-**	**-**	**2,199**	**2,540**	**285**
Deferred amounts and other assets	**450**	**-**	**4**	**-**	**-**	**99**	**2,667**	**3,220**	**553**
Liabilities									
Bank indebtedness	**102**	**-**	**-**	**-**	**-**	**-**	**-**	**102**	**102**
Short-term borrowings	**-**	**-**	**-**	**-**	**548**	**-**	**-**	**548**	**548**
Accounts payable and other	**365**	**-**	**-**	**-**	**2,728**	**346**	**283**	**3,722**	**3,439**
Interest payable	**-**	**-**	**-**	**-**	**114**	**-**	**-**	**114**	**114**
Long-term debt	**-**	**-**	**-**	**-**	**14,509**	**-**	**-**	**14,509**	**16,772**
Non-recourse long-term debt	**-**	**-**	**-**	**-**	**1,073**	**-**	**-**	**1,073**	**1,248**
Other long-term liabilities	**88**	**-**	**-**	**-**	**-**	**345**	**1,459**	**1,892**	**433**

December 31, 2010	Held for Trading	Available for Sale[1]	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value[2]
(millions of Canadian dollars)									
Assets									
Cash and cash equivalents	342	-	-	-	-	-	-	342	342
Accounts receivable and other	145	-	2,113	-	-	25	423	2,706	2,283
Long-term investments	-	54	339	181	-	-	1,624	2,198	520
Deferred amounts and other assets	277	-	334	-	-	185	2,090	2,886	462
Liabilities									
Bank indebtedness	100	-	-	-	-	-	-	100	100
Short-term borrowings	-	-	-	-	326	-	-	326	326
Accounts payable and other	62	-	-	-	2,393	76	157	2,688	2,531
Interest payable	-	-	-	-	117	-	-	117	117
Long-term debt	-	-	-	-	13,715	-	-	13,715	14,770
Non-recourse long-term debt	-	-	-	-	1,131	-	-	1,131	1,298
Other long-term liabilities	6	-	-	-	-	127	1,340	1,473	133

1 Classified as Other investments carried at cost under U.S. GAAP.

2 Fair value does not include non-financial instruments, which includes investments accounted for under the equity method, available for sale equity instruments held at cost that do not trade on an actively quoted market and affiliate long-term notes receivable resulting from related party transactions carried at historical cost.

The fair value of financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments other than derivatives represents the amounts estimated to be received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of Cash and cash equivalents and Short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of financial assets carried as long-term investments, other than those classified as available for sale, approximates their carrying value due to interest terms which approximate floating market rates. The fair value of the Company's long-term debt and non-recourse long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates.

FAIR VALUE OF DERIVATIVES

The Company categorizes its derivative assets and liabilities, measured at fair value, into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company's Level 1 instruments consist primarily of exchange-traded derivatives used to mitigate the risk of crude oil price fluctuations in the Gas Pipelines, Processing and Energy Services segment.

Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter foreign exchange forward and cross currency swap contracts, interest rate swaps, physical forward commodity contracts as

well as commodity swaps and options for which observable inputs can be obtained. These instruments are used primarily in the Gas Pipelines, Processing and Energy Services and Corporate segments.

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs include long-dated derivative power contracts and NGL and natural gas contracts in the Gas Pipelines, Processing and Energy Services segment.

When possible the estimated fair value is based on quoted market prices and, if not available, estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes pricing models for options. Depending on the type of derivative and nature of the underlying risk, primary inputs to these techniques include observable market prices (interest, foreign exchange and commodity) and volatility. The Company uses inputs and data used by willing market participants when valuing derivatives and considers its own credit default swap spread as well as those of its counterparties in its determination of fair value. Where possible, the Company uses observable inputs.

The Company has categorized its derivative assets and liabilities measured at fair value as follows:

December 31, 2011	Level 1	Level 2	Level 3	Total
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**-**	**334**	**-**	**334**
Interest rate contracts	**-**	**7**	**-**	**7**
Commodity contracts	**1**	**59**	**54**	**114**
Equity contracts	**-**	**10**	**-**	**10**
	1	**410**	**54**	**465**
Long-term derivative assets				
Foreign exchange contracts	**-**	**297**	**-**	**297**
Interest rate contracts	**-**	**23**	**-**	**23**
Commodity contracts	**-**	**193**	**31**	**224**
Equity contracts	**-**	**5**	**-**	**5**
	-	**518**	**31**	**549**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**-**	**(279)**	**-**	**(279)**
Interest rate contracts	**-**	**(344)**	**-**	**(344)**
Commodity contracts	**-**	**(42)**	**(46)**	**(88)**
	-	**(665)**	**(46)**	**(711)**
Long-term derivative liabilities				
Foreign exchange contracts	**-**	**(91)**	**-**	**(91)**
Interest rate contracts	**-**	**(321)**	**-**	**(321)**
Commodity contracts	**-**	**(16)**	**(5)**	**(21)**
	-	**(428)**	**(5)**	**(433)**
Total net derivative asset/(liability)				
Foreign exchange contracts	**-**	**261**	**-**	**261**
Interest rate contracts	**-**	**(635)**	**-**	**(635)**
Commodity contracts	**1**	**194**	**34**	**229**
Equity contracts	**-**	**15**	**-**	**15**
	1	**(165)**	**34**	**(130)**

December 31, 2010	Level 1	Level 2	Level 3	Total
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	-	130	-	130
Interest rate contracts	-	6	-	6
Commodity contracts	-	5	28	33
Other contracts	-	-	1	1
	-	141	29	170
Long-term derivative assets				
Foreign exchange contracts	-	393	-	393
Interest rate contracts	-	67	-	67
Commodity contracts	-	-	2	2
	-	460	2	462
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	-	(15)	-	(15)
Interest rate contracts	-	(72)	-	(72)
Commodity contracts	(9)	(2)	(40)	(51)
	(9)	(89)	(40)	(138)
Long-term derivative liabilities				
Foreign exchange contracts	-	(50)	-	(50)
Interest rate contracts	-	(80)	-	(80)
Commodity contracts	-	(1)	(2)	(3)
	-	(131)	(2)	(133)
Total net derivative asset/(liability)				
Foreign exchange contracts	-	458	-	458
Interest rate contracts	-	(79)	-	(79)
Commodity contracts	(9)	2	(12)	(19)
Other contracts	-	-	1	1
	(9)	381	(11)	361

Changes in net fair value of derivative assets and liabilities classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of year	**(11)**	(28)
Total gains/(losses), unrealized		
Included in earnings[1]	**46**	19
Included in OCI	**(4)**	3
Settlements	**3**	(5)
Level 3 net derivative asset/(liability) at end of year	**34**	(11)

1 Gain reported within Transportation and other services revenue, Commodity costs and Operating and administrative expense.

The Company's policy is to recognize transfers as of the last day of the reporting period. There were no transfers between levels as of December 31, 2011 and December 31, 2010.

25. CAPITAL DISCLOSURES

The Company defines capital as shareholders' equity (excluding AOCI and reciprocal shareholdings), long-term debt (excluding non-recourse debt and transaction costs), short-term borrowings and noncontrolling interests less cash and cash equivalents (excluding restricted cash of amounts in trust and proportionately consolidated cash from joint ventures, net of bank indebtedness). Non-recourse debt, including debt proportionately consolidated from joint venture interests, is excluded from the Company's definition of capital as it is not controlled or managed exclusively by the Company.

The Company's capital is calculated as follows.

December 31,	**2011**	2010
(millions of Canadian dollars)		
Short-term borrowings	**548**	326
Long-term debt (includes current portion)	**14,608**	13,810
Noncontrolling interests	**846**	658
Shareholders' equity	**10,122**	8,601
Cash and cash equivalents	**(77)**	(282)
	26,047	23,113

The Company seeks to balance a number of objectives when managing capital, including enabling its businesses to operate at the highest efficiency while maintaining safety and reliability; ensuring liquidity for growth opportunities; and minimizing cost of capital. These objectives are primarily met through maintenance of an investment grade credit rating, disciplined investment criteria and sufficient committed credit facilities. Capital is available generally through the issuance of both short and long-term debt and various forms of equity.

The Company manages its capital by monitoring its debt to debt plus equity ratio (excluding non-recourse debt), with a target range of 60% to 70%, to meet its capital management objectives. The debt to capitalization ratio at December 31, 2011, including short-term borrowings but excluding non-recourse short and long-term debt, was 58.0% compared with 60.4% at the end of 2010.

Under terms of the Company's Trust Indenture, in order to continue to issue long-term debt, the Company must maintain a ratio of consolidated funded obligations (essentially all debt except non-recourse debt) to total consolidated capitalization of less than 75%. This covenant also applies to the Company's credit facilities that are used to backstop its commercial paper program. Total consolidated capitalization consists of shareholders' equity, long-term debt, noncontrolling interests and future income taxes.

During the year ended December 31, 2011, the Company was in compliance with externally imposed capital requirements.

26. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings attributable to Enbridge Inc. before income taxes	**1,572**	1,221	1,868
Combined statutory income tax rate	**27.3%**	28.9%	30.5%
Income taxes at statutory rate	**429**	353	570
Increase/(decrease) resulting from:			
Future income taxes related to regulated operations	**(35)**	(62)	(68)
Higher/(lower) foreign tax rates	**84**	(22)	(61)
Tax rates and legislated tax changes	**2**	(23)	(58)
Non-taxable items, net	**1**	(2)	11
Intercompany sale of investments[1]	**98**	-	(99)
Other	**(11)**	7	11
Income taxes	**568**	251	306
Effective income tax rate	**36.1%**	20.6%	16.4%

1 In October 2011, EPI sold three renewable energy assets to the Fund. As the transaction occurred between entities under common control of the Company, the intercompany gain realized as a result of this transfer has been eliminated, although cash income taxes of $98 million remain as a charge to earnings. The Company retains the benefit of cash taxes paid in the form of increased tax basis of its investment in the underlying partnerships; however, accounting recognition of such benefit is not permitted until such time as the partnerships are sold outside of the consolidated group.

COMPONENTS OF FUTURE INCOME TAXES

December 31,	**2011**	2010
(millions of Canadian dollars)		
Net future income tax liabilities/(assets)		
Differences in accounting and tax bases of property, plant and equipment	**1,831**	1,468
Differences in accounting and tax bases of investments	**603**	479
Regulatory assets/(liabilities)	**308**	340
Financial instruments	**(24)**	105
Loss carryforwards	**(126)**	(81)
Other	**63**	56
Net future income tax liability	**2,655**	2,367

Net future income tax liability of $2,655 million (2010 - $2,367 million) is comprised of future income tax liabilities of $2,696 million (2010 - $2,447 million) net of future income tax assets of $41 million (2010 - $80 million).

At December 31, 2011, the Company had recognized the benefit of unused tax loss carryforwards of $401 million (2010 - $248 million) which start to expire in 2020 and beyond.

GEOGRAPHICAL COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings before income taxes			
Canada	**600**	711	954
United States	**839**	379	334
Other	**133**	131	580
	1,572	1,221	1,868
Current income taxes			
Canada	**207**	(29)	49
United States	**(48)**	37	35
Other	**(6)**	5	4
	153	13	88
Future income taxes			
Canada	**31**	134	117
United States	**384**	104	101
	415	238	218
Current and future income taxes	**568**	251	306

27. POST-EMPLOYMENT BENEFITS

PENSION PLANS

The Company has three registered pension plans which provide either defined benefit or defined contribution pension benefits, or both, to employees of the Company. The Liquids Pipelines and Gas Distribution pension plans (collectively, the Canadian Plans) provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge United States pension plan (the United States Plan) provides Company funded defined benefit pension benefits for United States based employees. The Company has four supplemental pension plans which provide pension benefits in excess of the basic plans for certain employees.

A measurement date of December 31, 2011 was used to determine the plan assets and the accrued benefit obligation for the Canadian and United States Plans.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuations and the next required actuarial valuations for the basic plans are as follows:

	Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
Canadian Plans		
Liquids Pipelines	December 31, 2010	December 31, 2011
Gas Distribution	December 31, 2009	December 31, 2012
United States Plan	December 31, 2010	December 31, 2011

The defined benefit pension plan costs have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages.

Defined Contribution Plans

Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

Post-Employment Benefits Other than Pensions

OPEB primarily include supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

DEFINED BENEFIT PLANS

The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

	Pension Benefits		OPEB	
December 31,	**2011**	2010	**2011**	2010
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**1,323**	1,119	**195**	170
Service cost	**61**	48	**6**	5
Interest cost	**73**	72	**11**	11
Amendments	**-**	-	**-**	6
Employees' contributions	**-**	-	**1**	1
Actuarial loss[1]	**270**	145	**28**	12
Benefits paid	**(54)**	(52)	**(7)**	(7)
Other	**8**	-	**7**	-
Effect of foreign exchange rate changes	**5**	(9)	**2**	(3)
Benefit obligation at end of year	**1,686**	1,323	**243**	195
Change in plan assets				
Fair value of plan assets at beginning of year	**1,324**	1,167	**41**	38
Actual return on plan assets[1]	**16**	127	**1**	2
Employer's contributions	**72**	89	**13**	9
Employees' contributions	**-**	-	**1**	1
Benefits paid	**(54)**	(52)	**(7)**	(7)
Other	**4**	(1)	**4**	-
Effect of foreign exchange rate changes	**3**	(6)	**1**	(2)
Fair value of plan assets at end of year	**1,365**	1,324	**54**	41
Funded status				
Benefit obligation	**(1,686)**	(1,323)	**(243)**	(195)
Fair value of plan assets	**1,365**	1,324	**54**	41
Overfunded/(underfunded) status at end of year	**(321)**	1	**(189)**	(154)
Unamortized prior service cost	**2**	4	**5**	6
Unamortized transitional obligation/(asset)	**(9)**	(11)	**7**	8
Unamortized net loss	**648**	307	**50**	22
Net amount recognized in the Consolidated Statements of Financial Position at end of year	**320**	301	**(127)**	(118)
Presented as follows:				
Deferred amounts and other assets *(Note 12)*	**320**	301	**-**	-
Other long-term liabilities *(Note 18)*	**-**	-	**(127)**	(118)

1 Includes revaluing plan assets and liabilities for December 31, 2010.

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension Benefits			OPEB		
Year ended December 31,	**2011**	2010	2009	**2011**	2010	2009
Discount rate	**4.46%**	5.64%	6.46%	**4.44%**	5.55%	6.28%
Average rate of salary increases	**3.50%**	3.50%	3.73%			

Net Benefit Costs Recognized

	Pension Benefits			OPEB		
Year ended December 31,	**2011**	2010	2009	**2011**	2010	2009
(millions of Canadian dollars)						
Benefits earned during the year	**61**	48	53	**6**	5	4
Interest cost on projected benefit obligations	**73**	72	71	**11**	11	11
Actual return on plan assets	**(16)**	(127)	(51)	**(1)**	(2)	(6)
Difference between actual and expected return on plan assets	**(76)**	47	(27)	**(2)**	-	3
Amortization of prior service costs	**2**	2	2	**1**	-	-
Amortization of transitional obligation	**(2)**	(2)	(2)	**1**	1	1
Amortization of actuarial loss	**25**	19	21	**1**	1	1
Amount charged to EEP[1]	**(15)**	(15)	(20)	**(6)**	(5)	(5)
Net defined benefit costs on an accrual basis	**52**	44	47	**11**	11	9
Defined contribution benefit costs	**4**	5	4	**-**	-	-
Net benefit cost recognized in the Consolidated Statements of Earnings	**56**	49	51	**11**	11	9

1 EEP does not have employees and uses the services of the Company for managing and operating its businesses. EEP is charged an amount, measured at cost, for pension benefits and OPEB.

For certain gas distribution businesses, regulatory adjustments are recorded in the Consolidated Statement of Earnings and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Differences arise since accounting is based on an accrual basis whereas ratemaking is based on a cash basis or funding approach. Regulatory assets or liabilities recognized in the Consolidated Statements of Financial Position are disclosed in Note 5.

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows.

	Pension Benefits			OPEB		
Year ended December 31,	**2011**	2010	2009	**2011**	2010	2009
Discount rate	**5.64%**	6.47%	6.59%	**5.55%**	6.31%	6.42%
Average rate of return on pension plan assets	**7.30%**	7.30%	7.30%	**6.00%**	6.00%	6.09%
Average rate of salary increases	**3.50%**	3.73%	5.00%			

MEDICAL COST TRENDS

The assumed rates for the next year used to measure the expected cost of benefits are as follows.

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Canadian Plans			
Drugs	8.4%	4.5%	2029
Other Medical and Dental	4.5%	4.5%	2029
United States Plan	7.8%	4.5%	2030

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $36 million in the accumulated post-employment benefit obligations and an increase of $3 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $29 million in the accumulated post-employment benefit obligations and a decrease of $2 million in benefit and interest costs.

PLAN ASSETS

The Company manages the investment risk of its defined benefit pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

Target Mix for Plan Assets

	Liquids Pipelines Pension Plan	Gas Distribution Pension Plan	United States Plan
Equity securities	62.5%	53.5%	62.5%
Fixed income securities	30.0%	40.0%	30.0%
Other	7.5%	6.5%	7.5%

Expected Rate of Return on Plan Assets

	Pension Benefits		OPEB	
Year ended December 31,	**2011**	2010	**2011**	2010
Canadian Plans	7.0%	7.25%		
United States Plan	7.5%	7.75%	6.0%	6.00%

Major Categories of Plan Assets

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities.

As at December 31, 2011, assets securing pension benefits were invested 56.6% (2010 - 60.2%) in equity securities, 36.5% (2010 - 33.8%) in fixed income securities and 6.9% (2010 - 6.0%) in other. OPEB assets securing OPEB benefits were invested 55.3% (2010 - 51.2%) in equity securities, 40.3% (2010 - 48.8%) in fixed income securities and 4.3% (2010 - nil) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $82 million (2010 - $69 million) have been excluded from the table below.

December 31,	**2011**				2010			
	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Pension benefits								
Cash and cash equivalents	**14**	**-**	**-**	**14**	10	-	-	10
Fixed income securities								
Canadian government bonds	**-**	**115**	**-**	**115**	-	97	-	97
Corporate bonds and debentures	**-**	**4**	**-**	**4**	4	-	-	4
Canadian corporate bond index fund	**158**	**-**	**-**	**158**	151	-	-	151
Canadian government bond index fund	**157**	**-**	**-**	**157**	149	-	-	149
United States debt index fund	**62**	**-**	**-**	**62**	47	-	-	47
Equity								
Canadian equity securities	**148**	**-**	**-**	**148**	163	-	-	163
Canadian equity funds	**23**	**74**	**-**	**97**	26	80	-	106
United States equity funds	**172**	**89**	**-**	**261**	147	76	-	223
Global equity funds	**192**	**7**	**-**	**199**	221	19	-	240
Private equity investment[4]	**-**	**-**	**68**	**68**	-	-	65	65
OPEB								
Cash and cash equivalents	**3**	**-**	**-**	**3**	-	-	-	-
Fixed income securities								
United States government and government agency bonds	**22**	**-**	**-**	**22**	20	-	-	20
Equity								
United States equity funds	**15**	**14**	**-**	**29**	9	-	-	9
Global equity funds	**-**	**-**	**-**	**-**	-	12	-	12

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 The fair value of the investment in United States Limited Partnership – Global Infrastructure Fund is established through the use of valuation models.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows.

	Private Equity Investment
Balance at beginning of year	65
Total gains, unrealized	8
Purchases, issuances, settlements, net	(5)
Balance at end of year	68

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension Benefits		OPEB	
Year ended December 31,	**2011**	2010	**2011**	2010
(millions of Canadian dollars)				
Total contributions	**72**	89	**13**	9
Contributions expected to be paid in 2012	**94**		**11**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2012	2013	2014	2015	2016	2017-2021
(millions of Canadian dollars)						
Expected future benefit payments	66	68	72	76	80	466

28. OTHER INCOME

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Net foreign currency gains/(loss)	**(109)**	132	444
Gain on reduction of EEP ownership interest	**141**	81	-
AEDC	**3**	80	135
Interest income on affiliate loans	**38**	37	38
Noverco preferred dividends income	**30**	15	15
Hurricane insurance recoveries	**-**	5	13
OCENSA investment income	**-**	-	6
Other	**9**	24	27
	112	374	678

29. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Accounts receivable and other	**(94)**	(480)	99
Inventory	**54**	(42)	99
Deferred amounts and other assets	**(253)**	(98)	(354)
Accounts payable and other	**504**	254	105
Interest payable	**(3)**	13	2
Other long-term liabilities	**43**	60	281
	251	(293)	232

30. RELATED PARTY TRANSACTIONS

All related party transactions are provided in the normal course of business and, unless otherwise noted, measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

EEP, an equity investee, does not have employees and uses the services of the Company for managing and operating its businesses. Vector Pipeline, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, are as follows.

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
EEP	**380**	332	342
Vector Pipeline	**6**	7	6
	386	339	348

At December 31, 2011, the Company had accounts receivable of $35 million (2010 - $29 million) from EEP and nil (2010 - nil) from Vector Pipeline.

The Company previously provided EEP with an unsecured revolving credit agreement for general liquidity support. The credit facility provided for a maximum principal amount of US$500 million for a three-year term maturing in December 2010. In March 2010, the unsecured revolving credit agreement was cancelled in accordance with the terms of the agreement and without penalty.

EGD, a subsidiary of the Company, has contracts for gas transportation services with Alliance Pipeline Canada, Alliance Pipeline US and Vector Pipeline. EGD is charged market prices for these services as follows:

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Alliance Pipeline Canada	**25**	25	24
Alliance Pipeline US	**17**	17	18
Vector Pipeline	**25**	28	29
	67	70	71

Tidal Energy Marketing (US) L.L.C., a subsidiary of the Company, purchases and sells gas at prevailing market prices with Enbridge Marketing (US) Inc., a subsidiary of EEP. Amounts charged/(recovered) are as follows:

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Purchases	**1**	2	16
Sales	**-**	-	(6)
	1	2	10

Tidal Energy Marketing Inc. and Tidal Energy Marketing (US) L.L.C., subsidiaries of the Company, have transportation commitments, measured at market value, through 2015 on Alliance Pipeline Canada, Alliance Pipeline US and Vector Pipeline. Amounts charged are as follows:

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Alliance Pipeline Canada	**17**	13	9
Alliance Pipeline US	**11**	9	7
Vector Pipeline	**11**	10	16
	39	32	32

Tidal Energy Marketing Inc., a subsidiary of the Company, purchases and sells commodities at prevailing market prices with EEP and a subsidiary of EEP as follows:

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Purchases	**122**	151	80
Sales	**(4)**	(3)	(7)
	118	148	73

ALBERTA CLIPPER PROJECT

In July 2009, the Company committed to fund 66.7% of the United States segment of the Alberta Clipper Project. The total cost of the United States segment was US$1,200 million. As at December 31, 2011, the Company had met all funding commitments. The Company funded 66.7% of the project's equity requirements through EELP, an equity investee.

The Company also provided a $348 million (US$342 million) (2010 - $346 million (US$347 million)) loan to EEP for debt financing related to the construction. At December 31, 2011, $336 million (2010 - $334 million) is included in Deferred amounts and other assets with the remaining $12 million (2010 - $12

million) included in Accounts receivable and other. The loan, denominated in United States dollars, matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. Semi-annual payments of principal and accrued interest are required. Semi-annual principal payments are based upon a straight-line amortization of the principal balance over a 30 year period.

During the year ended December 31, 2011, the Board of Directors of EEM declared distributions of $74 million (US$76 million) (2010 - $40 million (US$39 million)) payable to the Company relating to its series AC interests in the Alberta Clipper Project.

SPEARHEAD NORTH PIPELINE
In May 2009, the Company sold a section of the Spearhead Pipeline to its affiliate EEP for proceeds of US$75 million. This related party transaction has been recorded at the exchange amount which was equal to the carrying amount.

SOUTHERN LIGHTS PIPELINE
In February 2009, as part of its Southern Lights Pipeline project, the Company transferred the United States section of a newly constructed light sour pipeline to EEP in exchange for a pipeline referred to as Line 13. This non-monetary transaction has been recorded at the carrying amount.

In connection with the exchange discussed above, EEP entered into an arrangement to lease Line 13 from the Company for monthly payments of US$2 million to ensure adequate southbound pipeline capacity prior to the completion of the Alberta Clipper Project. The lease arrangement, which became effective in February 2009, expired in April 2010. For the year ended December 31, 2010, EEP paid $5 million (2009 - $21 million) to the Company to lease Line 13.

LONG-TERM RECEIVABLE FROM AFFILIATE
An affiliate long-term note receivable of $159 million (US$130 million) was repaid by EEP in November 2009. Interest income for the year ended December 31, 2009 related to the note receivable was $11 million.

LAKEHEAD LINE 6B CRUDE OIL RELEASE
In connection with the Lakehead Line 6B Leak, the Company provided personnel support and other services to its affiliate, EEP, to assist in the clean-up and remediation efforts. These services, which were charged at cost, totaled $6 million (2010 - $18 million) for the year ended December 31, 2011.

31. COMMITMENTS AND CONTINGENCIES

COMMITMENTS
The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation totaling $4,120 million which are expected to be paid within the next five years.

ENBRIDGE GAS DISTRIBUTION INC.
Bloor Street Incident
EGD was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred in April 2003 on Bloor Street West in Toronto. In December 2011, EGD pleaded guilty before the Ontario Court of Justice to one charge under the OHSA and one charge under the TSSA. The Court imposed a fine of $350,000 in connection with each charge. With the application of a required 25% Victim Fine Surcharge, the total amount payable by EGD was $875,000, which management believes concludes this matter.

ENBRIDGE GAS NEW BRUNSWICK INC.
Regulatory Matters
On December 9, 2011, the Government of New Brunswick tabled and subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. The legislation permits the government to implement new regulations which could affect the franchise agreement between EGNB and the province, impact prior decisions by the province's independent regulator and

influence the regulator's future decisions. Significant details of the rate setting process were left to be established in the new regulations which have yet to be published.

As at December 31, 2011, the carrying value of EGNB's regulatory asset and property, plant and equipment totaled $180 million and $264 million, respectively (2010 - $171 million and $254 million, respectively). Earnings from EGNB approximate $20 million per year. As the details of the regulations have not yet been made available, the effect of such regulations is not determinable as at February 21, 2012. While EGNB continues to engage in discussions with the province about the potential effect of the regulations, EGNB will preserve its legal rights.

ENBRIDGE ENERGY PARTNERS, L.P.
EEP Lakehead System Line 6A and 6B Crude Oil Releases

Enbridge holds an approximate 23.0% combined direct and indirect ownership interest in EEP, which is accounted for as an equity investment. Subsidiaries of Enbridge provide services to EEP in connection with its operation of the Lakehead System.

Line 6B Crude Oil Release

On July 26, 2010, a release of crude oil on Line 6B of EEP's Lakehead System was reported near Marshall, Michigan. EEP estimates that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. The pipelines in the vicinity were shut down, appropriate United States federal, state and local officials were notified, and emergency response crews were dispatched to oversee containment of the released crude oil and cleanup of the affected areas. The released crude oil affected approximately 61 kilometres (38 miles) of area along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan. The cause of the release remains the subject of an investigation by the National Transportation Safety Board and other United States federal and state regulatory agencies.

Pursuant to an administrative order issued by the Environmental Protection Agency (EPA) under the United States Clean Water Act, EEP was directed to clean up the released oil and remediate and restore the affected areas – a process EEP had begun upon discovering the release.

As at December 31, 2010, EEP estimated that before insurance recoveries, and not including fines and penalties, costs of approximately US$550 million ($96 million after-tax net to Enbridge), excluding lost revenue of approximately US$13 million ($2 million after-tax net to Enbridge), would be incurred in connection with this incident. These costs included emergency response, environmental remediation and cleanup activities associated with the crude oil release, as well as potential claims by third parties.

As at December 31, 2011, EEP revised its total estimate for this crude oil release to US$765 million ($129 million after-tax net to Enbridge), an increase of US$215 million ($33 million after-tax net to Enbridge) from December 31, 2010. The change in estimate was primarily based on a review of costs and commitments incurred, and additional information concerning the reassessment of the overall monitoring area, related cleanup, including submerged oil recovery operations and remediation activities, including the estimated costs related to the additional scope of work set forth in its response to the EPA directive it submitted to the EPA on October 20, 2011. During the fourth quarter of 2011, EEP resubmitted a revised work plan which was approved by the EPA on December 19, 2011.

EEP continues to make progress on the cleanup, remediation and restoration of the areas affected by the Line 6B crude oil release. All of the initiatives EEP undertakes in the monitoring and restoration phases are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

Expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at December 31, 2011. The estimates do not include amounts capitalized or any fines, penalties or claims associated with the release that may later become evident and are before insurance recoveries. Despite the efforts EEP has made to ensure the reasonableness of its estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. There continues to be the potential for EEP to

incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

Line 6A Crude Oil Release

A crude oil release from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. The pipeline in the vicinity was immediately shut down and emergency response crews were dispatched to oversee containment, cleanup and replacement of the pipeline segment. EEP estimated approximately 9,000 barrels of crude oil were released, of which approximately 1,400 barrels were removed from the pipeline as part of the repair. Excavation and replacement of the pipeline segment were completed and the pipeline was returned to service on September 17, 2010. The cause of the crude oil release remains subject to investigation by United States federal and state environmental and pipeline safety regulators.

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been substantially completed.

As at December 31, 2010, EEP estimated that before insurance recoveries, and not including fines and penalties, costs for emergency response, environmental remediation and cleanup activities associated with the Line 6A crude oil release would be approximately US$45 million ($7 million after-tax net to Enbridge), excluding lost revenue of approximately US$3 million ($1 million after-tax net to Enbridge).

As at December 31, 2011, EEP revised its cost estimate for this crude oil release to US$48 million ($7 million after-tax net to Enbridge), before insurance recoveries and excluding fines and penalties. The US$3 million increase was based on a refinement of future costs based on additional information.

EEP included those costs it considered probable and that it could reasonably estimate for purposes of determining its expected losses associated with the Line 6A crude oil release. The estimates do not include consideration of any unasserted claims associated with the release that later may become evident, nor has EEP considered any potential recoveries from third-parties that may later be determined to have contributed to the release. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews in May of each year. The program includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties. The claims for the crude oil release for Line 6B are covered by Enbridge's comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Based on EEP's increased estimate of costs associated with the crude oil releases, Enbridge and its affiliates will exceed the limits of its coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

EEP recognized US$335 million ($50 million after-tax net to Enbridge) for the year ended December 31, 2011 for insurance claims filed in connection with the Line 6B crude oil release. EEP expects to record a receivable for additional amounts claimed for recovery pursuant to insurance policies during the period it deems realization of the claim for recovery is probable.

During the second quarter of 2011, the Company renewed its comprehensive insurance program. The current coverage year has an aggregate limit of US$575 million for pollution liability for the period from May 1, 2011 through April 30, 2012.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases. Approximately 25 actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B

crude oil release, including direct actions and actions seeking class status. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against Enbridge, EEP or their affiliates as at December 31, 2011. One claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in a United States state court. The parties are currently operating under an agreed interim order.

TAX MATTERS

Enbridge and its subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LEGAL AND REGULATORY PROCEEDINGS

The Company and its subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, Management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

32. GUARANTEES

The Company has agreed to indemnify EEP from and against substantially all liabilities, including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance or to any liabilities relating to a change in laws after December 27, 1991.

The Company has also agreed to indemnify EEM for any tax liability related to EEM's formation, management of EEP and ownership of i-units of EEP. The Company has not made any significant payment under these tax indemnifications. The Company does not believe there is a material exposure at this time.

In the normal course of conducting business, the Company enters into agreements which indemnify third parties. The Company cannot reasonably estimate the maximum potential amounts that could become payable to third parties under these agreements; however, historically, the Company has not made any significant payments under these indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. Examples of such indemnification obligations include the following.

Sale Agreements for Assets or Businesses:

- breaches of representations, warranties or covenants;
- loss or damages to property;
- environmental liabilities;
- changes in laws;
- valuation differences;
- litigation; and
- contingent liabilities.

Provision of Services and Other Agreements:

- breaches of representations, warranties or covenants;
- changes in laws;
- intellectual property rights infringement; and
- litigation.

When disposing of assets or businesses, the Company may indemnify the purchaser for certain tax liabilities incurred while the Company owned the assets or for a misrepresentation related to taxes that result in a loss to the purchaser. Similarly, the Company may indemnify the purchaser of assets for certain tax liabilities related to those assets.

The above-noted indemnifications and guarantees have not had, and are not reasonably likely to have, a material effect on the Company's financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

33. UNITED STATES ACCOUNTING PRINCIPLES

These consolidated financial statements have been prepared in accordance with Canadian GAAP. The effects of significant differences between Canadian GAAP and U.S. GAAP for the Company are described below.

EARNINGS

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars, except per share amounts)			
Earnings attributable to Enbridge Inc. common shareholders under Canadian GAAP	**991**	963	1,555
Earnings attributable to Enbridge Inc. under Canadian GAAP	**1,004**	970	1,562
Dilution gains, net of tax[4]	**(88)**	(52)	-
Gain on acquisition, net of tax[1]	**-**	20	-
Inventory valuation adjustment, net of tax[2]	**13**	4	(24)
Amortization of underfunded pension adjustment[3]	**(7)**	(7)	(7)
Unrealized foreign exchange loss adjustment[12]	**155**	-	-
Earnings/(loss) attributable to noncontrolling interests			
EEP	**351**	(172)	177
Other	**56**	25	37
Earnings under U.S. GAAP	**1,484**	788	1,745
(Earnings)/loss attributable to noncontrolling interests	**(407)**	147	(214)
Earnings attributable to Enbridge Inc. under U.S. GAAP	**1,077**	935	1,531
Preference share dividends	**(13)**	(7)	(7)
Earnings attributable to Enbridge Inc. common shareholders under U.S. GAAP	**1,064**	928	1,524
Earnings per common share attributable to Enbridge Inc. common shareholders	**1.42**	1.25	2.09
Diluted earnings per common share attributable to Enbridge Inc. common shareholders	**1.40**	1.24	2.08

COMPREHENSIVE INCOME

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings under U.S. GAAP	**1,484**	788	1,745
Other comprehensive loss including noncontrolling interests under Canadian GAAP	**(225)**	(372)	(648)
Underfunded pension adjustment[3]	**(145)**	(38)	11
Unrealized foreign exchange loss adjustment[12]	**(155)**	-	-
Other comprehensive loss attributable to noncontrolling interests in EEP under U.S. GAAP[4]	**(124)**	(29)	(62)
Other comprehensive loss including noncontrolling interests under U.S. GAAP	**(649)**	(439)	(699)
Comprehensive income	**835**	349	1,046
Comprehensive (income)/loss attributable to noncontrolling interests	**(270)**	224	(80)
Comprehensive income attributable to Enbridge Inc. under U.S. GAAP	**565**	573	966
Preference share dividends	**(13)**	(7)	(7)
Comprehensive income attributable to Enbridge Inc. common shareholders under U.S. GAAP	**552**	566	959

FINANCIAL POSITION

December 31,	**2011**		2010	
	Canada	**United States**	Canada	United States
(millions of Canadian dollars)				
Assets				
Current assets				
Cash and cash equivalents[4,6]	**420**	**811**	342	456
Accounts receivable and other[4,6,9]	**3,136**	**3,990**	2,706	3,582
Inventory[2,4,6]	**739**	**714**	813	915
	4,295	**5,515**	3,861	4,953
Property, plant and equipment, net[4,6,8,9]	**22,623**	**31,833**	20,332	28,562
Long-term investments[4,6]	**2,540**	**510**	2,198	367
Deferred amounts and other assets[3,4,6,7,9]	**3,220**	**2,615**	2,886	2,212
Intangible assets[4,8]	**600**	**798**	478	676
Goodwill[4,8]	**1,024**	**1,091**	385	445
Future income taxes[1]	**41**	**40**	80	79
	34,343	**42,402**	30,220	37,294
Liabilities and shareholders' equity				
Current liabilities				
Bank indebtedness	**102**	**102**	100	100
Short-term borrowings	**548**	**548**	326	326
Accounts payable and other[4,6,9]	**3,722**	**4,904**	2,688	3,811
Interest payable[4]	**114**	**185**	117	177
Current maturities of long-term debt[4]	**252**	**354**	154	185
Current maturities of non-recourse long-term debt[6]	**122**	**103**	70	68
	4,860	**6,196**	3,455	4,667
Long-term debt[4,7,8]	**14,257**	**19,222**	13,561	18,374
Non-recourse long-term debt[6]	**951**	**606**	1,061	701
Other long-term liabilities[3,4,6,9]	**1,892**	**2,306**	1,473	1,658
Future income taxes[1,2,3,6,8]	**2,696**	**2,574**	2,447	2,370
	24,656	**30,904**	21,997	27,770
Redeemable noncontrolling interests[5]	**-**	**640**	-	364
Shareholders' equity				
Share capital				
Preference shares	**1,056**	**1,056**	125	125
Common shares	**3,969**	**3,969**	3,683	3,683
Contributed surplus	**106**	**-**	59	-
Retained earnings[1,2,3,5,8,9,12]	**4,991**	**4,172**	4,734	3,977
Additional paid-in capital[4]	**-**	**244**	-	131
Accumulated other comprehensive loss[3,12]	**(1,094)**	**(1,536)**	(882)	(1,026)
Reciprocal shareholding	**(187)**	**(187)**	(154)	(154)
Total Enbridge Inc. shareholders' equity	**8,841**	**7,718**	7,565	6,736
Noncontrolling interests[4,5]	**846**	**3,140**	658	2,424
	9,687	**10,858**	8,223	9,160
	34,343	**42,402**	30,220	37,294

1 Gain on Acquisition

At December 31, 2010 under Canadian GAAP, the original equity interest in a step acquisition continued to be carried at book value subsequent to the acquisition date of the additional interest. Under U.S. GAAP, the original equity interest and noncontrolling interest in a step acquisition were re-measured to fair value on the date control was obtained. Under Canadian GAAP, the original equity interest and noncontrolling interest were not re-measured to fair value. At December 31, 2011, this recognition difference between Canadian GAAP and U.S. GAAP no longer exists.

On June 16, 2010, the Company acquired the remaining 50% interest in Hardisty Caverns, an oil storage facility, increasing its ownership interest to 100%. The acquisition date fair value of the original equity interest in Hardisty Caverns was $52 million, which was determined based on the valuation of the additional 50% interest. As a result of the re-measurement of Hardisty Caverns, a $20 million gain, net of tax, was recorded in earnings for the year ended December 31, 2010 under U.S. GAAP.

2 Commodity Inventories Valuation

Under Canadian GAAP commodity inventories are recorded at fair value. U.S. GAAP requires that commodity inventories be recorded at the lower of cost or market. For the year ended December 31, 2011, lower of cost or market adjustments resulted in a $11 million (2010 - $32 million) decrease to inventory, a $4 million increase (2010 - $6 million decrease) to the future income tax liability and a $13 million increase (2010 - $4 million increase; 2009 - $24 million decrease) to earnings.

3 Pension Accounting

U.S. GAAP requires an employer to recognize the overfunded or underfunded status of a defined benefit post retirement plan or OPEB plan as an asset or liability and to recognize changes in the funded status in the period in which they occur through OCI while Canadian GAAP does not require the recognition of the defined benefit post retirement plan or OPEB plan funding status. Pension funding status adjustments resulted in a decrease in the net pension asset of $704 million (2010 - $337 million) for the underfunded status of the plans, a decrease in regulatory liabilities of $304 million (2010 - $138 million), a decrease in future tax liability of $114 million (2010 - $58 million) and a decrease in AOCI of $286 million (2010 - $141 million) at December 31, 2011.

Under Canadian GAAP, an unrecognized net transitional asset was recognized as part of the net pension asset on the adoption of CICA Handbook Section 3461, Employee Future Benefits. There is no corresponding asset under U.S. GAAP. At December 31, 2011, this adjustment resulted in a $2 million (2010 - $3 million) increase to the net pension asset with an offset to retained earnings, and a $1 million decrease to earnings (2010 - $1 million; 2009 - $1 million).

Under Canadian GAAP, a regulatory asset is recorded in relation to recoverable costs associated with OPEB plans. There is no corresponding regulatory asset under U.S. GAAP. At December 31, 2011, this adjustment resulted in a $88 million (2010 - $85 million) decrease to regulatory assets with a corresponding decrease to retained earnings, and a $6 million decrease to earnings (2010 - $6 million; 2009 - $6 million).

Amounts removed from OCI and recognized as components of the net pension and OPEB costs in the year are as follows.

	2011	2010	2009
(millions of Canadian dollars)			
Prior service cost	**-**	1	-
Net loss	**10**	7	5
	10	8	5

Amounts included in AOCI that have not yet been recognized as a component of net periodic benefit cost are as follows:

	2011	2010	2009
(millions of Canadian dollars)			
Prior service cost	**3**	4	1
Accumulated net loss	**283**	137	102
	286	141	103

Net amounts reflected in OCI for the year are as follows:

	2011	2010	2009
(millions of Canadian dollars)			
Unamortized prior service cost	**(1)**	3	-
Net loss/(gain)	**146**	35	(10)
	145	38	(10)

The Company estimates that approximately $25 million related to pension and OPEB plans at December 31, 2011 will be reclassified into earnings in the next twelve months, as follows:

	Pension Benefits	OPEB	Total
(millions of Canadian dollars)			
Prior service costs	-	1	1
Loss	22	2	24
	22	3	25

4 Consolidation of a Limited Partnership

Under U.S. GAAP the Company is deemed to have control of EEP and therefore consolidates its 23.0 % interest in the partnership, resulting in an increase to assets of $8,920 million (2010 - $7,972 million), an increase in liabilities of $6,398 million (2010 - $6,098 million) and an increase in noncontrolling interests of $2,519 million (2010 - $1,871 million) at December 31, 2011. During the year ended December 31, 2011, dilution gains of $88 million, net of tax of $53 million (2010 - $52 million, net of tax of $30 million) were reclassified from earnings to equity as a result of the consolidation of EEP.

5 Redeemable Noncontrolling Interests

Under Canadian GAAP, a subsidiary's redeemable units classified as equity are eliminated on consolidation when held by the parent, or presented by the parent in the Consolidated Statements of Financial Position as noncontrolling interest in equity. Under U.S. GAAP, noncontrolling interest in a redeemable equity security is classified outside of permanent equity. Further, under U.S. GAAP, noncontrolling interest in a redeemable equity security is required to be presented at its redemption value with changes in value recognized in retained earnings. At December 31, 2011, this difference resulted in an increase to noncontrolling interests, with a corresponding decrease to retained earnings, of $411 million (2010 - $255 million).

6 Accounting for Joint Ventures

Canadian GAAP requires that investments in joint ventures are proportionately consolidated. U.S. GAAP requires the Company's investments in joint ventures be accounted for using the equity method. However, under an accommodation of the SEC, accounting for jointly controlled investments need not be reconciled from Canadian to U.S. GAAP if the joint venture is jointly controlled by all parties having an equity interest in the entity. Joint ventures in which all owners do not share joint control are reconciled to U.S. GAAP. The different accounting treatment affects only presentation and classification and not earnings or shareholders' equity.

7 Transaction Costs

Under Canadian GAAP transaction costs arising from the issuance of debt are recorded in Long-term debt. For U.S. GAAP, these costs are reclassified to Deferred amounts and other assets. As at December 31, 2011, $92 million (2010 - $89 million) of transaction costs were reclassified.

8 Common Control Transactions

U.S. GAAP requires common control transactions to be measured at the carrying amount, with any difference between the carrying value and consideration reflected as a charge or credit to equity. At December 31, 2011, a decrease in assets of $408 million (2010 - $414 million), a decrease in liabilities of $54 million (2010 - $61 million), and a decrease in retained earnings of $354 million (2010 - $353 million), related to a historic transaction with the Fund were retroactively reflected in the U.S. GAAP Statement of Financial Position. There was a $1 million decrease to earnings (2010 - $1 million; 2009 - $1 million).

9 Accounting for Leases

The criteria for determining whether an arrangement contains a lease are consistent under both Canadian and U.S. GAAP; however, the U.S. GAAP guidance was effective prior to the Canadian GAAP guidance. As a result, one of the Company's pipeline transportation agreements is considered a lease under U.S. GAAP, resulting in an increase in assets of $122 million (2010 - $129 million), an increase in liabilities of $114 million (2010 - $122 million), an increase in retained earnings of $8 million (2010 - $7 million) and an increase in earnings of $1 million (2010 - $1 million; 2009 - $1 million).

10 Unrecognized Tax Benefits

(millions of Canadian dollars)	**2011**	2010
Unrecognized tax benefits at beginning of year	**17**	22
Gross increases for tax positions of current year	**3**	2
Gross increases for tax positions of prior years	**-**	-
Gross decreases for tax positions of prior years	**(1)**	(2)
Reduction for lapse of statute of limitations	**(1)**	(2)
Changes in translation of foreign currency	**-**	-
Decreases relating to settlements with taxing authority	**-**	(3)
Unrecognized tax benefits at end of year	**18**	17

The unrecognized tax benefits at December 31, 2011, if recognized, would affect the Company's effective income tax rate. The Company does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its consolidated financial statements.

The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of income tax expense. Income tax expense for the year ended December 31, 2011 includes a $1 million expense (2010 - $2 million recovery; 2009 - $1 million expense) of interest and penalties. As at December 31, 2011, interest and penalties of $9 million (2010 - $8 million; 2009 - $10 million) have been accrued.

The Company and its subsidiaries are subject to either Canadian federal and provincial income tax, United States federal, state and local income tax, or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2007 and all returns are generally closed through 2006. Generally, all United States federal income tax returns and state and local income tax returns are closed through 2007.

11 Indefinite Reversal Rule

The Company has not provided future taxes on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. These earnings relate to ongoing operations and as at December 31, 2011 were approximately $524 million (2010 - $491 million; 2009 - $406 million).

12 Unrealized Foreign Exchange Loss

Under Canadian GAAP, an unrealized foreign exchange loss in AOCI was recognized in earnings during the year ended December 31, 2011 due to a dividend paid by a subsidiary. Under U.S. GAAP, this foreign exchange loss should remain in AOCI until the subsidiary is sold. At December 31, 2011, this difference resulted in an increase to earnings of $155 million with a corresponding decrease in OCI. This difference did not result in an adjustment at December 31, 2010 or December 31, 2009.

FUTURE ACCOUNTING STANDARDS UNDER U.S. GAAP

The following standards will be effective for the Company beginning on January 1, 2012. Management does not expect the adoption of any of these standards to significantly impact the consolidated financial statements.

Fair Value Measurement

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-04, which revises the existing guidance on fair value measurement under U.S. GAAP as part of the FASB's joint project with the International Accounting Standards Board. Under the revised standard, the Company will be required to provide additional disclosures about fair value measurements, including information about the unobservable inputs and assumptions used in Level 3 fair value measurements, a description of the valuation methodologies used in Level 3 fair value measurements, and the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. The adoption of this pronouncement is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for the first reporting period beginning after December 15, 2011.

Statement of Comprehensive Income

In June 2011, the FASB issued ASU 2011-05, which updates the existing guidance on comprehensive income under U.S. GAAP, requiring presentation of net income and OCI either in one continuous statement, referred to as the Statement of Comprehensive Income, or in two separate but consecutive statements of net income and OCI. The adoption of this pronouncement does not affect the Company's presentation of comprehensive income, and will not have an impact on the Company's financial statements. This accounting update is effective for the first reporting period beginning after December 15, 2011.

Goodwill Impairment

In September 2011, the FASB issued ASU 2011-08, which is intended to reduce the overall costs and complexity of goodwill impairment testing. The standard allows an entity to first assess qualitative factors to determine whether it is necessary to perform the current two-step goodwill impairment test. An entity will not be required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The standard does not change the current two-step test and applies to all entities that have goodwill reported in their financial statements. The adoption of this pronouncement is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011.

Balance Sheet Offsetting

In December 2011, the FASB issued ASU 2011-11, which provides enhanced disclosures on the effect or potential effect of netting arrangements on an entity's financial position. The adoption of the pronouncement affects financial statement disclosures only and is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for annual and interim beginning on or after January 1, 2013.

EGD Asset Plan

2012-2021











May 9, 2012

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1. Executive Summary

Enbridge Gas Distribution (EGD) is one of North America's oldest investor-owned, regulated natural gas distribution utilities and shares many of the challenges facing some of its North American counterparts – an increased focus on safety and reliability, aging assets, an aging workforce, and the need to cost-effectively meet the demands of customer growth in its franchise area.

In response to these challenges, EGD has been adopting an Asset Management System approach to managing its distribution assets. Through the adoption of this approach, EGD is striving to enhance the value delivered to its customers through enhanced safety, reduced service disruptions, and improved cost effectiveness.

An Asset Plan is an important component of any Asset Management System. It defines and communicates what needs to be done with the organization's core assets over a specified period of time, the rationale behind these activities, and the resources needed for execution.

EGD's Asset Plan is a rolling 10-year plan that establishes the Company's distribution asset spending priorities over the term of the plan in a manner which attempts to address system needs while being mindful of ratepayer impacts.

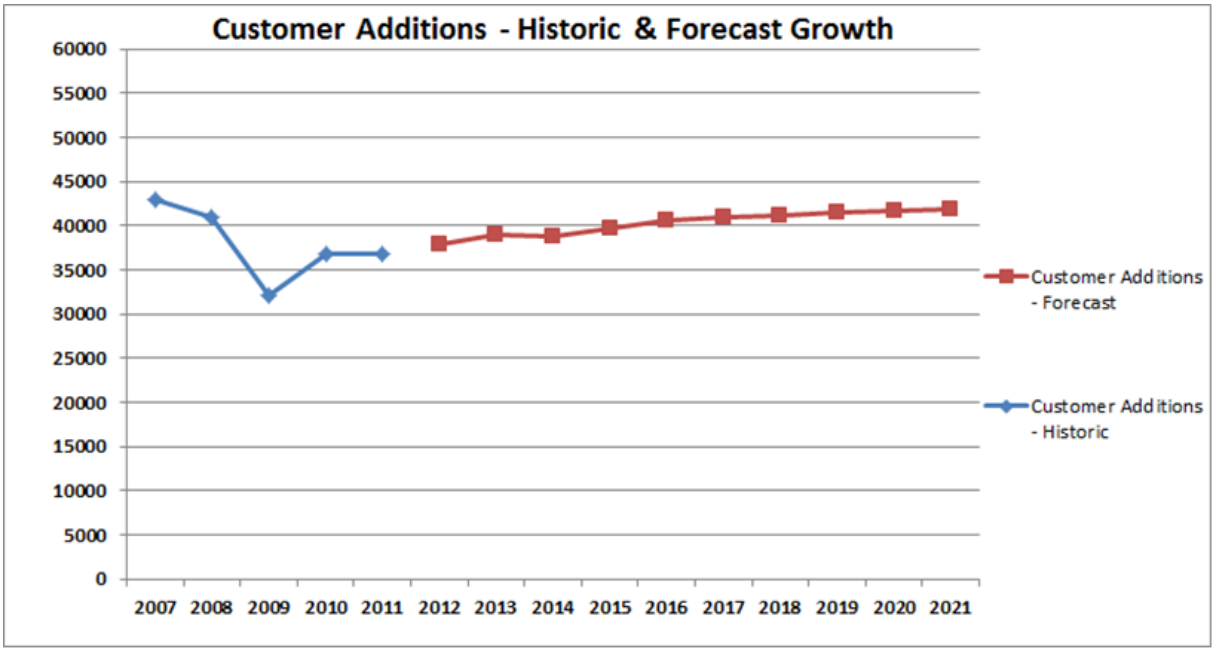
This first iteration of the Asset Plan applies to the 2012-2021 time period. Going forward, the plan will be reviewed and updated on an annual basis. The scope of the plan includes EGD's core gas distribution system assets – Pipelines (Mains and Services), Valves, Fittings, and Measurement & Regulation equipment such as stations.

The Asset Plan includes a set of guiding principles which define EGD's Asset Management Objectives, Policies and Strategies.

Consistent with these guiding principles, the Asset Plan establishes the requirements and estimates the related capital expenditures to support four primary kinds of asset-related investments - Customer Additions, Reinforcements, System Integrity & Reliability, and Relocations.

Customer Additions:

EGD has experienced significant customer growth in its franchise area. This growth is forecast to continue in the future, as outlined in the chart below, driving the need to make continued investments in new distribution plant to service these new customers.



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
42920	41052	32089	36902	36753	37927	38896	38725	39752	40540	41014	41236	41483	41760	41882

Chart 1 - Executive Summary: Customer Additions – Historic & Forecast Growth

Reinforcements:

Reinforcements increase the capacity and operating flexibility of the distribution system. Investments required to reinforce the distribution system are primarily driven by Customer Growth and System Integrity & Reliability considerations. As part of the Asset Planning process, network analysis is performed to establish the need and timing for reinforcements within each of the operating areas that make up EGD's franchise area (Areas 10, 20, 30, 40, 50, 60 and 80). This analysis has determined that a significant increase in reinforcement investment is required over the 10 year horizon of this Asset Plan.

In addition to several routine reinforcements, two major reinforcements of the extra-high pressure grid mains that form the major backbone of the distribution system serving the GTA

and Ottawa areas are required to further support customer growth and address significant system reliability and security of supply issues.

System Integrity & Reliability:

A critical responsibility in managing a gas distribution system is understanding potential threats to the safety and reliability of the system. This can be accomplished through condition monitoring, as well as reference to historical knowledge and industry developments and trends. By understanding these threats and the risks that they can manifest, mitigation programs have been, and continue to be developed and implemented to effectively manage these risks.

In addition, recent events in the natural gas industry, such as the tragic San Bruno explosion in September 2010, the Philadelphia explosion in January 2011, and the Allentown explosion in February 2011, have resulted in increased focus on public safety.

As part of applying an Asset Management System approach, EGD has made a concerted effort to identify, assess and prioritize risks to its distribution system and to continue to develop and implement programs to monitor, repair or replace components of the system as required, as part of this Asset Plan. In cases where risks require further analysis before the extent of mitigation can be determined, targeted risk studies have been identified and also included in this plan. These studies may result in additional programs or projects to address risks in future iterations of the plan.

The following are some of the key initiatives that represent a significant portion of the capital investments for System Integrity and Reliability requirements outlined in the Asset Plan:

- The need to continue to address classes of assets that are near the end of their useful life. Examples include Copper Services, Steel Tubing Services, AMP Fittings, and Mainline Compression Couplings
- The need to continue to conduct studies to improve our understanding of the condition of specific classes of assets where risks have been identified. These studies will help establish the requirements and scope of any related mitigation programs
- A number of initiatives to continue to enhance Records Integrity, including completeness, accuracy, verifiability, timeliness, and accessibility
- In-line inspect targetted XHP pipelines operating over 20% Specified Minimum Yield Strength (SMYS)

- Install additional mainline valves at key locations to enhance EGD's capability to effectively isolate portions of the system to minimize the impact of planned or unplanned service disruptions

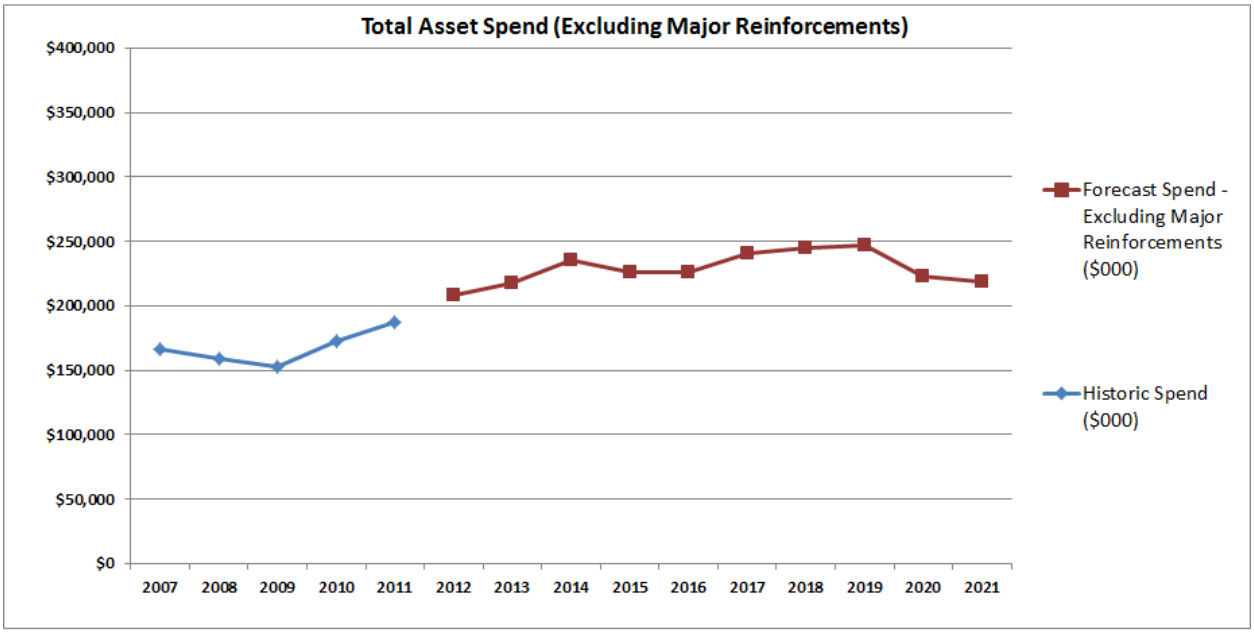
Relocations:

Distribution assets generally need to be relocated for reasons such as road-widening and other municipal or third party construction projects.

In forecasting future years' relocations, EGD begins with the historical level of relocation activity and then adds projects or programs identified as incremental to that historical level. Within the 10 year horizon of this Asset Plan, a number of incremental activities, which are already underway or announced, are driving forecast relocation costs above historical levels. These activities include items such as Infrastructure Stimulus Fund activities, major transit projects (TTC Subway expansion, GTAA Rail Link, Rapid Transit – Eglinton LRT, York Region Rapid Transit, and Ottawa LRT), major road expansions (407 Extension) and preparations for the 2016 Pan Am Games.

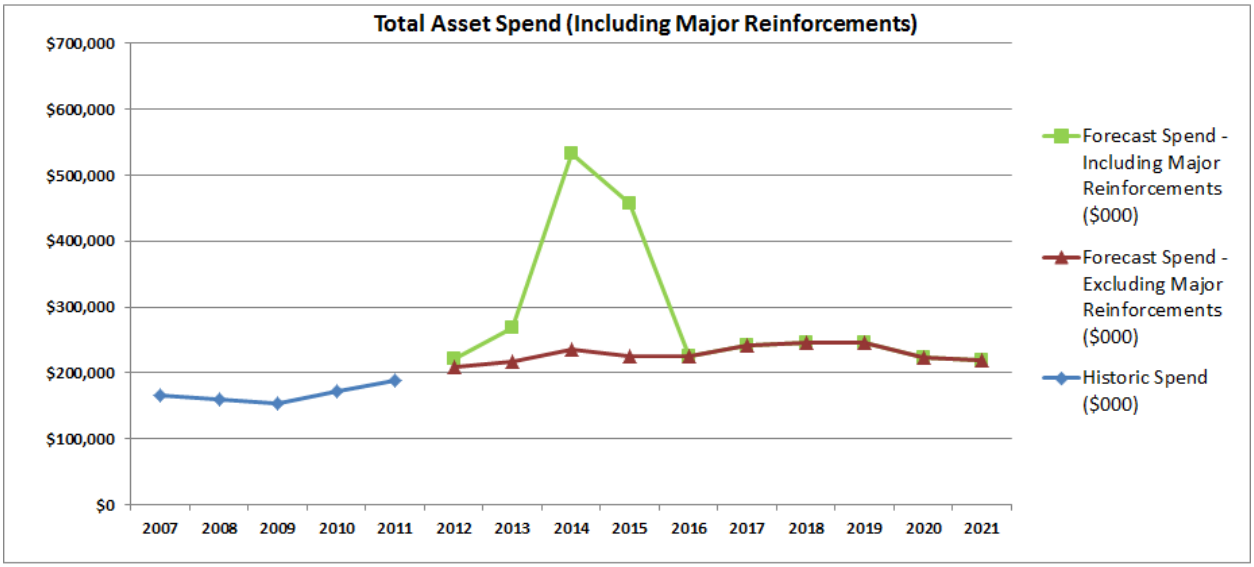
Forecast Capital Cost of the Asset Plan

The following two charts summarize the total capital spend profile required to effectively meet the Customer Additions, Reinforcement, System Integrity & Reliability, and Relocation requirements included in this Asset Plan, as compared to the historic spend. The forecast costs are based on 2012 dollars (i.e. inflation and other time-based adjustments have not been applied) and include only the direct capital costs of the projects and initiatives.



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
$166,355	$158,783	$152,971	$172,927	$187,586	$208,671	$217,213	$235,614	$225,624	$226,207	$241,130	$245,164	$246,417	$223,345	$218,341

Chart 2 - Executive Summary: Historic & Forecast Capital Spend (Excluding Major Reinforcements)



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Excluding Major Reinforcements($000)	$166,355	$158,783	$152,971	$172,927	$187,586	$208,671	$217,213	$235,614	$225,624	$226,207	$241,130	$245,164	$246,417	$223,345	$218,341
Including Major Reinforcements($000)	$166,355	$158,783	$152,971	$172,927	$187,586	$221,798	$268,330	$532,360	$457,524	$226,207	$241,130	$245,164	$246,417	$223,345	$218,341

Chart 3 - Executive Summary: Historic & Forecast Capital Spend (Including Major Reinforcements)

2. Introduction

2.1 Background & Context

EGD is one of North America's oldest investor-owned, regulated natural gas distribution utilities and shares many of the challenges facing some of its North American counterparts – an increased focus on safety and reliability, aging assets, an aging workforce, and the need to cost-effectively meet the demands of customer growth in its franchise area. While meeting these challenges, EGD remains committed to the safe, reliable operation of its gas distribution network.

In response to these challenges, EGD has been working over the past several years to build on and enhance its past practices using an Asset Management System approach. Asset Management, as an approach, has been evolving over the past several years in a broad range of asset intensive industries, including utilities. The primary objective of an Asset Management System is to provide management with a systematic approach to making optimal asset related decisions based on trying to achieve an appropriate balance of risks, operational performance and costs. Achieving this balance enhances the value that EGD delivers to its customers through enhanced safety, reduced service disruptions, and improved cost effectiveness.

In working to adopt an Asset Management System approach, EGD has been using an asset management conceptual model developed by the Institute of Asset Management. This model was detailed in the asset management standard called PAS 55, a "Publicly Available Specification" published by the British Standards Institute. EGD took this model and adapted it to its gas distribution business.

Another important reference used by the Company was the Guiding Document on Asset Management released by the Canadian Gas Association in 2009. The CGA defines Asset Management as:

> A strategic management system used to optimally manage assets over their life cycle by balancing performance, risk, and expenditures to achieve corporate strategic objectives.

From these reference sources, EGD created a framework that outlines all the major components of a comprehensive Asset Management System. EGD has used this framework to assess its current Asset Management activities to identify gaps and areas for improvement. Addressing these opportunities has become a continuous improvement process. Some areas

where work has already started include system health and performance monitoring, risk assessment and management, asset data, capital management, life cycle cost and value optimization and asset management leadership and accountability. These areas will continue to improve, through the Asset Management process going forward.

A key component of the Asset Management System is Asset Management Strategy and Planning. In addressing this Asset Management System requirement, EGD turned its attention to the development of a 10 year Asset Plan which will guide asset-related investments.

This document provides the first iteration of the plan, which will be reviewed, updated and improved every year going forward, thereby creating a 10-year rolling plan.

2.2 Purpose & Objectives of the Asset Plan

The purpose of an asset plan is to define and communicate what needs to be done with the organization's core assets over a specified period of time, the rationale behind these activities, and the resources needed for execution, consistent with the Company's key priorities. The needs of the assets should be considered over their entire life cycle including creation or acquisition, operation, maintenance and decommissioning.

EGD's Asset Plan establishes the Company's distribution asset spending priorities over a 10-year period (2012-2021) in a manner which attempts to address system needs while being mindful of ratepayer impacts.

More specifically, the objectives of this plan are:

- Align asset-related activities with the Company's key priorities (including safety, reliability, risk management, customer satisfaction, productivity and innovation)
- Provide inputs to the Company's long term planning and budgeting processes
- Provide a basis for substantiating financial requirements
- Meet regulatory requirements
- Serve as a mechanism to communicate EGD's asset management priorities and planned investments with internal and external parties

The target audience of the plan includes EGD's Senior Management, Operational Managers, partners, and external parties such as the OEB and other applicable stakeholders.

2.3 Scope of the Asset Plan

The following are the key elements that define the scope of this Asset Plan:

- The planning horizon for the Asset Plan is 10 years, 2012 to 2021.
- Organizationally, the Plan is limited to assets owned and operated by EGD across all regions within its franchise area.
- The Plan applies to core gas distribution assets only. These are physical plant assets that primarily make up the gas distribution system, including Pipelines (Mains & Services), Fittings, Valves, Stations, Meters and other Measurement & Regulation assets.
- The Plan does not include other assets such as Facilities, IT and Fleet.
- For this first iteration of the Asset Plan, Storage assets at EGD's Tecumseh Storage facility have not been included. In the future, EGD expects to include storage assets within the scope of the Asset Plan.
- This first iteration of the Asset Plan is focused on the capital investment requirements to optimally manage EGD's distribution assets. In future iterations, O&M requirements which are currently addressed in our O&M budgets will be addressed in more detail in the Asset Plan.

Based on the scope assumptions above, the Asset Plan will help substantiate a significant portion, but not all of EGD's capital requirements.

The Asset Plan is intended to supplement, but not replace, the evidence to be filed by the Company in support of its budget requirements in rate application filings.

2.4 High Level Overview of EGD's Asset Planning Process

Based on industry best-practices and internal expertise, EGD has developed, adapted and employed its own asset planning process. At the high level, this four-step process can be summarized as follows.

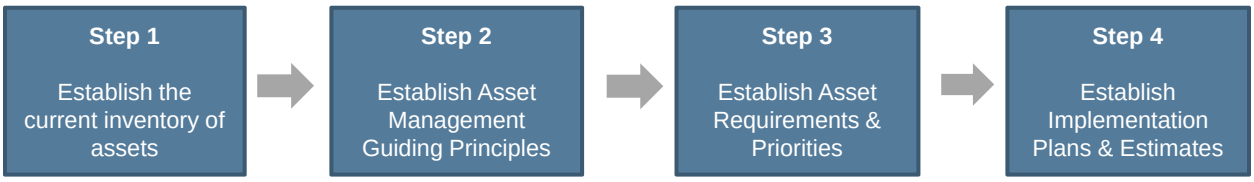


Figure 1 - Asset Planning Process

Step 1: Establish the Current Inventory of Assets:

The Distribution System is comprised of thousands of discrete components. To analyze and determine the needs of the assets, it is necessary to develop an appropriate classification for those assets, and inventory those assets by class rather than try to deal with discrete components.

- Based on the scope of the Asset Plan, a suitable "Asset taxonomy" has been established. The taxonomy identifies the key assets, and classifies them into a hierarchy
- Using the taxonomy as a reference, an inventory of assets was established. This represents a count of the key assets within the asset hierarchy
- Information on the asset inventory is supported by an explanation of relevant details on each class of asset, such as its age distribution

Step 2: Establish Asset Management Guiding Principles:

- Guiding Principles provide the basis and rationale for Asset Management decisions
- These principles include Asset Management Objectives, Policies, and Strategies

Step 3: Establish Asset Requirements & Priorities:

When considering asset requirements and priorities, it is necessary to consider the various types of asset investments that are required to build, operate and maintain the distribution system.

- Considering the various types of asset investments, there are primarily four categories of requirements that determine the overall plan for all the assets within the scope of the Asset Plan:
    a. Customer Additions
    b. Relocations
    c. Reinforcements
    d. System Integrity & Reliability
- The approach to establishing these requirements and prioritizing them varies by category
- In general, the requirements and priorities are determined based on a variety of sources of information, including asset condition data from operational systems, results of risk assessments, studies, forecasts, tacit knowledge, and historical information.

Step 4: Establish Implementation Plans & Estimates:

- The implementation plan establishes the scope and timing of asset-related projects, programs and investments that are needed to meet the asset requirements and priorities
- Capital investments needed to support the execution of the implementation plans are estimated by using a variety of approaches as appropriate, including historical expenditures and unit costs where available
- To the extent possible, an attempt has been made to manage potential rate impacts and resource availability by smoothing the expenditure profile and spreading out the costs over a longer term

3. Overview of EGD's Distribution Assets

This section provides an overview of how EGD classifies distribution assets, an inventory count, geographic distribution, and age-related profiles. This information will particularly help set the context for the discussion on System Integrity and Reliability requirements, strategies and plans that are discussed in subsequent sections of this document.

3.1 Asset Taxonomy and Inventory

EGD's distribution assets have been classified into four classes – Pipe, Fittings, Measurement & Regulation Equipment including Stations, and Valves. A further level of categorization has been done based on the sub-type of assets by material type / function. Figure 2 below is a depiction of the asset hierarchy.

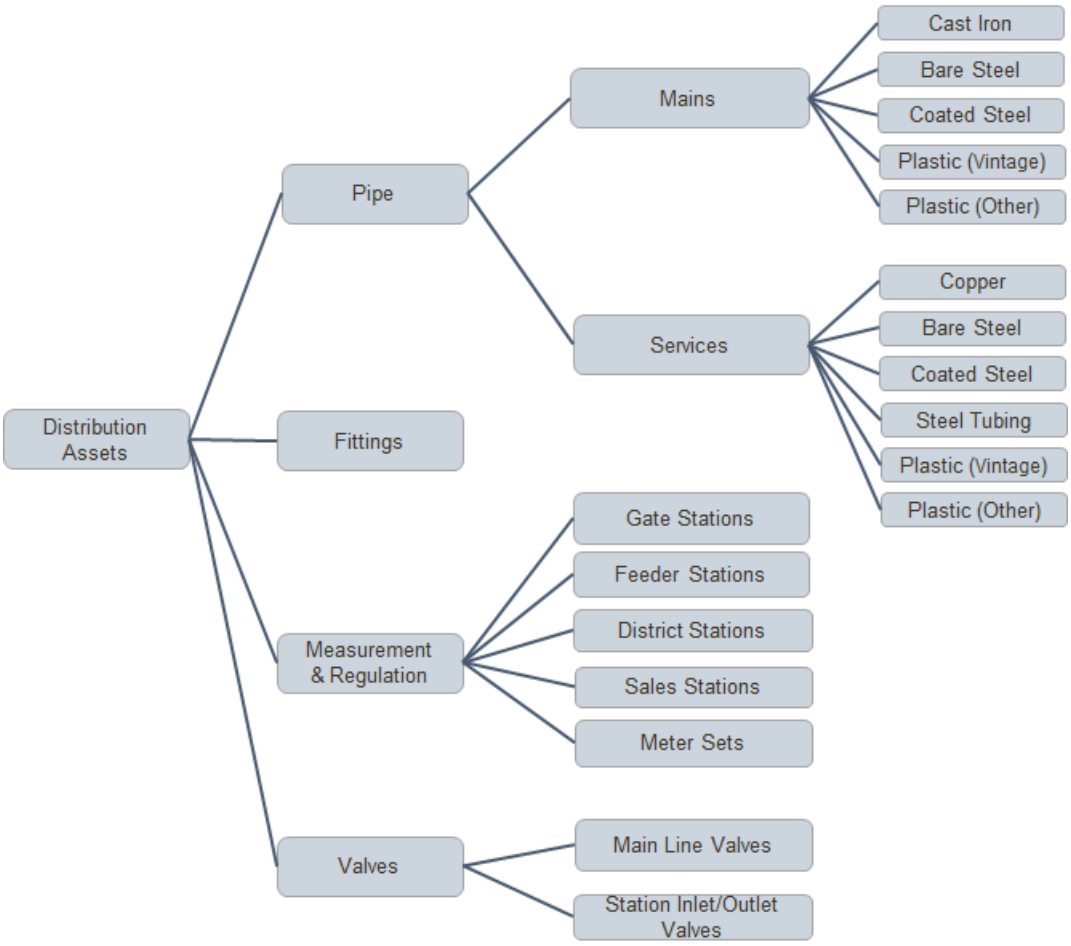


Figure 2 - Asset Taxonomy

Based on the Asset hierarchy above, Table 1 below quantifies the assets, as of March 2012.

Distribution Asset Classes		Quantity
Pipe		
Mains (#kms)		**35,181**
	Cast Iron	138
	Bare Steel	17
	Coated Steel	12,773
	Plastic - Vintage	3,689
	Plastic - Other	18,559
	Unclassified	5
Service Lines (#)		**1,947,325**
	Copper	6,754
	Bare Steel	30,714
	Coated Steel	159,744
	Steel Tubing	423
	Plastic - Vintage	284,892
	Plastic - Other	1,463,535
	Unclassified	1,263
Measurement & Regulation		
Gate Stations (#)		**47**
Feeder Stations (#)		**19**
District Stations(#)		**4,613**
Sales Stations (#)		**9,391**
Customer Meter Sets (#)		**2,025,872**
Main & Station Valves		
Main Line Valves (#)		**19,884**
Station Inlet/Outlet Valves (#)		**9,273**
Unclassified		**1,225**

Table 1 - Asset Inventory

A common reality faced by the natural gas industry is legacy records where some information about the asset that would be instructive to have is not available. In many cases this is because collection of specific types of data was not part of the records collection standard at the time of installation.

Where adequate information was not available to accurately classify the assets, they have been labeled “Unclassified”.

Although fittings are recognized as an important element of EGD’s asset inventory, historically these have not been recorded as separate assets, but rather associated with pipe assets. This makes it difficult to determine a precise inventory of these assets.

3.2 Geographic Distribution of Assets

EGD's franchise area is divided into seven administrative areas (Areas 10, 20, 30, 40, 50, 60, 80) as shown below. All of EGD's distribution assets reside in these areas.

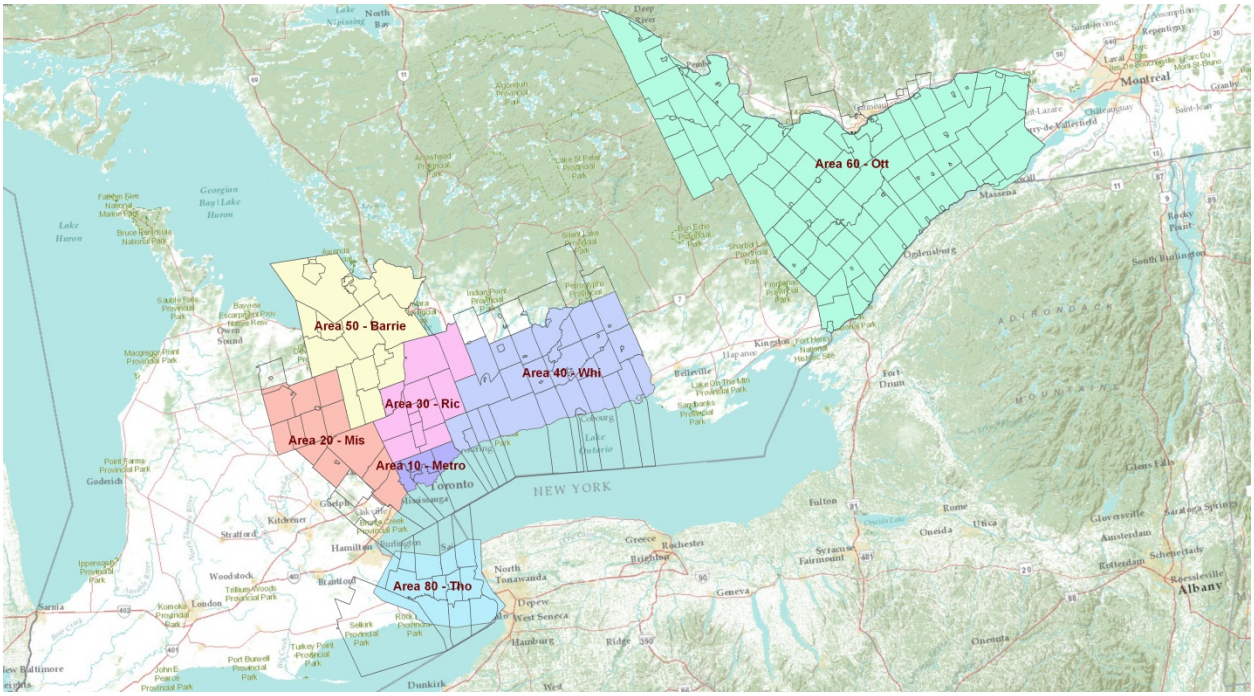


Figure 3 - EGD's Geographic Organization

Area 10 covers Toronto. Areas 20, 30, 40 and 50 cover the remainder of the Greater Toronto area. Area 60 covers the Ottawa region, and Area 80 covers the Niagara region.

In some cases, asset requirements can vary by area based on historic and future customer growth trends, historic regional practices, geographical conditions such as topography, soil conditions, and other factors.

The asset inventory outlined in Table 1 Asset Inventory is an aggregate of assets by asset class across all areas.

3.3 Understanding Assets by Age

EGD, as Ontario's oldest natural gas utility, has assets of varying age. Understanding the in-service date of the assets is important since materials degrade, and the performance characteristics of the assets can change over time. This understanding can help inform the need, scope and timing of replacement programs.

Histograms of Mains, Services and Main/Station Valves based on age follow.

Mains:

EGD's distribution system has over 35,000 km of mains. Based on when these assets were installed and their material type, there are different generations or distributions of mains as shown in the chart below.

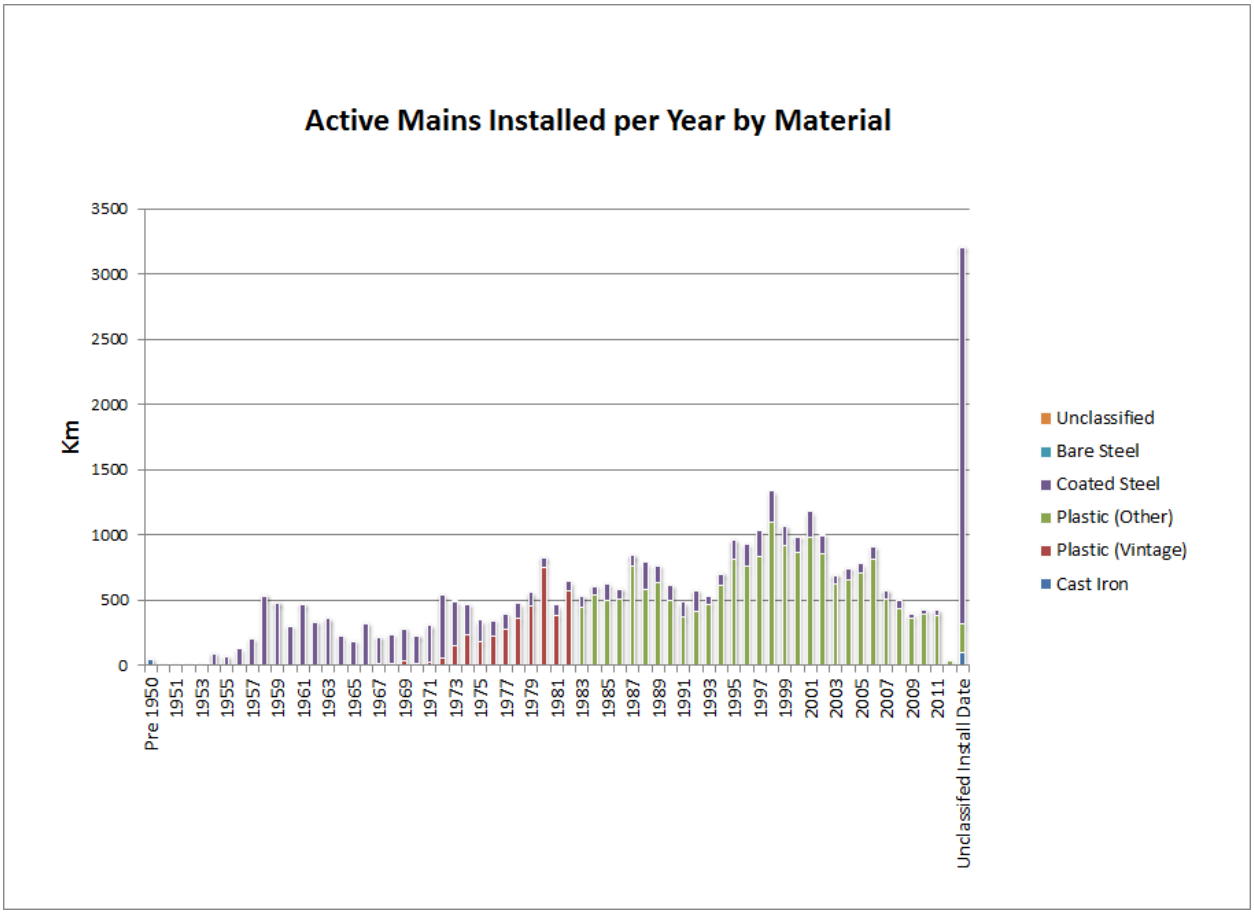


Chart 4 - Active Mains Installed by Year by Material

Services:

There are approximately 1.9 million active services across the franchise area. Similar to mains, there are several generations or distributions of services, based on their material type as shown in the chart below.

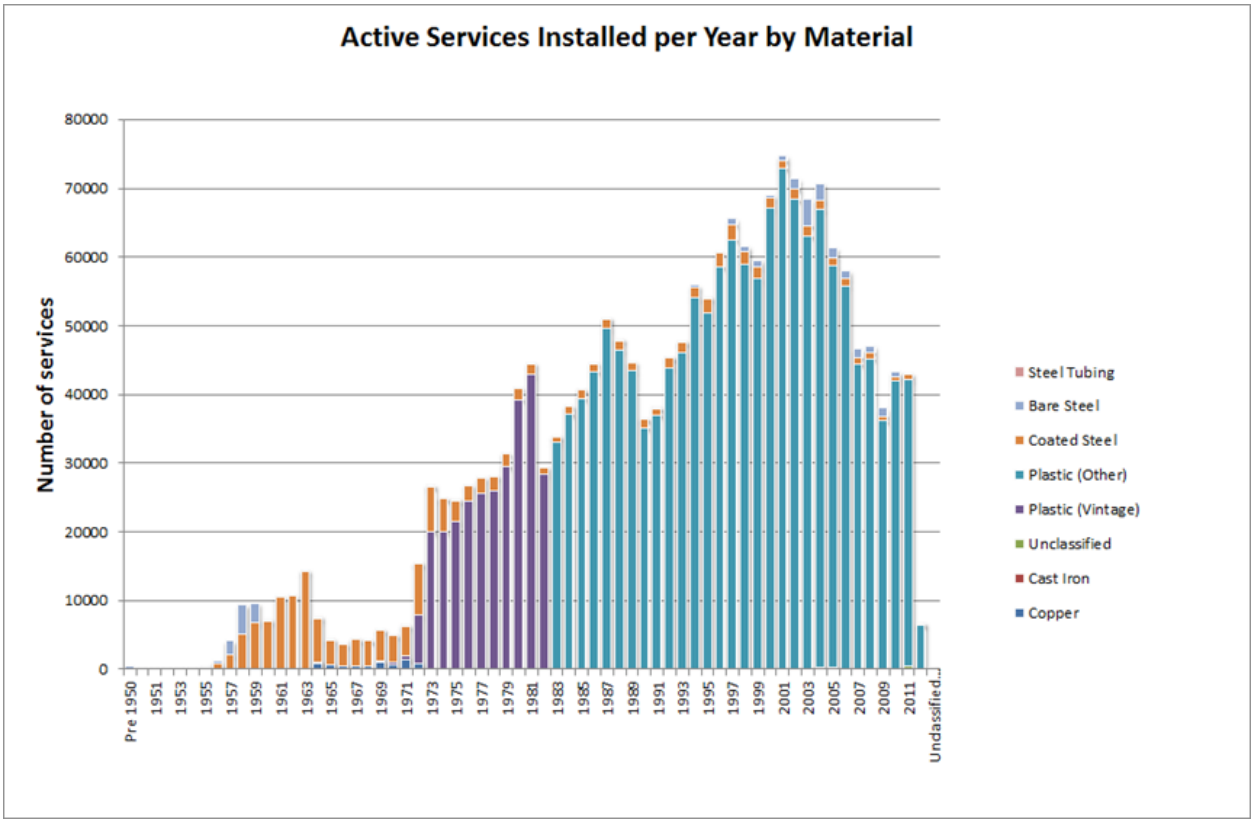


Chart 5 - Active Services Installed by Year by Material

Main and Station Valves

There are approximately 34,000 active main and station valves across the franchise area. Approximately 95% of these valves are steel, with the remaining 5% being plastic. These valves are located in system pressure regulating facilities, in-line in mains, as well as at customer sales stations. Similar to mains and services, there are several generations or distributions of valves as depicted in the chart below.

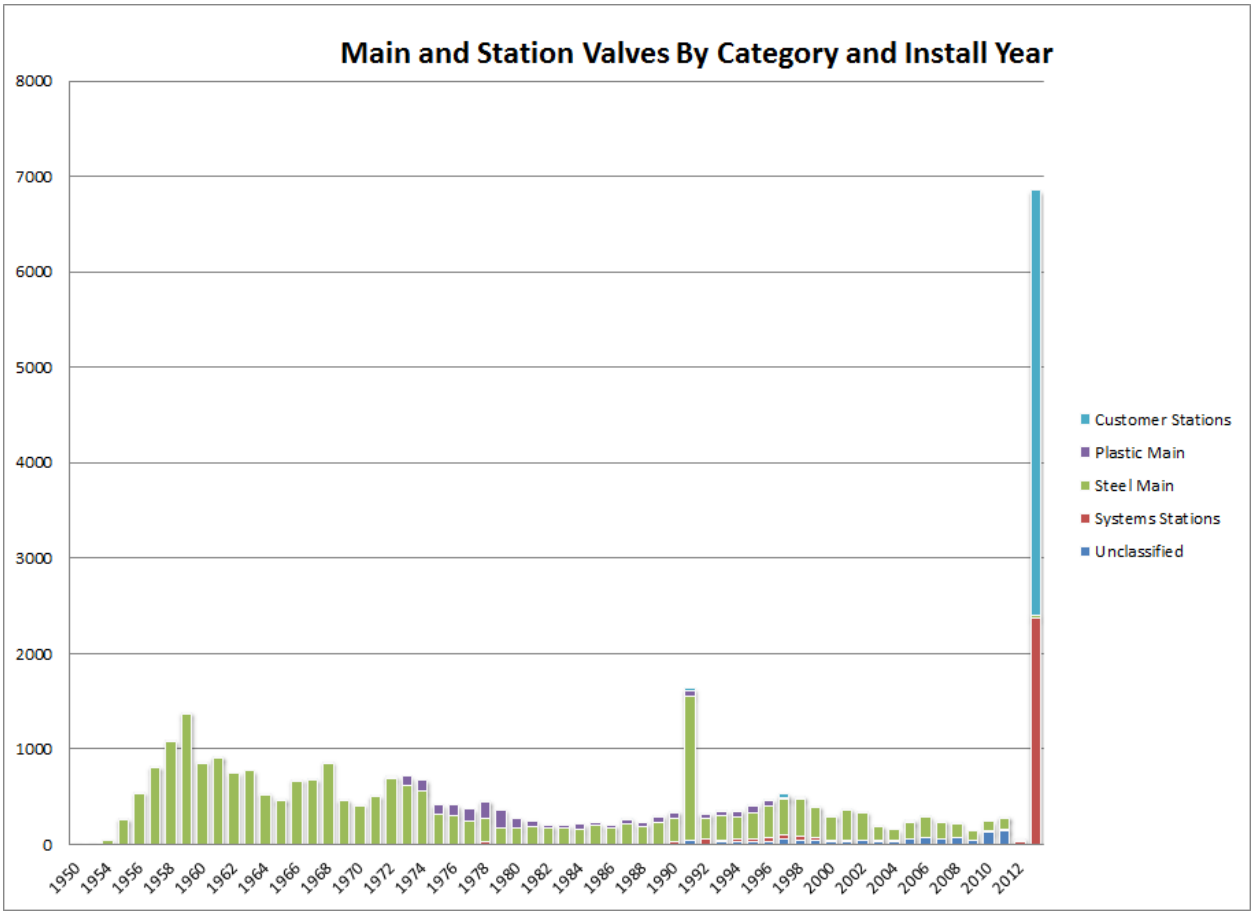


Chart 6 - Main and Station Valves by Category and Install Year

4. EGD's Asset Management Principles

As part of EGD's Asset Management System, several guiding principles have been developed. The principles are expressed as Objectives, Policies, and Strategies. These principles have been used to guide the development of the Asset Plan, more specifically with respect to the identification of requirements, their prioritization, and definition of plans to address requirements.

- Asset Management Objectives help align asset investments with the Company's strategic priorities
- Policies define the key considerations that should apply to ensure the effective management of the Company's assets
- Strategies define the high level approach to meet the Asset Management Objectives, consistent with the Asset Management Policies

4.1 Asset Management Objectives

The overall purpose of EGD's Asset Management System is to optimize the long term value of its distribution assets by achieving an effective balance of Risk, Operational Performance and Cost.

The specific objectives are:

- Safety : Continue to drive to zero incidents and property damage
- Reliability : Proactively identify and address asset related risks that can result in disruption of gas distribution service to customers
- Growth: Expand the distribution system to meet the growth in EGD's customer base in a sustainable manner
- Cost Effectiveness : Make prudent asset investment decisions while being mindful of rate payer impacts
- Environmental stewardship : Effectively manage the lifecycle of the Company's assets to reduce their environmental impact
- Compliance : Meet all applicable industry and regulatory requirements related to management of assets

4.2 Asset Management Policies

Enbridge Gas Distribution is committed to the safe, reliable, cost effective and environmentally responsible provision of gas distribution and services. At the core of this commitment is the effective stewardship of the company's distribution assets. It is through these assets that the company ultimately provides value to all of its stakeholders.

The following are policies that EGD has established to effectively manage its distribution assets:

1. The Company shall use the Asset Manager – System Operator model as the fundamental organizational construct to manage and operate its assets. This model provides a clear separation of accountabilities such that the Asset Manager is primarily responsible for decisions related to asset investments, while the System Operator executes building and operating the assets in the most efficient manner
2. The Company is committed to making all asset-related decisions on the basis of striving to achieve the appropriate balance of Risk, Operational Performance and Cost
3. The Company is committed to the regular assessment of risks associated with its assets, and ensuring that these risks are effectively managed
4. The Company acknowledges that asset information is critical to the effective management of its assets. Therefore, the organization shall ensure that its processes, systems and controls collectively strive to deliver complete, timely, accurate, verifiable and accessible asset information
5. The Company shall have an Asset Plan that is consistent with its key priorities. This plan will be reviewed, revised and ratified on an annual basis
6. The Company is committed to managing every stage in the lifecycle of its assets in compliance with all applicable laws and regulations, industry codes of practice, and internal company policies

4.3 Asset Management Strategies

The following table summarizes the high level strategies that have been developed by Management to address the asset requirements included in this Asset Plan.

Type of Investment	Strategies
Customer Additions	• The strategy for customer additions is to add all customers in existing and new communities that meet feasibility guidelines
Reinforcements	• Reinforce existing distribution assets to ensure that the system has the capacity to reliably meet current and future customer load demand • Ensure security of supply by enhancing the flexibility of the system to address disruptions in upstream supply or failures with major components of the system
System Integrity & Reliability	• Replace existing assets that are near the end of their useful life • Conduct studies to improve understanding of the condition of specific classes of assets where risks have been identified. Leverage these studies to develop mitigation plans, including risk prioritized replacement, repair or monitoring programs • Comply with all applicable rules and regulations related to system integrity and safety • Enhance the integrity of distribution asset records to reduce operational risk • Enhance our understanding of the condition of our critical assets by expanding the scope of inline inspection programs to include select XHP lines operating over 20% Specified Minimum Yield Strength (SMYS), consistent with current industry best-practices • Enhance the safety and reliability of our critical assets by verifying the Maximum Allowable Operating Pressure (MAOP) of targeted lines • Protect the distribution assets from damages through enhanced monitoring, installation of protective equipment, and the implementation of programs to address specific risks such as sewer laterals

	• Enhance the capability to effectively isolate portions of the system to minimize the impact of planned or unplanned service disruptions • Continue with existing programs already in place to address operational and asset risks and compliance requirements
Relocations	• The need to relocate EGD assets is primarily driven by external parties such as municipal authorities. EGD's strategy is to meet these relocation requirements in the most cost-effective way while recovering costs allowed by franchise and other agreements

Table 2 - Asset Management Strategies

5. Asset Management Requirements

This section of the Asset Plan defines:

- The known, and anticipated requirements related to our assets
- The approach to fulfill these requirements, consistent with the Company's Asset Management Objectives, Policies and Strategies
- Estimates of the financial investments needed to meet these requirements

5.1 Overview of Requirements

The following diagram depicts the four primary types of asset-related capital investments that are required over the term of the asset plan.

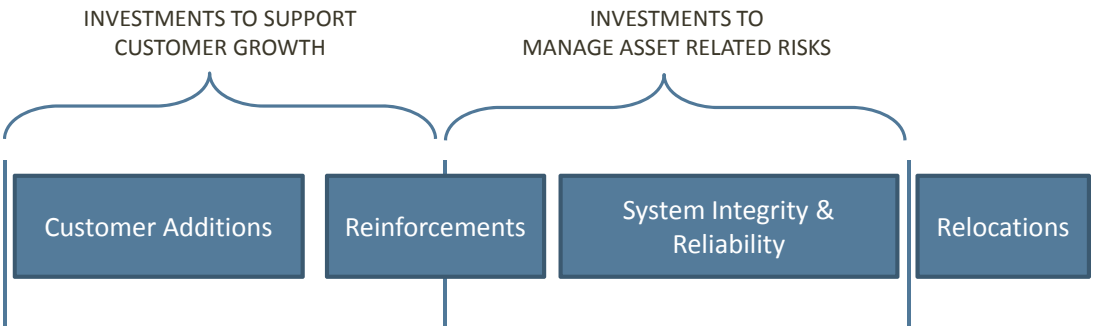


Figure 4 - Types of Asset Related Capital Investments

Customer Additions:

EGD is obligated to meet its customer growth demand by attaching customers that meet feasibility guidelines. Each year, there are several thousand Customer Addition projects that accomplish this. Customer Addition projects typically involve installing new segments of mains, installing services, and related meter sets.

In some cases, new Measurement & Regulation equipment such as stations need to be added or existing equipment needs to be upgraded due to increased loads.

Reinforcements:

Reinforcements increase the capacity and operating flexibility of the distribution system. They primarily refer to Mains. These projects are driven by Customer Growth and/or System Integrity & Reliability requirements.

System Integrity & Reliability:

In order to ensure safety and reliability, assets need to be effectively monitored, and risks need to be addressed in a proactive manner. There are a number of programs currently in place that address known risks. As new risks are identified, existing programs may need to be amended, or new programs may need to be established. Before amending existing programs or establishing new programs, studies are necessary to validate the requirements.

Relocations:

Distribution assets generally need to be relocated for reasons such as road-widening and other municipal or third party construction projects. The requirement and timing for these Relocation projects are primarily driven by municipal authorities. EGD recovers a portion of the capital investments for such projects.

5.2 Customer Additions

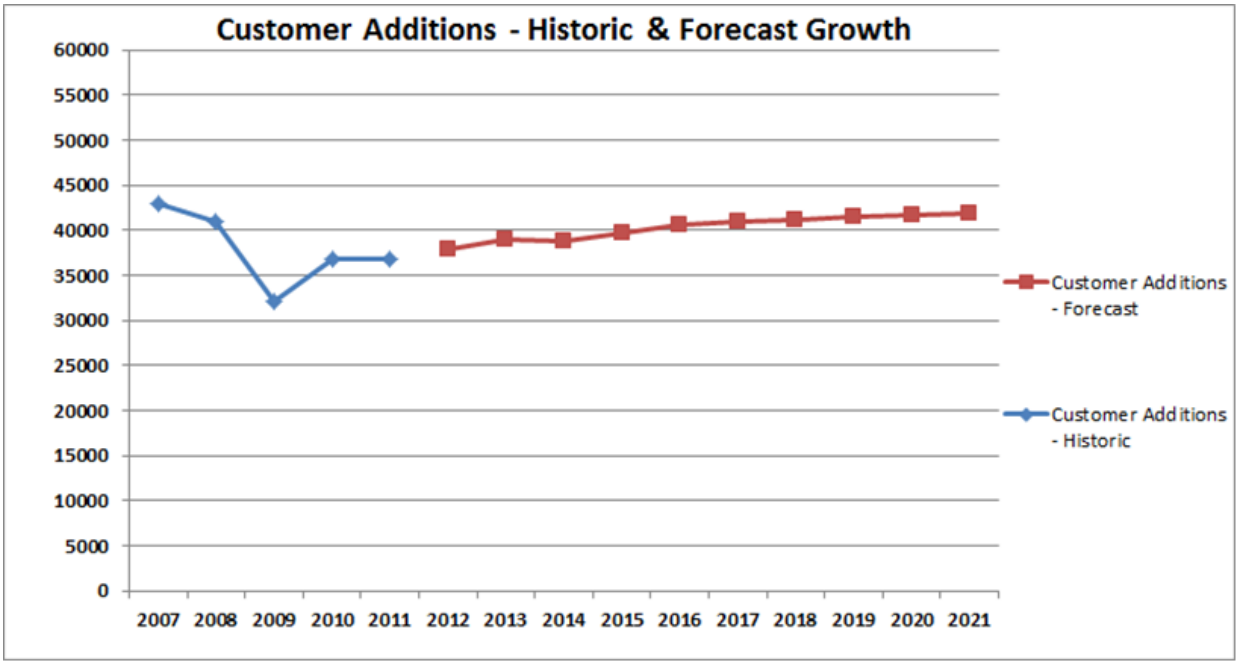
Requirements

EGD has experienced significant customer growth in its franchise area. This growth is expected to continue in the future.

The customer additions forecast at EGD is developed using a number of information sources:

1. Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
2. Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment, and mortgage rates
3. Projections developed by external consultants specializing in population growth forecasting, as well as municipality long term plans

The following chart depicts the historic customer additions and the forecast for the term of the Asset Plan.



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
42920	41052	32089	36902	36753	37927	38896	38725	39752	40540	41014	41236	41483	41760	41882

Chart 7 - Customer Additions: Historic & Forecast Growth

The pace of customer growth is expected to continue from 2012 to 2021.

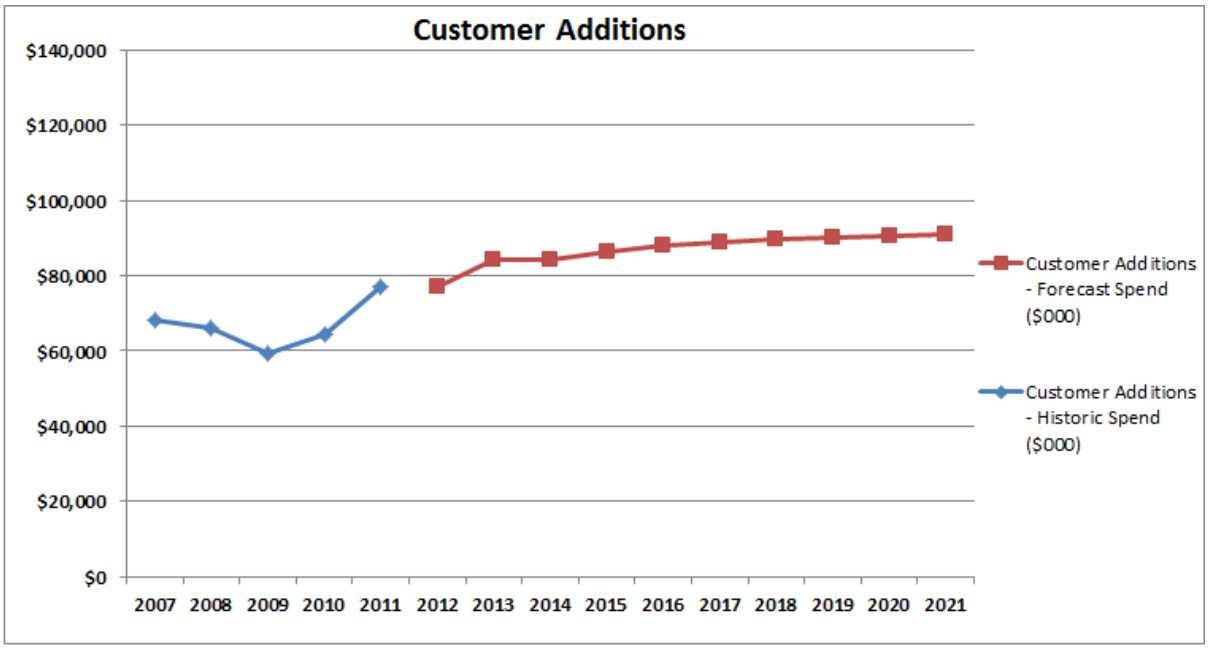
- The majority of these customer additions will be for new residential customers in existing communities
- Toronto (Area 10) will see approx. 10% of the annual customer additions. The Niagara region (Area 80) is expected to see the smallest share of these customer additions – under 3%. The Ottawa region (Area 60) will see approximately 20%. Over 60% of the new customer additions are expected to take place in the GTA, representing Areas 20, 30, 40 and 50. This in turn will inform when and where reinforcements to the system may be required

Implementation Plan & Estimated Capital Investments

Generally, there are three components of capital investments needed to support the customer additions requirements:

- Installation costs related to Mains, Services and Meters
- Material costs related to Mains, Services and Meters
- Cost related to Measurement & Regulation equipment required to support customer growth

The following chart depicts the historic capital spend on customer additions and the forecast spend for 2012-2021 based on the customer addition forecast numbers.



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
$68,323	$66,132	$59,257	$64,226	$77,116	$76,982	$84,413	$84,036	$86,264	$87,974	$89,003	$89,485	$90,021	$90,622	$90,887

Chart 8 - Customer Additions: Historic & Forecast Capital Spend

5.3 Reinforcements

Requirements

Reinforcement requirements are primarily driven by Customer Growth and System Integrity & Reliability considerations.

As part of the Asset Planning process, network analysis is performed to establish the need and timing for reinforcements within each of the operating areas that make up EGD's franchise area as defined in Section 3.2 - Geographic Distribution of Assets.

Routine Reinforcements:

Reinforcements to the distribution system are required to ensure that the system can continue to reliably deliver the gas load required by existing and new customers.

The basic objective at EGD for network design is that the system must meet anticipated peak demand at a temperature-dependent design condition. All load additions to the system are modeled based on this design temperature.

To determine the timing of the necessary reinforcements, yearly load additions are modeled by geographical area. Reinforcements are specified based on the system's ability to meet minimum system pressures at key control locations. The ultimate design is based on a minimum of 10 years of customer growth with due consideration given to 20 years of growth, security of supply, and operational flexibility.

This analysis yields the specific reinforcement projects in the following table. In addition, other reinforcements that have not been previously identified will be required from time to time. A provision has been made in the implementation plan to account for these.

The following is a summary of the known requirements by area as of December 2011.

AREA	PROJECT DESCRIPTION
Area 10	4.2 km of HP on Bathurst from Steeles to Sheppard & 3.5 km E on Sheppard to Bayview plus a new HP to IP District Station
	4.0 km of NPS 12" HP from Node 1802294 to 1802241 to 1801503, On Oriole from Roselawn to Kilbarry to Roxborough
	4.5 km of NPS 12" HP from Node 1803252 to 1890057, On Spadina from MacPherson to Lakeshore
	3.5 km of NPS 16" HP Steel Main from New Bayview Station to existing NPS 24" HP Main at Avenue /McPherson
	2.5 km of NPS 16" HP from Node 1803363 to 1900043 from Victoria Park on Dawes to Woodbine & Strathmore
Area 20	Install approximately 2500m of 4" XHP on Mayfield east to Airport Rd
	Install approximately 1000m of NPS 6 ST HP on Hurontario from Steeles to County Court
	Install approx 5 km of NPS 8 XHP from the newly elevated Bondhead line northbound to increase the pressure in Dundalk and Shelburne
	Replace 1181.5m of NPS 4 with NPS 8 on Hurontario, from Steeles to County Court
	Replace 1279.9m NPS 4 with NPS 8 from 1803184 to 1802257
	Install 253.7m NPS 6 connect 21820195 to NPS 24 PineValley line (Mississauga Rd close to CNR)
Area 30	Scarborough Reinforcement - Phase 2 Station Installation
	Install 1200m NPS 12 HP main in new development to avoid construction on Steels and crossing of Rouge
	Install approximately 2000m of XHP NPS 8 ST on Carrville from Bathurst to Yonge
	Install approximately 1400m of NPS 4 ST on Keele from McNaughton to Teston
	Install 7400m of NPS 16 on Woodbine, from Victoria Square to Bloomington
	Install 1050m of NPS 4 on 6th Concession, from Silver Spring Cres to Old Stouffville Sdrd
	Install 200m of NPS 4 on Holburn, from Leslie to Woodbine
	Install 570m of NPS 8 on 16th Ave, from Granton to Spadina
	Install 1200m of NPS 8 on Hwy 7, from stn# 33027 to Woodbine
	Install 2200m of NPS 8 on 19th Ave, from 9th Line to Reesor
	Install 6500m of NPS 16 on Woodbine, from Bloomington to St. Johns Sdrd
	Install 6800m of NPS 8 on Glenwoods/Warden, from Woodbine to Bethel Sdrd

AREA	PROJECT DESCRIPTION
Area 40	Peterborough Reinforcement Phase 1 - Install approximately 1.5 km of NPS 8
	Peterborough Reinforcement Phase 2 - Install approximately 2.4 km of NPS 8 on Preston from the terminus of Phase 1 north to Mount Pleasant at Hwy 7
	Peterborough Reinforcement Phase 3 - Install 1.9 km of NPS 8 ST XHP on HWY 7 from north of Mt Pleasant to Lily Lake
	Kingston Road Reinforcement, install 2.4 km of NPS 4 ST XHP from Lakeridge to Salem with Station
	Approx 8 km NPS 12 XHP, to support OPG and Durham EFW
	Install 300m of NPS 4 ST HP on Whites from south of HWY 401 to Oklahoma Drive, Pickering
	Replace 1.8 km of NPS 12 XHP main with 1.8km of NPS 16 XHP from Oshawa gate to Conlin and Wilson
	NPS 8XHP reinforcement - Kawartha Ethanol Reinforcement - Phase 2 & 3
	Install 2.8 km of NPS 8 ST HP main from ex NPS 8 HP main on at Brock & Kingston, Pickering to Ex.NPS 6 ST HP main at Westney and Kingston Rd in Pickering
Area 50	Alliston Reinforcement, 9 km NPS 8
	Angus Reinforcement
	Alliston Reinforcement Phase 2, 1.5 km NPS 8
	Stayner Second source, NPS 4 XHP with Station
	Alliston Reinforcement Phase 3, 2.8 km NPS 8
	Install 400m of NPS 4 on Hwy 27, from Hwy 9 south, with XHP to HP station Schomberg
	Alliston Reinforcement Phase 4, 3 km NPS 6
Area 60	Approx. 900m OF NPS 8 ST XHP River Crossing @ Woodroofe & Hwy.# 16 towards River Rd
	Mitch Owens Rebuild and install 2 km NPS 4 XHP
	Ottawa Innes Road Replacement - Replace 3.0 km of NPS 8 main with NPS 12, and remove an existing system bottleneck while ensuring a mandated inspection or elimination of high stress pipeline is completed by Dec 2013
	Pressure elevate HP network 6597 feeding Richmond to XHP, approx. 5300m of NPS 4 ST
	Approx. 6700m of NPS 20 ST HP pipe from Greenbank to Rideau Heights
Area 80	Chippawa Creek Road Reinforcement, Replace approx. 400m of NPS 6 ST HP with NPS 12 ST HP

Table 3 - Routine Reinforcements

Major Reinforcements:

In addition to the routine reinforcements, from time to time major reinforcements of the extra-high pressure grid mains that form the major backbone of the distribution system are required to further support customer growth and address significant system reliability and security of supply issues. These reinforcements are characterized by their size and complexity, and do not arise as frequently as the routine reinforcements.

Analysis of the supply chain and failure risks within the supply chain has indicated the potential for significant customer outages under certain upstream and downstream upset conditions affecting areas of high population densities, including the GTA and the Ottawa region.

This has led to the identification for the need of two major reinforcements in the 10-year planning horizon of this Asset Plan:

- The GTA Project will address these concerns for the Greater Toronto Area
- The Ottawa Reinforcement will address similar concerns for the Ottawa area

While these projects have been included within this Asset Plan, further details will be provided in the Leave-To-Construct applications that will be filed for each of these projects later in 2012.

The following is a summary of the Major Reinforcements.

PROJECT	PROJECT DESCRIPTION
GTA Project	Upgrading the XHP grid system in the Greater Toronto Area to meet load growth, ensure continued reliability and enable access to lower cost natural gas supplies
Ottawa Reinforcement	Ottawa Reinforcement Pre-Engineering
	Approx. 19300m of NPS 24 ST XHP pipe from Richmond Gate Station, North easterly to Greenbank
	Ottawa Reinforcement additional construction costs

Table 4 - Major Reinforcements

Implementation Plan & Estimated Capital Investments

Based on the reinforcement requirements, an implementation schedule was developed for reinforcement projects over the term of the Asset Plan. An estimate was also developed for the capital spend required for each of the projects. The following is a summary of this schedule.

Routine Reinforcements:

AREA	PROJECT DESCRIPTION	Dates	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Forecast (2012-2021) ($000)
Area 10	4.2 km of HP on Bathurst from Steeles to Sheppard & 3.5 km E on Sheppard to Bayview plus a new HP to IP District Station	2018							A-10				$9,000
	4.0 km of NPS 12" HP from Node 1802294 to 1802241 to 1801503, On Oriole from Roselawn to Kilbarry to Roxborough	2018							A-10				$6,000
	4.5 km of NPS 12" HP from Node 1803252 to 1890057, On Spadina from MacPherson to Lakeshore	2019								A-10			$7,000
	3.5 km of NPS 16" HP Steel Main from New Bayview Station to existing NPS 24" HP Main at Avenue /McPherson	2017						A-10					$20,000
	2.5 km of NPS 16" HP from Node 1803363 to 1900043 from Victoria Park on Dawes to Woodbine & Strathmore	2019								A-10			$5,000
Area 20	Install approximately 2500m of 4" XHP on Mayfield east to Airport Rd	2012	A-20										$1,000
	Install approximately 1000m of NPS 6 ST HP on Hurontario from Steeles to County Court	2012	A-20										$750
	Install approx 5 km of NPS 8 XHP from the newly elevated Bondhead line northbound to increase the pressure in Dundalk and Shelburne	2012	A-20										$1,900
	Replace 1181.5m of NPS 4 with NPS 8 on Hurontario, from Steeles to County Court	2017						A-20					$1,000
	Replace 1279.9m NPS 4 with NPS 8 from 1803184 to 1802257	2019								A-20			$1,000
	Install 253.7m NPS 6 connect 21820195 to NPS 24 PineValley line (Mississauga Rd close to CNR)	2020									A-20		$250
Area 30	Scarborough Reinforcement - Phase 2 Station Installation	2012	A-30										$751
	Install 1200m NPS 12 HP main in new development to avoid construction on Steels and crossing of Rouge	2012	A-30										$1,000
	Install approximately 2000m of XHP NPS 8 ST on Carrville from Bathurst to Yonge	2013		A-30									$1,900
	Install approximately 1400m of NPS 4 ST on Keele from McNaughton to Teston	2012	A-30										$560
	Install 7400m of NPS 16 on Woodbine, from Victoria Square to Bloomington	2014			A-30								$15,000
	Install 1050m of NPS 4 on 6th Concession, from Silver Spring Cres to Old Stouffville Sdrd	2016					A-30						$400
	Install 200m of NPS 4 on Holburn, from Leslie to Woodbine	2017						A-30					$600
	Install 570m of NPS 8 on 16th Ave, from Granton to Spadina	2018							A-30				$600
	Install 1200m of NPS 8 on Hwy 7, from stn# 33027 to Woodbine	2018							A-30				$800
	Install 2200m of NPS 8 on 19th Ave, from 9th Line to Reesor	2018							A-30				$1,600
	Install 6500m of NPS 16 on Woodbine, from Bloomington to St. Johns Sdrd	2019								A-30			$14,000
	Install 6800m of NPS 8 on Glenwoods/Warden, from Woodbine to Bethel Sdrd	2020									A-30		$5,000

AREA	PROJECT DESCRIPTION	Dates	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Forecast (2012-2021) ($000)
Area 40	Peterborough Reinforcement Phase 1 - Install approximately 1.5 km of NPS 8	2012	A-40										$485
	Peterborough Reinforcement Phase 2 - Install approximately 2.4 km of NPS 8 on Preston from the terminus of Phase 1 north to Mount Pleasant at Hwy 7	2012	A-40										$1,900
	Peterborough Reinforcement Phase 3 - Install 1.9 km of NPS 8 ST XHP on HWY 7 from north of Mt Pleasant to Lily Lake	2014			A-40								$1,500
	Kingston Road Reinforcement, install 2.4 km of NPS 4 ST XHP from Lakeridge to Salem with Station	2013		A-40									$1,000
	Approx 8 km NPS 12 XHP, to support OPG and Durham EFW	2014			A-40								$12,000
	Install 300m of NPS 4 ST HP on Whites from south of HWY 401 to Oklahoma Drive, Pickering	2015				A-40							$200
	Replace 1.8 km of NPS 12 XHP main with 1.8km of NPS 16 XHP from Oshawa gate to Conlin and Wilson	2016					A-40						$3,500
	NPS 8XHP reinforcement - Kawartha Ethanol Reinforcement - Phase 2 & 3	2012	A-40										$2,200
	Install 2.8 km of NPS 8 ST HP main from ex NPS 8 HP main on at Brock & Kingston, Pickering to Ex.NPS 6 ST HP main at Westney and Kingston Rd in Pickering	2017						A-40					$2,500
Area 50	Alliston Reinforcement, 9 km NPS 8	2012	A-50										$4,660
	Angus Reinforcement	2012	A-50										$6,000
	Alliston Reinforcement Phase 2, 1.5 km NPS 8	2014			A-50								$1,150
	Stayner Second source, NPS 4 XHP with Station	2013		A-50									$750
	Alliston Reinforcement Phase 3, 2.8 km NPS 8	2015				A-50							$1,989
	Install 400m of NPS 4 on Hwy 27, from Hwy 9 south, with XHP to HP station Schomberg	2017						A-50					$500
	Alliston Reinforcement Phase 4, 3 km NPS 6	2019								A-50			$1,917
Area 60	Approx. 900m OF NPS 8 ST XHP River Crossing @ Woodroofe & Hwy.# 16 towards River Rd	2012	A-60										$1,600
	Mitch Owens Rebuild and install 2 km NPS 4 XHP	2012	A-60										$950
	Ottawa Innes Road Replacement - Replace 3.0 km of NPS 8 main with NPS 12, and remove an existing system bottleneck while ensuring a mandated inspection or elimination of high stress pipeline is completed by Dec 2013	2013		A-60									$6,000
	Pressure elevate HP network 6597 feeding Richmond to XHP, approx. 5300m of NPS 4 ST	2017						A-60					$200
	Approx. 6700m of NPS 20 ST HP pipe from Greenbank to Rideau Heights	2018							A-60				$10,000
Area 80	Chippawa Creek Road Reinforcement, Replace approx. 400m of NPS 6 ST HP with NPS 12 ST HP	2013		A-80									$400
Contingency for Reinforcements	Contingency to account for additional Reinforcement requirements that might come up within each year	2012-2021											$18,250

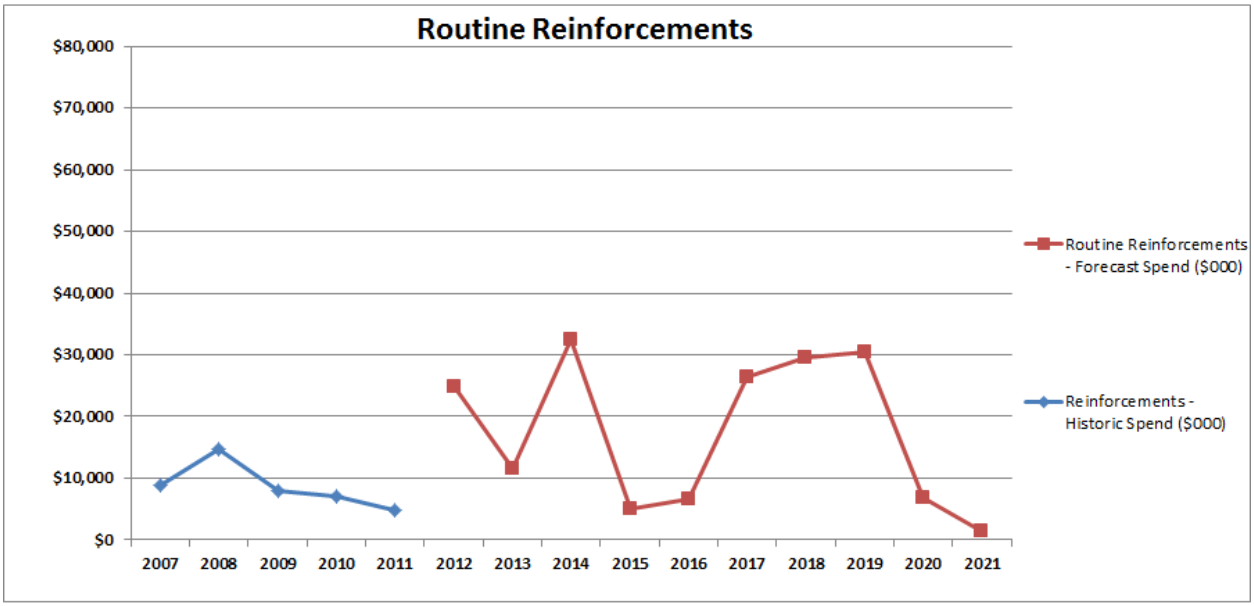
Figure 5 - Routine Reinforcements: Implementation Schedule & Cost

Major Reinforcements:

PROJECT	PROJECT DESCRIPTION	Dates	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Forecast (2012-2021) ($000)
GTA Project	Upgrading the XHP grid system in the Greater Toronto Area to meet load growth, ensure continued reliability and enable access to lower cost natural gas supplies	2012-2015	A-10										$548,144
Ottawa Reinforcement	Ottawa Reinforcement Pre-Engineering	2012	A-60										$1,500
	Approx. 19300m of NPS 24 ST XHP pipe from Richmond Gate Station, North easterly to Greenbank	2013		A-60									$30,000
	Ottawa Reinforcement additional construction costs	2014			A-60								$13,246

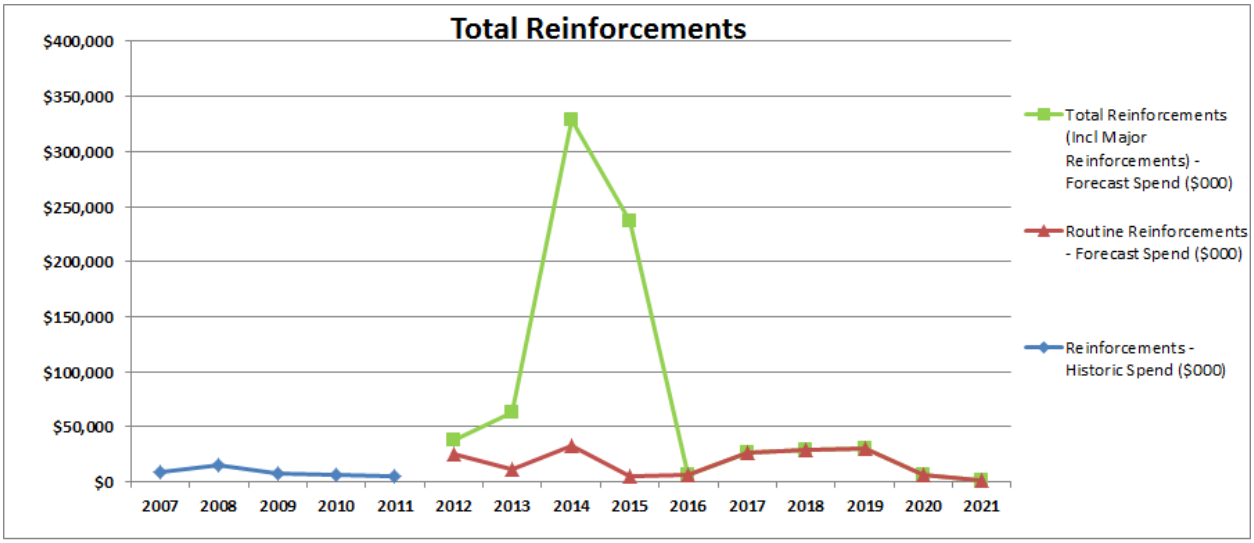
Figure 6 - Major Reinforcements: Implementation Schedule & Cost

The charts below depict the historic and forecast capital spend for routine reinforcements alone, and the total reinforcements within the term of the Asset Plan.



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
$8,795	$14,710	$8,061	$7,054	$4,742	$24,756	$11,550	$32,400	$4,939	$6,650	$26,300	$29,500	$30,417	$6,750	$1,500

Chart 9 - Routine Reinforcements: Historic & Forecast Capital Spend



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Routine Reinforcements ($000)						$24,756	$11,550	$32,400	$4,939	$6,650	$26,300	$29,500	$30,417	$6,750	$1,500
Total Reinforcements ($000)	$8,795	$14,710	$8,061	$7,054	$4,742	$37,883	$62,667	$329,146	$236,839	$6,650	$26,300	$29,500	$30,417	$6,750	$1,500

Chart 10 - Total Reinforcements: Historic & Forecast Capital Spend

At this time, the forecast of costs for the GTA project for 2014 and 2015 are still being refined, and the estimates are only available as a range. The chart above assumes the mid-point of the estimated range.

5.4 System Integrity & Reliability

The Need for Integrity Management

A critical responsibility in managing a natural gas distribution system is to understand potential threats to the safety and reliability of the system. Threats to the system can manifest risks (defined as a combination of likelihood and impact), which if not appropriately managed, can lead to serious incidents.

In general, risks associated with gas distribution assets occur when there is a loss of containment of gas from the system. Two basic characteristics of natural gas are that it is lighter than air and when it is released from containment, it will follow the path of least resistance. In most cases, a release of gas will result in the gas escaping to the atmosphere with minor consequences. However, if the gas ignites or if the release of gas follows a path of least resistance to a confined space, increasing the probability of ignition, serious consequences can result. There are several threats to a gas distribution system, such as third party damages, corrosion or degradation, equipment malfunction, etc. which can result in a loss of containment of gas from the system.

In terms of System Integrity, EGD must meet its regulatory obligation to comply with the CSA Z662 Oil and Gas Pipeline Systems standard. EGD will be required to comply with Annex N of the 2011 edition of this standard, Integrity Management Programs and Activities, when the Technical Standards and Safety Authority (TSSA) adopts the standard, likely later this year. At this time, EGD is required to comply with a form of Annex N that is included in the current standard.

The following figure depicts the requirements of Annex N. To ultimately comply with this regulation, EGD must plan, assess, act, measure and improve its management of integrity on a continuous improvement cycle.

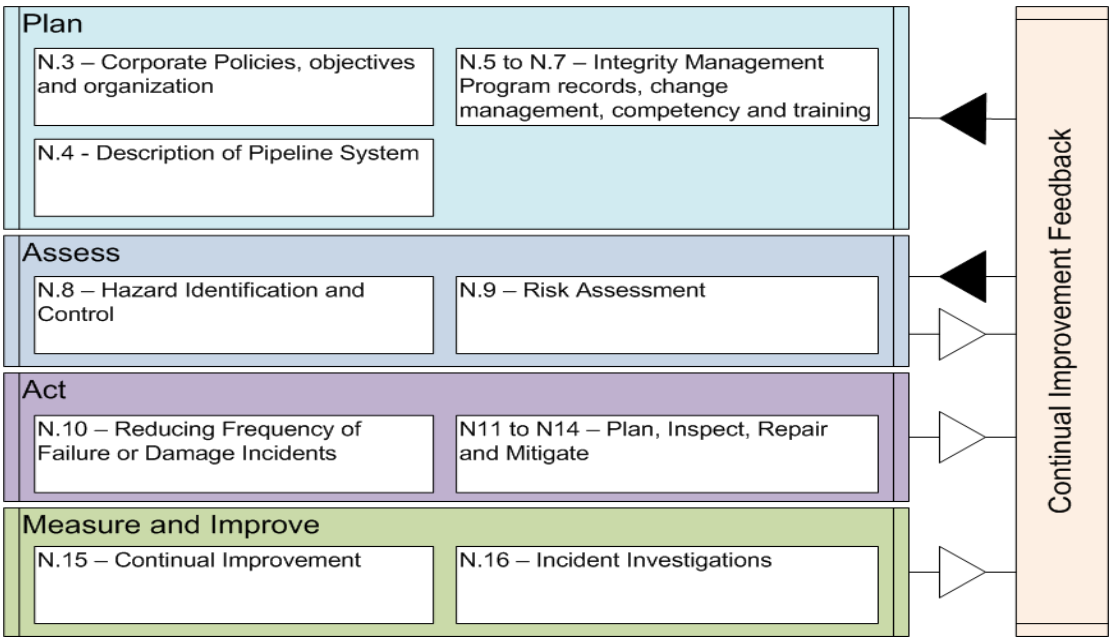


Figure 7 - Elements of CSA Z662 Annex N

In addition, recent events in the natural gas industry, such as the tragic San Bruno explosion in September 2010, the Philadelphia explosion in January 2011, and the Allentown explosion in February 2011, have resulted in increased focus on public safety. Lessons learned from these tragedies are expected to lead to changes in legislation and standards as the industry and regulators seek to minimize the chances of incidents occurring in the future.

EGD's Evolving Integrity Management Practice

Threats to the gas distribution system have existed from the inception of the industry. EGD has practiced a form of asset management to address integrity issues throughout its history. Integrity Management practices have focused on a wide variety of mitigation programs, including ongoing leak detection and damage prevention programs supported by effective emergency response processes to reactively respond to leaks and damages. In some cases, Integrity Management practices have been directed at proactively addressing specific assets that posed significant risks such as cast iron or bare steel mains and services.

In the case of cast iron, leak and failure rates due to cracking were significantly higher than with newer plastic and steel components. Assessing these risks led to a long term program to replace cast iron on a risk prioritized basis. Similarly, bare steel mains are approaching the end of their useful life due to corrosion failure. Therefore, a replacement program was also initiated

to replace EGD's bare steel mains. Both the Cast Iron and Bare Steel Main Replacement Programs are due to be completed in 2012.

Learning from these experiences and consistent with an Asset Management System approach, EGD has been working to adopt a broader risk based decision making approach to Integrity Management. This is not only consistent with a best practice industry trend, it is consistent with the evolution of regulations from a traditional "prescriptive" approach to a "goal oriented" or "risk based" approach. Annex N of CSA Z662 is an example of regulation that is evolving in this direction.

A risk based approach can be defined as a comprehensive and defensible process to identify threats, assess the potential risks from those threats, prioritize these risks and specify appropriate asset investments to mitigate likelihoods and impacts to effectively manage the risks.

The following figure is a high level representation of a risk based Integrity Management process.

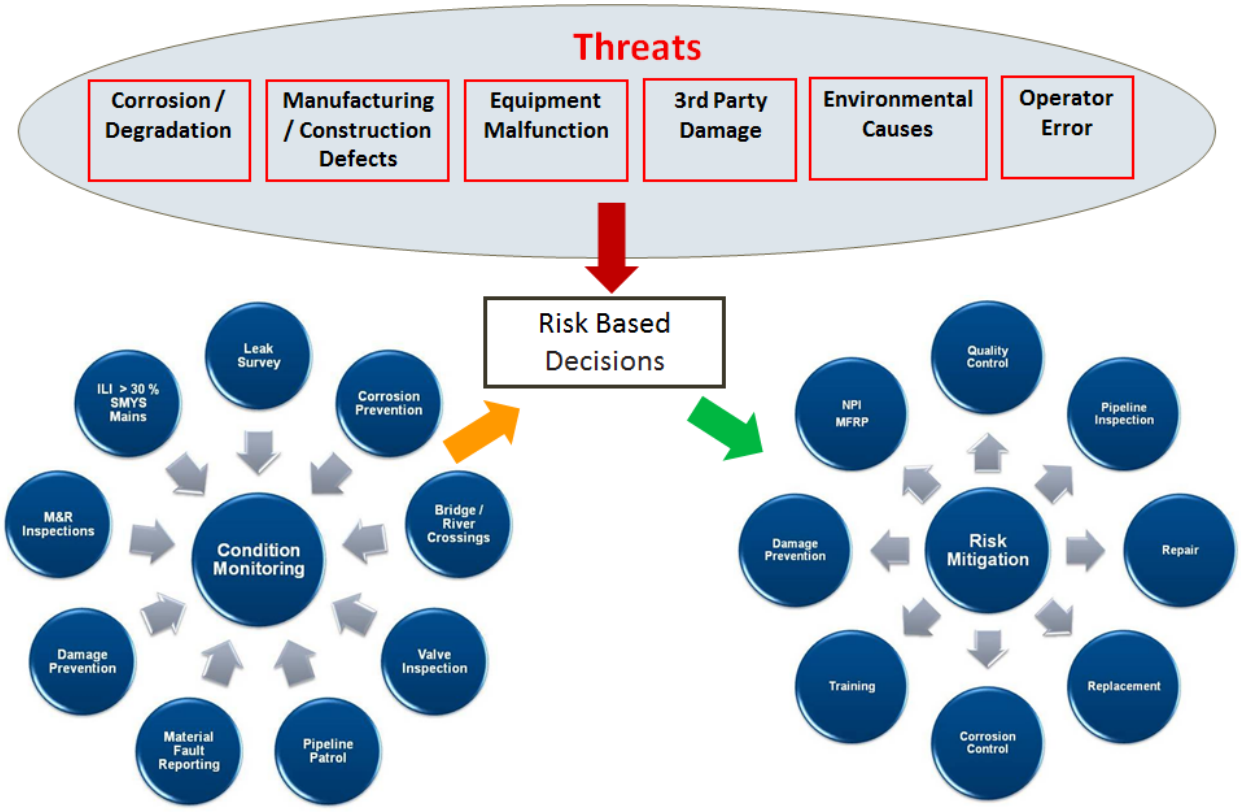


Figure 8 - Threats, Condition Monitoring and Risk Mitigation Programs

Following this risk based approach, EGD has been striving to better understand threats and related risks to the distribution system. One area of focus has been working to gain a better understanding of the condition of different classes of assets that comprise the system based on factors such as the age profile of the assets. As assets age, failure rates are anticipated to increase with the failure profile becoming more acute as the assets approach the end of their useful life. This increasing failure profile is expected to drive an increasing spend profile to maintain and ultimately replace the assets.

EGD has also been striving to improve the condition monitoring of its assets to better understand the factors that contribute to failure rates. For the past five years, since Distribution System Integrity Management Programs have been mandated through the CSA standard and the TSSA, EGD has been working to comprehensively and proactively analyze asset condition and assess which threats contribute to higher failure rates.

In the past, this form of analysis has at times been limited by the availability and completeness of the required asset information, which occurs throughout the industry. EGD continues to seek to improve its capture of asset information, which in turn continues to yield improved understanding of the condition and risks associated with the assets.

These analytical approaches are expected to play an increasing role in Integrity Management, particularly as improvements are made in gathering and correlating the required asset information. However, it is also expected that the tacit knowledge of experienced personnel will remain an important component in understanding and assessing threats and risks, prioritizing these risks and defining the mitigations needed to effectively manage these risks. Industry developments and trends will also continue to play an important role.

In summary, this evolving Integrity Management approach is intended to help ensure that EGD can continue to comply with current and future regulations and that EGD is constantly working to continue to reduce overall asset risks in a cost effective manner over time.

The development of the System Integrity and Reliability Requirements section of this Asset Plan has leveraged this Integrity Management work done to-date. It has also helped to focus these efforts and draw them together into a more formal Integrity Management process which will continue to evolve with subsequent iterations of the Asset Plan.

Theory Applied

As mentioned above, EGD has been comprehensively and proactively analyzing asset condition and failure incidents.

One trend that has been identified is the increased failure rate of a particular component, corrosion of the copper service riser immediately downstream of an AMP fitting (AMP fitting failure). A graph of the growing trend of AMP fitting failures is shown in the chart below. EGD has a Material Fault Program, under which field workers submit material failures so that the Company can physically evaluate why a component has failed through an analysis performed by EGD's Engineering Materials Evaluation Centre (EMEC). The increased trend of material faults on this asset highlighted an emerging risk. Further analysis through EGD's Work and Asset Management System identified the full scope of the issue. The red bars on the graph show the Material Fault Report submissions for AMP fitting failures. The green bars represent the failure rate as analyzed through EGD's Work and Asset Management systems.

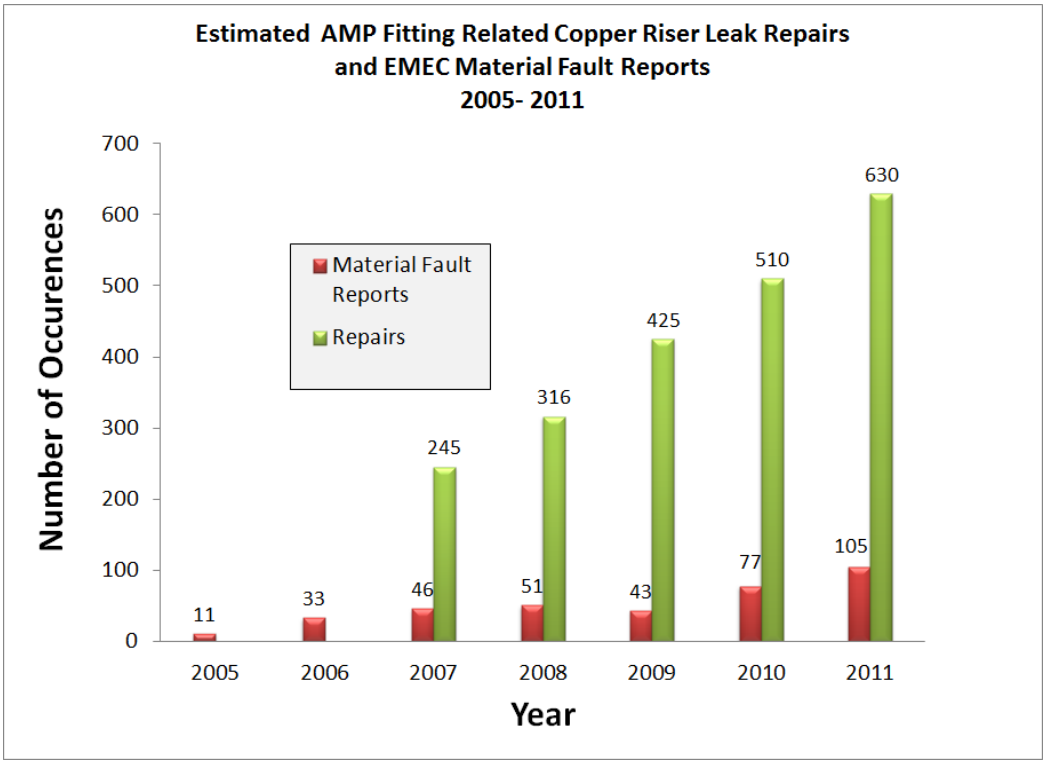


Chart 11 - Failure Analysis

Although EGD cannot predict exact future AMP fitting failure rates, the Company can predict that failures will increase over time.

Therefore, a program to mitigate failures for services that contain AMP fittings will be required going forward. This program will be designed to mitigate the risk of this failure mechanism, and

to the extent that EGD can predict which AMP fittings will fail next, a risk prioritized proactive program should be more cost effective than a reactive program.

EGD is continuing to work to understand how to predict which AMP fitting failures will occur next. In 2012, the Company plans to proactively extract physical samples in order to investigate the failure mechanisms in more detail. The outcome will provide insight into the prioritization of future replacement programs or activities.

The above failure analysis illustrates how EGD is evolving its understanding of its assets, threats to the assets, failures associated with these threats, and recommended mitigation plans.

Requirements

In applying the above Integrity Management approach, the process EGD undertook to develop the System Integrity and Reliability requirements of the Asset Plan is outlined below.

Step 1: System Integrity & Reliability asset risks were identified through three primary approaches:

- Asset condition assessment, by leveraging data gathered from EGD's operating systems and existing asset condition monitoring programs
- Tacit knowledge, gathered by engaging experienced Operations field staff to identify risks, that EGD has encountered historically
- Relevant industry developments and trends. This includes legislative and regulatory changes that are being implemented or contemplated in the United States in the wake of incidents that have occurred in the recent past as mentioned above.

The risks gathered by using these approaches were catalogued into a Risk Register.

Step 2: Risks within the Risk Register were assessed to establish a relative risk ranking.

This was accomplished by defining the risk, the current mitigation programs in place and asking a group of experienced Operational and Engineering personnel to determine the likelihood and impact of potential events based on their knowledge and experience. The following figure depicts the range of likelihood and impact that was used.

		Impact					
	Value	Minor	Moderate	Major	Severe	Worst Case	
Daily to monthly	5	P3	P2	P1	P1	P1	Likelihood
Monthly to yearly	4	P3	P2	P2	P1	P1	
Once in 1 to 10 years	3	P3	P3	P2	P2	P1	
Once in 10 to 100 years	2	P4	P3	P3	P2	P2	
Once in > 100 years	1	P4	P4	P3	P3	P3	
		1	2	3	4	5	

Figure 9 - Risk Prioritization: Likelihood & Impact Chart

The results of this qualitative risk assessment were validated with further analysis of available data.

As a result of this assessment, risks were prioritized into categories with items in the top right corner of the matrix having the greatest relative risk (Priority 1) and items in the bottom left having the least relative risk (Priority 4).

Step 3: Programs or other initiatives were defined to address each of the prioritized risks based on the Asset Management objectives, policies and strategies described in Section 4 - EGD's Asset Management Principles.

The outcome of this step was the identification of four different types of integrity initiatives to address the identified risks:

- Continuation of existing System Integrity risk mitigation programs (e.g. Cast Iron Replacement, Failure of M&R Station Components)
- Expansion of scope of existing System Integrity programs (e.g. In-Line Inspection (ILI) Scope and Technology, Damage to Non-Excess Flow Valve (EFV) Services)
- New System Integrity Programs (e.g. Corrosion Downstream of Amp Fittings)
- Studies to determine whether New System Integrity Programs are required (e.g. Field Applied Coatings on Tie-in to Steel)

The figure below provides a high-level summary of the process used to establish System Integrity and Reliability requirements.

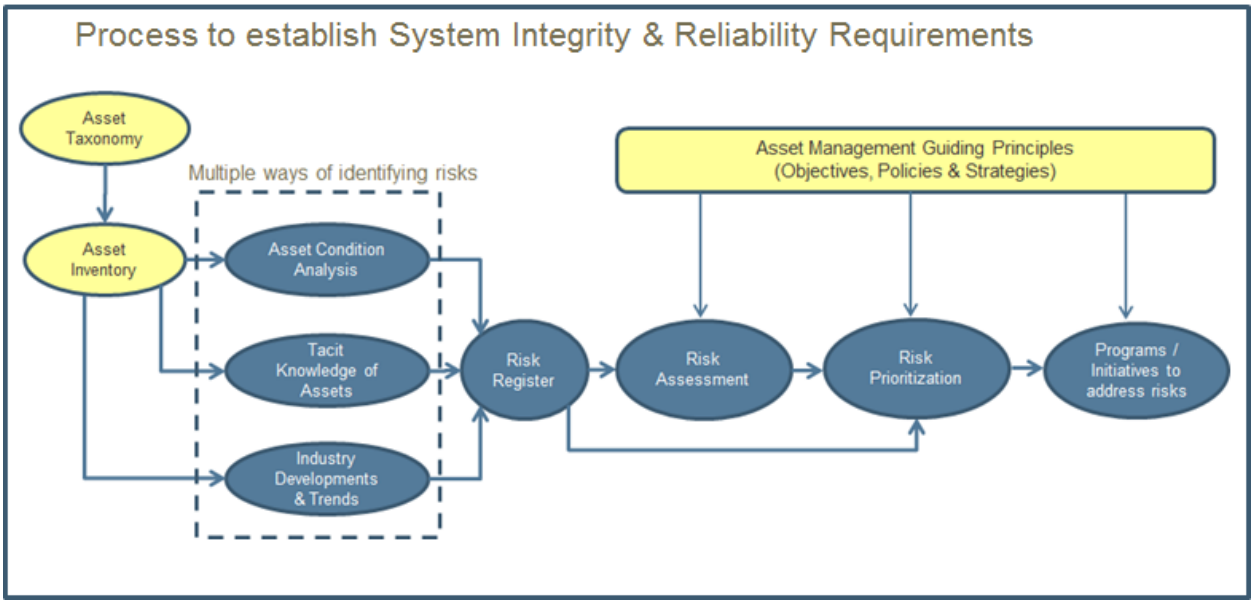


Figure 10 - Process to Establish System Integrity & Reliability Requirements

This is the first time EGD has applied the above process to support the development of a comprehensive, long range asset plan. Therefore, many of the methodologies and tools used to develop portions of the plan are first time efforts. It is expected that these methodologies and tools will be continuously improved over time with resultant improvements in future iterations of the Asset Plan.

Step 1: The Risk Register

The following table was developed through Step 1 of the process described above.

ASSET CLASS	RISK	RISK DESCRIPTION
Mains	**Cast Iron**	Cast iron mains have good corrosion resistance but the material can degrade due to graphitization. Leaks occur at main breaks or may occur at bell joints with the primary threat being ground movement by natural forces or excavation.
	Bare Steel	Bare steel mains may leak due to corrosion and cannot be effectively protected from corrosion in the same manner as coated steel.
	ILI Scope & Technology	The scope of current inspection programs consists of pipelines with operating pressures at or greater than 30% Specified Minimum Yield Strength (SMYS). Defects that are beyond the current scope and identification technology may not get identified.
	Older Coated Steel	Corrosion may occur where the coating is damaged.
	Field Applied Coatings on Tie-In to Steel	For certain field applied coatings on tie-in to steel, the coating may be disbonding from the steel pipe, leaving the area prone to corrosion.
	Plastic Mains (including Services)	Brittle like cracking has been identified by the industry in certain vintage plastic pipes. As a result, leaks may occur at stress points.
	Corrosion of Carrier Pipe in Casings	In situations where the steel carrier pipe touches the casing, cathodic protection may be compromised, possibly accelerating corrosion of the carrier pipe resulting in loss of containment.
	Reliability of Supply	Failure risk within supply chain. Potential for significant customer outages under certain upstream and downstream upset conditions.
	Don River Bridge Crossing	Extra High Pressure 30-inch line on bridge may be damaged in a flood resulting in significant customer outages.
	Corrosion of segment of the 20-inch Lakeshore line	There is a 650m segment of the line that has known coating disbondment leading to a risk of corrosion.
Services	**Corrosion on Copper Services**	Copper services were installed between the mid 1960's and early 1970's. Due to their age, these services are subject to the risk of leaks due to internal and external corrosion.
	Corrosion of Steel Tubing	Steel tubing is thin wall and can fail due to corrosion more quickly than steel pipe. It has a greater likelihood of release of gas than thicker wall steel pipe.
	Corrosion on Bare Steel Services	Bare steel services may leak due to corrosion and cannot be effectively protected from corrosion in the same manner as coated steel.
	Corrosion on Isolated Steel	Isolated steel pipe may not be cathodically protected from corrosion and therefore may be subject to accelerated corrosion.
	Damage to Non-EFV Services	Significant volume of gas may be released when a service is damaged and the service does not have an Excess Flow Valve (EFV).
M&R Equipment	**Failure of Gate Station Components**	Failure of gate station components can lead to overpressure and/or loss of containment of high pressure gas or odourant.
	Failure of District Station Components	Failure of district station components can lead to overpressure and/or loss of containment of gas.
	Failure of LP Station Components	Failure of Low Pressure (LP) station components can lead to overpressure and/or loss of containment of gas.
	Failure of Farm Tap Components	Failure of farm tap components can lead to overpressure and/or loss of containment of gas.

ASSET CLASS	RISK	RISK DESCRIPTION
Valves	**Failure of Bonnet Bolts on Valves (1.25" to 2")**	Valve malfunction due to corrosion of bolts and material brittleness may result in loss of containment of gas.
	Failure of WingLock Valves	Incorrect application of force to operate such valves can cause the internal components of the valve to break which may result in loss of containment of gas.
	Isolation Valves	Due to limited number and/or the technology associated with isolation valves, the company may be constrained when addressing an emergency related to line failure.
	Main Line Valves	Main line valves may be difficult to access or may not operate as required which may result in delay in response to an emergency.
	Load Shed Zones	Due to a limited number and/or the technology associated with isolation valves, the company may be constrained when addressing an emergency related to gas supply disruptions.
Fittings	**Corrosion downstream of AMP Fittings**	Potential for an underground gas leak to occur downstream of the AMP fitting due to corrosion of the copper risers connected to plastic services.
	Mainline Compression Couplings	Unrestrained compression couplings, when exposed at a point of thrust, can lead to loss of containment.
	Anodeless Risers	Anodeless risers were purchased to avoid the need for cathodic protection. Corrosion may be occurring where the epoxy coating may have been chipped. Exposed plastic pipe can then degrade in sunlight.
	Chicago Fittings	Potential for an above ground gas leak to occur at the Chicago fitting due to age and/or ground movement.
	Compression Outlet Service Tees	Compression outlet on a steel service connection may pull apart due to third party damage or ground movement resulting in loss of containment of gas.
	Jumpers & Service Extensions	Steel jumpers and service extensions are used to connect regulators located outside of a building to piping or meters located inside a building. The jumper or service extension may corrode if the coating is damaged leading to a loss of containment of gas.
	Punch Tee Cap	Punch Tee Cap, including vintage plastic material variety are susceptible to cracking when over-torqued during installation which may result in leaks.
	Expansion Joints	Failure of aging expansion joints, resulting in leaks.
General	**Records Integrity**	Inaccurate or incomplete records may impact operational decisions and safety.
	Cross Bores	Homeowner/Plumber/City, while attempting to clear a sewer may damage a gas line that at time of installation was inadvertently installed through a sewer lateral, resulting in loss of containment of gas.
	Meter Barriers	A lack of meter barriers in areas where meters may be susceptible to damage from vehicles may result in damage to the meter set, resulting in loss of containment of gas.
	Residential Meter Sets	Changes to requirements around meter exchange government inspections (MXGIs).
	Inside Regulators	Third party damage to a service line may result in an unregulated gas escape inside a customer premise.
	Encased Bridge Crossings	Leaks or pipe support deterioration could develop where visual inspection isn't possible.

Table 5 - Risk Register

Step 2: Relative Risk Ranking

The result of the risk assessment and prioritization from Step 2 is summarized in the table below:

	Priority 1	Priority 2	Priority 3
Mains	Cast Iron	Older Coated Steel	
	Field Applied Coating on Tie-In to Steel	Corrosion of Carrier Pipe in Casings	
	Corrosion of segment of the 20-inch Lakeshore Line	Inline Inspection Scope and Technology	
	Don River Bridge Crossing	Plastic Mains	
		Bare Steel	
Services		Corrosion on Copper Services	
		Corrosion of Steel Tubing	
		Corrosion on Bare Steel Services	
		Corrosion on Isolated Steel	
		Damage to Non-EFV Services	
M&R Equipment	Failure of Gate Station Components	Failure of Farm Tap Components	
	Failure of District Station Components		
	Failure of LP Station Components		
Valves	Isolation Valves	Failure of Bonnet Bolts on Valves (1.25" to 2")	
	Main Line Valves	Failure of WingLock Valves	
	Load Shed Zones		
Fittings	Corrosion downstream of AMP Fittings	Anodeless Risers	Expansion Joints
	Mainline Compression Couplings	Chicago Fittings	
	Compression Outlet Service Tees	Jumpers & Service Extensions	
		Punch Tee Cap	
General	Records Integrity	Inside Regulators	
	Cross Bores	Encased Bridge Crossings	
	Meter Barriers	Residential Meter Sets	

Table 6 - Risk Prioritization

Assets assessed as Priority 4 risks are considered to simply require monitoring to ensure that their risk level is not increasing.

Step 3: Programs Defined to Address Risks

As an outcome of Step 3, the following table shows the initiatives that have been established to address the risks contained in the risk register.

ASSET CLASS	RISK	INITIATIVE NAME	INITIATIVE DESCRIPTION
Mains	Cast Iron	Cast Iron Replacement Program	Complete the replacement and abandonment of all cast iron mains by 2012. Some restoration may be required in 2013.
	Bare Steel	Bare Steel Replacement Program	Complete replacement and abandonment of all bare steel mains by 2012.
	ILI Scope & Technology	ILI for pipelines over 20% SMYS	Continue the existing inline inspection (ILI) program, expand the scope to include targeted lines over 20% SMYS and include new technology ILI tools in future ILI runs.
	Older Coated Steel	Coated Steel Program (Mains & Services)	Study to evaluate the effectiveness of different manufacturer applied coatings to protect from corrosion over time in order to determine where upgrades or additional corrosion protection may be required.
	Field Applied Coatings on Tie-In to Steel	Field Applied Coatings Study	Study to understand issues with field applied coatings on tie-in to steel, and how to resolve it.
	Plastic Mains (including Services)	Plastic Mains (incl Services) Study	Study to understand plastic pipe susceptibility to cracking. Study to be done in conjunction with the Gas Technology Institute (GTI).
	Corrosion of Carrier Pipe in Casings	Casing Study & Program	Study to enhance knowledge of the effectiveness of cathodic protection of the carrier pipe in casing locations.
	Reliability of Supply	Reinforcement Projects	Projects to construct Reinforcement Mains in networks to address capacity or reliability issues.
	Don River Bridge Crossing	Don River Bridge Crossing Replacement	Determine the purpose, need and timing of a replacement solution and implement the solution.
	Corrosion of segment of the 20-inch Lakeshore line	20-Inch Lakeshore Line Replacement	Determine the purpose, need and timing of a replacement solution and implement the solution.
Services	Corrosion on Copper Services	Copper Services Replacement	Complete the current replacement program for copper services.
	Corrosion of Steel Tubing	Steel Tubing Service Replacement	Complete the current replacement program for steel tubing services.
	Corrosion on Bare Steel Services	Bare Steel Services Study	Identify locations of bare steel services not being replaced with the cast iron program in order to develop a proactive replacement program.
	Corrosion on Isolated Steel	Isolated Steel Study	Study to increase knowledge of where isolated steel pipe may occur to enhance corrosion prevention strategies.
	Damage to Non-EFV Services	EFV Program	Study and related pilot to determine how to install EFVs on pre-2006 services. Expand installation of EFVs to additional customers such as multi-family and small commercial customers.

ASSET CLASS	RISK	INITIATIVE NAME	INITIATIVE DESCRIPTION
M&R Equipment	Failure of Gate Station Components	Gate Station Equipment Replacement	Continue with existing gate station maintenance & replacement programs.
	Failure of District Station Components	District Station Equipment Replacement	Continue with existing district station maintenance & replacement programs.
	Failure of LP Station Components	Low Pressure Delivery Meter Set Program	Study to enhance the knowledge of LP station condition and prioritize related upgrades, followed by required upgrade/replacement programs.
	Failure of Farm Tap Components	Farm Tap Study	Study to determine condition of farm taps and to define program requirements if necessary.
Valves	Failure of Bonnet Bolts on Valves (1.25" to 2")	Failure of Bonnet Bolts on Valves Study	Study to determine condition of Bonnet Bolts on Valves and to define program requirements if necessary.
	Failure of WingLock Valves	WingLock Valve Study & Replacement	Study to determine the condition of WingLock valves and to define program requirements if necessary.
	Isolation Valves	Isolation Valve Study & Installation (RCV / ASV)	Study to validate the adequacy of Enbridge Gas Distribution's current main line valve design requirements and any new/retrofit installations required associated with a change in the design requirement (including automatic shutoff and remote (ASV) control valves (RCV)).
	Main Line Valves		
	Load Shed Zones		
Fittings	Corrosion downstream of AMP Fittings	AMP Fitting Replacement	Study to examine leak rate trends and develop a replacement plan, followed by execution of the replacement plan.
	Mainline Compression Couplings	Targeted Compression Couplings Pressure Containment Sleeve Program	Study to identify targeted compression couplings and to install pressure containment sleeves over these couplings.
	Anodeless Risers	Anodeless Riser Replacement	Study to better understand the nature and extent of corrosion issues associated with anodeless risers, followed by a repair/replacement program as appropriate.
	Chicago Fittings	Chicago Fitting Study	Study to determine if a proactive replacement program would be more effective than reactive repair.
	Compression Outlet Service Tees	Compression Outlet Service Tee Study	Study to identify the most effective risk mitigation and define program requirements if necessary.
	Jumpers & Service Extensions	Jumper and Service Extension Study	Study to increase knowledge regarding steel jumper and service extension condition and determine program requirements if necessary, followed by program execution. This study will be done in conjunction with the Isolated Steel study.
	Punch Tee Cap	Punch Tee Cap Program	Continue to monitor and repair as required leveraging the material fault report program and Construction and Maintenance manual.
	Expansion Joints	Expansion Joint Study	Study to determine the condition of expansion joints.

ASSET CLASS	RISK	INITIATIVE NAME	INITIATIVE DESCRIPTION
General	Records Integrity	Distribution Records Management Program	Set of projects to identify and resolve various records related issues, including clean-up of data, refinement of processes and technology changes.
		Verification of MAOP	Required to mitigate records risks via MAOP verification and resulting in-line inspections requirements.
	Cross Bores	Sewer Safety Program	Inspection and other programs to proactively identify sewer lateral risks, ensure construction practices do not create new risks, increase public awareness, and resolve instances where identified.
	Meter Barriers	Meter Barrier Study & Program	Study followed by program to install meter barriers where field conditions have changed resulting in a meter barrier being required.
	Residential Meter Sets	Residential Meter Sets Study (incl. SMART system)	Study to evaluate the application of new technologies for improved management of residential meters while addressing revised requirements for meter exchanges
	Inside Regulators	Inside Regulator Replacement	Create exterior weak link on inside regulators so that break occurs outside if external force applied to the meter set. Move inside meters outside where possible.
	Encased Bridge Crossings	Encased Bridge Crossings Study	Study to evaluate the condition of bridge crossings.

Table 7 - System Integrity & Reliability Risk Mitigation Initiatives

Implementation Plan & Estimated Capital Investments

Based on the relative risk ranking, project interdependencies and current work in progress, an implementation schedule was established for the various initiatives that are required to meet the System Integrity & Reliability requirements. The relative risk ranking identified initiatives with varying priorities from 1 to 3 which consists of continuing existing programs, expanding the scope of other existing programs, initiating new programs and conducting studies.

Risks were prioritized based on current asset condition and tacit and industry knowledge information. As more knowledge is gained through studies, certain prioritization may change. Priority 1 initiatives address high impact assets. Priority 2 and 3 initiatives include risk mitigation programs for assets whose combination of likelihood of an event and degree of impact are lower.

Consistent with the risk based approach, Priority 1 and select priority 2 initiatives are identified early in the schedule. Select Priority 2 and Priority 3 initiatives are scheduled later. Within each risk mitigation program, a second level of prioritization is applied to address higher risk assets early in each program.

Some risks identified by the process are currently not well understood. These risks require studies to further analyze and understand risk dynamics and potential mitigation strategies. In the plan, where a risk study is followed by a program, EGD has a high confidence, based on failure data and tacit knowledge, that a risk mitigation program will be required, even though the form of the program may not be fully understood. Where a risk study does not have a program illustrated beyond the study, the level of certainty that a risk mitigation program will be required is lower. The study itself may allow EGD to reduce the assessment of the risk to a lower priority.

To the extent possible, EGD has attempted to smooth the spending on the overall system integrity and reliability programs. For example, many of the programs have been defined as multi-year, long term initiatives. However, it should be noted that, due to aging infrastructure and other factors such as increased Company or industry knowledge, EGD's belief is that asset investments will require increased spending over time. It should also be noted that improved understanding of certain risks may require a higher rate of spend to stay ahead of the failure curve, and reduce risk in a more timely manner.

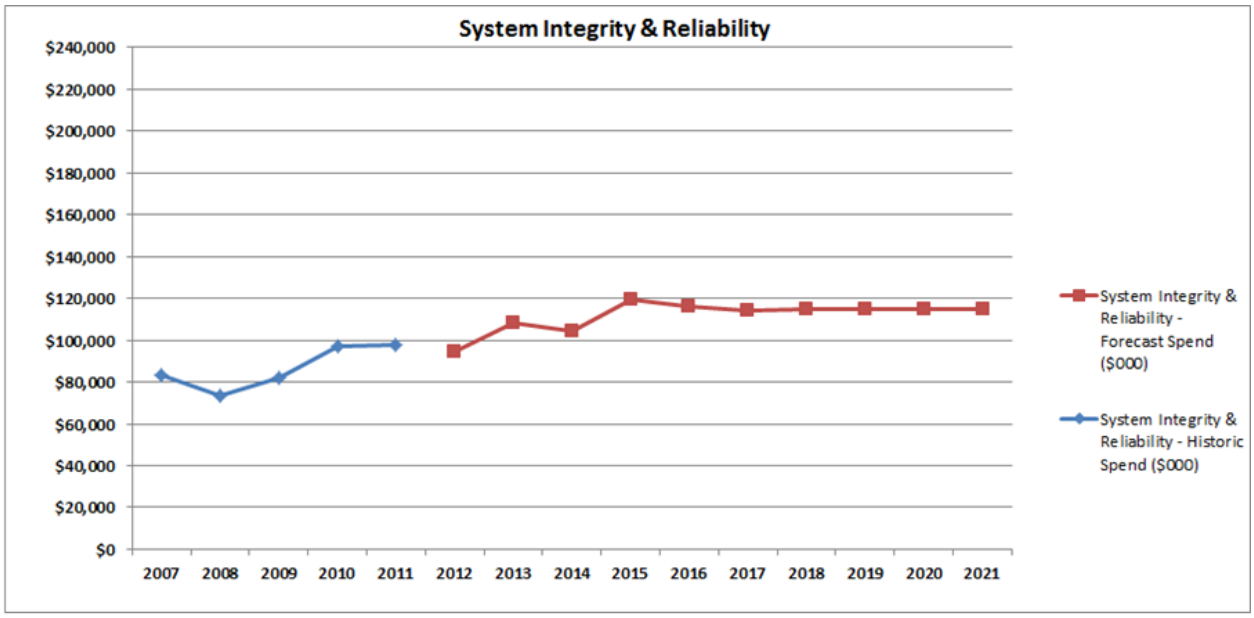
The figure below summarizes the implementation plan for the initiatives, and provides an estimate for the required capital investments over the 2012 to 2021 period.

ASSET CLASS	RISK	INITIATIVE NAME	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Forecast (2012-2021) ($000)
Mains	Cast Iron	Cast Iron Replacement Program	Prog										$26,132
	Bare Steel	Bare Steel Replacement Program	Prog										$900
	ILI Scope & Technology	ILI for pipelines over 20% SMYS	Program										$82,600
	Older Coated Steel	Coated Steel Program (Mains & Services)			Study								$720
	Field Applied Coatings on Tie-In to Steel	Field Applied Coatings Study	Study										$720
	Plastic Mains (including Services)	Plastic Mains (incl Services) Study	Study										$40
	Corrosion of Carrier Pipe in Casings	Casing Study & Program	Study		Program								$4,200
	Reliability of Supply	Reinforcement Projects											Covered as part of Reinforcements
	Don River Bridge Crossing	Don River Bridge Crossing Replacement		Prog									$3,500
	Corrosion of segment of the 20-inch Lakeshore line	20-Inch Lakeshore Line Replacement	Prog										$2,000
Services	Corrosion on Copper Services	Copper Services Replacement	Program										$15,000
	Corrosion of Steel Tubing	Steel Tubing Service Replacement	Program										$2,000
	Corrosion on Bare Steel Services	Bare Steel Services Study				Study							$200
	Corrosion on Isolated Steel	Isolated Steel Study	Study										$200
	Damage to Non-EFV Services	EFV Program		Study									$1,500
M&R Equipment	Failure of Gate Station Components	Gate Station Equipment Replacement	Program										$50,424
	Failure of District Station Components	District Station Equipment Replacement	Program										$25,013
	Failure of LP Station Components	Low Pressure Delivery Meter Set Program	Program										$95,380
	Failure of Farm Tap Components	Farm Tap Study				Study							$200

ASSET CLASS	RISK	INITIATIVE NAME	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Forecast (2012-2021) ($000)
Valves	Failure of Bonnet Bolts on Valves (1.25" to 2")	Failure of Bonnet Bolts on Valves Study					Study						$200
	Failure of WingLock Valves	WingLock Valve Study & Replacement		Study	Program								$26,300
	Isolation Valves	Isolation Valve Study & Installation (RCV / ASV)	Study	Program									$27,480
	Main Line Valves												
	Load Shed Zones												
Fittings	Corrosion downstream of AMP Fittings	AMP Fitting Replacement	Study	Program									$221,200
	Mainline Compression Couplings	Targeted Compression Couplings Pressure Containment Sleeve Program	Study	Program									$18,200
	Anodeless Risers	Anodeless Riser Replacement			Study		Program						$4,320
	Chicago Fittings	Chicago Fitting Study			Study								$200
	Compression Outlet Service Tees	Compression Outlet Service Tee Study	Study										$400
	Jumpers & Service Extensions	Jumper and Service Extension Study	Study		Program								$500
	Punch Tee Cap	Punch Tee Cap Program		Program									Covered through O&M (maintenance cost)
	Expansion Joints	Expansion Joint Study							Study				$200
General	Records Integrity	Distribution Records Management Program		Program									$59,023
		Verification of MAOP		Program									$18,300
	Cross Bores	Sewer Safety Program		Program									$8,976
	Meter Barriers	Meter Barrier Study & Program		Program									Included as part of Customer Growth related M&R
	Residential Meter Sets	Residential Meter Sets Study (incl. SMART system)			Study								$200
	Inside Regulators	Inside Regulator Replacement	Prog										$380
	Encased Bridge Crossings	Encased Bridge Crossings Study				Study							$200

Figure 11 - System Integrity & Reliability: Implementation Schedule & Cost

The following chart depicts EGD's historic and forecast capital spend for System Integrity & Reliability.



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
$83,467	$73,223	$81,905	$97,096	$97,763	$94,583	$108,041	$104,143	$119,271	$116,324	$114,427	$114,779	$114,579	$114,573	$114,554

Chart 12 - System Integrity & Reliability: Historic & Forecast Capital Spend

The forecast spend for System Integrity and Reliability trends up between 2012 and 2015 and then stays relatively flat until 2021.

There are several reasons that contribute to the upward trend in the capital spend from 2012 to 2015 :

- Beyond the existing programs to replace Cast Iron and Bare Steel, the risk assessment has identified the need to address additional classes of assets that are near the end of their useful life. Examples include Copper Services, Steel Tubing Services, AMP Fittings, and Mainline Compression Couplings
- Studies will need to be conducted to improve our understanding of the condition of specific classes of assets where risks have been identified. These studies will help establish the requirements and scope of any related mitigation programs
- Records Integrity, including completeness, accuracy, verifiability, timeliness, and accessibility, was assessed as one of the key risks. EGD has identified a number of initiatives, with significant upfront investments in 2013 and continuing investments in 2014 to 2021 to address this risk. For example, the Company is embarking on utilizing

Geospacial Positioning System (GPS) technology to more accurately identify the location of EGD's distribution assets

- Consistent with industry best-practices, EGD will expand its current in-line inspection program to include targetted XHP pipelines operating over 20% Specified Minimum Yield Strength (SMYS)
- EGD will enhance its capability to effectively isolate portions of the system to minimize the impact of planned or unplanned service disruptions by installing additional mainline valves at key locations

Many of the programs that are needed to mitigate System Integrity & Reliability risks span multiple years. An effort was made to smooth these expenses over the term of the Asset Plan.

5.5 Relocations

Requirements

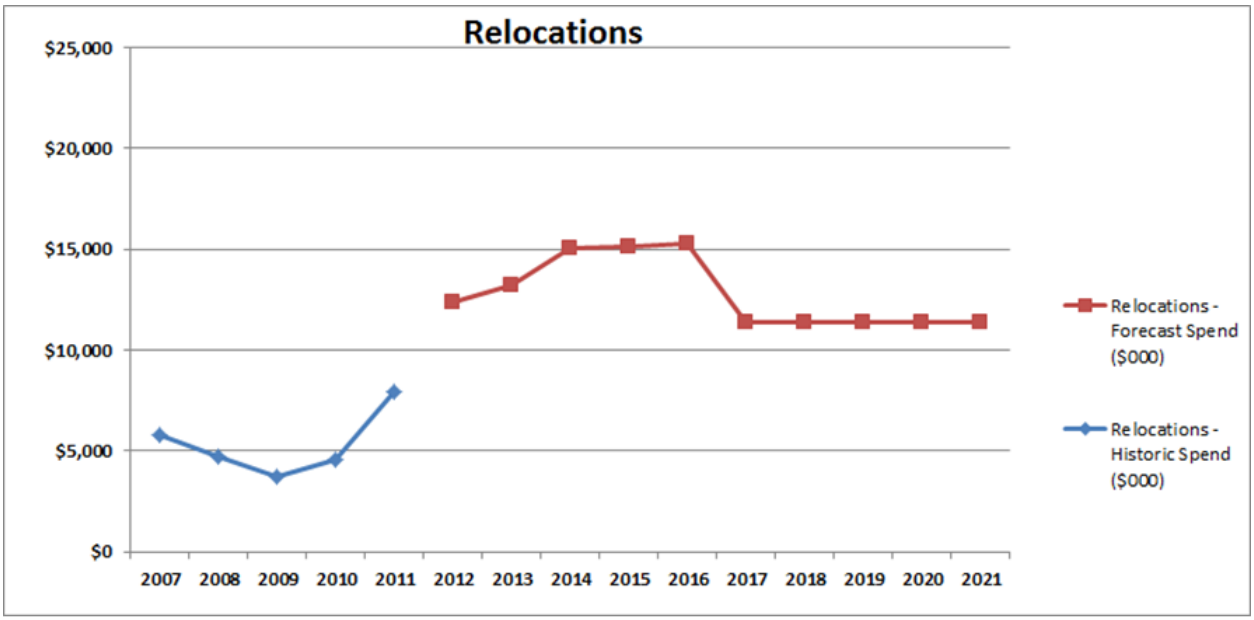
Relocation requirements are generally driven by municipal and other third party works. While some of these relocation requirements are known for the next few years, it is not possible to comprehensively forecast the future relocation requirements over the term of the Asset Plan. Hence, known future projects have to be combined with historic and projected trends to estimate the capital investments needed to support relocation requirements.

Relocation requirements primarily arise from road realignments and expansions, bridge rehabilitation, grade separations or other developments that are initiated by a city, municipality or other third party. In most cases, EGD is able to recover a portion of the relocation costs from the municipality or other party requiring the relocation.

While forecasting relocation requirements and costs, EGD takes into account the normal activity level of relocations and their associated costs. Projects or programs identified as incremental to that normal activity level are then added. Incremental activity could include items such as Infrastructure Stimulus Fund activities, major transit projects (subway expansion, GTAA Rail Link, Rapid Transit – Eglinton LRT, York Region Rapid Transit, Ottawa LRT), major road expansions (407 Extension) and preparation for the 2016 Pan Am Games.

Implementation Plan & Estimated Capital Investments

The following chart depicts the historic and forecast capital investments, net of the re-billable portion, required for relocations.



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
$5,770	$4,717	$3,749	$4,551	$7,965	$12,350	$13,209	$15,035	$15,150	$15,259	$11,400	$11,400	$11,400	$11,400	$11,400

Chart 13 - Relocations: Historic & Forecast Capital Spend

The capital spend profile shows an escalation of relocation expenditure over the period of this Asset Plan. In addition to known relocation projects in this time period, EGD expects additional relocations driven by preparations for the Pan Am games, and light rail transit and subway projects that have been planned and already under way in the GTA and Ottawa.

6. Financial Summary

The table below summarizes the forecasted capital spend profile to meet the four types of asset related requirements within the scope of the Asset Plan.

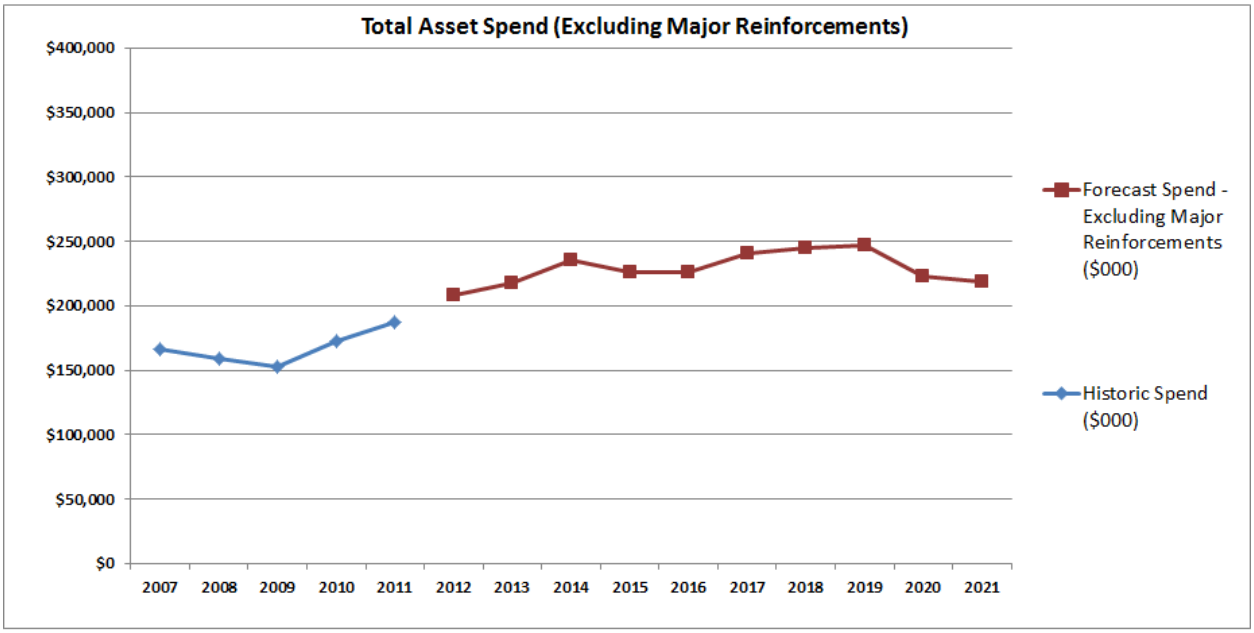
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Customer Additions ($000)	$76,982	$84,413	$84,036	$86,264	$87,974	$89,003	$89,485	$90,021	$90,622	$90,887
Relocations ($000)	$12,350	$13,209	$15,035	$15,150	$15,259	$11,400	$11,400	$11,400	$11,400	$11,400
Routine Reinforcements ($000)	$24,756	$11,550	$32,400	$4,939	$6,650	$26,300	$29,500	$30,417	$6,750	$1,500
System Integrity & Reliability ($000)	$94,583	$108,041	$104,143	$119,271	$116,324	$114,427	$114,779	$114,579	$114,573	$114,554
Total (Excluding Major Reinforcements)	**$208,671**	**$217,213**	**$235,614**	**$225,624**	**$226,207**	**$241,130**	**$245,164**	**$246,417**	**$223,345**	**$218,341**
Major Reinforcements ($000)	$13,127	$51,117	$296,746	$231,900	$0	$0	$0	$0	$0	$0
Total (Including Major Reinforcements)	**$221,798**	**$268,330**	**$532,360**	**$457,524**	**$226,207**	**$241,130**	**$245,164**	**$246,417**	**$223,345**	**$218,341**

Chart 14 - Financial Summary of Asset Spend by Category of Requirements

The following is a general set of assumptions that was used in developing these forecasts:

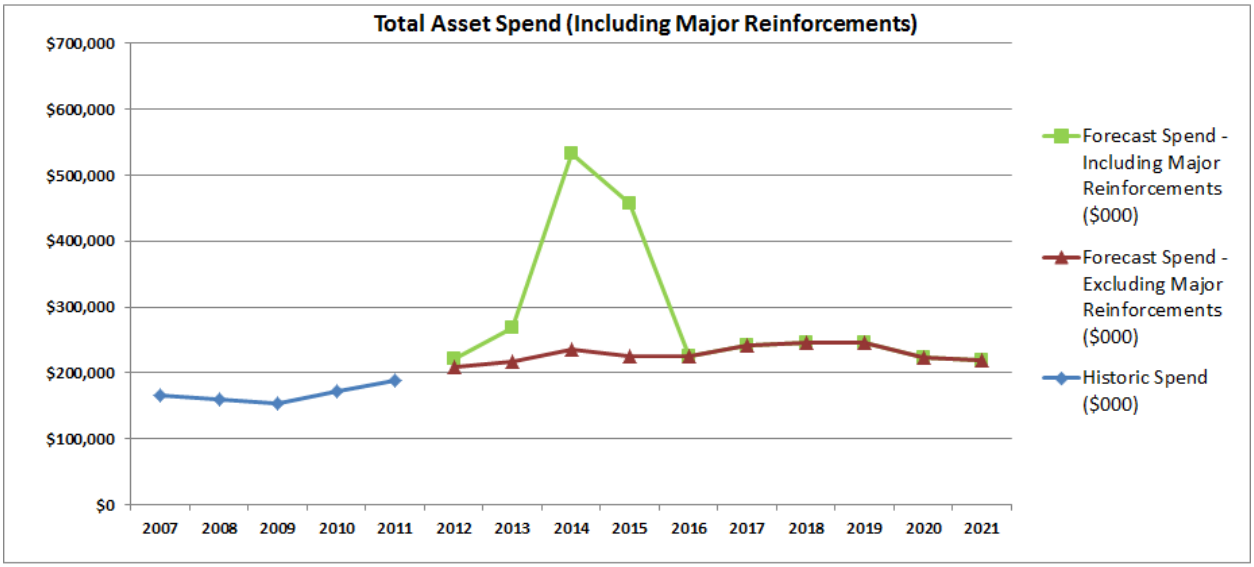
- For the term 2014-2021, the estimated capital spend is based on 2012 dollars, i.e. inflation and other time-based adjustments have not been applied
- Estimates are based on EGD's asset requirements as of December 2011. Going forward, as part of the annual Asset Planning cycle, these requirements will be reviewed and revised as needed. The capital investment profile is expected to change as the requirements evolve
- Estimates include only the direct capital costs of the projects and initiatives set out in the Asset Plan
- At this time, only a range of estimates is available for the GTA project. The mid-point of this range has been assumed for the purpose of the Asset Plan

The charts below depict the overall spend for the term of the Asset Plan excluding and including major reinforcements.



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
$166,355	$158,783	$152,971	$172,927	$187,586	$208,671	$217,213	$235,614	$225,624	$226,207	$241,130	$245,164	$246,417	$223,345	$218,341

Chart 15 - Financial Summary of Total Asset Capital Spend (Excluding Major Reinforcements)



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Excluding Major Reinforcements($000)	$166,355	$158,783	$152,971	$172,927	$187,586	$208,671	$217,213	$235,614	$225,624	$226,207	$241,130	$245,164	$246,417	$223,345	$218,341
Including Major Reinforcements($000)	$166,355	$158,783	$152,971	$172,927	$187,586	$221,798	$268,330	$532,360	$457,524	$226,207	$241,130	$245,164	$246,417	$223,345	$218,341

Chart 16 - Financial Summary of Total Asset Capital Spend (Including Major Reinforcements)

ENBRIDGE GAS DISTRIBUTION INC

INDEPENDENT EVALUATION OF THE 2013 REGULATORY COST ALLOCATION METHODOLOGY RESULTS

FINAL REPORT

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MNP

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Appendix B: EGD Service Schedules
Appendix C: MNP Interview Guides
Appendix D: MNP Individual Service Analyses
Appendix E: EGD Intercorporate Services Agreement
Appendix F: MNP Detailed ISA Review
Appendix G: MNP Curriculum Vitaes

1 EXECUTIVE SUMMARY

In the 2010 Earnings Sharing Mechanism ("ESM") proceeding, EB-2011-0008, Enbridge Gas Distribution ("EGD") agreed that as part of the evidence in support of its 2013 Application, EGD would work with a third party consultant to prepare and file an updated study addressing the costs sought to be recoverable under the Regulatory Cost Allocation Methodology ("RCAM") for future years.

EGD selected MNP to conduct an independent review of EGD's RCAM, and assess the reasonableness and appropriateness of corporate service charges calculated by the RCAM for 2012 and 2013. The foundational framework for this assessment is the Ontario Energy Board ("OEB" or "Board") Three Prong Test, which is designed for the Board to determine if the corporate shared services costs are in the public interest of ratepayers based upon the prudence of the services as a standalone utility, appropriate allocation based on cost causality and the relative benefits of the service weighed against its cost.

MNP SCOPE AND APPROACH

It was agreed by EGD that MNP would perform the following primary activities in assessing the reasonableness and appropriateness of RCAM allocations:

- Intercorporate Services Agreement ("ISA") Review.
- RCAM Methodology Review.
- Review of Recommendations from the 2007 MNP Report.
- Conduct a Three Prong Test for RCAM allocated services (Primary Services, Direct Charges and General Expenses).

MNP has based its analysis and conclusions on a combination of information sources, including the following:

- Intercorporate Services Agreement between Enbridge Inc. ("EI") and EGD.
- EGD Service Schedules and Business Cases.
- Interviews and other Direct Communications.
- Secondary Research – Market Data, Relevant External Reports.
- 2007 MNP Report.
- MNP Experience and Opinion.

KEY FINDINGS

Upon conducting its independent review, MNP made the following key findings:

RCAM METHODOLOGY REVIEW

a) The ISA is compliant with the Board's Affiliate Relationships Code ("ARC") for gas utilities as amended.
b) The RCAM Methodology remains appropriate for EGD and was adhered to in the development of allocations for 2012 (and 2013 through the escalator).
c) Further to MNP's integrity testing on a sample basis, MNP found no calculation errors with the RCAM financial model. The RCAM financial model appears to operate as expected.

COST ALLOCATION REVIEW

The review focussed on relevant services for which there were 2012 RCAM allocations, including 30 Primary Services and 6 General Expense and Direct Charge categories.

d) With consideration for exclusions and service levels required for EGD 2012 business activity, all services passed the Incurrence component of the Three Prong Test.
e) All services passed the Allocation component of the Three Prong Test for 2012.
f) All but three Primary services passed the Cost Benefit component of the Three Prong Test. The three failed Primary services included Capital Market Financing and Access, Employee Development and HRIS Program Management and Development.
g) The escalation factor selected by EGD to estimate 2013 RCAM allocation is reasonable.

In MNP's opinion, incorporating MNP proposed adjustments based on the failed Prong Three Tests, the 2012 and 2013 RCAM corporate services allocations are being incurred prudently and allocated appropriately with benefits that exceed costs for ratepayers.

RECOMMENDATIONS

ADJUSTMENTS

With the three failed Prong Three Tests, MNP proposes a consolidated downward adjustment to 2012 and 2013 RCAM allocations of $154,923 and $158,329, respectively.

IMPROVEMENT OPPORTUNITIES

Based upon observation and investigation, MNP has identified a number of opportunities to improve the RCAM process.

1. Categorize and Roll up Services for Comparison Purposes – MNP recommends that EGD categorize and roll up services to levels more consistent with reporting of other utilities for comparison purposes, and subsequently undertake a more structured benchmarking study to evaluate costs.
2. Business Case Upgrades – MNP recommends that EGD develop two specific upgrades to business cases:
    a. Criteria for External Estimates of Cost – EGD should develop and implement more refined criteria for Service Recipients to facilitate the development of cost estimates for the provision of external service.
    b. Variance Analysis – MNP feels it would be prudent to add a section to each business case to track year over year variances in allocation cost.
3. Service Level Evaluation –Leading practices in the area of procurement and vendor management suggest that the service recipient work with the provider to develop agreed-upon performance metrics using a service level agreement or other evaluation mechanism.
4. Recovery Mechanism –MNP feels it would be prudent on behalf of ratepayers to consider employing a new or existing mechanism to recover or otherwise true-up any material discrepancies based on unanticipated differences between budget and actual allocations for the budget year.

LIMITATIONS OF MNP REVIEW

- MNP's review consisted of enquiry, analytical procedures, and discussions related to information supplied to us by EI and EGD. MNP did not perform an audit of this data and did not perform a detailed examination of underlying transactions or validate source records, except where specifically noted in our approach.
- MNP did not conduct a benchmark study for the Cost/Benefit component of the Three Prong Test. Our analysis is a Fair Market Value assessment using comparative market data and MNP's expert opinion on the costs of internal and external provision of services.

2012 AND 2013 RCAM PROPOSED ALLOCATIONS

2013 RCAM - Services Review - ($)		2012 RCAM Allocation			2013 RCAM Allocation		
	Service Function	2012 Agreed under ISA	2012 Prong 3 MNP Proposed Adjustment	2012 MNP Proposed	2013 EGD Proposed	2013 Prong 3 MNP Proposed Adjustment (escalated 2012 Adjustment)	2013 MNP Proposed
1	Audit & Accounting Advice	91,270	-	91,270	93,278	-	93,278
2	Board of Directors Support	769,368	-	769,368	785,892	-	785,892
3	Business Development	736,918	-	736,918	753,039	-	753,039
4	Capital Market Financing & Access	1,020,173	(28,303)	991,870	1,042,564	(28,924)	1,013,640
5	Cash Management & Banking	481,073	-	481,073	491,656	-	491,656
6	Consolidation and Planning System Technical Support	245,089	-	245,089	249,486	-	249,486
7	Corporate Compliance	197,202	-	197,202	201,540	-	201,540
8	Employee and Labour Relations	478,201	-	478,201	488,722	-	488,722
9	Employee Development	1,260,568	(14,945)	1,245,623	1,288,299	(15,274)	1,273,025
10	Enterprise IT Program Management	868,494	-	868,494	887,579	-	887,579
11	Enterprise IT Strategy Planning & Management	624,115	-	624,115	637,845	-	637,845
12	Expense System Management & Technical Support	95,490	-	95,490	97,384	-	97,384
13	External Audit Coordination	103,399	-	103,399	105,673	-	105,673
14	Financial and Project Accounting System Technical Support	352,161	-	352,161	358,097	-	358,097
15	Government Relations	44,917	-	44,917	45,895	-	45,895
16	HRIS Program Management and Development	3,009,273	(111,675)	2,897,598	3,075,443	(114,131)	2,961,312
17	Human Resource Advice	201,779	-	201,779	206,184	-	206,184
18	Industry Relations & Corporate Social Responsibility	384,365	-	384,365	392,741	-	392,741
19	Insurance Claims Support, Strategy and Management	108,240	-	108,240	109,912	-	109,912
20	Investor Services	883,837	-	883,837	903,044	-	903,044
21	Legal Advice	514,396	-	514,396	525,600	-	525,600
22	Planning, Management, & Execution of Internal Audits	191,528	-	191,528	195,741	-	195,741
23	Portal Suite Operations and Technical Support	330,881	-	330,881	338,160	-	338,160
24	Rate Regulated Entity Support	253,904	-	253,904	259,490	-	259,490
25	Records & Information Management	538,352	-	538,352	550,195	-	550,195
26	Risk Assessment & Management	878,461	-	878,461	897,681	-	897,681
27	Strategic Planning	327,890	-	327,890	335,020	-	335,020
28	Supply Chain Management	39,706	-	39,706	40,580	-	40,580
29	Tax Reporting & Planning	55,308	-	55,308	56,525	-	56,525
30	Total Compensation & Benefits	1,781,809	-	1,781,809	1,820,969	-	1,820,969
	Primary Service Totals	16,868,167	(154,923)	16,713,244	17,234,234	(158,329)	17,075,905
31	Depreciation - Risk Management System	64,951	-	64,951	64,951	-	64,951
32	Direct EFS Charge	(2,314,784)	-	(2,314,784)	(2,314,784)	-	(2,314,784)
33	Directors Fees & Charges	744,819	-	744,819	761,205	-	761,205
34	Audit Fees	N/A	N/A	N/A	N/A	N/A	N/A
35	EGD Stock Based Compensation	7,549,229	-	7,549,229	7,715,312	-	7,715,312
36	Insurance Premiums	8,483,868	-	8,483,868	8,483,868	-	8,483,868
	Direct Charges and General Expenses Total	14,528,083		14,528,083	14,710,552	-	14,710,552
	Return on Investment	368,896		368,896	357,703	-	357,703
	Total RCAM Allocation	31,765,146	(154,923)	31,610,223	32,302,489	(158,329)	32,144,160

2 BACKGROUND

EI supplies a number of corporate services to its affiliates (one of which is EGD) and determines the respective service cost allocation amongst the service recipients using an internally developed methodology.

EI maintains a Corporate Cost Allocation Methodology ("CAM") to transfer costs to all its affiliates, including EGD, for internal management and performance measurement purposes. The RCAM has been developed to determine the cost allocations from EI to EGD for regulatory rate making purposes pursuant to filings submitted to the Board. The RCAM methodology has been developed for specific alignment with the ARC, originally issued on July 31, 1999 and last revised on November 25, 2010.

In 2006, the OEB directed EGD to retain an independent third-party to conduct an evaluation of the RCAM and the resultant shared service charges that EI allocated to EGD. EGD chose MNP as the independent evaluator for the review and analysis at that time. MNP prepared an analysis and provided recommendations of all corporate shared services between EI and EGD in 2006 using leading practices and subject matter expertise along with the OEB-defined Three Prong Test (defined in section 10.2).

EGD has asked MNP to conduct an updated review to support its 2013 Rate Application.

3 OVERVIEW & OBJECTIVES

MNP was engaged by EGD to produce this written report and act as an independent expert witness to Enbridge's 2013 Rate Application, if required.

The objective of the evaluation is to assess the appropriateness of the 2012 and 2013 allocation results generated using the RCAM methodology, which was previously approved by the Board and used to calculate the corporate service charges in the 2007 Rate Case. MNP will also undertake an independent review and determine the status of recommendations made in MNP's 2007 Independent Evaluation of Enbridge Gas Distribution Inc.'s Regulatory Corporate Cost Allocation Methodology ("2007 MNP Report"). The Study will also review any revisions or updates to RCAM subsequent to the 2007 MNP Report. This report encompasses the methodology and findings for MNP's independent evaluation.

3.1 SCOPE OF THE 2011 ENGAGEMENT

EGD and MNP determined the following analysis activities to be in scope for this evaluation:

Activity	Description
ISA Review	Determine changes to the Intercorporate Service Agreement ("ISA") between 2006 and 2012 and assess the effect of changes to the cost allocations from EI to EGD. Review for compliance with OEB's ARC.

Activity	Description
RCAM Methodology Review	Determine the changes to the RCAM between 2007 and 2012 and comment on the effect of changes to current cost allocations from EI to EGD. Review the model for operational integrity.
Recommendations from 2006 Report	Review the recommendations made by MNP in the 2007 Report and comment on the status of implementation of the recommendations.
OEB Directives	Conduct a review of OEB directives to identify applicable decisions and directives related to EGD or other affiliates regulatory cost allocations.
Primary Service Analysis	Conduct an analysis (including a Three Prong Test) on all Primary Services cost allocations from EI to EGD.
Direct Charge and General Expense Analysis	Conduct an analysis (including the Three Prong Test) on 6 General Expenses and Direct Charges that have cost allocations from EI to EGD.
Return on Investment Analysis	Review the cost allocation to ensure compliance with the ARC.

The scope of the Project as agreed within MNP's Consulting Agreement with EGD may be found in Appendix A.

4 STAKEHOLDERS

In the 2006, OEB directed EGD to conduct an independent assessment and perform a prescribed level of stakeholder engagement[1]. EGD has also conducted annual corporate cost allocation consultative sessions with Intervenors pursuant to the Supplementary Settlement Proposal appended to Decision with Reasons EB-2006-0034 of May 20, 2008. While there was no such directive from the OEB for this engagement, EGD and Intervenors agreed an updated study would be prepared.

In order to understand and respond to any questions or concerns relating to the terms of reference for this Study, MNP met with Intervenors and EGD on January 31, 2012. Several concerns were raised by the Intervenor group, including escalating year over year allocations and the integrity and operation of the RCAM financial model. Pursuant to this meeting, MNP expanded the scope of its RCAM financial model review to provide a level of assurance in its estimation commensurate with Intervenor concerns. Year over year escalations are also considered in this Study.

The stakeholder process also included distribution of a draft of this Report to the Intervenor group for review, and a subsequent meeting for discussion. This additional meeting allowed MNP the opportunity to further consider Intervenor questions or concerns prior to finalization of the Report.

[1] Decision with Reasons, EB 2005-0001, February 9, 2006.

4.1 KEY STAKEHOLDERS

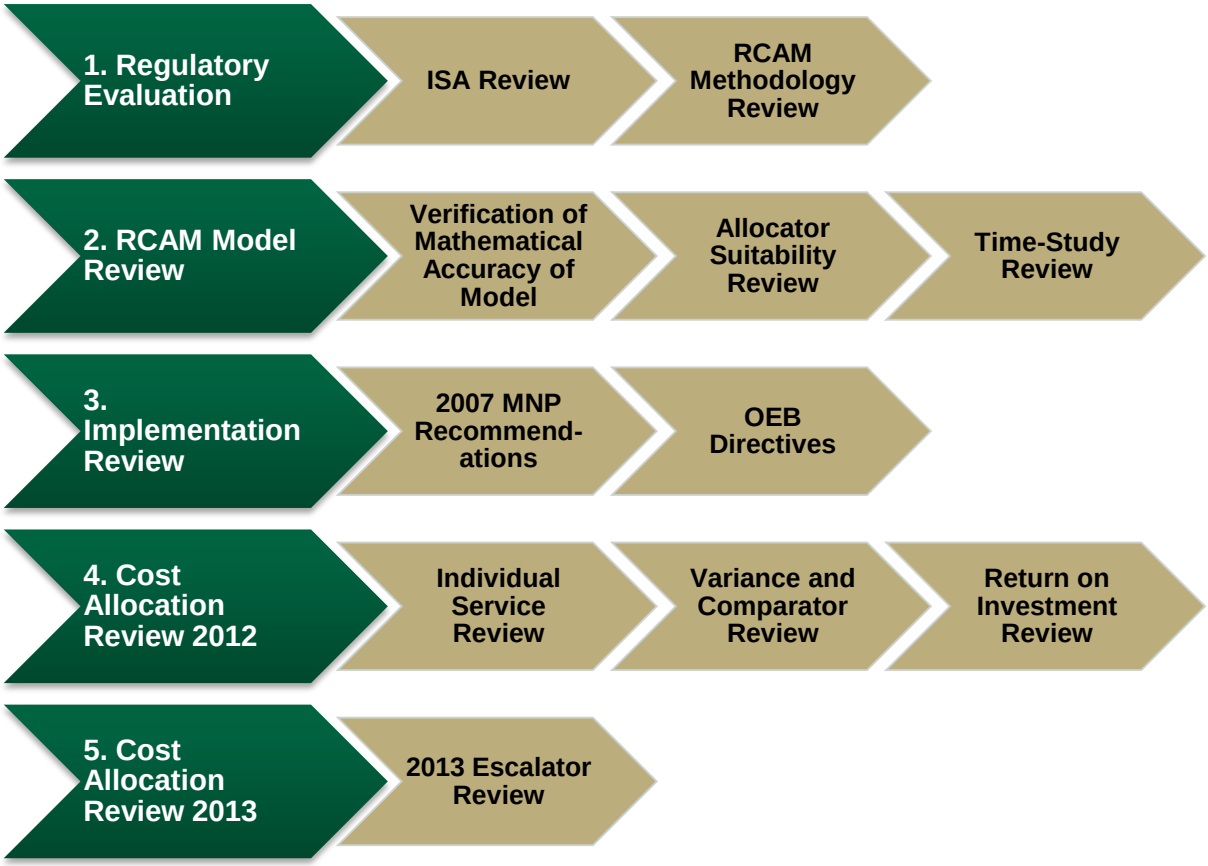
Stakeholder Group	Role	Interest
Enbridge Gas Distribution Inc.	• Regulated Entity and Project Sponsor. • 'Service Recipient' of EI corporate services. • Management of operations and delivery of customer service. • Interview participant. • EI budget review.	• Satisfy ARC requirements. • Appropriate application of RCAM process with EI. • Accuracy and completeness of shared services allocations.
Enbridge Inc.	• Corporate services 'Service Provider' to EGD. • Custodian of CAM and RCAM model. • RCAM subject matter expert and source of RCAM knowledge to project team. • Interview participant. • Preparation of budget.	• Appropriate application of RCAM process with EGD. • Accuracy and completeness of shared services allocations.
Intervenor Group	• Review and comment on RCAM process, allocation results, and MNP independent evaluation.	• Represent the interests of Ontario ratepayers and ratepayer groups.
MNP LLP	• Independent evaluator.	• Independence and objectiveness of evaluation of RCAM process and cost allocations against established standards.
Ontario Energy Board	• Protect in interest of consumers in the gas distribution market. • Provides regulatory framework and oversight. • Issues regulatory Directives and Decisions.	• Ensure interests of the Ontario rate payers are protected while affording EGD an opportunity to earn an acceptable Return on Investment.
Ratepayers	• Represented by Intervenors.	• Achieve most appropriate level of service for reasonable cost.

4.2 PROJECT PARTICIPANTS

Stakeholder Group	Project Participant(s)
Enbridge Gas Distribution Inc.	Barry Yuzwa, Controller Robert Bourke, Manager Regulatory Proceedings Lee Liauw, RCAM Coordinator Robert Cappadocia, Consultant (Elenchus Research Associates)
EGD Service Recipients	Arunas Pleckaitis, VP, Business Development & Customer Strategy Debbie Boukydis, Director, Public and Government Affairs Henry Wong, Director, Information Technology Jamie Milner, VP Pipeline Integrity and Safety Marc Weil, Director, Human Resources Mark Boyce, VP, Law and Information Technology Mark Sabatini (for Glenn Beaumont), Manager, Supply Chain Narin Kishinchandani, VP, Finance
EI RCAM Coordinators	Fahreen Rattani, CAM Coordinator Jonathan Morgan, (former) RCAM Designer/Developer Ola Olatunde, RCAM Coordinator
Participating Intervenors	Roger Higgin, Vulnerable Energy Consumers Coalition Vincent DeRose, Canadian Manufacturers & Exporters Jay Shepherd, School Energy Coalition Julie Girven, Consumers Council of Canada David MacIntosh, Energy Probe Ian Mondrow, Industrial Gas Users Association
MNP LLP	Jason Hails, Engagement Leader Ysobella Phillipe, Project Manager Chris Balkaran, Core Project Team Member Khalid Abdul Razak, Core Project Team Member Arthur Kao, Core Project Team Member Various other Team Contributors

5 MNP APPROACH

MNP has structured its approach and findings into the following sequence:



6 INFORMATION SOURCES

MNP has based its analysis and conclusions on a combination of information sources, including the following:

- Intercorporate Services Agreement between EI and EGD, including EGD's Regulatory Cost Allocation Methodology (Schedule 1 to the ISA).
- EGD Regulatory Cost Allocation Methodology Service Schedules.
- EGD Business Cases.
- Primary Research – Interviews and other Direct Communications.
- Consultative sessions with Intervenors.
- Secondary Research – Market Data, Relevant External Reports.
- MNP 2007 Report "Independent Evaluation of Enbridge Gas Distribution Inc.'s Regulatory Corporate Cost Allocation Methodology – Final Report" dated February 28, 2007.
- MNP Experience and Opinion.

6.1 REGULATORY COST ALLOCATION METHODOLOGY (RCAM)

The RCAM is discussed at length in the RCAM Methodology Review Section of this report and details EGD's regulatory design objectives and principles (just and reasonable, cost of service, prudence), regulatory design features (services based approach, multi-step allocation process, service description transparency, demand pull by recipients) and cost drivers and rationale for allocation modelling.

6.2 EGD SERVICE SCHEDULES

EGD Service Schedules provide key information by service, including:

- Service description.
- Services identified by EI supporting departments, at a detailed level, with costs.
- Service recipient.
- Expected deliverables.
- Quantity and quality of service.

6.3 EGD BUSINESS CASES

Business cases prepared by EGD add context for each of the shared services, and provides MNP with EGD's documented account of key characteristics and benefits for each service. Business cases provide the following information:

- Specific service requirement for the operation of EGD.
- Itemized services/deliverables and expected service levels (quantity and quality indicators).
- Identification of EI as a sole or supplemental provider.
- Excluded services based on exclusion criteria (standardization, minding the investment, additional management layer, other).
- Existence of a reasonably competitive market for the required services.
- Estimated cost of services if acquired externally.
- Estimated cost of services if provided internally at EGD.
- Cost breakdown (direct, indirect, primary, support) of EI provided services.
- Cost benefit analysis of EI, External and EGD provision of service.

6.4 PRIMARY RESEARCH

A critical element of information gathering and analysis was the interview process with representatives the Service Recipients (EGD) and the RCAM Coordinators at both EI and EGD. The primary purpose of the Service Recipient interviews was to determine the Service Recipient's understanding of the RCAM process, the services required to manage their business and related costs. These interviews were important to determine the 'demand pull' or needs based provisioning of services, as opposed to provisioning being 'pushed' on EGD by EI.

The primary purpose of the RCAM Coordinator interviews was to verify the RCAM methodology, ascertain the services allocation process and verify the demand pull.

MNP developed interview guides to facilitate information sharing. In most cases the guides were provided to the interviewees in advance of the interview to enable the participants to provide thoughtful responses to information requests. In each interview, MNP referred to the service schedules and business cases signed off by the Service Recipient, and the interview questions were created to frame the discussion and foster open dialogue for additional context. Follow-on questions typically related to the services provided, management challenges and opportunities, business cases development, and alternative service delivery models.

Over the course of the information gathering phases, MNP conducted 8 interviews with the Service Recipients (EGD) and 4 interviews with the RCAM Coordinators (EI and EGD). Any requirement for further clarification arising from this analysis was followed-up directly with the relevant service recipients. In many cases additional supporting information was provided by the Service Recipients.

Interview question templates are included in Appendix C.

6.5 SECONDARY RESEARCH

Secondary research includes data found in the public sphere, including regulatory reports (e.g. benchmarking, shared services reports, independent assessments), applications, decisions and orders, financial data (e.g. annual reports), white papers, published articles and interviews, etc.

MNP has incorporated footnotes to cite references.

6.6 MNP EXPERIENCE AND OPINION

MNP is a Canadian Accounting, Tax and Consulting firm and has about 300 principal partners and over 1,800 staff. The MNP Consulting services group has 20 partners supported by over 110 consulting professionals. This broad team brings significant senior management and operations subject matter knowledge in finance, accounting, administration, business development, human resources, information technology and various other shared service functions. In addition, MNP has significant experience in operations and consulting for regulated energy and utilities companies.

The MNP team appointed for this assessment includes MNP's national practice leader for Energy & Utilities, and the engagement team has worked with over 20 utilities, regulators, energy related ministries and Intervenors across Canada.

This industry familiarity is augmented by direct experience with shared service allocation models. As noted, MNP was retained by Enbridge in 2006 to conduct an independent evaluation of the RCAM results for EGD's 2007 filing, so the team has the benefit of the file and its working papers for the current exercise. Additionally, the team has hands on experience working with shared services allocation models in a utility environment.

MNP has provided its expert opinion throughout this final report. Opinions have been developed based on the engagement team's experience, supported by primary and secondary research and reference materials noted above.

6.7 LIMITATIONS OF THE MNP REVIEW

As discussed above, MNP's review consisted of enquiry, analytical procedures, and discussions related to information supplied to us by EI and EGD. Given these circumstances, MNP notes the following limitations:

1. **Information Reliance on EI and EGD**
   For financial results and data specific to EI and EGD, MNP relied primarily on information provided by EI and EGD. MNP also relied on the representation of the staff, management, and executives of EI and EGD. EI and EGD therefore retain responsibility for the accuracy and completeness of the data provided.

   MNP did not:
   - Audit any of the data received.
   - Perform a detailed examination of underlying transactions or validate source records, except as specifically noted in our approach. MNP believes however that this update Study is a robust examination of 2012 and 2013 RCAM methodology and results.

2. **Not a Benchmarking Study**
   MNP did not conduct a benchmark study for the Cost/Benefit component of the Three Prong Test. By definition, a benchmark study compares very specifically defined and acquired data from a similar sample of willing participants. For this review, the cost/benefit analysis was based on comparative market data and MNP's expert opinion about the costs of internal and external provision of services.

7 ISA REVIEW

The ISA between EI and EGD presents a code of conduct for the provision of shared services and resources. MNP conducted a review of the 2011 ISA to ensure compliance with the OEB's *Affiliate Relationships Code for Gas Utilities*. The ISA included in the appendices to this report is comprised of the following:

- The main ISA agreement dated 1 January, 2011.
- Schedule 1 Regulatory Cost Allocation Methodology (revised January 2011).
- Appendix A to Schedule 1 RCAM Allocator Definitions (revised January 2011).
- Schedule 2(b) executed RCAM Confirmation Notice for 2012.
- Appendix A to Schedule 2(b) RCAM 2012 Allocations to EGD (financial tables).
- Appendix B to Schedule 2(b) RCAM Service Schedules (effective January 1, 2012).

The main agreement and schedules are included in Appendix E. MNP reviewed the agreement, the supporting schedules and appendices against industry and regulatory standards including compliance with OEB's Affiliate Relationships Code (ARC).

MNP's assessment of ISA compliance with the Affiliate Relationships Code for Gas Utilities (as revised on November 25, 2010) focused on Section 2.2.1 and 2.3 requirements (see below). Recommendations for improvement have been made for Sections 2.3.3. Please refer to Appendix F for the detailed analysis and recommendations.

MNP ISA Review Conclusion:

The ISA complies with the criteria specified in the ARC and compares favourably against industry standards.

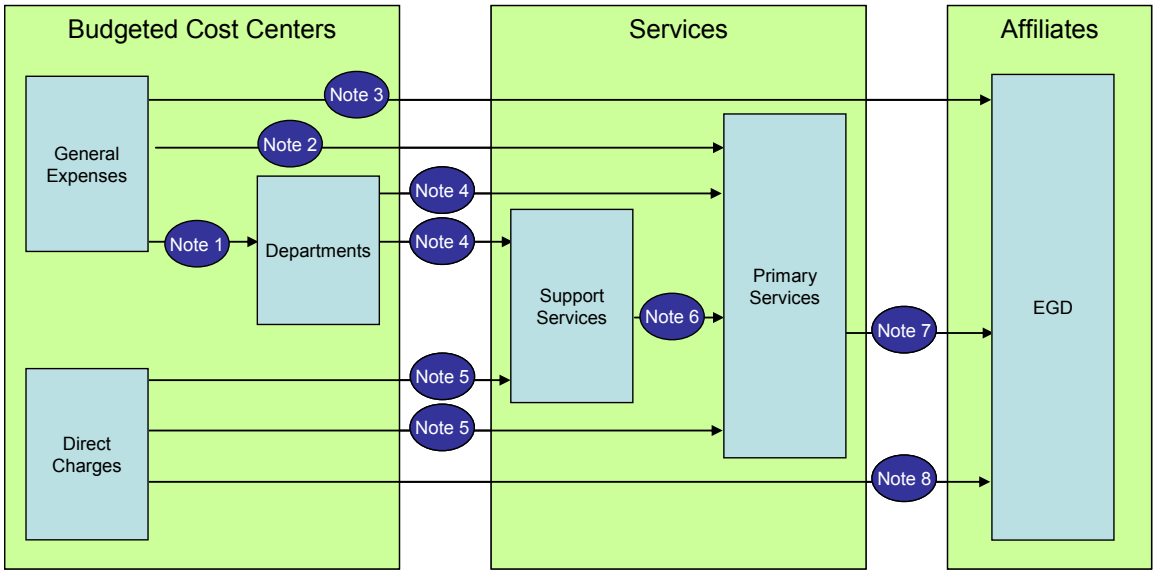
8 RCAM METHODOLOGY REVIEW

MNP understands that the Board and the stakeholder group involved with the 2007 MNP Report accepted the methodology utilized, and MNP has therefore focused its review on integrity of the various process inputs, EGD's application of the methods for 2012 and 2013, proper functioning of the model and any changes to the methodology from 2007 to the present.

8.1 RCAM OVERVIEW

The RCAM forms an integral part of the ISA between EI and EGD and is included in Appendix E to this report. The RCAM is manifested through time study and financial modeling tools. MNP reviewed the mechanics of these tools to evaluate the application of the methodology as documented in the ISA.

RCAM is a services-based approach to allocating shared corporate costs from the parent company (EI) to the affiliate (EGD). The following diagram, reproduced from Appendix E, illustrates the conceptual approach to allocating the shared corporate costs. Detailed descriptions of each step (corresponding to Notes 1 - 8) are included in Appendix E and summarized below:



Step 1, 2, 3: General Expenses are attributed to Departments, Primary Services, or directly to EGD as determined by respective benefit.

Step 4: Loaded Department costs are allocated to the relevant Primary Services or Support Services.

Step 5 and 8: Direct Charges are allocated to relevant Support Services, Primary Services, or directly to EGD.

Step 6: Support Services are allocated (loaded) to Primary Services.

Step 7: Primary Services are allocated to EGD.

8.2 SERVICE SCHEDULES AND BUSINESS CASES

To further demonstrate the cost-benefit, establish the demand-pull process for services and support the requirement of delivery of services from EI to EGD, EGD independently undertakes preparation of internal business cases for each service. The OEB's Affiliate Relationships Code for Gas Utilities, as revised November 2010, included a requirement that a business case analysis be prepared once every 5 years if a utility wishes to continue to receive services from an affiliate. However, EGD prepares business cases for all service areas on an annual basis.

The business cases are completed by the various business unit managers at EGD following revisions by Service Providers to EI's menu of service offerings entitled "RCAM Time Study Service Descriptions". The Service Recipient determines which of the EI service offerings are required, and Recipients prepare proposals for the level, type, source, description, and cost of service to be provided by EI to EGD for ultimate approval.

The business cases define the nature of the service, the source of the service, the level of the service required, estimated cost of the service and alternate methods of service acquisition and delivery. They provide estimates of provisioning options, including EGD (Internal) and External, and outline strengths and weaknesses to each provisioning option. Each business case indicates which activities the Service Recipients selects for exclusion based on exclusion criteria (beyond the scope of a utility, minding the investment or additional layers of management or other).

The business cases were used by MNP to conduct its review, as the business cases provided insight into the delivery of services from the perspective of the Service Recipients. This information was independently examined by MNP in its estimation of Fair Market Value for both internal and external provisioning estimates.

Service schedules are included in Appendix B.

MNP RCAM Methodology Conclusion:

The RCAM allocation methodology is valid and the allocating factors are reflected appropriately through the respective cost drivers.

8.3 RCAM MODEL REVIEW

MNP verified the mathematical accuracy of the RCAM, which is developed and executed on Microsoft Excel. The model verification process consisted of two tests:

1. **Structural Comparison** – A comparative analysis of the current RCAM model against the 2007 RCAM by examining formulae differences.

2. **Integrity Test** – An integrity evaluation of calculations within the current RCAM model by verifying the built-in reconciliation "checks" in the model.

Source information:

File Name	Retrieved from
2012 RCAM Allocation Model v10.xlsx	Ola Olatunde, Budget Advisor
2007 RCAM Allocation Model - Master - 11-07-06.xls	Fahreen Rattani, Advisor, Budgets and Forecasts

8.3.1 Model Review Methodology

Structural Comparison
For the structure comparison, MNP analyzed formula groups (blocks of copied formulae in a spreadsheet) for changes. Formulae within a formula group are expected to share the same structure but differ in cell references. Therefore, by using formula group comparison, MNP reduced complexity to identify changes.

Prior to the structural comparison, MNP excluded six new output worksheets that were not present in the 2007 model. Output worksheets have precedents but no dependents, therefore they did not have any effect on model operations and no analysis was required.

Using *Rainbow Analyst* spreadsheet audit software, MNP compared the models on a cell-by-cell basis through formula groups, and subsequently flagged possible changes. MNP manually reviewed the flagged changes through sampling focusing on the critical input, calculation, allocation and summary worksheets outlined in the 'Model Overview' tab, to increase the effectiveness and relevance of sampling.

Integrity Test
To ensure the validity of the calculations, the RCAM model has a series of built-in reconciliation worksheets that verify the correctness of the calculations, noting any identified discrepancies.

MNP examined the dependency links between the reconciliation worksheets and the 'Input', 'Allocation', and 'Calculation' worksheet groups. In order for the verification mechanism to be effective, reconciliation worksheets must not be dependent on the calculation being reconciled.

Furthermore, using formula error-checking, MNP inspected the formula construction within the Reconciliation worksheets to identify inconsistencies.

8.3.2 Model Review Results

Test	Result
Structural Test	MNP noted 1,025 variances in the formula groups between the 2007 and 2012 models. To further examine the differences, MNP used *Caseware IDEA*, a data analytic and audit software, to randomly sample 140 changes to account for the risk of incorrect acceptance. The risk of incorrect acceptance is defined as the risk of incorrectly inferring the number of changes found is less than an acceptable rate of changes. For this comparison, no deviations were observed in the sampled 140 changes; therefore MNP is at least 99% confident that the changes in the population do not exceed 3%. MNP manually examined the sampled cell formulae on the 2012 model. Most of the changes occurred due to departmental additions and change in constants, therefore causing the cell reference to change. MNP noted there were 20 changes in the "XII. EI SBC Detail" worksheet, resulting from a valuation methodology change. These changes were attributed to previous recommendations and the actual valuation calculation was performed outside of the model.
Integrity Test	MNP analyzed the formula references and found the worksheets to be consistent without references directly to calculation worksheets. MNP did not find any formula inconsistencies that would result in errors of calculation.

MNP Verification of Mathematical Accuracy of Model Conclusion:

The 2012 RCAM model workbook remains consistent with the 2006 version, and MNP found no calculation errors.

8.3.3 Allocator Suitability Review

MNP's consideration of the appropriateness of cost allocators was based on a detailed analysis of the RCAM model. In order to assess the overall integrity of the allocations to EGD, several sessions with the EI RCAM Coordinators responsible for managing the model were conducted to provide clarification on the allocation process. Where required, MNP requested additional data to provide context for the cost drivers, model calculations, and the mechanics of the model.

Based on its analysis, MNP found that:

- Salary-weighted time estimates were derived from individual salary grades and data gathered in the Time Studies. In addition, total loaded Primary Service costs were allocated directly to specific affiliates and, where activities benefit all affiliates, to the "All" bucket.

- The common costs related to activities attributed to "all affiliates" by the time study participants are costs that cannot be specifically attributed to an individual affiliate. In those instances, an allocator other than time, which best reflects causality, must be selected. The exception is where the time allocated to specific affiliates is a significant proportion (80% or greater) of total time allocated to the Service. In that case, the proportion of direct time is deemed a fair representation of common effort.

- Type of service determines attribution and degree of common activity. Examples of services which are comprised entirely of common activities include IT technical support services. Allocation of service provider time and related costs to "all affiliates" is appropriate due to the general nature of program support activities. In these services, system users or usage best reflect cost causality.

The use of salary-weighted time to allocate direct costs to EGD is still consistent with the OEB's directive (re: salary-weighting) and the principle of causality (time measures effort). MNP's Prong Two analysis focuses on the rationale and appropriateness of the selected allocators.

The following table summarizes the allocators used to determine EGD common charges:

Allocator	Cost Driver	Service / Direct or General Expense
FCER	Number of Meetings Company Complexity	Director Fees and Expenses
	Company Complexity	Audit & Accounting Advice
	Company Complexity	Board of Directors Support
	Financing Activity	Capital Market Financing & Access
	M&A Activity Financing Activity	Investor Services
	Entity Risk	Risk Assessment & Management
	Company & Markets Complexity	Strategic Planning
EGD % of Direct Time	Legal Entities M&A Activity Financing	Tax Reporting & Planning
	M&A Activity	Business & Economic Financial Analysis
	Cash Volume	Cash Management & Banking

Allocator	Cost Driver	Service / Direct or General Expense
	Raw Materials Volume	Gas Supply, Storage, and Transportation Strategy
ACER	Raw Material Volumes	Supply Chain Management
	Mergers & Acquisitions M&A Activity	Business Development
	Company Complexity	Corporate Compliance
	New Technologies	Emerging Energy Technology Research
	IT Programs	Enterprise IT Program Management
	IT Assets	Enterprise IT Strategy Planning & Management
	Regulations	Government Relations
	Customer Base & Public Interest	Industry Relations and Corporate Social Responsibility (CSR)
	Regulations Contracts M&A Activity	Legal Advice
System Users	Transactions Contracts Documents	Records & Information Management
	IT Asset Usage	Consolidation and Planning System Technical Support (Khalix)
	IT Asset Usage	Expense System Management & Technical Support (Oracle iExpense)
	IT Asset Usage	Financial and Project Accounting System Technical Support (Oracle)
	Portal IT Asset Usage	Portal Suite Operations and Technical Support
AHC	HRIS IT Asset Usage	HRIS Program Management and Development
	Employees Unionized Employees	Employee and Labour Relations
	Employees	Human Resource Advice
	Employees	Total Compensation and Benefits
Non-Union EFTE	Employees	Employee Development
Audit Fees*	Audit Size (hence company complexity)	External Audit Coordination
	Company Complexity	Planning, Management & Execution of Internal Audits
N/A	Regulations Company Complexity	Rate Regulated Entity Support
Insurance Premiums**	Claims Entity Risk	Insurance Claims Support, Strategy and Management
Direct	Risk	Insurance Premiums
	Usage	Direct EFS Charge (Credit)
	Usage/Transactions	Depreciation – Risk Management System
Head Count - Specific	Usage	EGD Stock Based Compensation

* Audit Fees - Percentage of EGD audit allocations of total EI Audit Fees.

** Insurance Premiums - Percentage of EGD insurance premium allocations of total EI Insurance premium budget.

Section 2.4 of Schedule 1 of the ISA details the basis of allocation and cost drivers used by EI, and is supplemented by an appendix containing RCAM allocator definitions. MNP found that the allocators were reasonable in the context of cost drivers and causality.

ACER and FCER Review

Due to previous concerns expressed by Intervenors, MNP conducted a detailed examination on the Adjusted Capital Employed Ratio (ACER) and Financing Capital Employed Ratio (FCER) allocators to determine method of determination and appropriateness.

FCER is used when the common activities are considered to benefit all EI affiliates in which EI maintains an investment, including minority equity investments. Therefore FCER has the broadest denominator for costs. The cost drivers that best reflect causality for services that use FCER to allocate common costs include company size and complexity as proxies for effort.

ACER represents the respective percentage of capital employed by EI in all affiliates for which EI is responsible for day to day operations. ACER has a smaller denominator to reflect only those affiliates that benefit directly from specific services. The rationale for using ACER is linked to cost incurrence. If the affiliate does not need the service, it is not part of the denominator over which costs are allocated. Similar to FCER, company size and complexity were considered proxies for effort for those services using ACER to allocate common costs to operated affiliates.

A previous concern raised by Intervenors was that common costs allocated to EGD automatically increase as a consequence of EI's growth rather than driven by EGD's need. The table below provides historical data of the percentage of common cost and the related ACER percentage allocated to EGD.

Year	EI % of Common Cost Allocated to EGD	EGD % of EI ACER	EGD % of EI FCER
2007	28	25	20
2008	27	24	20
2009	25	22	18
2010	20	17	15
2011	20	16	14
2012	19	16	14
2013	19	16	14

Across all services in 2012, EGD was allocated 19% of common costs while EGD represented 16% of EI ACER and 14% of FCER. Since 2007, as EGD's ratio of ACER and FCER has dropped, the percentage of EI common costs allocated to EGD has seen a reduction by the same approximate proportion.

In addition, primary service allocations based on ACER and FCER as a group have experienced a compound annual growth rate (CAGR) of 7.6% between 2007 (Board approved) and 2012 (Agreed under the ISA), which compares to an overall CAGR of all primary services of 12.0% for the same period.

8.3.4 Change in Allocator Review

MNP noted that allocation factors have not changed from 2007.

MNP Allocator Suitability Review Conclusion:

Primary Services were allocated appropriately, based on cost drivers rooted in cost causality.

8.3.5 Time-Study Review

MNP reviewed the methods for allocating time to the services. Through the interview process, MNP verified that time estimation studies are completed quarterly and reviewed the methodology for collating time study information and allocating time to the services. The EI time study process collects corresponding time allocation by categories. The time study categories represent all EI business units and correspond to the segments used for EI financial reporting purposes. Business units are identified as:

1. Enbridge Gas Distribution Only.
2. Enbridge Inc (Corporate Office).
3. Gas Pipelines Segment and all other Distribution Entities, excluding EGD.
4. Liquid Pipelines and Major Projects Segment.
5. Sponsored Investments Segment.
6. International Segment.
7. All Enbridge Inc. Affiliates and Segments (of benefit to all affiliates).

Time estimation is conceptually consistent with the rate application process, which uses prospective (forecast) costs. MNP is satisfied that the time estimation process adequately accounts for the amount of time spent on services and affiliate activities.

MNP acknowledges that while there is an opportunity to implement a more automated time tracking and collation system, incorporating a system to potentially improve the accuracy of data collection would involve significant implementation and administration costs. The Board's consultative on its own costs stated "the cost of time tracking and cost allocation should not exceed the benefit derived"[2], and MNP feels it would be difficult to demonstrate a benefit that exceeds costs for such an implementation.

MNP Time-Study Review Conclusion:

MNP is satisfied that the time estimation process adequately accounts for the amount of time spent on services and affiliate activities.

[2] Navigant Consulting Ltd., "Ontario Energy Board Cost Assessment Model "prepared by Navigant Consulting Ltd., October 28, 2004.

9 IMPLEMENTATION REVIEW

The Implementation Review component consists of two parts:

1. **2007 Recommendations**
   As part of the evolution of the RCAM, EI and EGD were encouraged by MNP to implement recommendations from the 2007 MNP Report. MNP reviewed each recommendation, determined the status of its implementation, and identified the reasoning and potential completion timelines for unimplemented recommendations.

2. **OEB Directives**
   MNP reviewed OEB directives to identify applicable decisions and directives related to EGD or other affiliates regulatory cost allocations.

MNP reviewed each recommendation, determined the status of its implementation, and identified the reasoning and potential completion timelines for unimplemented recommendations.

9.1 IMPLEMENTATION OF 2007 RECOMMENDATIONS

The following table details the 2007 MNP recommendations, implementation status, and outcomes.

2007 Recommendation	Implemented	Outcomes
Adjustment: MNP recommended a downward adjustment of $1.33 million be made to the 2007 Corporate Cost Allocation determined under the revised RCAM.	Yes	• EGD accepted all adjustments proposed by MNP for the 2007 allocations. These adjustments were approved by the Board
Service Schedules: MNP recommended that service descriptions be amended to be more service-specific, and distinguish between activities that are EGD-specific and common activities benefiting all EI affiliates.	No	• Review of the current Service Schedules shows that this recommendation was not implemented. Service descriptions remain reasonably similar to the 2007 state, with no clear distinction between activities that are EGD-specific and common activities benefitting all EI affiliates.
Service Schedules: MNP also recommended that the services schedules are adjusted to explicitly state activities which relate to the service, but which are to be excluded from the allocation for rate-making purposes.	Yes	• Review of the current Service Schedule shows that this recommendation was not implemented within the Service Schedules, however this recommendation is satisfied within the business cases.
Service Refinement: For the purposes of cost comparison, leading practices analysis, and	No	• Review of the current Service Schedules shows that this recommendation was not

2007 Recommendation	Implemented	Outcomes
organization structure, it would be more useful to all stakeholders for EGD to identify services by related functions, consistent with the overall accountabilities of the service recipients.		implemented. The level of granularity in services remains relatively similar to that in 2007. • EGD provides information consistent with the essence of the RCAM service-based methodology as approved by the Board.
Service Refinement: MNP recommended further refining the number of services to reflect functional categories consistent with the ARC definition of shared core corporate services, being "business functions that provide shared strategic management and policy support to the corporate group of which the utility is a member, relating to legal, finance, tax, treasury, pensions, risk management, audit services, corporate planning, human resources, health and safety, communications, investor relations, trustee, or public affairs.	No	• Review of the current Service Schedules shows that this recommendation was not implemented. The number of service functions remains very similar to that when the 2007 evaluation was conducted. • EGD provides information consistent with the essence of the RCAM service-based methodology as approved by the Board.
Business Case Quality: MNP recommended that EGD initiate a quality assurance process to enhance the quality and completeness of the business cases.	Yes	• EGD has enhanced the business case process (consistency/completeness, quality control and rigour) and EGD has dedicated resources to perform RCAM quality control and coordination.
Business Case Review: MNP recommended that an independent review of business cases, with particular attention to alternative service provision and the associated costs, be completed in 2008 and then again on renewal of the prevailing ISA which expires December 31, 2010.	No	
Business Case Enhancement: Additional enhancements to the business case process should include more consistent review and editing, additional critical analysis of EGD capabilities where EI is the sole provider of a service and inclusion of costs and application of budget data where EI provides a service on a supplementary basis.	Yes	

2007 Recommendation	Implemented	Outcomes
Use of Business Cases: MNP recommended that EGD use the business case as a key element of annual service and performance review.	No	• EGD does not currently use a performance measurement process with EI. EGD weighed costs against the benefits, and determined that this recommendation was not beneficial. Performance is managed through the annual review process which is conducted informally through discussions between EGD service recipients and EI service providers.

Implementation Review Findings:

Although all recommendations were not adopted, MNP generally found an increased level of quality and detail in the business cases.

MNP Recommendation:

Despite alignment with RCAM methodology, MNP recommends that EGD categorize and roll up services to levels more consistent with reporting of other utilities for comparison purposes.

9.2 OEB DIRECTIVES

In February 2006, Enbridge Gas Distribution Inc. (EGD) was directed by the Ontario Energy Board (OEB) to have an independent evaluation of corporate service charges calculated by an amended Regulatory Cost Allocation Methodology (RCAM) and have the evaluation make the necessary adjustments to the allocations for the assessment of need, scope, allocation and cost/benefit[3]. MNP considered the 2006 directives of the Board in conducting this review for EGD's 2013 test year. No other current directive exists.

MNP has found no significant directive or decision issued by the OEB that impacts the RCAM or the resultant allocated costs.

3 Paragraph 10.5.18 of the OEB's EB-2005-0001 Decision with Reasons dated February 9, 2006.

10 COST ALLOCATION REVIEW

The objective of this cost allocation review was to assess the reasonableness of RCAM corporate services charges by independently analyzing, assessing and providing proposed adjustments where necessary to the RCAM corporate services charges allocated from EI to EGD. Corporate services are broken down into two categories:

1. **Primary Services** – Defined by EGD as a service provided by the Service Provider to the Service Recipient either as the sole provider where EGD relies soley on EI for this service or as a supplemental provider (where EGD performs a component of the required activities of the service).

2. **Direct Charges and General Expenses** – Direct Charges are defined by EGD as a service related item separately included in the Service Providers budgets that can be specifically attributed to the Service Recipient without loading. Defined by EGD as significant costs that benefit the Service Recipient, these costs require allocation on a basis separate from the Primary Services because the driver of the cost is different, or because the cost is a large, third party cost. [4]

10.1 COST ALLOCATION REVIEW METHODOLOGY

The OEB requires that a standard of prudence be met, whereby customers are charged only for prudently incurred costs of the utility. Where there is normally a presumption of management prudence in the operation of its business, for affiliate transactions the OEB has applied what is referred to as a Three Prong Test to avoid a potential conflict between affiliates in the delivery of intercorporate services. This test services as the foundational framework for MNP's assessment of the RCAM results for 2012 and 2013.

Using the Three Prong Test as a basis for our review, MNP has chosen two primary methods to establish prudence of 2012 RCAM allocation results:

1. Individual Service Reviews for 2012.
2. Variance and Comparator Review.

Each of these methods is described in detail in this section.

[4] Regulatory Cost Allocation Methodology Service Schedules, Effective January 1, 2012 – Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012.

List of 2012 Services Reviewed

Service / Function		
Primary Services	1	Audit & Accounting Advice
	2	Board of Directors Support
	3	Business Development
	4	Capital Market Financing & Access
	5	Cash Management & Banking
	6	Consolidation and Planning System Technical Support
	7	Corporate Compliance
	8	Employee and Labour Relations
	9	Employee Development
	10	Enterprise IT Program Management
	11	Enterprise IT Strategy Planning & Management
	12	Expense System Management & Technical Support
	13	External Audit Coordination
	14	Financial and Project Accounting System Technical Support
	15	Government Relations
	16	HRIS Program Management and Development
	17	Human Resource Advice
	18	Industry Relations & Corporate Social Responsibility
	19	Insurance Claims Support, Strategy and Management
	20	Investor Services
	21	Legal Advice
	22	Planning, Management, & Execution of Internal Audits
	23	Portal Suite Operations and Technical Support
	24	Rate Regulated Entity Support
	25	Records & Information Management
	26	Risk Assessment & Management
	27	Strategic Planning
	28	Supply Chain Management
	29	Tax Reporting & Planning
	30	Total Compensation & Benefits
Direct Charges and General Expenses	31	Depreciation - Risk Management System
	32	Direct EFS Charge
	33	Directors Fees & Charges
	34	Audit Fees
	35	EGD Stock Based Compensation
	36	Insurance Premiums

Note that 3 services have been excluded from analysis within this Study due to zero RCAM allocations having been calculated for 2012 and 2013. These services include:

- Emerging Energy Technology Research – This service had been allocated relatively small amounts in prior years, with a zero allocation for 2012 and 2013.

- Gas Supply, Storage, and Transportation Strategy – This service is provided by corporate groups outside of the RCAM (except for the CEO department), and has not been allocated costs via the RCAM since 2010.
- Insurance Claims Support – This service has been rolled into Insurance Strategy and Management, entitled "Insurance Claims Support, Strategy and Management" for 2012.

10.2 FOUNDATION ASSESSMENT FRAMEWORK – OEB THREE PRONG TEST

The 'Three Prong Test' is a method defined in the OEB Decision with Reasons dated March 20, 1997 (EBRO 493/494)[5] to help with cost allocation decisions. Each prong is assessed only in the event of a 'passing' grade for the previous prong.

Prong One: Cost Incurrence

Are the proposed charges prudently incurred by, or on behalf of, the companies for the provision of a service required by Ontario ratepayers? In the Board's view, costs will not pass this test if they relate to activities which:

- Go beyond the scope required for a utility;
- Are associated with overall governance from a shareholder perspective or "minding the investment"; or
- Represent additional and superfluous management layers.[6]

Prong Two: Cost Allocation

If properly incurred, are the proposed corporate centre charges allocated appropriately to the companies, based on the application of cost drivers/allocation factors supported by principles of cost causality?

Prong Three: Cost Benefit

Do the benefits to the company's Ontario ratepayers equal or exceed the costs? For the third test, Cost/Benefit, the Board has accepted the [following] four categories ... as a basis for assessing quantifiable benefits:

1. Replacement benefits – the services provided replace an equivalent service at equal or lower cost;
2. Synergistic or linkage benefits – the services allow the Companies to reduce costs by means of being part of the larger ... group and operating in concert for the procurement of products and services;
3. Revenue enhancement or cost recovery benefits – the Companies' activities and capabilities provide value to other affiliates for which payment in cash or kind is received; and
4. Stand-alone benefits – strategic actions and activities instituted by the Corporate Centre that produce direct value to the Companies.

[5] Paragraph 5.5.14 and 5.5.17 EBRO 493/494 Decision with Reasons dated March 20, 1997
[6] Paragraph 10.9.1 EB-2005-0001 Decision with Reasons dated February 9, 2006

10.3 METHOD ONE - INDIVIDUAL SERVICE REVIEW

Method one incorporates a detailed assessment of each allocated service identified through the 2012 RCAM. MNP developed the mock template below to present key service informational components, form the basis for its assessment and present findings. Explanations in **blue** font provide some context for the content that appears in each completed service review. Completed service reviews and detailed consolidated results of these reviews may be found in Appendix D.

Appendix D Template for Each Service

Service Name – 2012 RCAM Analysis

EGD Service Recipient

Name, Title (as of Feb 29, 2012)

Service Definition

Borrowed from EGD Service Schedule

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	EGD Allocation%	EGD Total Cost	
A	B	C=AxB	D		E	F=DxE	G=C+F
$X	X%	$X	$X	XXX	X%	$X	$X

Cost by Department

EI Department	*Charges*
Example Department 1	$X
Example Department 2	$X
Example Department 3	$X
Total	**$X**

Prong 1 Test
Determine if EI's charges to EGD are prudently incurred.

Grade (Pass or Fail)

Cost Incurrence Review
MNP opinion and explanation.

Prong 2 Test
Determine if EI's charges to EGD are appropriately allocated.

Grade

Cost Allocation Review
Direct Cost
- MNP opinion of direct cost allocator

Common Costs
- MNP opinion of activity driver and allocator for the service

Prong 3 Test
Do the benefits to ratepayers exceed the costs?

Grade

Cost/Benefit Analysis

EGD Internal Provision of Service
MNP low and high estimates of the staffing complement and other costs required for EGD to fulfill this service function and level internally.

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Example Position 1	X	$ X	X	$ X
Example Position 2	X	$ X	X	$ X
Example Position 3	X	$ X	X	$ X
Total	**X**	**$ X**	**X**	**$ X**

MNP estimate of the range of internal costs based on the staffing complement noted above; and where EI's 2012 allocation falls within that range.

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ X	$ X	$ X	Below, Within or Above Range

Service Name – 2012 RCAM Analysis

External Provision

Description of EGD's estimates for effort and cost to incur the provision of service externally.

MNP opinion of the reasonableness of EGD external provision estimates and any subjective benefits or detriments to external sourcing. Where an estimate was not created by EGD, MNP provide its own estimate for external provision.

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Example Position 1	$ X / hour	X	XXX	$ X
Example Position 2	$ X / hour	X	XXX	$ X
Example Position 2	$ X / hour	X	XXX	$ X
	Total	**X**	**4,400**	**$ X**
			Low Range (80% of Total)	**$ X**
			High Range (120% of Total)	**$ X**

OEB Benefits

MNP opinion of the benefits of EI provision of services by 'benefit type' as defined by the four categories of the Prong Three Test.

Benefit Type	*Reasoning*
Replacement	**The services provided replace an equivalent service at equal or lower cost.**
Synergistic	**The services allow the Companies to reduce costs by means of being part of the larger ... group and operating in concert for the procurement of products and services.**
Revenue Enhancement	**The Companies' activities and capabilities provide value to other affiliates for which payment in cash or kind is received.**
Stand-alone	**Strategic actions and activities instituted by the Corporate Centre that produce direct value to the Companies.**

MNP Conclusion

MNP opinion as to whether or not the provision of service by EI benefits ratepayers.

MNP Conclusion

- **Status of MNP prong test results.**
- **MNP proposed adjustment to the 2012 EGD allocation (if required).**

Given the repetitive nature of the individual service assessments and categorization of results, MNP will comment on common factors considered for each prong test across services and identify anomalies as appropriate.

10.4 METHOD TWO – VARIANCE AND COMPARATOR REVIEW

The Individual Service Review (Method 1) focuses exclusively on analysis of the 2012 RCAM results in light of service requirements as agreed between EGD and EI. Acknowledging stakeholder interest in the variance of RCAM results over time and the appropriateness of the magnitude of shared service allocations, MNP undertook three additional types of analysis:

1. **Variance Review** – MNP identified and reviewed cost escalations from prior years, focusing specifically on larger increases from 2007 to 2012. Based on these variances and Intervenor comment, in order to facilitate a more comprehensive review MNP undertook assess Human Resources (HR) and Information Technology (IT) costs. With HR and IT RCAM allocations evaluated individually for 2012 based on levels of activity under Method 1, MNP focused on annual variances for EGD entity-level Operating, Maintenance and Administration ("OM&A") costs within the same categories of HR and IT and compared annual variances in these entity level costs against other rate regulated transmission/ distribution entities in Ontario and other jurisdictions.

2. **Comparator Review** – For HR and IT, MNP compared entity level OM&A costs to other large rate regulated distribution entities in Ontario and other jurisdictions by assessing several comparative metrics indicative of cost-effectiveness for service management.

3. **Departmental Cost Review** – While RCAM costs are primarily reported at the Primary Service level, allocations to individual Primary Services are built up using time estimates and allocators at the departmental level within EI. MNP reviewed EI budget and RCAM allocations consolidated by department, and noted changes in the ratio of costs being allocated to EGD from 2007 to 2012.

MNP was unable to draw direct comparisons between EGD and other utilities specifically for shared services allocated from an affiliate due to the inability to determine comparative information at the same level of granularity for other entities. Categories of costs are grouped differently, and there is no way to establish specific services and service levels based on reported data.

The value in conducting the variance and comparator review at the entity level for O&M costs (HR and IT) is to show how EGD compares to other similar organizations for measures of cost effectiveness. These comparisons may logically extend to the subset of costs in each area allocated from EI through the RCAM.

11 COST ALLOCATION REVIEW – 2012 – ANALYSIS & FINDINGS

The cost allocation analysis and findings section is organized to detail the analytical approach that led to our findings and present our conclusions.

11.1 INDIVIDUAL SERVICE REVIEWS

11.1.1 Prong One – Incurrence Review

MNP's analysis of the first prong test was based on a definition of need in the context of a standalone public entity of roughly the same size and complexity as EGD. To conduct its review of cost incurrence for each service, MNP reviewed the EGD service schedules and business cases, interviewed Service Recipients and EI RCAM coordinators, reviewed regulatory filings and evidence from previous rate cases, and considered the logic built into the 2007 MNP Report.

In addition, MNP paid particular attention to the exclusion criteria noted in the definition of Prong One, including the exclusions that formed the basis for adjustments in the 2007 MNP Report; namely those in the service areas of 'Government Relations', 'Industry Relations and Corporate Social Responsibility', and 'Internal Employee Communications'. Each of these Service Recipients made note of these 2007 adjusted exclusions in their business cases.

Based on the menu of EI service offerings, EGD identifies exclusions for consideration in development of the allocations. EI then distributes an EI developed RCAM Time Study description and instructions document to EI Service Providers that explains the exclusion criteria and notes which service elements should not be allocated to EGD. The instructions are reviewed by departmental Service Providers and form part of the time entry process. Allocations are then cross checked by the RCAM coordinator to ensure compliance to the exclusion criteria.

For 2012, EGD has noted exclusions in 17 of 30 Primary Services reviewed by MNP. MNP reviewed all departmental exclusions and corresponding logic and found them to be reasonable.

MNP supported its analysis and findings by specifically inquiring about exclusions with Service Recipients in the interviews.

MNP Incurrence Finding:

MNP finds that the proposed charges are prudently incurred by EGD for the provision of service required by Ontario ratepayers.

11.1.2 Prong Two – Cost Allocation Review

The process for allocator selection and the results of our analysis are documented in the RCAM Process Review section of this report. As discussed, EGD maintains strong standards in their selection of cost drivers for direct and common costs and continues to review allocators to ensure that each is most reflective of the principles of cost causality.

For direct costs, EI loaded Primary Services costs were allocated directly to specific affiliates, and where activities benefit all affiliates, costs were allocated to the 'all affiliates' bucket. MNP found that the use of salary-weighted time to allocate direct costs to EGD is consistent with the OEB's directive (regarding salary-weighting) and the principle of causality (time measures effort). For common costs, MNP focused on the rationale for the selection of allocators, and similarly to the 2007 MNP Report[7] found that all allocators used were appropriate.

MNP concludes that all costs for Primary Services were allocated appropriately based on cost causality.

MNP Allocation Conclusion:

MNP concludes that all costs for Primary Services were allocated appropriately based on cost causality.

11.1.3 Prong Three – Cost Benefit Review

In undertaking the cost benefit review for each service, MNP completed 3 steps:

1. **Internal Provision Estimates** – MNP estimated the costs of EGD internal provision of service, with lower and upper ranges.
2. **Reasonableness of External Provision** – MNP assessed the reasonableness of EGD's external provision estimates, also including lower and upper ranges.
3. **Benefits Assessment** - In the context of comparison against internal and external provisions, MNP evaluated RCAM allocated costs against benefits as defined by the OEB.

Upon completion of Steps 1 and 2, 2012 RCAM allocations that fell under the upper range estimates for internal and external provisioning options were deemed to pass the Prong Three Test. MNP then determined a potential adjustment to 2012 RCAM service cost based on any

[7] Independent Evaluation of Enbridge Gas Distribution Inc.'s Regulatory Corporate Cost Allocation Methodology – Final Report, Meyers Norris Penny LLP, February 28, 2007, page 37.

amounts that exceeded the upper range estimates for internal or external provisioning options. Step 3 was undertaken in all cases to qualify the types of benefits attributed to each service that may offset, where appropriate, any potential adjustments.

11.1.3.1 Internal Provision Estimates

For each service and service level, MNP performed the following steps in determining internal provision estimates:

1. **Estimate Staff Requirements** – Based on service schedules, business cases, primary and secondary research and MNP experience and opinion, MNP estimated an internal staff complement internal to EGD (as a standalone utility) that would be required to perform the services currently being provided by EI (finite number of FTEs or a range).
2. **Assign Fully Loaded Costs** – Assign a range of fully loaded costs to each FTE based on their role and level, including salary, bonus, long-term incentive, benefits, and office/facilities costs.
3. **Add Third Party Costs** – As required, add any additional third party costs necessary to provide the same level of service.
4. **Compare Results** – Compare 2012 RCAM allocation to the range of MNP's internal service provision estimates, identifying the RCAM allocation as 'Below Range', 'Within Range' or 'Above Range'.

MNP did not quantify the costs of planning, establishing, transitioning and implementing an internal service model however EGD estimates one-time recruiting costs alone to represent 1.5 times the recruited staff's annual salary, or 15% of the salary on an annualized basis. Other costs might include travel and training & development. Acknowledging these costs as provisional, MNP did not incorporate transition costs into its findings.

MNP Internal Provision Finding:

Of the 30 primary services reviewed by MNP, 3 services yielded RCAM allocations above the MNP range, 11 fell within the range and 16 fell below the range. As a whole, the total proposed 2012 RCAM primary service allocations fell below the midpoint of the MNP range (33rd percentile).

The 3 services that yielded above-range results were a combined $154,923 over the range.

11.1.3.2 Reasonableness of External Provision

For each of its service business cased EGD performed an estimate of the effort and costs that an external party would require in providing the same level of support being provided by EI through the RCAM. External parties are broadly defined as professional services firms, including legal firms, accounting and advisory firms or specialist firms (e.g. pension, investment banking). These EGD estimates were developed or approved by the Service Recipients, generally at the Director or VP level within EGD, with the benefit of many years of management experience.

EGD estimates incorporated a team of external staff full time equivalents (FTEs) at various levels of seniority, utilization rates or effort required for each staff member, and average fee rates to arrive at an annual cost for the team. In some cases other disbursements necessary to

fulfill the service requirement were identified and added to the total external cost. This finite cost was established as a mean, and low and high ranges were developed by selecting 80% and 120% of the mean, respectively.

MNP Approach to External Provisioning

MNP assessed the reasonableness of the Fair Market Value range of costs identified by EGD, and noted how the costs compared to the RCAM allocation and the internal provision estimates. MNP relied on this method for several reasons:

1. **MNP Experience** - As a professional services firm, MNP has significant experience providing consulting and out-sourced services and collaborating with or employing a wide cross-section of external consultants. There are several subsets of external parties, including Consulting (e.g. Management, IT, Finance, HR, Compensation, Regulatory), Specialist Services (e.g. Actuarial, Public Relations) and Legal Services. MNP has direct relevant experience with these categories, and hourly rates attributed to external consultants by EGD generally align with our experience.

2. **The Purpose for External Provisioning** - Standard industry practice is to acquire the services of external consultants in order to fulfill needs for:
    a. Specialty skills not housed internally.
    b. Urgency requiring focus that only dedicated external resources can bring.
    c. Short term capacity to meet temporary or project-based resource requirements.
    d. Objectivity that may only be provided by those external to the organization.

    These external resources command a premium hourly rate compared to calculated total hourly compensation for internal staff based on specialty skills, focus and availability. For external parties to provide a service otherwise available from internal staff (or related party staff) is intuitive only in cases where the external party can be dramatically more efficient. For shared services, any efficiency gains in these cases are normally offset by premium rates, thereby making external sourcing imprudent. This is particularly the case for EGD's numerous small departmental requirements where there are minimal opportunities for external providers to enjoy economies of scale (large teams for extended durations). Without this opportunity, external providers are not in a position to offer the volume discounts that would yield stronger competition to EGD's current arrangement with EI or the option to source the services internally. This fact resulted in the majority of external estimates being much higher than the EI allocations, even with broad-based conservative or aggressive assumptions.

3. **EGD Estimate of External Provisioning Time Requirements** – MNP found that EGD estimates for utilization of external staff was either reasonable or conservative, whereby actual time to fulfill the required services would in many cases consume more hours than estimated.

Results of Analysis

For 8 services categories where EGD was allocated more than zero for 2012, EGD did not attempt an external estimate. Although the exemption criteria to decline making an estimate of external cost is stated in the business cases as the lack of a reasonably competitive market for the services in question, in MNP's opinion external estimates in 6 cases were not attempted due generally to one or more of three factors:

- The perceived lack of a reasonably competitive market from which to procure the services.
- Perceived high cost to secure an external party.
- Lack of the external party's familiarity or alignment with EGD strategy, operations and history, rendering the provision of service ineffective or inappropriate.

For those services not estimated, MNP was of the opinion that a reasonably competitive market did exist and that an external estimate may have been appropriate. In each case, MNP developed its own estimate of Fair Market Value for the services as described in the business cases and discussed with Service Recipients.

Of the 22 services for which external estimates were created, 14 of the external estimate's low ranges were higher than the 2012 RCAM allocation, and no RCAM allocations exceeded the upper ranges. As noted, MNP found that each estimate was either reasonable or conservative. In addition, each of the MNP estimates of Fair Market Value exceeded the RCAM allocations. Given these results, MNP recommends no proposed adjustments to 2012 RCAM allocations due to lower alternative costs of provisioning externally.

MNP External Provision Finding:

EGD estimates of external service provision were reasonable or conservative and none warranted serious consideration for outsourcing from a cost perspective.

MNP External Provision Recommendation:
MNP recommends that EGD develop more defined criteria for Service Recipients to facilitate the development of external service estimates.

11.1.3.3 Cost Benefits Assessment

Conservatism, Assumptions and Limitations

There are a number of factors that are relevant for consideration of MNP analysis and findings, particularly relating to the assessment of benefits against any potential cost savings driven by alternative service delivery.

MNP has chosen to take a conservative approach in its assessment of internal and external service costs. This approach results in conservative estimates, and is warranted given the inherent subjective nature of service schedules, service levels and cost estimates for shared services as defined by EGD and the RCAM. The following are examples of MNP's assumptions in its calculations:

- The source for MNP salary data to estimate internal provision of service, Salary.com, generates salary data that is a blend of sectors and industries in Ontario. Average cross-industry salaries are slightly lower than those in the energy & utilities sector.[8] This finding has been adjusted for by MNP incorporating 50th percentile of job wages as the low end of the range and 75th percentile for the high end of the range.

[8] Watson Wyatt "Annual Canadian Salary Survey - 2008/2009 Executive Compensation Report", October 15, 2008.

- Salary.com data was acquired for 2011 based on availability and escalated by MNP for the purposes of its 2012 evaluation. Salary data was escalated using Statistics Canada data to calculate average wage growth in Ontario between 2007 and 2011 (2.75%).
- The bonus element of fully loaded costs is represented by a tighter range of 10% to 25% and is on average is lower than bonus attributions of EGD at 7% to 35% for non-union staff.
- The burden element of fully loaded costs is similar to EGD attributions at 30% to 32%.
- MNP has attributed a lower portion of wages to long term incentive plan (e.g. stock based compensation), from 10% to 20% compared to 15% to 70% at EGD.

The following assumptions and limitations should also be noted in conjunction with the data presented in the Cost Benefit Quantum Results table:

- Market value, as defined in the ARC for Gas Utilities, "means the price reached in an open and unrestricted market between informed and prudent parties, acting at arm's length and under no compulsion to act."[9] Given the relative difficulty and high cost of conducting benchmarking for shared services as defined by EGD, MNP did not carry out a benchmark analysis. Instead, MNP applied comparative market cost data to the most common market element of a service (salaries and hourly rates) to determine a reasonable range of comparative costs that can be used to measure Fair Market Value. There is no single market price in the range that is more or less appropriate.
- MNP relied on the EGD business cases to ascertain third party costs incremental to staff costs for internal and external provision of service (e.g. license fees, registration costs, production costs, external consulting fees). This allows comparisons of 2012 RCAM costs to external and internal provision costs based on equivalent services and service levels.
- Cost alone is not an appropriate measure for the benefits of alternative service provision. Factors such as economies of scale, strategic benefits, availability, service quality continuity and on-demand availability need to be considered. This is particularly relevant where 2012 RCAM allocations fell within the lower and upper ranges for internal and external provision costs.
- The costs of switching providers or in-sourcing a service are real in may in some cases be substantial from an effort and cost perspective. These costs and the resource requirements to plan, implement and sustain alternate provisioning are not included in the internal and external cost estimates.

11.1.3.3.1 Prong Three Benefit Category Assessment

Further to the internal and external provision estimate findings, of the 30 primary services reviewed MNP found the following results:

- Three RCAM service allocations fell above the MNP range for internal provision (RCAM Status noted in red below).
- Eleven services fell above the midpoint of the range.
- Nineteen services fell below the midpoint of the range.
- The total 2012 RCAM allocations registered at the 33rd percentile of the range.

[9] Affiliate Relationships Code for Gas Utilities, OEB, last Revised November 25, 2010.

The object of the Prong Three Test is to determine if the benefits of services exceed the costs. Each MNP service review template in Appendix D contains MNP's assessment of each prong three benefit for all services, regardless of the status of the RCAM allocations in relation to the internal or external provision ranges.

Replacement Benefit
The Replacement category of benefits stipulates that the service cannot be replaced at equal or lower cost. MNP has applied the Prong Three Test for each primary service such that the replacement test is met under two conditions:

1. The RCAM allocation falls below or within the MNP range of internal provision estimates.
2. The RCAM allocation for each service falls below or within the range of external cost estimates MNP has assessed as reasonable.

Should the replacement test not be met, meaning that the 2012 RCAM allocation exceeds the internal or external range; MNP deems the service in question to have failed Prong Three based on the OEB stipulation.

Analysis of the results for the 3 services above the MNP range demonstrates that even a small cost attributed to switching to external providers or in-sourcing the service may escalate the MNP high range estimate beyond the 2012 RCAM allocations. However, MNP recognizes that these costs are considered to be one-time and can be highly variable depending on the nature of the transition to the preferred alternative provisioning arrangement.

Synergistic Benefit
This benefit is defined by a reduction in the cost for a service because it is spread over two or more affiliates, or economy of scale. Synergistic benefits are achieved through the buying power of a larger entity or the sharing of costs among affiliates that might otherwise be borne entirely by a standalone entity.

The concept of scale economies is important in assessing the third prong test. Economies of scale are most effectively derived through collective and standardized decision-making, where all interested parties have influence to determine the most effective method of delivering services. This influence contributes to the implementation of corporate standard and business unit specific requirements, provided at a reasonable cost compared to market alternatives. It is the understanding of and comparison to alternatives that drive the choice and method of service, as demonstrated by EGD Service Recipients in their business cases.

Economies of scale are most obvious either through lower negotiated charges for products or services required by the affiliate, or when the cost for a service element (program, asset, or resource) is shared among affiliates; effectively reducing or eliminating multiple instances of that element. Examples of these service elements are common in IT departments, examples being IT applications (implementation, upgrade and support), network infrastructure, hardware, data and knowledge management, and help desk support.

HR departments also typically enjoy synergistic benefits of employee surveys and employee training programs. HR policy and processes are typically common across many business units or departments. Recruiting, compensation, pension, labour relations, employee development and succession programs may be standardized according to leading practices and managed by a core service provider, internally or externally, all to the benefit of ratepayers who experience

higher quality service through better operations management by employees of the utility. As noted in the Appendix D templates, MNP found that the majority of RCAM allocations yielded a synergistic benefit for EGD.

Revenue Enhancement / Cost Recovery Benefits
This benefit category stipulates that costs incurred provide value to other affiliates for which payment is received. This category is not relevant for MNP analysis given that EGD does not incur costs that meet this criterion.

Stand-alone Benefits
Stand-alone benefits arise from strategic actions and activities instituted by the EI that produce direct value to its affiliates. These benefits are typical for functions that require an intimate knowledge of the affiliate's operations or history that may only be acquired by those internal to the company.

Examples of services for which stand-alone benefits prevail are Board of Directors Support, Corporate Compliance, Capital Market Financing and Labour Relations, where the service provider employs a broad and deep understanding of the affiliate's objectives, capabilities and multitude of stakeholder expectations in order to bring broader insight and credibility to bear with affiliate shared services. These benefits in many cases may not be achieved by sourcing services from an external party or an internal party that is not privy to or experienced with broader issues of the Service Provider.

MNP Cost Benefit Findings:

1. **All but 3 RCAM primary service costs met the replacement test and are deemed to pass the Prong Three Test.**

2. **The 3 RCAM primary service allocations that did not meet the replacement test are deemed to have failed Prong Three given that 2012 RCAM allocations fell above the MNP fair market value range of internal service provision costs.**

3. **For the 3 primary service allocations that fell above the MNP range (Capital Market Financing and Access, Employee Development and HRIS Program Management and Development), MNP recommends a combined downward adjustment to the 2012 RCAM allocations of $154,923.**

11.1.4 Consolidated Three Prong Test Results – Primary Services

Three Prong Test Results for Primary Services

2012 RCAM - Services Review - ($)		RCAM Allocation	2012 MNP Range for Internal Provision			2012 RCAM MNP Range Status		MNP Three Prong Test Results - 2012		
	Service Function	2012 Agreed under ISA	Low	High	Midpoint	Status	Amount Above Range	Prong 1 Incurrence	Prong 2 Allocation	Prong 3 Cost Benefit
1	Audit & Accounting Advice	91,270	119,694	155,653	137,674	Below	-	Pass	Pass	Pass
2	Board of Directors Support	769,368	615,496	849,000	732,248	Within	-	Pass	Pass	Pass
3	Business Development	736,918	446,785	829,088	637,937	Within	-	Pass	Pass	Pass
4	Capital Market Financing & Access	1,020,173	621,880	991,870	806,875	Above	28,303	Pass	Pass	Fail
5	Cash Management & Banking	481,073	413,971	537,442	475,706	Within	-	Pass	Pass	Pass
6	Consolidation and Planning System Technical Support	245,089	328,197	542,554	435,375	Below	-	Pass	Pass	Pass
7	Corporate Compliance	197,202	277,083	406,726	341,904	Below	-	Pass	Pass	Pass
8	Employee and Labour Relations	478,201	450,312	558,181	504,246	Within	-	Pass	Pass	Pass
9	Employee Development	1,260,568	904,406	1,245,623	1,075,014	Above	14,945	Pass	Pass	Fail
10	Enterprise IT Program Management	868,494	927,584	1,725,687	1,326,636	Below	-	Pass	Pass	Pass
11	Enterprise IT Strategy Planning & Management	624,115	414,244	791,610	602,927	Within	-	Pass	Pass	Pass
12	Expense System Management & Technical Support	95,490	153,098	193,210	173,154	Below	-	Pass	Pass	Pass
13	External Audit Coordination	103,399	119,694	155,653	137,674	Below	-	Pass	Pass	Pass
14	Financial and Project Accounting System Technical Support	352,161	362,776	595,786	479,281	Below	-	Pass	Pass	Pass
15	Government Relations	44,917	80,390	106,472	93,431	Below	-	Pass	Pass	Pass
16	HRIS Program Management and Development	3,009,273	2,472,121	2,897,598	2,684,860	Above	111,675	Pass	Pass	Fail
17	Human Resource Advice	201,779	247,330	333,171	290,250	Below	-	Pass	Pass	Pass
18	Industry Relations & Corporate Social Responsibility	384,365	402,816	530,244	466,530	Below	-	Pass	Pass	Pass
19	Insurance Strategy and Management	108,240	222,266	363,932	293,099	Below	-	Pass	Pass	Pass
20	Investor Services	883,837	720,333	931,769	826,051	Within	-	Pass	Pass	Pass
21	Legal Advice	514,396	430,606	549,488	490,047	Within	-	Pass	Pass	Pass
22	Planning, Management, & Execution of Internal Audits	191,528	422,307	590,362	506,335	Below	-	Pass	Pass	Pass
23	Portal Suite Operations and Technical Support	330,881	322,748	403,707	363,228	Within	-	Pass	Pass	Pass
24	Rate Regulated Entity Support	253,904	266,894	345,206	306,050	Below	-	Pass	Pass	Pass
25	Records & Information Management	538,352	524,070	725,934	625,002	Within	-	Pass	Pass	Pass
26	Risk Assessment & Management	878,461	657,012	908,804	782,908	Within	-	Pass	Pass	Pass
27	Strategic Planning	327,890	403,192	509,795	456,494	Below	-	Pass	Pass	Pass
28	Supply Chain Management	39,706	68,069	91,218	79,644	Below	-	Pass	Pass	Pass
29	Tax Reporting & Planning	55,308	82,109	104,242	93,175	Below	-	Pass	Pass	Pass
30	Total Compensation & Benefits	1,781,809	1,435,149	1,805,350	1,620,250	Within	-	Pass	Pass	Pass
	Primary Service Totals	16,868,167	14,912,632	20,775,374	17,844,003	Within	-			
							154,923	Total Amount Above Range		

11.1.5 Direct Charge and General Expense Analysis

Detailed analysis of each General Expense and Direct Charge is included in Appendix D, with a summary table of our prong results below.

Three Prong Test Results for Direct Charges and General Expenses

2012 RCAM - Services Review - ($)		RCAM Allocation	MNP Three Prong Test Results - 2012		
	Service Function	2012 Agreed under ISA	Prong 1 Incurrence	Prong 2 Allocation	Prong 3 Cost Benefit
31	Depreciation - Risk Management System	64,951	Pass	Pass	Pass
32	Direct EFS Charge	(2,314,784)	Pass	Pass	Pass
33	Directors Fees & Charges	744,819	Pass	Pass	Pass
34	Audit Fees	N/A	N/A	N/A	N/A
35	EGD Stock Based Compensation	7,549,229	Pass	Pass	Pass
36	Insurance Premiums	8,483,868	Pass	Pass	Pass
	Direct Charges and General Expenses Total	14,528,083			

Items of Note:

Audit Fees
Audit Fees were a direct charge, and are now accounted for outside the RCAM (as of 2012) to better reflect the nature of the billing, whereby EGD pays PwC audit fee invoices directly. Prong tests are therefore not applicable.

EGD Stock Based Compensation (SBC)
For 2007, significant adjustments were proposed by MNP to reflect what was deemed to be an inappropriate valuation method for SBC. While the majority of publicly traded companies on the TSX used the CICA Handbook approved Black-Scholes method for valuation, EGD SBC was valued using the intrinsic method. Allocations for SBC thereafter have been based on the Black-Scholes valuation method.

Insurance Premiums - 2011
Insurance premiums are considered to be largely outside the control of EGD and EI. While each company can mitigate losses and/or premium increases through proactive risk management, the premiums amounts are quantified using risk factors and losses external to EGD and EI.

Early in 2011, EGD accepted an RCAM allocation of $4.3 million based on the EI budget approved in December 2010. In the second quarter of 2011, actual insurance premium allocation costs of $7.2 million became known, resulting in an effective $2.9 million shortfall for EGD compared to budget. MNP's recommendation is that EI and EGD develop and/or employ an equitable mechanism to ensure ratepayers are kept whole with material unforeseen events that result in large variances against budget pursuant to the RCAM process. This mechanism should account for actual variances both over and under budget.

MNP's understanding is that there is a general mechanism that may be used to accommodate amendments to the ISA (Sections 5 and 7); however, this mechanism has not been triggered for these types of large variances of budget to actual.

MNP Direct Charge and General Expense Findings:
MNP passed each relevant charge on all prong tests

MNP Recommendation:
EGD and EI should implement a process to account for material unforeseen expenses that result in actual variances over or under budget allocations.

11.2 VARIANCE AND COMPARATOR REVIEW – 2007 TO 2012

The table below shows the compound annual growth rate (CAGR) in expenses by Primary Service between 2007 and 2012, excluding the 3 service areas allocating zero dollars for 2012.

2012 RCAM - Services Review - ($)		RCAM Allocation				
	Service Function	MNP Categorization	2007 OEB Approved	2012 Agreed under ISA	Increase (Decrease) from 2007 to 2012	CAGR from 2007 to 2012
1	Audit & Accounting Advice	Finance & Accounting	86,095	91,270	5,175	1.2%
2	Board of Directors Support	Corporate Management	511,270	769,368	258,098	8.5%
3	Business Development	Corporate Management	652,513	736,918	84,405	2.5%
4	Capital Market Financing & Access	Finance & Accounting	681,246	1,020,173	338,927	8.4%
5	Cash Management & Banking	Finance & Accounting	222,036	481,073	259,037	16.7%
6	Consolidation and Planning System Technical Support	Information Technology	375,868	245,089	(130,779)	-8.2%
7	Corporate Compliance	Regulatory & Government Affairs	99,725	197,202	97,477	14.6%
8	Employee and Labour Relations	Human Resources	253,529	478,201	224,672	13.5%
9	Employee Development	Human Resources	255,425	1,260,568	1,005,143	37.6%
10	Enterprise IT Program Management	Information Technology	149,002	868,494	719,492	42.3%
11	Enterprise IT Strategy Planning & Management	Information Technology	550,749	624,115	73,366	2.5%
12	Expense System Management & Technical Support	Information Technology	119,526	95,490	(24,036)	-4.4%
13	External Audit Coordination	Finance & Accounting	43,174	103,399	60,225	19.1%
14	Financial and Project Accounting System Technical Support	Information Technology	320,766	352,161	31,395	1.9%
15	Government Relations	Regulatory & Government Affairs	119,234	44,917	(74,317)	-17.7%
16	HRIS Program Management and Development	Information Technology	689,995	3,009,273	2,319,278	34.3%
17	Human Resource Advice	Human Resources	101,190	201,779	100,589	14.8%
18	Industry Relations & Corporate Social Responsibility	Corporate Communication & Services	245,307	384,365	139,058	9.4%
19	Insurance Claims Support, Strategy and Management	Corporate Management	84,730	108,240	23,510	5.0%
20	Investor Services	Corporate Communication & Services	994,024	883,837	(110,187)	-2.3%
21	Legal Advice	Legal	303,414	514,396	210,982	11.1%
22	Planning, Management, & Execution of Internal Audits	Finance & Accounting	82,338	191,528	109,190	18.4%
23	Portal Suite Operations and Technical Support	Information Technology	259,283	330,881	71,598	5.0%
24	Rate Regulated Entity Support	Regulatory & Government Affairs	328,451	253,904	(74,547)	-5.0%
25	Records & Information Management	Information Technology	456,875	538,352	81,477	3.3%
26	Risk Assessment & Management	Corporate Management	541,913	878,461	336,548	10.1%
27	Strategic Planning	Corporate Management	167,834	327,890	160,056	14.3%
28	Supply Chain Management	Corporate Management	19,504	39,706	20,202	15.3%
29	Tax Reporting & Planning	Finance & Accounting	10,196	55,308	45,112	40.2%
30	Total Compensation & Benefits	Human Resources	865,843	1,781,809	915,966	15.5%
	Primary Service Totals		9,591,055	16,868,167	7,277,112	12.0%

As evidenced with Individual Service Reviews (Method 1) and Appendix D templates for each RCAM service, MNP examined the prudency and appropriateness of allocations for the 2012 RCAM based on service descriptions and service levels required. The purpose of the variance and comparator review is to examine the increases and decreases in RCAM allocations from 2007 to 2012.

Of the $7.3 million increase in Primary Services from 2007 to 2012 (as noted in the table above), $5.4 million or 74% is attributed to services that MNP has categorized as IT and HR functions. MNP also understands that year over year variance explanations have been provided to the Intervenor group through consultative sessions since 2007 and that the Intervenor group has expressed interest in RCAM allocation increases in these same service categories.

Given that costs related to IT and HR are built up based on specific information management requirements and labour force conditions, respectively, it is difficult to draw direct cost comparisons from company to company without a benchmarking exercise or very detailed examination of technology/software or HR program implementation lifecycles specific to each company. This challenge is further complicated by three factors:

1. EGD's categorization of broader shared services 'departmental' costs into 36 unique individual shared services for the purposes of RCAM allocation.
2. RCAM allocations are only a subset of general and administrative costs incurred by EGD.
3. Service levels related to service provision are difficult to quantify, as evidenced by the complex RCAM principles and model used to undertake the allocation effort between EI and EGD.

In an effort to further assess the appropriateness of the RCAM allocations, MNP undertook to elevate its examination of EGD HR and IT costs by reviewing entity level Operating, Maintenance and Administration ("OM&A"), and Capital costs for EGD in these areas. This incremental analysis provides insight into the efficiency or effectiveness of OM&A cost management of EGD during similar periods and in similar operating environments compared to other rate regulated transmission/distribution entities in several Canadian jurisdictions.

Limitations

Due to varying company approaches to financial and regulatory reporting, MNP found it difficult to obtain relevant publicly available data for preferred comparable entities over similar periods of time at the department level for HR and IT. MNP's assessment is based on the meaningful and comparable data it was able to source.

In addition, MNP has evaluated year over year variances using the Compound Annual Growth Rate (CAGR) calculation. This method calculates average annual growth from one year to another, and is useful to capture trends over time. The limitation of using the CAGR calculation is that it does not reflect high or low values (outliers) or reflect total spending during the time span contemplated.

11.2.1 Information Technology

Modern utility companies of the size and complexity of EGD typically incur substantial IT costs on an annual basis and hold large IT asset values on their balance sheets. To effectively maintain infrastructure and systems, deliver utility services and provide billing and customer services, companies like EGD invest in and maintain sophisticated IT hardware and software.

It is reasonable to expect that annual IT expenditures will be highly variable during periods when new programs and large-scale development projects are implemented. In years when new project systems are implemented or upgraded, costs are comparatively high. In years when

systems are stable and in sustainment mode, costs are comparatively low. These peaks and valleys are typically smoothed by periods of overlapping systems projects.

From 2007 to 2012, like its industry peers, EGD has undertaken numerous IT projects to evolve and modernize its information management capabilities to improve operations and customer service. Increases in IT RCAM allocations during this period are reflective of increased support requirements of EI, where many of EGD's systems are housed. Generally EI will implement or upgrade central systems while EGD and its other affiliates benefit from their use.

Increases in RCAM IT allocations in recent years have been due to support requirements for a number of system implementations and enhancements, including (but not limited to):

- Multi-year Financial Renewal project.
- Financial reporting requirements (i.e. U.S. GAAP).
- Khalix upgrades.
- Expense report system enhancements.
- HRCore Project (May 2010 launch to July 2012 go-live)
- Enterprise content management enhancements.
- SharePoint upgrade.
- Microsoft upgrades (e.g. email).
- Program and project management for upgrades.

2012 RCAM - Services Review - ($)		RCAM Allocation				
	Service Function	MNP Categorization	2007 OEB Approved	2012 Agreed under ISA	Increase (Decrease) from 2007 to 2012	CAGR from 2007 to 2012
6	Consolidation and Planning System Technical Support	Information Technology	375,868	245,089	(130,779)	-8.2%
10	Enterprise IT Program Management	Information Technology	149,002	868,494	719,492	42.3%
11	Enterprise IT Strategy Planning & Management	Information Technology	550,749	624,115	73,366	2.5%
12	Expense System Management & Technical Support	Information Technology	119,526	95,490	(24,036)	-4.4%
14	Financial and Project Accounting System Technical Support	Information Technology	320,766	352,161	31,395	1.9%
16	HRIS Program Management and Development	Information Technology	689,995	3,009,273	2,319,278	34.3%
23	Portal Suite Operations and Technical Support	Information Technology	259,283	330,881	71,598	5.0%
25	Records & Information Management	Information Technology	456,875	538,352	81,477	3.3%
		Information Technology Total	2,922,064	6,063,855	3,141,791	15.7%

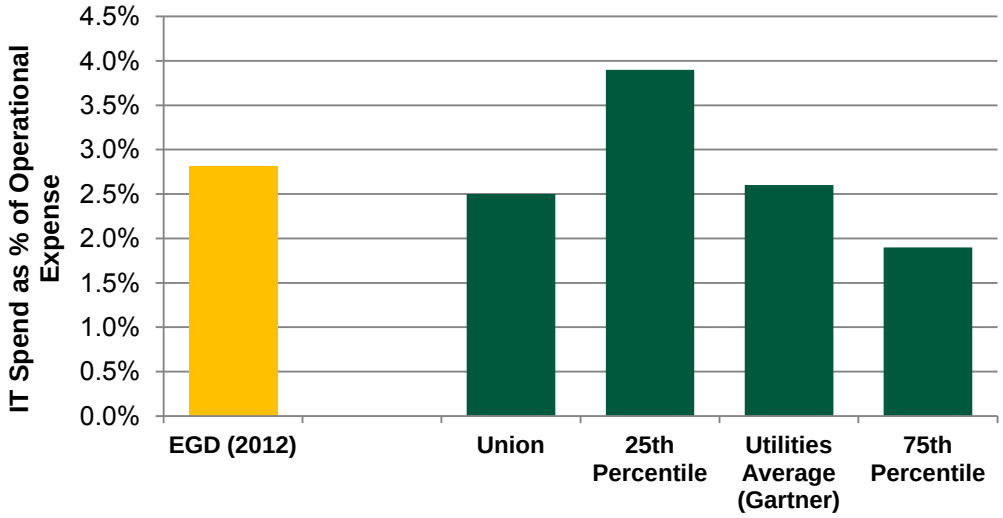
Comparator Analysis

The analysis below demonstrates that EGD's total annual information technology (IT) expenditures are reasonably aligned with other utility industry firms when measured as a percentage of total operating expenses. MNP drew on a study completed by KPMG for Union Gas Ltd. (Union) and its current rate filed case and rebasing application[10]. Using 2010 industry data developed by Gartner in the KPMG report, MNP compared EGD to Union and a set of over 90 other utilities from North America and international markets. In relation to Gartner's utilities average metric, Figure 1 below shows that EGD's total IT spend[11] (including all IT related O&M expenses and IT capital investments budgeted) as a percentage of its total 2012 budgeted operations expenses is 2.8%, which is in line with the industry average of 2.6%.

[10] Union Gas Ltd. 2013 Rebasing Application. EB-2011-0210, Exhibit D1 Tab 7 Appendix A.

[11] Enbridge Gas Distribution Inc. 2013 Rates Application. EB-2011-0354, Exhibit D1 Tab 1 Schedule 1 and Exhibits B1 Tab 4 and D1 Tab 16, Schedule 1.

Figure 1: IT Spend as a % of Operational Expense



Variance Analysis

MNP analysis of the growth in EGD IT-related spending also demonstrates reasonableness when compared to utility industry peers. The table below shows that EGD's average annual growth in IT expenditures falls near the bottom of the range of companies for which MNP found relevant data.

Average Annual IT Expense Growth[12]

Company	IT CAGR	Timeline
FortisBC	17.8%	2006 to 2012
Hydro One Networks Distribution	12.5%	2007 to 2011
Hydro One Total	10.9%	2007 to 2011
Toronto Hydro	9.8%	2008 to 2012
EGD	**6.4%**	**2007 to 2012**
Union Gas	4.4%	2010 to 2013

11.2.2 Human Resources

EGD is facing challenging conditions in terms of employee development and succession in light of its aging workforce and a strong commitment to employee and customer safety. According to EGD, 18% of its workforce (including 26% of its business leaders) is eligible to retire today, and 30% can retire within the next 5 years. This presents challenges to plan for and implement succession plans for continuity of leadership, ensure institutional knowledge is maintained as senior staff retire, enhance staff and management skills development, and attract and retain high performing staff while maintaining 50th percentile total compensation targets in the Toronto market.

[12] **Enbridge Gas Distribution** Inc. 2013 Rates Application. EB-2011-0354, Exhibit D1 Tab 1 Schedule 1 and Exhibits B1 Tab 4 and D1 Tab 16, Schedule 1.
Toronto Hydro 2012-2014 Electricity Distribution Rates Application. EB-2011-0144, Exhibits F2 Tab 1 Schedule 9 and D1 Tab 8 Schedule 1.
Hydro One Networks 2010 and 2011 Rate Application Update. EB-2009-0096, Exhibit C, Tab 2 Schedule 9.
Union Gas Ltd. 2013 Rebasing Application EB-2011-0210 Exhibit D3 Tab 3 and B1 Tab 7.
FortisBC Energy Utilities 2012 & 2013 Revenue Requirements & Natural Gas Rates Application. Appendix D-3, D-6.

EGD is undertaking a program to address these issues and position itself to continue to meet operational and customer service obligations in the future. As noted in the table below, the bulk of the increase from 2007 to 2012 lies with the Employee Development and Total Compensation & Benefits services. RCAM allocations to each HR service have increased due to support requirements in the following areas:

- Enhanced leadership development program, including:
  - Succession planning.
  - Knightsbridge Executive Development Program.
  - Mentoring Program.
  - New Union performance management process.
- Enbridge Learning Management System online training program.
- HRIS and PeopleSoft optimization.
- Total Compensation system design.

2012 RCAM - Services Review - ($)		RCAM Allocation				
	Service Function	MNP Categorization	2007 OEB Approved	2012 Agreed under ISA	Increase (Decrease) from 2007 to 2012	CAGR from 2007 to 2012
8	Employee and Labour Relations	Human Resources	253,529	478,201	224,672	13.5%
9	Employee Development	Human Resources	255,425	1,260,568	1,005,143	37.6%
17	Human Resource Advice	Human Resources	101,190	201,779	100,589	14.8%
30	Total Compensation & Benefits	Human Resources	865,843	1,781,809	915,966	15.5%
		Human Resources Total	1,475,987	3,722,357	2,246,370	20.3%

Comparator Analysis

Relative to other Ontario utility firms, EGD's entity level HR expenditures appear reasonable and within the range of comparable organizations when evaluating their cost effectiveness by the following metrics:

- Dollars of Revenue per dollar of HR expense.
- Dollars of Total Assets Managed per dollar of HR expense.
- FTE per million dollars of HR expense[13,14].

Figure 2 below summarizes HR expenses per FTE. The presumption within this analysis is that the lower the expense per FTE, the more cost-effectively HR services are delivered.

Using the most recent widely available data from 2011, Figure 3 summarizes revenue and assets per dollar of HR expense. Greater efficiency is directionally indicated by a higher result. EGD falls in line with its utility industry peers, particularly with the similar sized organizations of Union Gas and Toronto Hydro.

[13] Revenue and Assets – Company Annual Reports 2008 – 2011 (Toronto Hydro, Hydro One, Union Gas, EGD, Fortis BC, Manitoba Hydro, ENMAX).
[14] FTE - Board Filings: *Enbridge* EB-2011-0354, *Union* EB-2011-2010, *Hydro One* EB-2009-0096, *Toronto Hydro* EB-2011-0144 Appendix A.

Figure 2: HR Cost-Effectiveness Metrics – Resources per FTE (2011)

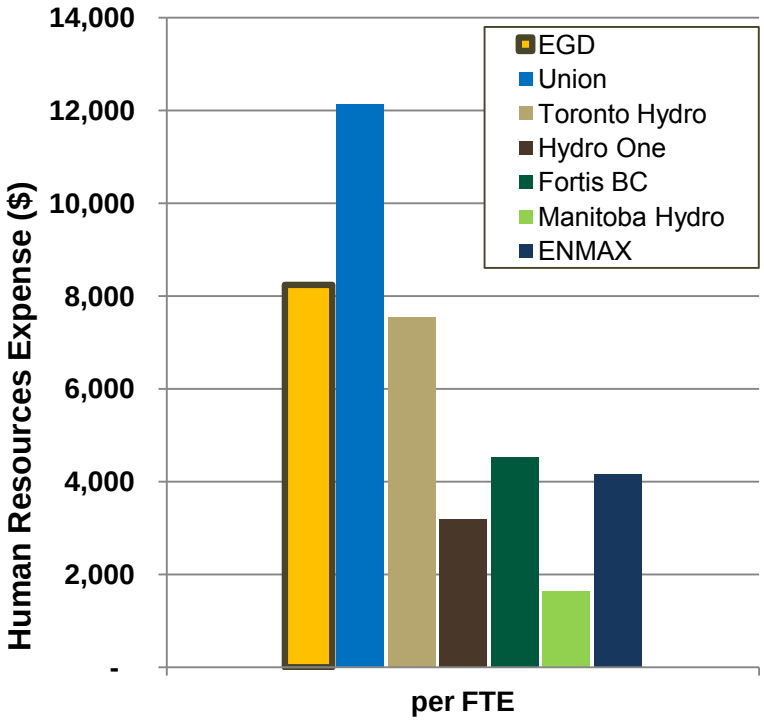
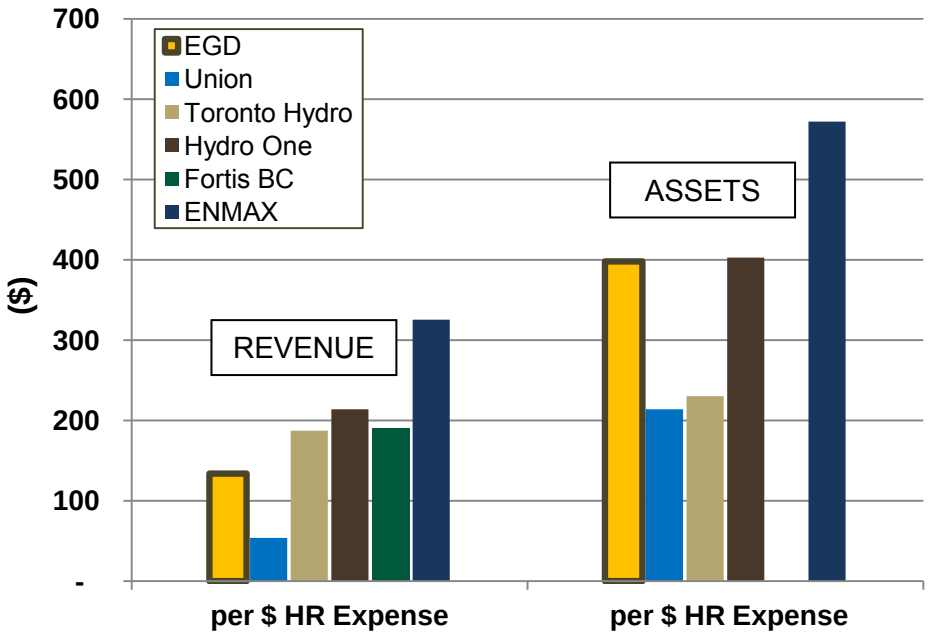


Figure 3: HR Cost-Effectiveness Metrics – Revenue & Assets (2011)



Variance Analysis

The growth of EGD human resources expenses also appears reasonable and on average, compounded annual growth is lower than other comparable utility firms where data was available. The table below demonstrates a 0.7% increase in EGD's average annualized growth rate, which is at the lower end of the range of annual growth estimates for other Ontario utilities. MNP found only recent and highly variable data for HR expenses for Union Gas, and could not therefore attribute relevant trend data.

Average Annual HR Expense Growth[15]

Company	HR CAGR	Timeline
Toronto Hydro	16.2%	2008 to 2011
Hydro One Total	11.3%	2007 to 2011
Hydro One Distribution	11.1%	2007 to 2011
FortisBC	8.7%	2007 to 2012
ENMAX Power	3.1%	2007 to 2010
EGD	**0.7%**	**2007 to 2012**
Manitoba Hydro	0.6%	2007 to 2012

Variance and Comparator Review Findings:

For IT and HR entity level expenditures, EGD demonstrates reasonable and competitive operational cost-effectiveness compared to other rate regulated utilities.

11.2.3 Departmental Cost Review

For each Primary Service, direct and common costs are allocated by EI at the departmental level to individual Primary Services through the use of time estimates and various cost drivers and associated allocators. Intervenors have expressed an interest in examination of the proportion of EI costs allocated to EGD by department (as opposed to Primary Service) over time, noting that EI departmental budgets have increased substantially since 2007.

MNP collected RCAM allocation data for 2007 and 2012, consolidated by department, and calculated the % of total EI departmental budgets allocated to EGD through the RCAM. MNP then calculated the increase or decrease in the % of departmental costs allocated to EGD from 2007 to 2012.

Excluding costs of new departments, MNP noted that EGD RCAM allocation ratios of the total EI department budget cost went from 13.2% in 2007 to 7.9% in 2012, a reduction of 5.2%.

[15] **Hydro One** Application, EB-2009-0096 Exhibit C1 Tab 2 Schedule 7, Schedule 8.
ENMAX Power Corp. AUC Rule 5: Annual Operations Financial and Operating Reporting. Years Ending 2009, 2010. Schedule 3.
FortisBC Energy Utilities 2012 & 2013 Revenue Requirements & Natural Gas Rates Application. Appendix D-1, D-3.
Toronto Hydro 2012-2014 Electricity Distribution Rates Application. EB-2011-0144, Exhibit F2, Tab 1 Schedule 10.
Manitoba Hydro 2010/11 & 2011/12 General Rate Application. Tab 6 & 11 and Appendix 4.4 & 11.
Enbridge Gas Distribution Inc. 2013 Rates Application. EB-2011-0354, Exhibit A1 Tab 2 Schedule 1.

Including the support services budget (incorporating primarily administration, accounting and IT), EGD's RCAM ratio went from 12.3% to 7.9%. While EI total budget costs for departments and support services increased by 255% from $84.1 million to $214.4 million from 2007 to 2012, EGD's RCAM allocation for Primary Services increased by 164% from $10.3 million to $16.9 million over the same period.

Unless EGD's demand for shared services has kept pace with the growth of EI departmental budgets, MNP would expect to see EGD take on a smaller portion of EI's department costs through the RCAM. Although EGD demand for services has increased, particularly for HR and IT support, as evidenced below the ratio of EI's department costs has decreased over time.

2012 RCAM - Services Review - ($)	EI Department Budget		RCAM Allocation		EGD RCAM % of EI Dept Budget		
EI Department	2007	2012 ISA Agreed	2007 OEB Approved	2012 ISA Agreed	2007	2012 ISA Agreed	Variance from 2007 to 2012
Alternative & Emerging Technology (10106)	2,110,298	5,332,830	132,892	-	6.3%	0.0%	-6.3%
Audit Services (Calgary) (10050)	1,013,972	2,598,546	56,281	137,506	5.6%	5.3%	-0.3%
CEO (10000)	5,602,432	12,954,780	843,476	1,918,027	15.1%	14.8%	-0.2%
CFO (10045)	1,530,913	3,719,515	220,142	330,663	14.4%	8.9%	-5.5%
CIO (10001)	2,697,401	4,030,466	1,180,225	1,254,040	43.8%	31.1%	-12.6%
Corp Climate Change	61,320	-	15,238	-	24.9%	0.0%	-24.9%
Corporate Admin. (10071)	641,502	1,544,417	59,057	28,055	9.2%	1.8%	-7.4%
Development and Planning (10107)	3,078,670	10,826,264	790	-	0.0%	0.0%	0.0%
Corporate Controller (10047)	5,302,675	15,939,163	208,518	268,893	3.9%	1.7%	-2.2%
Corporate HR (10092)	1,453,644	3,946,946	328,785	457,808	22.6%	11.6%	-11.0%
Corporate IT Operations (10009) livelink licence only	-	702,993	-	36,743	0.0%	5.2%	5.2%
Corporate IT Operations (10009) no livelink licence	1,674,358	1,479,996	151,216	105,770	9.0%	7.1%	-1.9%
Corporate Law (10077)	1,459,539	5,979,072	208,594	326,004	14.3%	5.5%	-8.8%
Corporate Law Legal Fees (10020)	306,600	600,000	44,226	36,612	14.4%	6.1%	-8.3%
Corporate Secretarial (10070)	2,314,249	4,423,865	310,424	138,077	13.4%	3.1%	-10.3%
Corporate Secretarial Legal Fees (10024)	1,175,300	1,220,000	179,319	87,253	15.3%	7.2%	-8.1%
BD East	1,075,543	-	107,554	-	10.0%	0.0%	-10.0%
EFS Strategy & Services (10040)	1,048,304	701,602	350,486	145,374	33.4%	20.7%	-12.7%
EGD Charge	334,194	1,716,941	16,265	2,113	4.9%	0.1%	-4.7%
Enterprise Content Management (10075)	523,784	5,821,798	221,714	304,287	42.3%	5.2%	-37.1%
Enterprise Risk (10046)	-	10,938,498	-	673,278	0.0%	6.2%	6.2%
EPI Charge	4,015,713	14,905,724	54,825	48,135	1.4%	0.3%	-1.0%
Executive VP Corporate Law	-	3,765,602	-	112,968	0.0%	3.0%	3.0%
Group VP Gas Strategy	3,371,759	-	570,125	-	16.9%	0.0%	-16.9%
People & Partners (10094)	1,703,382	3,898,081	394,860	763,916	23.2%	19.6%	-3.6%
HR Enterprise Business Solutions (10089)	-	2,001,904	-	599,029	0.0%	29.9%	29.9%
HRIS Services (10095)	994,368	4,698,241	371,208	1,460,590	37.3%	31.1%	-6.2%
Industry Associations (10023)	475,211	15,914	44,321	856	9.3%	5.4%	-3.9%
Investor Relations (10043)	1,993,628	2,423,890	314,820	65,225	15.8%	2.7%	-13.1%
IT Planning and Governance (10012)	-	4,772,072	-	751,601	0.0%	15.8%	15.8%
Labour Relations (10093)	437,232	1,014,064	177,611	453,245	40.6%	44.7%	4.1%
Risk Insurance (10051)	555,782	1,108,561	67,219	33,257	12.1%	3.0%	-9.1%
Pension & Benefits (10096)	572,092	-	237,893	-	41.6%	0.0%	-41.6%
Investment Review (10109)	1,991,541	2,423,985	35,413	-	1.8%	0.0%	-1.8%
Public & Government Affairs (10072)	3,311,502	16,935,260	319,489	444,382	9.6%	2.6%	-7.0%
Records Management (10079)	-	1,151,750	-	60,198	0.0%	5.2%	5.2%
Organizational Effectiveness(10090)	468,447	3,004,859	52,235	530,855	11.2%	17.7%	6.5%
Tax Services (Calgary) (10049)	1,940,759	3,162,738	6,899	40,013	0.4%	1.3%	0.9%
Total Compensation (10091)	849,259	3,829,233	274,700	989,517	32.3%	25.8%	-6.5%
Treasury (10044)	6,529,362	7,222,792	1,004,875	917,929	15.4%	12.7%	-2.7%
Gas P/L Development (East) (10110)	1,355,126	-	40,507	-	3.0%	0.0%	-3.0%
Gas P/L Development (West) (10111)	1,727,342	-	38,213	-	2.2%	0.0%	-2.2%
Total Departmental Costs	65,697,198	170,812,364	8,640,415	13,522,222	13.2%	7.9%	-5.2%
Support Services Budget	18,395,199	43,594,682	1,671,762	3,345,945	9.1%	7.7%	-1.4%
Total Primary Services	84,092,397	214,407,046	10,312,177	16,868,167	12.3%	7.9%	-4.4%

11.3 RETURN ON INVESTMENT REVIEW

The ARC allows for a return on invested capital as indicated below.

> 2.3.10 Where it can be established that a reasonably competitive market does not exist for a service, product, resource or use of asset that a utility acquires from an affiliate, the utility shall pay no more than the affiliate's fully-allocated cost to provide that service, product, resource or use of asset. The fully-allocated cost may include a return on the affiliate's invested capital. The return on invested capital shall be no higher than the utility's approved weighted average cost of capital.[16]

A return on invested capital has not been incorporated as a part of each Primary Services' fully allocated cost, but is included as a separate charge in RCAM. The invested capital has been defined as the NBV (net book value) of PPE (property, plant and equipment) assets of EI required to provide the services.

The table below summarizes the Return on Investment calculations for 2012 and 2013. The 2013 return is consistent with EGD's 2013 rate case filing for the 2013 cost of service year.

Rate of Return Calculations

2012						2013	
Net Book Value of EI Assets	Allocation Mechanism to EGD	Allocation Percentage	EGD Portion of EI Assets	Allowable Rate of Return	EGD 2012 Rate of Return	Allowable Rate of Return	EGD 2013 Rate of Return
35,087,973	FCER	14%	4,866,702	7.58%	368,896	7.35%	357,703

[16] Affiliate Relationships Code for Gas Utilities, OEB, last Revised November 25, 2010.

12 COST ALLOCATION REVIEW – 2013 – ANALYSIS & FINDINGS

For purposes of evaluating the RCAM process and results, MNP conducted its research and analysis based on 2012 data. The completed 2012 RCAM build up process between EI and EGD has allowed MNP to conduct its assessment with a full suite of RCAM documentation.

Given that the suite of RCAM documents has not been prepared for 2013, the only analytical requirement in scope for MNP relating to 2013 is an assessment of the escalation factor and methodology used to inflate 2012 RCAM allocations. EGD has opted to use 2012 RCAM data to provide the basis for its 2013 RCAM budget. The 2013 budget for primary services has been escalated by a factor approved by EI, in this case 2.2%[17]. Directors Fees and Charges and EGD Stock Based Compensation are both escalated in the same manner for 2013, while other Direct Charges and General Expenses have been estimated by EI as constants from 2012.

12.1 ESCALATOR REVIEW

EGD has selected an escalator based on the average of Alberta consensus CPI forecasts from TD, RBC, BMO and CIBC, which indicates 2.2% growth for 2013, which MNP finds reasonable based on the logical escalating index of CPI, credible sources for the estimate, and independent corroboration.

The table presented below shows the calculated escalation factor by service, and in a number of instances the calculated escalation factor varies slightly from the stated factor of 2.2%, resulting in a consolidated escalation of 2.17% for primary services.

12.2 PRONG THREE PROPOSED MNP ADJUSTMENTS FOR 2013

For the 3 primary service allocations that fell above the MNP internal service provision range for 2012 (Capital Market Financing and Access, Employee Development and HRIS Program Management and Development), MNP has recommended a combined downward adjustment to the 2012 RCAM allocations of $154,923. Based on this 2012 RCAM adjustment and escalation factors used by EGD to develop 2013 RCAM estimates for each service, MNP recommends a corresponding combined downward adjustment to the 2013 RCAM allocations of $158,329.

Prong Three Adjustments for 2012 and 2013

2013 RCAM - Services Review - ($)		2012 RCAM Allocation			2013 RCAM Allocation		
	Service Function	2012 Agreed under ISA	2012 Prong 3 MNP Proposed Adjustment	2012 MNP Proposed	2013 EGD Proposed	2013 Prong 3 MNP Proposed Adjustment (escalated 2012 Adjustment)	2013 MNP Proposed
4	Capital Market Financing & Access	1,020,173	(28,303)	991,870	1,042,564	(28,924)	1,013,640
9	Employee Development	1,260,568	(14,945)	1,245,623	1,288,299	(15,274)	1,273,025
16	HRIS Program Management and Development	3,009,273	(111,675)	2,897,598	3,075,443	(114,131)	2,961,312
	Primary Service Totals	16,868,167	(154,923)	16,713,244	17,234,234	(158,329)	17,075,905

[17] Average of Alberta consensus CPI forecast from four banks - TD, RBC, BMO and CIBC.

Calculated Escalators for 2013

2013 RCAM - Services Review - ($)		RCAM Allocations		
	Service Function	2012 Agreed under ISA	2013 EGD Proposed	% Change
1	Audit & Accounting Advice	91,270	93,278	2.20%
2	Board of Directors Support	769,368	785,892	2.15%
3	Business Development	736,918	753,039	2.19%
4	Capital Market Financing & Access	1,020,173	1,042,564	2.19%
5	Cash Management & Banking	481,073	491,656	2.20%
6	Consolidation and Planning System Technical Support	245,089	249,486	1.79%
7	Corporate Compliance	197,202	201,540	2.20%
8	Employee and Labour Relations	478,201	488,722	2.20%
9	Employee Development	1,260,568	1,288,299	2.20%
10	Enterprise IT Program Management	868,494	887,579	2.20%
11	Enterprise IT Strategy Planning & Management	624,115	637,845	2.20%
12	Expense System Management & Technical Support	95,490	97,384	1.98%
13	External Audit Coordination	103,399	105,673	2.20%
14	Financial and Project Accounting System Technical Support	352,161	358,097	1.69%
15	Government Relations	44,917	45,895	2.18%
16	HRIS Program Management and Development	3,009,273	3,075,443	2.20%
17	Human Resource Advice	201,779	206,184	2.18%
18	Industry Relations & Corporate Social Responsibility	384,365	392,741	2.18%
19	Insurance Claims Support, Strategy and Management	108,240	109,912	1.54%
20	Investor Services	883,837	903,044	2.17%
21	Legal Advice	514,396	525,600	2.18%
22	Planning, Management, & Execution of Internal Audits	191,528	195,741	2.20%
23	Portal Suite Operations and Technical Support	330,881	338,160	2.20%
24	Rate Regulated Entity Support	253,904	259,490	2.20%
25	Records & Information Management	538,352	550,195	2.20%
26	Risk Assessment & Management	878,461	897,681	2.19%
27	Strategic Planning	327,890	335,020	2.17%
28	Supply Chain Management	39,706	40,580	2.20%
29	Tax Reporting & Planning	55,308	56,525	2.20%
30	Total Compensation & Benefits	1,781,809	1,820,969	2.20%
	Primary Service Totals	16,868,167	17,234,234	2.17%
31	Depreciation - Risk Management System	64,951	64,951	0.00%
32	Direct EFS Charge	(2,314,784)	(2,314,784)	0.00%
33	Directors Fees & Charges	744,819	761,205	2.20%
34	Audit Fees	N/A	N/A	N/A
35	EGD Stock Based Compensation	7,549,229	7,715,312	2.20%
36	Insurance Premiums	8,483,868	8,483,868	0.00%
	Direct Charges and General Expenses Total	14,528,083	14,710,552	1.26%
	Return on Investment	368,896	357,703	-3.03%
	Total RCAM Allocation	31,765,146	32,302,489	1.69%

13 CONCLUSION

13.1 MNP FINDINGS

Based on analysis of information gathered, interviews conducted, research undertaken, and comparisons to industry standards and leading practices, MNP made the following key findings:

RCAM Methodology Review

- The ISA is compliant with the ARC.
- The RCAM Methodology remains appropriate for EGD and is adhered to in the development of allocations for 2012 (and 2013 through the escalator).
- Further to MNP's integrity testing on a sample basis, MNP found no calculation errors with the RCAM financial model. The RCAM financial model appears to operate as expected.

Cost Allocation Review

- With consideration for exclusions and service levels required for EGD 2012 business activity, all services passed the Incurrence component of the Three Prong Test.
- All services passed the Allocation component of the Three Prong Test for 2012.
- All but three Primary services passed the Cost Benefit component of the Three Prong Test. The three failed Primary services are Capital Market Financing and Access, Employee Development and HRIS Program Management and Development. These test failures result in a combined MNP recommended downward adjustment to 2013 RCAM EGD proposed allocations by $158,329.
- Variance and comparator analysis shows that EGD's operational performance relating to entity level HR and IT expenditures is reasonable and competitive with other rate regulated utilities in Ontario and other jurisdictions.
- The Return on Invested Capital calculation for 2013 is appropriate and compliant with the ARC.
- The escalation factor selected by EGD to estimate 2013 RCAM allocation is reasonable.

In MNP's opinion, incorporating MNP proposed adjustments based on the failed Prong Three Tests, the 2012 and 2013 RCAM corporate services allocations are being incurred prudently and allocated appropriately with benefits that exceed costs for ratepayers.

2012 and 2013 RCAM Proposed Allocations

2013 RCAM - Services Review - ($)		2012 RCAM Allocation			2013 RCAM Allocation		
	Service Function	2012 Agreed under ISA	2012 Prong 3 MNP Proposed Adjustment	2012 MNP Proposed	2013 EGD Proposed	2013 Prong 3 MNP Proposed Adjustment (escalated 2012 Adjustment)	2013 MNP Proposed
1	Audit & Accounting Advice	91,270	-	91,270	93,278	-	93,278
2	Board of Directors Support	769,368	-	769,368	785,892	-	785,892
3	Business Development	736,918	-	736,918	753,039	-	753,039
4	Capital Market Financing & Access	1,020,173	(28,303)	991,870	1,042,564	(28,924)	1,013,640
5	Cash Management & Banking	481,073	-	481,073	491,656	-	491,656
6	Consolidation and Planning System Technical Support	245,089	-	245,089	249,486	-	249,486
7	Corporate Compliance	197,202	-	197,202	201,540	-	201,540
8	Employee and Labour Relations	478,201	-	478,201	488,722	-	488,722
9	Employee Development	1,260,568	(14,945)	1,245,623	1,288,299	(15,274)	1,273,025
10	Enterprise IT Program Management	868,494	-	868,494	887,579	-	887,579
11	Enterprise IT Strategy Planning & Management	624,115	-	624,115	637,845	-	637,845
12	Expense System Management & Technical Support	95,490	-	95,490	97,384	-	97,384
13	External Audit Coordination	103,399	-	103,399	105,673	-	105,673
14	Financial and Project Accounting System Technical Support	352,161	-	352,161	358,097	-	358,097
15	Government Relations	44,917	-	44,917	45,895	-	45,895
16	HRIS Program Management and Development	3,009,273	(111,675)	2,897,598	3,075,443	(114,131)	2,961,312
17	Human Resource Advice	201,779	-	201,779	206,184	-	206,184
18	Industry Relations & Corporate Social Responsibility	384,365	-	384,365	392,741	-	392,741
19	Insurance Claims Support, Strategy and Management	108,240	-	108,240	109,912	-	109,912
20	Investor Services	883,837	-	883,837	903,044	-	903,044
21	Legal Advice	514,396	-	514,396	525,600	-	525,600
22	Planning, Management, & Execution of Internal Audits	191,528	-	191,528	195,741	-	195,741
23	Portal Suite Operations and Technical Support	330,881	-	330,881	338,160	-	338,160
24	Rate Regulated Entity Support	253,904	-	253,904	259,490	-	259,490
25	Records & Information Management	538,352	-	538,352	550,195	-	550,195
26	Risk Assessment & Management	878,461	-	878,461	897,681	-	897,681
27	Strategic Planning	327,890	-	327,890	335,020	-	335,020
28	Supply Chain Management	39,706	-	39,706	40,580	-	40,580
29	Tax Reporting & Planning	55,308	-	55,308	56,525	-	56,525
30	Total Compensation & Benefits	1,781,809	-	1,781,809	1,820,969	-	1,820,969
	Primary Service Totals	16,868,167	(154,923)	16,713,244	17,234,234	(158,329)	17,075,905
31	Depreciation - Risk Management System	64,951	-	64,951	64,951	-	64,951
32	Direct EFS Charge	(2,314,784)	-	(2,314,784)	(2,314,784)	-	(2,314,784)
33	Directors Fees & Charges	744,819	-	744,819	761,205	-	761,205
34	Audit Fees	N/A	N/A	N/A	N/A	N/A	N/A
35	EGD Stock Based Compensation	7,549,229	-	7,549,229	7,715,312	-	7,715,312
36	Insurance Premiums	8,483,868	-	8,483,868	8,483,868	-	8,483,868
	Direct Charges and General Expenses Total	14,528,083		14,528,083	14,710,552	-	14,710,552
	Return on Investment	368,896		368,896	357,703	-	357,703
	Total RCAM Allocation	31,765,146	(154,923)	31,610,223	32,302,489	(158,329)	32,144,160

13.2 MNP RECOMMENDATIONS

ADJUSTMENTS

With the three failed Prong Three Tests, MNP proposes a consolidated downward adjustment to 2012 and 2013 RCAM allocations of $154,923 and $158,329, respectively.

IMPROVEMENT OPPORTUNITIES

Based upon observation and investigation, MNP has identified a number of opportunities to improve the RCAM process.

1. **Categorize and Roll up Services for Comparison Purposes** – Despite EGD's alignment with RCAM methodology, with 36 different services it still reports RCAM allocation information at a comparatively granular level with industry comparators. This makes it difficult to compare individual service allocation costs with others to evaluate cost/benefit, and in some cases inhibits the cost-effective opportunity to go to the competitive market to investigate alternative costing. MNP recommends that EGD categorize and roll up services to levels more consistent with reporting of other utilities for comparison purposes, and subsequently undertake a more structured benchmarking study to evaluate costs.

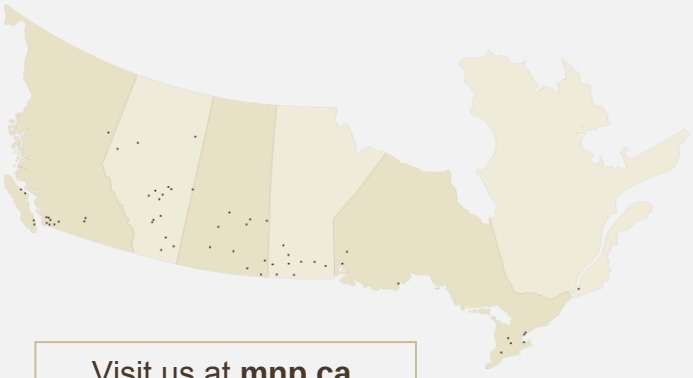
2. **Business Case Upgrades** – MNP recommends that EGD develop two specific upgrades to business cases:

    a. **Criteria for External Estimates of Cost** – Part III of the business cases requires Service Recipients to estimate costs for external provision of services. Part III also provides an exemption to this requirement if the Recipient deems that there is not a competitive market for equivalent services. In a number of cases, Recipients did not attempt estimates due to factors other than the "the lack of a reasonably competitive market", although an external estimate may have been of some value in assessing the provision of service. MNP recommends that EGD develop and implement more defined exemption criteria for Service Recipients external estimates.
    b. **Variance Analysis** – MNP feels it would be prudent to add a section to each business case to track year over year variances in allocation cost. The business cases do not attempt to justify how and why costs are increasing or decreasing over time. Capturing this information may result in new criteria for sourcing the services and allow the Recipient and other stakeholders to compare cost trends to competitors or the market.

3. **Service Level Evaluation** – Although it was apparent that Service Recipients and Service Providers are generally in regular if not frequent communication, MNP was not made aware of any formal retrospective evaluation of service levels or performance at year end or through the budgeting process for the upcoming year. Leading practices in the area of procurement and vendor management suggest that the service recipient hold the service provider to agreed upon performance metrics using a service level agreement or other evaluation mechanism. Similarly, if EGD were to source the services internally, employees would take part in EGD's performance management

process. This type of process benefits both parties by confirming expectations and providing opportunities to confirm the quality of provision and improve levels of service.

4. **Recovery Mechanism** – Through the course of its investigation, MNP discovered that for 2011, EGD incurred a large shortfall (approximately $2.9 million) in the allocation of insurance premiums due to a large unanticipated discrepancy between the budged allocation and the actual charge shortly thereafter. In cases like these where there is a windfall or shortfall, MNP feels it would be prudent on behalf of ratepayers to consider employing existing or new mechanisms to recover or otherwise true-up any material discrepancies based on unanticipated differences between budgeted and actual allocations for the budget year.



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Praxity MEMBER GLOBAL ALLIANCE OF INDEPENDENT FIRMS

MNP LLP

ENBRIDGE GAS DISTRIBUTION INC

INDEPENDENT EVALUATION OF THE 2013 REGULATORY COST ALLOCATION METHODOLOGY RESULTS

APPENDIX

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Date : May 17, 2012

MNP

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APPENDIX A – MNP SCOPE PER CONSULTING AGREEMENT

SCHEDULE "A"
Project Services Schedule

Project Service Schedule to the Consulting Agreement between
Enbridge Gas Distribution Inc. ("Enbridge") and
MNP LLP ("MNP")
dated September 29, 2011

1. **Project Overview**: Enbridge is a gas distributor whose rates and services are regulated by the Ontario Energy Board (the "**OEB**") under Part III of the *Ontario Energy Board Act*, 1998 as amended (the "**OEB Act**"). MNP will be conducting an Independent Update and Review (the "**Study**") of Enbridge's Regulatory Cost Allocation Methodology ("**RCAM**") in support of Enbridge's 2013 cost of service information to be filed with the OEB. As Independent Reviewer, MNP will assess the reasonableness and appropriateness of corporate service charges calculated by RCAM. MNP will complete the Study through the work plan, activities, deliverables and project team described in this Schedule.

2. **Scope of Work**: The scope of the Study will include the following in-scope objectives:

   MNP will provide a written report and shall act as expert witness to Enbridge's 2013 Rate Application, if required, by Enbridge or the OEB. The objective of the Study to be carried out by MNP is to review, to the extent MNP considers reasonably necessary, the results generated using the RCAM methodology which was previously approved by the Board and used to calculate the corporate service charges in the 2007 Rate Case. MNP will also undertake an independent review and determine the status of those recommendations made in MNP's 2007 Independent Evaluation of Enbridge Gas Distribution Inc.'s Regulatory Corporate Cost Allocation Methodology (the "**2007 MNP Report**"). The Study will further review any revisions or updates to RCAM subsequent to the 2007 MNP Report.

3. **Background:** MNP was earlier retained to undertake an independent evaluation of the regulatory corporate cost allocation methodology and the implementation of certain refinements and modifications which the OEB directed Enbridge to implement in its Decision with Reasons dated February 9, 2006, in EB-2005-001. MNP completed its independent evaluation and generated the 2007 MNP Report which confirmed that the refinements and modifications required by the Board had been implemented. The 2007 MNP Report further undertook an independent review of the results generated by the RCAM and generated an amount payable which MNP considered reasonable based upon its review. In the 2007 rates proceeding, EB-2006-0034, the OEB accepted that Enbridge had implemented the required refinements to the RCAM methodology and the quantum of the RCAM for 2007, as determined by MNP using the RCAM. This revised RCAM methodology has been utilized by Enbridge for the years 2008 through 2011 to generate the annual quantum used for ratemaking purposes.

4. In the 2010 Earnings Sharing Mechanism ("ESM") proceeding, EB-2011-0008, Enbridge agreed that as part of the evidence in support of its 2013 Application, Enbridge would work with a third party consultant to prepare and file an updated study addressing the costs sought to be recoverable under the RCAM for future years. As the RCAM methodology has previously been approved, MNP and Enbridge do not view MNP's mandate to involve a review of the methodology. While MNP is engaged to undertake a review as an independent evaluator, and retains the discretion to determine the extent and detail of its review, MNP may not consider it reasonably necessary to, for example, undertake a complete review and analysis of every service provided where, for example, there has been little or no change in the nature of the services delivered and received, or the immateriality of the amount.

5. Where MNP reviews services for the purposes of the Study, MNP shall consider whether:

- the service is specifically required by the utility;
- the level of service provided is required by the utility;
- the costs are allocated based on cost causality and cost drivers;
- the cost to provide the service internally would be higher and the cost to acquire the service externally on a stand-alone basis would be higher; and
- there are scale economies.

6. Where MNP reviews corporate service charges for the purposes of the Study, MNP will determine whether:

- the three-pronged regulatory test established by the OEB in the EBRO 493/494 Decision has been met[1];
- Enbridge Inc's ("**EI")** shared service offerings fall within the range of fair market value for a company of Enbridge's size and complexity; and
- the current Intercorporate Services Agreement ("**ISA")** complies with the OEB's Affiliate Relationships Code for Gas Utilities and how it compares to industry and regulatory precedent in Ontario and elsewhere.

7. MNP's role as an independent reviewer includes the mandate to receive and reasonably consider the comments of all stakeholders prior to finalizing the Study.

8. The following related work will be carried out under separate engagement, if and as necessary, after the delivery of the final Study:

- Completion of formal Working Papers in support of MNP's defence of its findings before the OEB
- Responses to information requests resulting from the regulatory process
- MNP's defence of its findings before the OEB, as an expert witness

9. In conducting its analysis, MNP will review, at a minimum the following documentation:

[1] In this decision, the OEB laid out the three-pronged regulatory test (Cost Incurrence, Cost Allocation and Cost/Benefit) according to which all corporate costs should be evaluated.

- The current ISA between EI (as service provider) and Enbridge (as service recipient) and attachments
- The evidence filed with the OEB, questions from intervenors, Enbridge's responses to these questions, and testimony by Enbridge and Intervenors on the subject of Corporate Cost Allocations for the 2013 rates proceeding
- OEB's Affiliate Relationships Code for Gas Utilities
- OEB's Decision with Reasons dated March 20, 1997 in EBRO 493/494 regarding the adoption of the three-pronged regulatory test
- Time Study Model
- RCAM Financial Model
- Time Estimates completed by EI that MNP considers reasonably necessary to review
- Business Case Analysis prepared by Service Recipients to rationalize and justify the corporate service allocation amounts
- The Settlement Proposal from the 2006 Rate Case; the OEB's Decision with Reasons from the 2006 Rate Case; and all prior and subsequent Settlement Proposals and OEB Decisions relevant to RCAM (which Enbridge shall supply)
- Results from MNP's data collection process and stakeholder comments on the draft Study
- Deloitte Report filed in EB-2005-001/2005-0437

10. **Deliverables:** Deliverables will comprise those items/activities set out in this Schedule and the Work Plan attached hereto. A draft Study will be provided to Enbridge for review and comment prior to issuance of a final Study reflecting changes requested by the stakeholders involved (Enbridge, EI, Intervenors), which MNP considers reasonable and consistent with the approved RCAM Methodology. MNP will provide at a minimum weekly updates which will detail progress against milestones, and discussions with any of the stakeholders.

Enbridge Gas Distribution – RCAM Study Update – Draft Scope and High-Level Workplan

Primary Task	Description	Notes	Due Date(s)
PLAN	Project Planning	• Objectives, Scope, Milestones • Communications (EGD and EI) • Detailed Workplan	Approx Oct 10
OEB	Review OEB Decisions and Directives	• Drives objective and scope	Nov 30 Target Date
ISA	ISA Review and Assessment	• Compliance with ARC	
RCAM	RCAM Methodology Review	• Updates since 2007	
RCAM	RCAM Integrity Testing	• Financial integrity	
RECC	Review Implementation of MNP Recommendations	• Service descriptions • EGD-specific vs. EI Common • Service schedules for exclusion • Services roll-up for comparison • Business cases	
PRONG TESTS	Prong 1 Test - Cost Incurrence Prong 2 Test - Cost Allocation Prong 3 Test - Cost/Benefit	• Focus on variances from 2007 as practicable • Primary Services • General Services • Direct Charge Services	
REPORT	Draft Report Development	• For review by stakeholders	
STAKE	Stakeholder Consultation	• EGD, EI, MNP, OEB • Participating Intervenors	Jan 15 Target Date
REPORT	Final Report	• Incorporate feedback and refine report	Jan 31 Target Date (based on Settlement Conference Guidelines)

APPENDIX B – EGD SERVICE SCHEDULES

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

Regulatory Cost Allocation Methodology Service Schedules

Effective January 1, 2012

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

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APPENDIX A. Cost Allocations to EGD

Primary Services

The following tables outline the primary services provided by the Service Provider to EGD. These primary services are agreed to in writing by a representative of EGD.

A primary service is defined as a service provided by the Service Provider to the Service Recipient either as the sole provider where EGD relies solely on EI for this service or as a supplemental provider (where EGD itself performs a component of the required activities of the service). A list of the primary services and the bases of allocation attributable thereto are set out in RCAM.

Each table provides details for:

- The service definition;
- The specific services provided by each Service Provider department;
- The EGD representative responsible for agreeing to the service;
- The EGD cost for the service as calculated in the RCAM model;
- The expected deliverables; and
- The quantity and quality of the service.

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1. Audit & Accounting Advice

Service Description	
Service Definition:	The Audit and Accounting Advice service is responsible for providing EGD with research and advice related to the company's audit and accounting practices. This includes advising on proposed changes relating to accounting guidance and securities regulation requirements and the related business impacts.
Services Identified by Department	**Audit Services Department** The Audit and Accounting Advice service is responsible for providing EGD with research and advice related to the company's audit and accounting practices. This includes advising on proposed changes relating to accounting guidance and securities regulation requirements and the related business impacts. The Audit Services Department supports this service by coordinating the collection and dissemination of changes in accounting and audit practices in relation to the statutory and regulatory environments (i.e. CICA, AcSB, FASB, OSC, CPAB, SEC, PCAOB, GAAP and GAAS) and their potential business impacts. Examples of activities related to the provision of the service include: • Research changes to GAAS as they relate to audit procedures and develop impact assessments **Corporate Controller Department** The Audit and Accounting Advice service is responsible for providing EGD with research and advice related to the company's audit and accounting practices. This includes advising on proposed changes relating to accounting guidance and securities regulation requirements and the related business impacts. The Corporate Controller Department supports this service by researching accounting issues designed to improve corporate knowledge of all new financial reporting requirements and is responsible for managing the implementation of new accounting standards Examples of activities related to the provision of this service include: • Research changes to GAAP as they relate to accounting policy and develop impact assessments, including recent changes to accounting for rate regulated entities • Restate historical results due to changes in GAAP • Assess changes in business practices and need for changes in accounting policies • Research general accounting and industry trends • Provide advice on specific transactions • Consultation on response to the securities regulator relating to detailed review of EGD's disclosure obligations **Enterprise Security Department** The Audit and Accounting Advice service is responsible for providing the organization with research and advice related to the company's audit and accounting practices. This includes advising EGD on proposed changes relating to accounting guidance and securities regulation requirements and the related business impacts. The Enterprise Security Department supports this service by being responsible for incident prevention policies across the organization with the ability to identify and understand security risks in the business environment, apply the necessary controls to mitigate those risks, and enlist the support of other departments (Risk Management, Internal Audit, Human Resources, etc) in order to mitigate the risks.

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	Examples of activities related to the provision of the service include: • Define, identify and understand security risks in the business environment of EGD • Monitor and update controls and policies in relation to mitigation of identified risks
Service Recipient:	Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
Audit Services (Calgary)	$16,636
Corporate Controller	$74,634
Enterprise Security	$0
Total	**$91,270**

Expected Deliverables

- Support EGD's audit and accounting infrastructure with accounting research, insights and knowledge

Quantity and Quality of Service

- On demand access to expertise and research and knowledge
- Effective, current accounting policies

Authorized Signature

Mr. Narin Kishinchandani
Vice-President Finance
Enbridge Gas Distribution

Mar 2, 2012
Date

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2. Board of Directors Support

Service Description	
Service Definition:	The Board of Directors Support service is responsible for providing lines of communication between EGD Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committees.
Services Identified by Department	**CEO Department** The Board of Directors Support service is responsible for providing lines of communication between EGD Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committees. The CEO Department supports this service by providing representation and a direct line of communication with the EGD Board. Examples of activities related to the provision of the service include: • Maintain a seat on the EGD Board of Directors • Keep the EGD Board informed on all relevant company issues; including receiving guidance from board on course of action and incorporating input into the strategic direction of the company • Communicating strategies for executive and board compensation • Provide active participation and leadership to board meeting preparation activities; including the development of presentations and other relevant material • Act as the central point of contact for Directors on issues and concerns **CFO Department** The Board of Directors Support service is responsible for providing lines of communication between EGD Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committees. The CFO Department supports this service by providing senior leadership, overall management guidance and advice regarding EGD's financial affairs. Examples of activities related to the provision of the service include: • Liaise between Finance Departments and the Board of Director's Audit Finance and Risk Committee **People and Partners Department** The Board of Directors Support service is responsible for providing lines of communication between EGD Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committees. The People and Partners Department supports this service by coordinating and providing the required administrative and consulting services that the EGD board requires as well as acting as a liaison between the Board of Directors and Board Committee. Examples of activities related to the provision of the service include: • Provide EGD representation on various board committees o Social Responsibility Committee ▪ Prepare agenda and documents for the chairperson ▪ Prepare formal EH&S report ▪ Prepare incident reports ▪ Prepare CSR annual report o Governance Committee

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- Assist with board committees
- Involved in the appointment of directors and officers to EGD Board
- Involved with whistle-blower protection and code of conduct

  - Human Resources and Compensation Committee
    - Assist board committee on compensation and succession planning
    - Recommend compensation for EGD
    - Responsible for recommendations for STIP and LTIP
    - Responsible for prudence and due diligence on compensation related matters
    - Engage consultants to provide independent counsel and advice
    - Provide guidance and advice to EGD related to succession planning and development plans
- Responsible for the community investment program
- Coordinate the production and distribution of materials for EGD Board and their supporting committees
- Coordinate and provide administrative and advisory consulting services to the EGD Board and its Committee
- Inform, assist and advise the EGD Board and its committee on security matters and community issues
- Manage the services of external consultants to the Board
- Develop programs and policies related to governance and corporate social responsibility issues
- Coordinate the administration of all travel and service allowances for the Board
- Oversee all Director fees and expenses budgeting and administration

Corporate Secretarial Department

The Board of Directors Support service is responsible for providing lines of communication between EGD Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committee. The Corporate Secretarial Department supports this service by providing governance, legal, paralegal and administrative services in respect of EGD Board and supporting committee activities.

Examples of activities related to the provision of the service include:

- Activities for EGD Board of Directors
  - Coordinate communication between Board and Executive Management
  - Provide and manage legal services for Board and Committee (e.g. financial statement certification)
  - Proactively develop policies and programs related to governance issues
    - Directors and officers liability insurance
    - Maintenance and administration of the Directors' compensation program
    - Board and committee evaluations
    - Management discussion and analysis
    - Board and committee membership
  - Manage processes and relationships related to maintaining a public entity
    - Public listings and filings
    - Oversight of transfer agents

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	Corporate Human Resources Department The Board of Directors Support service is responsible for providing lines of communication between EGD Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committee. The Corporate Human Resource Department supports this service by providing HR expertise. Examples of activities related to the provision of the service include: • Provide specialized resources for guiding and conducting work in the following areas o Governance – Board, Human Resources Compensation Committee, Executive Compensation, Pension Design **Pension & Benefits Department** The Board of Directors Support service is responsible for providing lines of communication between EGD Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committee.. The Pension & Benefits Department supports this service by providing pension, benefits and governance advice services to EGD Board of Directors and its Committees. Examples of activities related to the provision of the service: • Support to the Human Resources & Compensation Committee and Governance Committee o Coordinate meeting agendas and the dissemination of support material o Develop committee proposals, recommendations and guidance on further approvals o Coordinate the dissemination of decisions and oversee the implementation of those decisions o Provide orientation services as to role, policies and responsibilities of new and existing committee members • Develop the policies related to the process, implementation and administration of Board of Directors allowances **Total Compensation Department** The Board of Directors Support service is responsible for providing lines of communication between EGD Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committee. The Total Compensation Department supports this service by providing compensation and governance advice services to the EGD Board of Directors and its Committee. Examples of activities related to the provision of the service: • Support to the Human Resources & Compensation Committee and Governance Committee o Coordinate meeting agendas and the dissemination of support material o Develop committee proposals, recommendations and guidance on further approvals o Coordinate the dissemination of decisions and oversee the implementation of those decisions o Provide orientation services as to role, policies and responsibilities of new and existing committee members • Develop the policies related to the process, implementation and administration of Board of Directors allowances

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HR Enterprise Business Solutions Department

The Board of Directors Support service is responsible for providing lines of communication between various Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committees. The HR Enterprise Business Solutions Department supports this service by providing support to the talent management department in providing Board of Director Support.

Examples of activities related to the provision of the service:

- Through consultation with HR - develop the data definition of data points on the Board of Directors reporting materials
- Provide data to the Talent Management Department for reporting to the Board of Directors
- Make recommendations for improvement on data delivery
- Provide back-up data/materials for board presentation

New Ventures Department

The Board of Directors Support service is responsible for providing lines of communication between various Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committees. The New Ventures Department supports this service by coordinating and providing the required administrative and consulting services that the Board requires as well as acting as a liaison between the Board Committee.

Examples of activities related to the provision of the service include:

- Coordinate communication between Board and Executive Management for our renewable and clean energy opportunities
- Developing new initiatives and investigating renewable and clean energy opportunities
- Advice and support to assess the commercial viability of our renewable and clean energy markets, and other related investment opportunities

Executive VP Corporate Law Department

The Board of Directors Support service is responsible for providing lines of communication between various Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committees. The Executive VP Corporate Law Department supports this service by providing governance, compliance, legal and paralegal services and advice in respect of Board and supporting committee activities.

Examples of activities related to the provision of the service include:

- Activities for EGD Board of Directors
    - Responsible for all policies and processes of corporate governance and executive/board interface
    - Coordinate communication between Board and Executive Management on enterprise wide compliance program, involving designing company compliance policies and programs, overseeing, monitoring and investigation efforts and reporting to senior management and the Board of Directors
    - Provide and manage legal advice for Board and Committees
    - Ensures that practices, policies and records of the Boards of Directors meet executive, legal and corporate governance requirements
    - Secure a leadership position for the Board/Corporation.

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

- Organize and attend Board and Committee meetings and prepares meeting materials and minutes.
- Coordinates all subsidiary corporate secretarial work as consistent with governance, legal and corporate office requirements;
- Proactively develop policies and programs related to governance issues
  - Directors and officers liability insurance
  - Maintenance and administration of the Directors' compensation program
  - Board and committee evaluations
  - Disclosure issues
  - Board and committee membership

Service Recipient: Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$290,619
CFO	$28,330
People and Partners	$284,584
Corporate Secretarial	$95,023
Corporate HR	$15,380
Pension & Benefits	$0
Total Compensation	$49,879
HR Enterprise Business Solutions	$5,553
New Ventures	$0
Executive VP Corporate Law	$0
Total	**$769,368**

Expected Deliverables

- Support for the Board members with relevant information for decision making focused on EGD's regulatory environment, business objectives, strategies, financial and operational health as well as general market conditions and business improvement opportunities

Quantity and Quality of Service

- Achievement of the ROE prescribed by the Regulator, at a minimum

Authorized Signature

Mr. Narin Kishinchandani
Vice-President Finance
Enbridge Gas Distribution

Mar 2, 2012
Date

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

3. Business & Economic Financial Analysis

Service Description	
Service Definition:	The Business and Economic Financial Analysis service provides financial modeling and analysis expertise to support the assessment of business development investment opportunities as and when required, to complement the work of Strategy, Research and Planning Group at EGD.
Services Identified by Department	**Investment Review Department** The Business and Economic Financial Analysis service provides financial modeling and analysis expertise to support the assessment of business development investment opportunities. The Investment Review Department supports this service by providing financial modeling and analysis expertise to support the assessment of investment opportunities, as and when required, to complement the work of Strategy, Research and Planning Group at EGD. Examples of activities related to the provision of the service include: • Advice and support to set the standards, policies, frameworks, criteria and process for evaluating investment opportunities • Advice and support to assess the commercial viability of emerging operational technologies, markets and other related investment opportunities • Evaluate potential deal structures and ownership mechanisms relevant to EGD • Provide guidance on financial modeling and analysis activities and support process for securing Board approval (if required) related to investment opportunities • Provide research and analysis support to optimize gas supply and storage requirements • Advice and support to review post-project capital expenditures to determine potential areas for improvement; includes dissemination of lessons learned to the EGD executive team • Support corporate risk and project specific risk assessments including identifying risks and threats and supporting impact analysis **Corporate Development and Planning Department** The Business and Economic Financial Analysis service provides financial modeling and analysis expertise to support the assessment of business development investment opportunities. The Corporate Development and Planning Department supports this service by providing financial modeling and analysis expertise to support the assessment of investment opportunities, as and when required, to complement the work of Strategy, Research and Planning Group at EGD. Examples of activities related to the provision of the service include: • Advice and support to set the standards, policies, frameworks, criteria and process for evaluating investment opportunities • Advice and support to assess the commercial viability of emerging operational technologies, markets and other related investment opportunities • Evaluate potential deal structures and ownership mechanisms relevant to EGD • Provide guidance on financial modeling and analysis activities and support process for securing Board approval (if required) related to investment opportunities

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	• Provide research and analysis support to optimize gas supply and storage requirements • Advice and support to review post-project capital expenditures to determine potential areas for improvement; includes dissemination of lessons learned to the EGD executive team • Support corporate risk and project specific risk assessments including identifying risks and threats and supporting impact analysis
Service Recipient:	Mr. Arunas Pleckaitis, Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution
Cost of Service	

Department	Service Charge
Investment Review	$0
Corporate Development and Planning	$0
Total	**$0**

Expected Deliverables	
	• Support for Strategy, Research and Planning Group and EGD's management with relevant analytical models for decision making
Quantity and Quality of Service	
	• To complement the work of Strategy, Research and Planning Group • On demand access to expertise and reliable analysis • Analyze opportunities relevant to EGD
Authorized Signature	
	Mr. Arunas Pleckaitis Vice-President Business Development & Customer Strategy Enbridge Gas Distribution Mar 2/12 Date

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

4. Business Development

Service Description	
Service Definition:	The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation.
Services Identified by Department	**CEO Department** The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The CEO Department supports this service by providing leadership, guidance and approvals to large projects. Examples of activities related to the provision of the service include: • Active participation in concept definition and development, including support of analysis activities • Provide review of projects throughout business case development stages, including provision of final approval • Set and monitor project performance metrics, progress monitoring, and issue resolution • Provide project sponsorship and leadership to project teams as required • Monitor business development activities to ensure alignment to long range plan **CFO Department** The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The CFO Department supports this service by providing leadership and guidance on the financial aspects of all business development activities. In addition, the CFO Department is responsible for final sign-off on all business development financial analysis. Examples of activities related to the provision of the service include: • Active participation in concept definition and development, including support of analysis activities • Provide review of projects throughout business case development stages, including provision of final financial approval **Corporate Human Resources Department** The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Corporate Human Resources Department provides support to this service by conducting due diligence and coordinating the workforce integration and divestiture efforts.

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

Examples of activities related to the provision of the service include:

- Conduct due diligence research, impact assessments, support bid development, integration and transition planning
- Integration process development for mergers and acquisitions

Corporate Law Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Corporate Law Department supports this service by providing legal services to specific EGD projects and business development initiatives.

Examples of activities related to the provision of the service include:

- Providing legal advice related to:
  - Corporate or asset acquisitions
  - Obtaining regulatory approvals
  - Managing the due diligence process
  - Contract negotiation and review

Alternative and Emerging Technology Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Alternative and Emerging Technology Department supports this service by identifying investment opportunities and subsequently coordinating the evaluation and execution of opportunities.

Examples of activities related to the provision of the service include:

- Identify business improvement opportunities in Ontario (e.g. new technology deployment, geographic expansion, greenfield development, mergers, acquisitions and partnerships)
- Coordinate the required business and financial analysis required to evaluate investment opportunities and identify alternative strategies
- Implement deal strategies and structures, negotiations and other related aspects of investment opportunities
- Prepare presentations and other required material related to the investment approval process
- Draft, negotiate, document and finalize investment commercial terms and execute transactions
- Coordinate investment transition (if required) to operating groups
- Coordinate business development activities with outside stakeholders
- Manage any investments made with 3rd parties and coordinate the operations and management of these initiatives

Labour Relations Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Labour Relations Department supports this service by providing due diligence activities and integration expertise when unionized employees may be impacted.

Examples of activities related to the provision of this service include:

- Lead and co-ordinate the development of a Labour Relations strategy for business development initiatives
- Provide support and guidance in the due diligence and integration of an acquisition or merger
    - Review existing collective bargaining contracts
    - Liaise with union leadership
    - Coordinate union negotiations
    - Lead, coordinate and facilitate any workforce changes that arise out of mergers, acquisitions and divestitures

Risk Insurance Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Risk Insurance Department supports this service by providing qualified insurance expertise to support projects with material impacts on insurance requirements and costs. Projects include Mergers and Acquisitions and significant asset purchases or divestitures.

Examples of activities related to the provision of the service include:

- Develop insurance cost projections based on changes in assets, people, and nature of business
- Support scenario analysis through identification of insurance cost impact of material changes to business operations

Corporate Controller Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Corporate Controller Department supports this service by providing analytical financial support.

Examples of activities related to the provision of this service include:

- Provide accounting expertise, deal structuring, due diligence support, coordination of external accounting advisors, and financial model review

Public and Government Affairs Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Public and Government Affairs Department provides support to this service by providing advice relating to internal and external communications and for coordinating news releases and other communications.

Examples of activities related to the provision of the service include:

- Assist with development of communication plans for project specific activities/projects (e.g. mergers, acquisition, divestitures and partnerships and new ventures).

Investment Review Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Investment Review Department supports this service by establishing the process for identifying investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities globally.

Examples of activities related to the provision of the service include:

- Coordinate the required business and financial analysis required to evaluate investment opportunities and identify alternative strategies
- Provide advice, guidance, and execution expertise for determining deal strategies and structures, negotiations and other related aspects of investment opportunities
- Draft, negotiate, document and finalize investment commercial terms and execute transactions
- Coordinate business development activities with outside stakeholders

Corporate Development and Planning Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Corporate Development and Planning Department supports this service by establishing the process for identifying investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities globally.

Examples of activities related to the provision of the service include:

- Identify business improvement opportunities in Ontario (e.g. geographic expansion, mergers, acquisitions, divestitures and partnerships)
- Coordinate the required business and financial analysis required to evaluate investment opportunities and identify alternative strategies
- Provide advice, guidance, and execution expertise for determining deal strategies and structures, negotiations and other related aspects of investment opportunities
- Prepare presentations and other required material related to the investment approval process
- Draft, negotiate, document and finalize investment commercial terms and execute transactions
- Coordinate investment transition (if required) to operating groups
- Coordinate business development activities with outside stakeholders
- Manage any investments made with 3rd parties and coordinate the operations of these initiatives

Tax Services Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Tax Services Department supports this service by providing and coordinating tax advice to business development activities.

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	Examples of activities related to the provision of the service include: • Provide tax analysis, structure and modeling expertise on identified initiatives • Provide support and guidance in the due diligence process **Pension & Benefits Department** The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Pension & Benefits Department supports this service by providing due diligence support for pension and benefit related analysis. Examples of activities related to the provision of the service include: • Coordinate pension and benefit impact on mergers, acquisitions and divestiture activities • Conduct due diligence research, impact assessments, support bid development, integration and transition planning • Integration process development for mergers and acquisitions **HR Enterprise Business Solutions Department** The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The HR Enterprise Business Solutions Department provides support to this service by coordinating business requirements for Corporate HR. Examples of activities related to the provision of the service include: • Coordinate and gather requirements for Corporate HR for EGD's technology related initiatives ensuring all new and add-on opportunities are fully thought out and measured for value • Manage solution documentation for Enterprise technology initiatives (i.e. upgrade to PeopleSoft) for the benefit of EGD **New Ventures Department** The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The New Ventures Department supports this service by identifying investment opportunities within renewable and clean energy sources of opportunity and subsequently coordinating the evaluation and execution of these opportunities. Examples of activities related to the provision of the service include: • Identify business improvement opportunities in Ontario (e.g. geographic expansion, mergers, acquisitions, divestitures and partnerships) • Provide advice, guidance, and execution expertise for determining deal strategies and structures, negotiations and other related aspects of investment opportunities • Lead or participate in the EGD investment approval process • Draft, negotiate, document and finalize investment commercial terms and execute transactions • Coordinate business development activities with outside stakeholders

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- Prepare presentations and other required material related to the investment approval process
- Coordinate the required business and financial analysis required to evaluate investment opportunities and identify EGD renewable and clean energy strategies
- Coordinate investment transition (if required) to operating groups
- Manage any investments made with 3rd parties and coordinate the operations and management of these initiatives

Executive VP Corporate Law Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Executive VP Corporate Law Department supports this service by providing executive level legal expertise and guidance as well as overall direction for significant EGD projects and business development initiatives.

Examples of activities related to the provision of the service include:

- Providing legal advice related to:
  - Asset acquisitions
  - Obtaining regulatory approvals
  - Managing the due diligence process
  - Contract negotiation and review
  - Preparation of legal documents to complete transactions

Service Recipient: Mr. Arunas Pleckaitis, Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$291,407
CFO	$38,980
Corporate Human Resources	$0
Corporate Law	$88,197
Alternative and Emerging Technology	$0
Labour Relations	$125,862
Risk Insurance	$0
Corporate Controller	$92,071
Public & Government Affairs	$100,401
Investment Review	$0
Corporate Development and Planning	$0
Tax Services	$0
Pension & Benefits	$0
HR Enterprise Business Solutions	$0
New Ventures	$0
Executive VP Corporate Law	$0
Total	**$736,918**

Expected Deliverables

- Identify, evaluate and close merger, acquisition and/or divestiture deals for the benefit of EGD using leverage and expertise EGD would not have as a standalone entity

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	• Align business development to EGD's strategic plan
Quantity and Quality of Service	
	• Periodic beneficial acquisitions
Authorized Signature	
	Mr. Arunas Pleckaitis Vice-President Business Development & Customer Strategy Enbridge Gas Distribution MAR. 02/12 Date

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5. Capital Market Financing & Access

Service Description	
Service Definition:	The Capital Market Financing and Access service provides support to the process of raising capital (both debt and equity) and maintaining access to capital markets.
Services Identified by Department	**CEO Department** The Capital Market Financing and Access service provides support to the process of raising capital (both debt and equity) and maintaining access to capital markets. The CEO Department supports this service by providing leadership to the design process of the financing strategy, maintaining investment community contacts, and supporting due diligence efforts. Examples of activities related to the provision of the service include: • Provide leadership to the development and maintenance of the optimal capital structure and financing strategy • Maintain banking, fixed income, credit agency, and investment banking relationships • Provide guidance to Treasury and CFO on negotiation of terms for large debt or equity issues • Support due diligence efforts conducted by equity/debt issuers prior to receiving financing **CFO Department** The Capital Market Financing and Access service provides support to the process of raising capital (both debt and equity) and maintaining access to capital markets. The CFO Department supports this service by leading the development of the financing strategy, maintaining investment community contacts, participating in financing negotiations, certifying financial statements and supporting due diligence efforts. Examples activities related to the provision of the service include: • Lead the development of the capital structure and financing strategy • Maintain banking, fixed income, credit agency, and investment banking relationships • Provide guidance on capital structure to Treasury Group and other departments • Lead contract negotiations for large debt or equity issues • Support due diligence processes for equity/debt issues • Ensure investment dealer performance on capital market transactions is monitored and evaluated • Develop Annual Financing Plan in support of the long range plan **Investor Relations Department** The Capital Market Financing and Access service provides support to the process of raising capital (both debt and equity) and maintaining access to capital markets. The Investor Relations Department supports this service by developing and maintaining investment community contacts. Examples of activities related to the provision of the service include: • Maintain contacts in the investment community for future debt or equity issues • Conduct research on activities, market conditions, competitive issues, and other specific issues which could impact access to capital • Act as an inside analyst to monitor how the company is perceived by

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stakeholders (i.e. valuation of company)
- Manage 3rd party service contracts for research and other investment related information

Treasury Department

The Capital Market Financing and Access service provides support to the process of raising capital (both debt and equity) and maintaining access to capital markets. The Treasury Department supports this service by defining long-term financing requirements and developing and executing financing strategies in the bank and capital markets.

Examples of activities related to the provision of the service include:
- Develop schedule of debt and equity financing process, including preparation of projections and analysis, and liaison with tax, regulatory and accounting
- Monitor and update financing schedule based on changing internal requirements and external market conditions
- Prepare and file all required regulatory and securities documents for new financing activities
- Negotiate terms and rates for any capital raised in the market
- Maintain and lead credit rating agency, banking, fixed income, and investment banking relationships and presentations

Corporate Secretarial Department

The Capital Market Financing and Access service provides support to the process of raising capital (both debt and equity) and maintaining access to capital markets. The Corporate Secretarial Department supports this service by providing legal, paralegal and administrative services

Examples of activities related to the provision of the service include:
- Support the operations of EGD with legal advice and support in the following areas
  - Financing, credit facilities and tax issues
  - Financing documents (Financials, MD&A, press releases, prospectuses and annual information of the corporation)

Service Recipient: Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$157,595
CFO	$182,933
Investor Relations	$80,379
Treasury	$520,278
Corporate Secretarial	$78,988
Total	**$1,020,173**

Expected Deliverables

- Provide access to Capital Markets (Debt and Equity)
- Monitor and maintain an appropriate capital structure for EGD
- Provide lower cost financing to EGD than it would be able to achieve as a standalone entity

Quantity and Quality of Service

- Continuous Access to funds
- On demand access to expertise
- Low cost financing

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Authorized Signature	
	Mr. Narin Kishinchandani Vice-President Finance Enbridge Gas Distribution Mar 2/2012 Date

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6. Cash Management & Banking

Service Description	
Service Definition:	The Cash Management and Banking service determines the optimal short-term cash requirements and executes the supporting daily banking transactions. This includes responsibility for managing short-term liquidity and cash holdings.

Services Identified by Department	**Treasury Department**
	The Cash Management and Banking service determines the optimal short-term cash requirements and executes the supporting daily banking transactions. This includes responsibility for managing short-term liquidity and cash holdings. The Treasury Department supports this service by assuming responsibility for all operational support required to ensure short-term liquidity requirements are met.
	
	Examples of activities related to the provision of the service include:
	• Forecast the short term liquidity requirements to optimize the Company's cash balances
	• Establish and maintain the Company's bank accounts, banking relationships, and bank credit facilities to support liquidity needs
	• Coordinate changes to banking services and interactive processes
	• Coordinate large scale accounts payables/receivables transactions
	• Manage settlement of risk management vehicles, including those for foreign exchange, interest rate and commodity risk
	• Manage investment of surplus funds for short-term appreciation
	• Manage the daily operations of the Company's commercial paper program and credit facility borrowings
	• Coordinate EGD transactions
	  o Calculate invoice amounts and oversee payments
	  o Monitoring and managing to identified capital structures
	  o Directing internal and external interest and principal payments
	• Monitor and report on compliance requirements for debt facilities, regulatory and internal policies
	• Administer access to bank accounts and bank reporting systems
	• Update and maintain the treasury management reporting system (TMS) with money market and derivative transactions
	• Manage the interface of treasury transactions from the TMS to the general ledger for financial reporting purposes.

Service Recipient:	Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
Treasury	$481,073
Total	**$481,073**

Expected Deliverables

- Provide access to cash, credit and banking facilities for EGD
- Forecast, monitor and maintain short-term liquidity requirements
- Perform transactional support
- Provide lower cost facilities to EGD than it would be able to achieve as a standalone entity

Quantity and Quality of Service

- On demand access to expertise
- Low Cost borrowing facilities
- Accuracy of transactional data

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Authorized Signature	
	Mar 2, 2012 Date Mr. Narin Kishinchandani Vice-President Finance Enbridge Gas Distribution

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7. Consolidation and Planning System Technical Support (Khalix)

Service Description	
Service Definition:	The Consolidation and Planning System Technical Support (Khalix) service is responsible for the technical support and administration of the consolidation and planning system (Khalix). The Khalix consolidation and planning system consists of three instances used for consolidating the actual results, conducting the enterprise-wide budgeting and forecasting process on an annual basis (ABF), budgeting and forecasting process on a 5 year basis (LRP) and an instance specifically for project budgeting and forecasting (Ensight).
Services Identified by Department	**CIO Department** The Consolidation and Planning System Technical Support (Khalix) service is responsible for the technical support and administration of the Enbridge consolidation and planning system (Khalix). The CIO Department supports this service by providing leadership and management to IT resources providing services: IT System Analysts, IT DBA resources, IT Infrastructure resources, and IT contract resources. Responsible for overseeing all IT related activities from day-to-day technical support to strategic planning for Enterprise Financial Systems (Khalix). Examples of activities related to the provision of this service include: • Ensure Khalix applications are effectively managed. • Assist senior business leadership in terms of IT process changes, business process changes, incremental infrastructure, data, and support processes through interaction with the EFS Governance Committee, representing executive finance and IT management from across Enbridge. • Establish and maintain effective communication and relationship with systems' vendors to ensure prompt and cost efficient vendors support. • Develop, coach and mentor EFS Strategy and Services employees and contractors • Drive the implementation and compliance to quality assurance procedures, standards for process design, documentation, configuration changes, functionality enhancements, and a release management strategy to protect the integrity and reliability of financial data. • Proactively gather and make recommendations regarding complex intelligence from across Enbridge and externally to assess immediate and future impacts on EFS applications, processes, and priorities. • Establish and maintain an effective external network with appropriate application user groups, industry groups, and business partners to share knowledge, gain intelligence, learn cost avoidance strategies, understand alternatives and trends to anticipate, plan, and ensure continuing operational excellence in the support of EGD's evolving business needs. • Reporting & Analysis o Provision of standard reports o Ad hoc report generation / queries o Augment, add, or remove reporting requirements • Technical Support o Interface management o System configurations, customization or enhancements o Release management o Provide back up system support to EFS support group o Manage development life cycle o Monitor system performance

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- Vendor Management
  - Negotiate, monitor and manage vendor contract
  - Negotiate, monitor and manage IT outsourcing relationships
  - Research and monitor emerging technologies

EFS Strategy and Services Department

The Consolidation and Planning System Technical Support (Khalix) service is responsible for the technical support and administration of the Enbridge consolidation and planning system (Khalix). The EFS Strategy and Services Department supports this service by providing technical expertise and assuming responsibility for providing user training, support, system maintenance, customization and enhancements.

Examples of activities related to the provision of this service include:

- Manage client relationships and communication through enterprise-wide committees, of which EGD is a member (Governance Committee, Stakeholder Advisory Group), the EFS team and other stakeholders
- Lead the strategic planning process in relation to efficiency and effectiveness of EFS applications
- Support & Maintenance
  - System administration
  - User support, maintenance & security
  - User (incl. super user / power user) training & communication
  - Change management
  - Master file maintenance
  - System configurations, customization or enhancements
- Reporting & Analysis
  - Provision of standard reports
  - Ad hoc report generation / queries
  - Augment, add, or remove reporting requirements
- Vendor Management
  - Negotiate, monitor and manage vendor contract
  - Negotiate, monitor and manage IT outsourcing relationships
  - Research and monitor emerging technologies

Corporate Controller Department

The Consolidation and Planning System Technical Support (Khalix) service is responsible for the technical support and administration of the consolidation and planning system (Khalix). The Corporate Controller Department supports this service by providing end user training and support services for the consolidations and budgeting modules

Examples of activities related to the provision of this service include:

- Maintain Khalix training program
- Receive and respond to Khalix user issues
- Provide end user expertise supporting module enhancements, implementations, and customizations testing

Service Recipient:	Mr. Henry Wong, Director Information Technology, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CIO	$85,514
EFS Strategy and Services	$88,146
Corporate Controller	$71,429
Total	**$245,089**

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Expected Deliverables	
	• Ensure availability of the infrastructure and financial information contained within the Consolidation and Planning System (Khalix) to support long and short term planning in support of EGD management in decision making • Provide user support as required • Ensure availability of technical support and administration. • Ensure availability of a system that follows a diligent process of request prioritization, including assessing cost, resources, systems impacts, and business value to determine which requests will go forward. • Ensuring that EGD is up to date with application market developments in industry. • EGD requires a service that provides timely access to relevant Khalix information. This includes the delivery of OLAP reporting, canned reports, and custom reports.
Quantity and Quality of Service	
	• Continuous and uninterrupted access to Khalix system • Accuracy and integrity of data • On demand user support • Ensuring a consolidation and planning system that is adequately supported from a technical perspective. Including performance management, release management, service management and change management of the entire Khalix system, including interfaces. • Effective and efficient support for Khalix. • Ensure that the system is aligned with the goals and objectives of EGD and is driven by a relevant governance structure. • Ensuring an effective relationship with the Khalix vendor • Ensuring availability of competent staff • Compliance with all relevant best practices (e.g. ITIL, COSO) to maintain system integrity and reliability.
Authorized Signature	
	Mr. Henry Wong Director Information Technology Enbridge Gas Distribution Mar. 7, 2012 Date

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8. Corporate Compliance

Service Description	
Service Definition:	The Corporate Compliance service is responsible for developing the corporate governance structure and policies.
Services Identified by Department	**CEO Department** The Corporate Compliance service is responsible for developing the corporate governance structure and policies. The CEO Department supports this service by providing senior leadership, overall management guidance and advice regarding financial and operational affairs. Examples of activities related to the provision of the service include: • Approval and communication of policies and controls (i.e. capital spending, operating spending, Treasury Authorized Limits Policy, Risk management policies, etc.) • Provides ultimate responsibility for all personnel, safety & environmental, and regulatory policy issues • Provides ultimate responsibility for governance of the organization with respect to ensuring the proper procedures, policies, processes, people and culture to be successful **CFO Department** The Corporate Compliance service is responsible for developing the corporate governance structure and policies. The CFO Department supports this service by providing senior leadership, overall management guidance and advice regarding financial affairs. Examples of activities related to the provision of the service include: • Approval and communication of policies and controls (i.e. capital spending, operating spending, Treasury Authorized Limits Policy, Risk management policies, etc.) • Identification and resolution of financing concerns **People and Partners Department** The Corporate Compliance service is responsible for developing the corporate governance structure and policies. The People and Partners Department supports this service by assuming responsibility for developing the necessary corporate governance structure and supporting policies. Examples of activities related to the provision of the service include: • Define the governance structure of EGD • Monitor and update compliance to changes in corporate governance standards • Assume compliance on Code of Conduct, disclosure documents, etc. **Corporate Controller Department** The Corporate Compliance service is responsible for developing the corporate governance structure and policies. The Corporate Controller Department supports this service by ensuring alignment and adherence to accounting standards. Examples of activities related to the provision of this service include: • Coordinate and monitor EGD's accounting functions to maintain alignment with industry practices • Design and implement accounting policies (i.e. include the Spending

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Authorities Policy, IT Capitalization Policy, and Deferred Cost Policy)

Corporate Human Resources Department

The Corporate Compliance service is responsible for developing the corporate governance structure and policies. The Corporate Human Resources Department supports this service by providing human resources expertise, monitoring and ensuring compliance to regulatory and shareholder requirements.

Examples of activities related to the provision of the service include:

- Ensure compliance to regulatory and shareholder requirements on total compensation and governance related issues

Total Compensation Department

The Corporate Compliance service is responsible for developing the corporate governance structure and policies. The Total Compensation Department supports this service by providing human resources expertise, monitoring and ensuring compliance to regulatory and shareholder requirements.

Examples of activities related to the provision of the service include:

- Ensure compliance to regulatory and shareholder requirements on executive compensation and governance related issues

Enterprise Security Department

The Corporate Compliance service is responsible for developing the corporate governance structure and policies. The Enterprise Security Department supports this service by building, leading, motivating and maintaining the Corporate Security Steering Committee, a cross business unit team of Security professionals at Enbridge, responsible for the Enterprise Wide security and protection strategy and program development in compliance with US and Canadian government and industry standards and guidelines across the organization.

Examples of activities related to the provision of this service include:

- Support to EGD through the audit of EGD security vulnerability assessments for facilities in compliance with Canadian Standards' association standard Z246.1
- Investigation of allegations of non-compliance received through the Ethics and Conduct Anonymous Hotline at the request of the Chief Compliance officer

Service Recipient: Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$77,565
CFO	$16,626
People and Partners	$35,163
Corporate Controller	$18,331
Corporate HR	$6,540
Total Compensation	$42,977
Enterprise Security	$0
Total	**$197,202**

Expected Deliverables

- Develop and maintain corporate compliance guidelines, policies and standards designed to assist EGD management in its governance activities

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Quantity and Quality of Service	
	• Zero governance failures • Zero control failures • Timely policy changes to reflect changes in the regulatory environment and to safeguard assets
Authorized Signature	
	Mr. Narin Kishinchandani Vice-President Finance Enbridge Gas Distribution Mar 2, 2012 Date

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9. Emerging Energy Technology Research

Service Description	
Service Definition:	The Emerging Energy Technology Research service provides a single point of contact for the research and evaluation of all new or emerging technologies.
Services Identified by Department	**Corporate Development and Planning Department** The Emerging Energy Technology Research service provides a single point of contact for the research and evaluation of all new or emerging technologies. The Corporate Development and Planning Department supports this service by providing a single point of contact for the evaluation and management of all new or emerging technologies. Examples of activities related to the provision of the service include: • Respond to requests from EGD to examine new or emerging technologies that complement EGD's long term strategic objectives • Assess the commercial viability of emerging operational technologies, including analysis of markets and customers • Acts as an internal R&D function to examine the development of new capabilities related to service delivery or operational performance • Coordinate resources from EGD for evaluation and analysis purposes • Develop presentations for EGD EMT and Board of Directors on all potential opportunities **Alternative and Emerging Technology Department** The Emerging Energy Technology Research service provides a single point of contact for the research and evaluation of all new or emerging technologies. The Alternative and Emerging Technology Department supports this service by providing a single point of contact for the evaluation and management of all new or emerging technologies. Examples of activities related to the provision of the service include: • Respond to requests from EGD to examine new or emerging technologies that complement EGD's long term strategic objectives • Assess the commercial viability of emerging operational technologies, including analysis of markets and customers • Acts as an internal R&D function to examine the development of new capabilities related to service delivery or operational performance • Coordinate resources from EGD for evaluation and analysis purposes • Evaluate new energy technologies and pursue opportunities in the areas of carbon capture sequestration and stationary fuel cells • Develop presentations for EMT and EGD Board of Directors on all potential opportunities • Fuel Cell lobbying efforts with Government of Ontario • Clean Energy stakeholder submissions into the OPA's program development for CHPSOP and ERSOP • Federal level support for taxes on Clean Energy Credits that would support EGD investments and EGD customer investments • Collaboration efforts on claims for Scientific Research and Experiments Development (SRED) tax credits • Secure Government Funding from Environment Canada – up to $500k offsetting EGD operational costs as part of the Federal Government's Asia Pacific Partnership Funding • Collaborate with EGD technical staff for technology optimization of the pressure let-down asset(s)

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	• Enhance outreach and funding support for EGD participation in industry networks such as NYSEARCH, The Canadian Hydrogen and Fuel Cell Association, etc.
Service Recipient:	Mr. Arunas Pleckaitis, Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution
Cost of Service	

Department	Service Charge
Corporate Development and Planning	$0
Alternative and Energy Technology	$0
Total	**$0**

Expected Deliverables	
	• Support EGD leadership by researching and identifying business opportunities related to emerging energy technologies • Support for Investing in appropriate emerging technologies • Reports & presentations on emerging technologies, specifically fuel cells
Quantity and Quality of Service	
	• On demand access to expertise and research • Research analyses, reports and presentations relevant to EGD
Authorized Signature	
	Mr. Arunas Pleckaitis Vice-President Business Development & Customer Strategy Enbridge Gas Distribution March 2/12 Date

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10. Employee and Labour Relations

Service Description	
Service Definition:	The Employee and Labour Relations service provides the development of strategies (overall framework, vision and policies) and tactics for the management of unionized, JIC and potentially-unionized employees and supports the development of employee-related principles and policies.
Services Identified by Department	**People and Partners Department** The Employee and Labour Relations service provides the development strategies and tactics for the management of unionized, JIC and potentially-unionized employees and supports the development of employee-related principles and policies. The People and Partners Department supports this service by providing senior leadership and advice regarding EGD union employees. Examples of activities related to the provision of the service include: • Provides broad direction and oversight to employee and labour relations including providing EGD with a voice to the EI Board Human Resources Committee **Labour Relations Department** The Employee and Labour Relations service provides the development strategies and tactics for the management of organized employees (unionized, Joint Industrial Council and potentially-unionized employees) and supports the development of employee-related principles and policies. The Labour Relations Department supports this service by providing resources and operational support to the development and implementation of labour and labour relations strategies. Examples of activities related to the provision of this service include: • Providing advice and counsel to managers and supervisors, Services Recipient's HR Dept. with respect to all grievances and the arbitration process • Co-ordination of the grievance process with managers, union and employees • Coordinate legal resources to support Labour Board issues • Leading, coordinating and representing the Services Recipient during Arbitration process • Leads, researches and co-ordinates the response to Labour Board applications such as certifications, union labour practices and jurisdictional disputes. • Responding to all Policy grievances with respect to recognition and jurisdiction • Analyze grievance and arbitration trends as input to the collective bargaining process and/or education of line managers • Assisting in the development of a Unionized Performance Management Program • Liaise with HR to ensure consistency with non-unionized employee performance management program • Providing training to Managers on the implementation of a Unionized Performance Management Program • Participate and assist in the Health Center and Workers Safety and Insurance Board return to work programs that require Union concurrence • Support the "Healthwise" program for union employees including the coordination of the employees' entitlement to benefits • Facilitate the development and implementation of a collective bargaining

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	strategy, mandate and tactics • Support development of the mandate by collecting and analyzing competitive information on other negotiated agreements and other information provided by compensation and benefits staff within HR • Provide detailed trend and economic analysis with recommendations for mandate approval • Provide detailed current costing and final cost reporting • Develop communication materials and process to educate senior managers and HR consultants on terms of the new collective agreement, including the interpretation and administration of the agreement. • Coordinate legal resources to support collective agreement issues • Provide guidance to the Service Recipient with respect to the spirit and intent of the Collective Agreement • Providing advice to the Services Recipient's HR and Line Managers regarding Collective Agreement interpretation • Assess new positions to determine whether they are in or out of the Bargaining Unit based on current recognition clause • Assist in the development of the job evaluation system • Assist in the job evaluation committee's functions • Contribute to the overall growth and development of corporate strategy directions through participation on senior management committee/teams with an emphasis on labour relations issues and implications with respect to operational plans and/or change initiatives • Act as a Corporate resource in the development of employee relations principles and policies **Corporate Human Resources Department** The Employee and Labour Relations service provides the development strategies and tactics for the management of organized employees (unionized, Joint Industrial Council and potentially-unionized employees) and supports the development of employee-related principles and policies. The Corporate Human Resources Department supports this service by providing leadership and direction in managing organized employees and leadership in employee relations directly and indirectly through chairing the Human Resource Committee. Examples of activities related to the provision of this service include: • Provide policy direction and review for strategies and tactics for the management of organized employees and the development and oversight of EGD-specific and enterprise-wide employee relations strategies and employee-related policies. **Pension & Benefits Department** The Employee and Labour Relations service provides the development strategies and tactics for the management of organized employees (unionized, Joint Industrial Council and potentially-unionized employees) and supports the development of employee-related principles and policies. The Pension & Benefits Department supports this service by participating in union negotiations and contract administration activities and by providing the leadership both directly and indirectly through chairing the Human Resource Committee. Examples of activities related to the provision of this service include: • Provide specialized resources for developing and negotiating collective bargaining agreements with respect to pension and benefits • Assist in annual development and communication of pension and benefit changes and implications for members • Develop, coordinate and manage employee-related policy issues.

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Organizational Effectiveness Department

The Employee and Labour Relations service provides the development and strategies and tactics for the management of unionized employees (unionized, Joint Industrial Council and potentially-unionized employees) and supports the development of employee-related principles and policies. The Talent Management & Workforce Planning Department supports this service by identifying enterprise-wide and EGD-specific employee relations strategies and policies and (upon approval) developing same for implementation.

Examples of activities related to the provision of this service include:

- Work with EGD executive and leadership teams to develop enterprise-wide and EGD-specific employee relations strategies and HR policies

Service Recipient: Mr. Marc Weil, Director Human Resources, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
People and Partners	$13,543
Labour Relations	$428,522
Corporate HR	$36,136
Pension & Benefits	$0
Organizational Effectiveness	$0
Total	**$478,201**

Expected Deliverables

- Support EGD's leadership in the development of Labour Relations strategies and tactical plans
- Provide EGD management with policies, guidelines and resources designed to support the successful development and implementation of the Union/JIC Labour Plans and Employee Relations policies and plans

Quantity and Quality of Service

- Documented Strategies
- Implementable strategy (at a level of detail that allows EGD to execute)
- Successful Union relations - # grievances, arbitrations, Labour Board issues, cooperation/support for internal initiatives
- Successful employee relations – no issues regarding Humans Rights legislation, Privacy legislation etc.
- No Union labour disruptions
- Cost effective means to access senior level technical expertise as required

Authorized Signature

Mr. Marc Weil
Director Human Resources
Enbridge Gas Distribution

March 2, 2012
Date

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11. Employee Development

Service Description	
Service Definition:	The Employee Development service provides long-range planning and the development and support of employee development and talent management programs to support business strategies and ensure the supply and development of employees across the enterprise.

Services Identified by Department	**CEO Department**
	The Employee Development service provides long-range planning and the development and support of employee development and talent management programs to support business strategies and ensure the supply and development of employees across the enterprise. The CEO Department supports this service by providing senior leadership to executive recruiting and succession planning activities.
	
	Examples activities related to the provision of the service include:
	• Participate actively in the recruiting of all company officers for EGD
	• Participate in the executive succession planning activities
	  o Review finalized recommendations and develop plans for approval by the EI Board of Directors
	
	People and Partners Department
	The Employee Development service provides long-range planning and the development and support of employee development and talent management programs to support business strategies and ensure the supply and development of employees across the enterprise. The People and Partners Department supports this service by managing executive succession planning for senior EGD positions.
	
	Examples of activities related to the provision of the service include:
	• Coordinate the annual review process by Executive of their identified successors (either internally identified or externally required)
	  o Initiate review process through formal identification of executive succession candidates
	  o Coordinate assessment process of all executive succession candidates and positions
	  o Compile assessments, finalize recommendations and present findings and recommendations of Directors for approval
	  o Engage external consultants to conduct external recruitment if required
	  o Coordinate internal transfers of key staff if required
	  o Identify opportunities for EGD executives outside their own business unit
	  o Enhance attraction and retention of executive - level employees
	
	Organizational Effectiveness Department
	The Employee Development service provides long-range planning and the development and support of employee development and talent management programs to support business strategies and ensure the supply and development of employees across the enterprise. The Organizational Effectiveness Department supports this service by developing and coordinating the implementation of workforce plans, employee learning strategies and resources, and talent management initiatives.
	
	Examples of activities related to the provision of the service include:

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- Research industry, market and internal demographics (workforce analytics) to identify available skill sets and resources
- Conduct competency gap analysis of internal requirements based on strategic plans
- Identify internal (promotions, transfers and succession planning across enterprise) and external (contractors and consultants) alternatives to fill gaps at the executive level
- Coordinate the execution and implementation of succession management across the enterprise to expand EGD's potential talent pool
- Identify and assess internal competency requirements and develop learning plan to address competency gaps
    - Collaborate enterprise-wide (including EGD) to identify common cross company training and development needs
    - Coordinate the development of learning frameworks and implementation plan to address identified needs including competency profiling
    - Manage the research and development of Enbridge-wide training programs, communication requirements and supporting tools, both internally and externally with service providers, department leaders and staff for the benefit of EGD
    - Develop employee feedback mechanisms (performance assessments and employee surveys), manage the feedback mechanism and distribute results

Corporate Human Resources Department

The Employee Development service provides long-range planning and the development and support of employee development and talent management programs to support business strategies and ensure the supply and development of employees across the enterprise, including EGD. The Corporate Human Resources Department supports this service by providing operational support and resources for workforce planning, succession management, recruiting skill development, leadership development and workforce management activities.

Examples of activities related to the provision of the service include:

- Develop administrative policies and processes for enterprise wide workforce strategy development, workforce planning modeling, succession planning and employee development
- Provide operational and systems support to succession management, performance management and employee development processes
- VP HR provides oversight and senior level expertise in the determination and development of talent management strategies, policies and initiatives

HR Enterprise Business Solutions Department

The Employee Development service provides long-range planning and the development and support of employee development and talent management programs to support business strategies and ensure the supply and development of employees across the enterprise. The HR Enterprise Business Solutions Department supports this service by providing facilitation, business requirements and functional support for workforce planning, succession management, recruiting skill development, leadership development and workforce management activities.

Examples of activities related to the provision of the service include:

- Facilitate Corporate HR in the development of business processes for workforce strategy development, workforce planning modeling, succession planning and employee development
- Provide systems and functional support to succession management,

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	performance management and employee development processes
Service Recipient:	Mr. Marc Weil, Director Human Resources, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$503,231
People and Partners	$41,921
Organizational Effectiveness	$669,944
Corporate HR	$15,017
HR Enterprise Business Solutions	$30,455
Total	**$1,260,568**

Expected Deliverables

- Support EGD in the continuous development of competitive and innovative personnel strategies that balance EGD's employee retention and personal development goals with fiscal responsibility and the interests of shareholders
- Provide EGD management with policies, guidelines and resources designed to support the successful development and implementation of the Employee Development strategy
- Enterprise-wide Employee and Leadership Development learning programs

Quay and Quality of Service

- High Employee Engagement and Motivation as measured through the internal employee survey
- High Staff Retention rate
- Detailed workforce plans and skills assessments

Authorized Signature



Mr. Marc Weil
Director Human Resources
Enbridge Gas Distribution

March 2, 2012
Date

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12. Enterprise IT Program Management

Service Description	
Service Definition:	The Enterprise IT Program Management service is responsible for the overall coordination, and monitoring of major enterprise projects.
Services Identified by Department	**IT Planning and Governance Department** The Enterprise IT Program Management service is responsible for the overall coordination and monitoring of major enterprise projects. The IT Planning and Governance Department supports this service by assuming project management responsibilities for major enterprise projects, including their successful implementation on-time and on-budget. Examples of activities related to the provision of the service include: • Development of program / project management policies and procedures for implementing and managing enterprise wide systems • The development of complex project plans, charters, budgets and other required project documentation • Research new alternatives to conducting business through different service approaches (i.e. IT outsourcing) • Coordination of project teams including requisition of the appropriate IT skills when required • Monitoring ongoing projects to maintain alignment with strategic and project objectives; including the provision of progress reports to senior management • Run post-project reviews on corporate projects to assess and learn from the process • Provide financial reporting on corporate project performance to help EGD understand the financial specifics for all enterprise projects. • Implement change management requirements of IT projects. All enterprise IT projects must follow a rigorous process that includes strict adherence to change management processes. **CIO Department** The Enterprise IT Program Management service is responsible for the overall coordination and monitoring of major enterprise projects. The CIO Department supports this service by assuming project management responsibilities for major enterprise projects, including their successful implementation on-time and on-budget. Examples of activities related to the provision of the service include: • The development of project plans, charters, budgets and other required project documentation • Coordination of project teams including requisition of the appropriate IT skills when required • Monitoring ongoing projects to maintain alignment with strategic and project objectives; including the provision of progress reports to senior management • Develop training material and provide training to users of enterprise systems. Appropriate training ensures users are prepared to use the systems • Run post-project reviews on corporate projects to assess and learn from the process • Provide financial reporting on corporate project performance to help EGD

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	understand the financial specifics for all enterprise projects. • Implement change management requirements of IT projects. All enterprise IT projects must follow a rigorous process that includes strict adherence to change management processes.
Service Recipient:	Mr. Henry Wong, Director Information Technology, Enbridge Gas Distribution
Cost of Service	

Department	Service Charge
IT Planning and Governance	$465,106
CIO	$403,388
Total	**$868,494**

Expected Deliverables	
	• Provide strategic planning and management guidance in the identification and design of Enterprise IT systems for the benefit of EGD • Align technology strategy to EGD's long term strategic needs • Ensure technologies meet business needs and are scalable and serviceable as required • Ensuring security and maintenance of the integrity of the data and information content. • Ensuring availability of an intranet portal that is structured effectively for EGD needs. • Provide an IT Strategic Plan that is aligned with the goals and objectives of EGD. This includes all areas of IT service delivery. • Provide corporate IT policies to govern the administration and operation of EGD's systems and enterprise systems EGD uses. • Provide senior executive information technology expertise which is not resident within EGD. • Provide opportunities to share experiences, programs and initiatives with other internal IT organizations in order to take advantage of alternate delivery methodologies, technical architectures, IT processes, and apply the learnings to EGD's benefit. • For enterprise systems EGD utilizes (EFS, HRIS, Sharepoint, Livelink) providing a formal enterprise architecture plan. This includes the development and ongoing maintenance of the architecture plan. • For enterprise systems EGD utilizes (EFS, HRIS, Sharepoint, Livelink)) providing systems that meet performance and functionality objectives on an ongoing basis. • For those enterprise projects that benefit EGD, provide Project Management support needed to launch the projects. This would include project budgeting, and the initial solution architecture. • Provide corporate IT policies to govern the security of EGD's systems and enterprise systems EGD uses.
Quantity and Quality of Service	
	• Effective, reliable and low IT infrastructure • Ensure vendor relationships are managed effectively. • Ensuring compliance with all relevant legislation affecting information systems. • Ensuring that all supply chain initiatives conform to industry standards and best practices. • Ensuring that all of the contracts are effectively negotiated and managed.
Authorized Signature	

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FB	Mr. Henry Wong Director Information Technology Enbridge Gas Distribution Mar. 7, 2012 Date

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13. Enterprise IT Strategy Planning & Management

Service Description	
Service Definition:	The Enterprise IT Strategy Planning and Management service governs the development of enterprise wide strategies, policies and standards for information technologies.
Services Identified by Department	**People and Partners Department** The Enterprise IT Strategy Planning and Management service governs the development of enterprise wide strategies, policies and standards for information technologies. The People and Partners Department supports this service by providing senior leadership and advice regarding the corporate information technology strategy and its alignment to the EGD long range plan. Examples of activities related to the provision of the service include: • Responsible for the review and approval of information technology project concepts and IT project expenditure • Responsible for IT security and the interfaces around enterprise-wide applications, for example, EFS, HRIS and the intranet portal • Responsible for structure and usage of intranet portal related to human resource issues and internal communication issues **CIO Department** The Enterprise IT Strategy Planning and Management service governs the development of enterprise wide strategies, policies and standards for information technologies. The CIO Department supports this service by providing leadership and IT expertise. The CIO Department is also responsible for developing and implementing the IT strategy in support of the EGD long range plan. Examples of activities related to the provision of the service include: • Manage the development and alignment of the enterprise IT Strategic plan to the long range plan, with consideration of the following areas o Knowledge management o Document management o Information management o Network infrastructure o Information technology architecture o Application suite o Support and maintenance provisions • Manage the compliance of the IT strategic plan; ensure services are delivered in a manner consistent with the goals and objectives of EGD. • Set, administer, and manage compliance of IT policies and procedures for enterprise (posted on elink). • Manage and administer all of the enterprise-wide IT vendor and outsourcing relationships (e.g. Peoplesoft HR, Sharepoint Portal, and Livelink Records Management) • Manage the enterprise IT architecture including ongoing monitoring of new architecture requirements and issues; includes planned annual review of enterprise architecture • Research and analyze current trends, alternative delivery models, outsourcing and other related IT matters. Monitor current trends in the IT industry and apply those learnings at EGD. • Manage the enterprise IT system performance through customers feedback surveys, stakeholder workshops and internal/external IT audits • Identify opportunities for improved business support • Provide EGD with senior executive level information technology guidance

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to assist with improving how EGD IT supports the business.

- Coordinate and conduct the approval process for enterprise wide services, including execution of scoping, concept generation, and budgeting required to gain final approval
- Monitors and maintains compliance with regulatory requirements (e.g. privacy legislation and how it applies to voice over internet protocol (VOIP), security, password protection and employee/employer rights)
- Contributes to annual performance review of EGD IT Director and managers
- Provides leadership on dealing with security issues
    - Develop, update and deploy IT policies, methods, technology standards best practices, and tools to meet EGD security requirements
    - Monitor and manage security of data, applications, network, and computing platforms
    - Research and analyze new security technologies
    - Coordinate and manage implementation of new security technologies
    - Conduct annual IT Security Audit using ISO framework; Periodic coordination of external IT security audits
- Conduct RFP, vendor/system analysis, and ultimate selection of vendors for enterprise-wide systems that EGD uses (EFS, HRIS, Sharepoint, Livelink)
- Coordinate and participate in negotiation of new contracts and contract renewals for those enterprise systems that EGD uses (EFS, HRIS, Sharepoint, Livelink)
- Manage overall vendor relationship for those enterprise systems that EGD uses (EFS, HRIS, Sharepoint, Livelink) to ensure that appropriate management attention is paid to maintaining the vendor relationship so that maximum value can be attained for EGD.
    - Act as escalation point for all unresolved IT vendor issues.
    - Handle administration and payment approval of maintenance contracts and additional license fees for EGD applications

IT Planning and Governance Department

The Enterprise IT Strategy Planning and Management service governs the development of enterprise wide strategies, policies and standards for information technologies. The IT Planning and Governance Department supports this service by providing leadership and IT expertise. The IT Planning and Governance Department is also responsible for developing and implementing the IT strategy in support of the EGD long-range plans.

Examples of activities related to the provision of the service include:

- Develop and align the enterprise IT Strategic plan to the long range plan, with consideration of the following areas
    - Knowledge management
    - Document management
    - Information management
    - Network infrastructure
    - Information technology architecture
    - Application suite
    - Support and maintenance provisions
- Providing senior IT executive advice and counsel to EGD on the acquisition and implementation of new software products.
- Monitor compliance of the IT strategic plan, ensuring services are delivered in a manner consistent with the goals and objectives of EGD.
- Set, administer, and manage compliance of IT policies and procedures for

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EGD.

- Manage and administer all of the enterprise-wide IT vendor and outsourcing relationships (e.g. PeopleSoft HR, Employee Portal, and Livelink Records Management)
- Define the EGD IT architecture including ongoing monitoring of new architecture requirements and issues; includes planned annual review of IT Planning and Governance
- Research and analyze current trends, alternative delivery models, outsourcing and other related IT matters. Monitor current trends in the IT industry and apply those learnings at EGD.
- Monitor EGD IT system performance through customers feedback surveys, stakeholder workshops and internal/external IT audits
- Identify opportunities for improved business support
- Provide EGD with senior executive level information technology guidance to assist with improving how IT supports the business.
- Coordinate and conduct the approval process for EGD services, including execution of scoping, concept generation, and budgeting required to gain final approval
- Monitors and maintains compliance with regulatory requirements (e.g. privacy legislation and how it applies to voice over internet protocol (VOIP), security, password protection and employee/employer rights)
- Contributes to annual performance review of EGD IT managers
- Provides leadership on dealing with security issues
  - Develop, update and deploy IT policies, methods, technology standards best practices, and tools to meet EGD security requirements
  - Monitor and manage security of data, applications, network, and computing platforms
  - Research and analyze new security technologies
  - Coordinate and manage implementation of new security technologies
  - Conduct annual IT Security Audit using ISO framework; Periodic coordination of external IT security audits
- Conduct RFP, vendor/system analysis, and ultimate selection of vendors for EGD systems
- Coordinate and participate in negotiation of new contracts and contract renewals
- Manage overall vendor relationship for enterprise systems
- Act as escalation point for all unresolved IT vendor issues
- Handle administration and payment approval of maintenance contracts and additional license fees for corporate applications

Service Recipient: Mr. Henry Wong, Director Information Technology, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
People and Partners	$181,220
CIO	$0
IT Planning and Governance	$442,895
Total	**$624,115**

Expected Deliverables

- Provide strategic planning and management guidance in the identification and design of Enterprise IT systems for the benefit of EGD
- Align technology strategy to EGD's long term strategic needs
- Ensure technologies meet business needs and are scalable and

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	serviceable as required • Ensuring security and maintenance of the integrity of the data and information content. • Ensuring availability of an intranet portal that is structured effectively for EGD needs. • Provide an IT Strategic Plan that is aligned with the goals and objectives of EGD. This includes all areas of IT service delivery. • Provide corporate IT policies to govern the administration and operation of EGD's systems and enterprise systems EGD uses. • Provide senior executive information technology expertise which is not resident within EGD. • Provide opportunities to share experiences, programs and initiatives with other internal IT organizations in order to take advantage of alternate delivery methodologies, technical architectures, IT processes, and apply the learnings to EGD's benefit. • For enterprise systems EGD utilizes (EFS, HRIS, Sharepoint, Livelink) providing a formal enterprise architecture plan. This includes the development and ongoing maintenance of the architecture plan. • For enterprise systems EGD utilizes (EFS, HRIS, Sharepoint, Livelink)) providing systems that meet performance and functionality objectives on an ongoing basis. • For those enterprise projects that benefit EGD, provide Project Management support needed to launch the projects. This would include project budgeting, and the initial solution architecture. • Provide corporate IT policies to govern the security of EGD's systems and enterprise systems EGD uses.
Quantity and Quality of Service	
	• Effective, reliable and low IT infrastructure • Ensure vendor relationships are managed effectively. • Ensuring compliance with all relevant legislation affecting information systems. • Ensuring that all supply chain initiatives conform to industry standards and best practices. • Ensuring that all of the contracts are effectively negotiated and managed.
Authorized Signature	
RB	Mr. Henry Wong Director Information Technology Enbridge Gas Distribution Mar. 7, 2012 Date

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14. Expense System Management & Technical Support (Oracle iExpense)

Service Description	
Service Definition:	The Expense System Management and Technical Support (Oracle iExpense) service is responsible for the technical support and administration of the automated purchasing and employee expense reporting tool (Oracle iExpense). Oracle iExpense is an online system, used in reporting employee expenses, where all expenses incurred via Amex or BMO corporate cards are uploaded automatically. Oracle iExpense contains an approval hierarchy where all expense report approvals are done electronically. EGD requires this service to ensure efficient and accurate processing of automated purchasing and employee expenses
Services Identified by Department	**CIO Department** The Expense System Management and Technical Support (Oracle iExpense) service is responsible for the technical support and administration of the automated purchasing and employee expense reporting tool (Oracle iExpense). The CIO Department supports this service by providing leadership and management to IT resources providing services: IT System Analysts, IT DBA resources, IT Infrastructure resources, and IT contract resources. Responsible for overseeing all IT related activities from day-to-day technical support to strategic planning for Enterprise Financial Systems (Oracle iExpense). Examples of activities related to the provision of this service include: • Ensure the Oracle iExpense application is effectively managed • Assist senior business leadership in terms of IT process changes, business process changes, incremental infrastructure, data, and support processes through interaction with the EFS Governance Committee, representing executive finance and IT management from across Enbridge. • Establish and maintain effective communication and relationship with systems' vendors to ensure prompt and cost efficient vendors support. • Develop, coach and mentor EFS Strategy and Services employees and contractors • Drive the implementation and compliance to quality assurance procedures, standards for process design, documentation, configuration changes, functionality enhancements, and a release management strategy to protect the integrity and reliability of financial data. • Proactively gather and make recommendations regarding complex intelligence from across Enbridge and externally to assess immediate and future impacts on EFS applications, processes, and priorities. • Establish and maintain an effective external network with appropriate application user groups, industry groups, and business partners to share knowledge, gain intelligence, learn cost avoidance strategies, understand alternatives and trends to anticipate, plan, and ensure continuing operational excellence in the support of EGD's evolving business needs. • Vendor Management o Negotiate, monitor and manage expense management system vendor contract o Negotiate, monitor and manage IT outsourcing relationships with respect to the expense manage system o Research and monitor emerging technologies **EFS Strategy and Services Department**

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	The Expense System Management and Technical Support (Oracle iExpense) service is responsible for the technical support and administration of the automated purchasing and employee expense-reporting tool (Oracle iExpense). The EFS Strategy and Services Department supports this service by providing technical expertise to the operation of the expense system. Examples of activities related to the provision of this service include: • Manage client relationships and communication • Lead the strategic planning process in relation to efficiency and effectiveness of EFS applications • Reporting & Analysis o Provide reporting to management for tracking expenses and supply purchases to ensure policy compliance, spend volume and strategic sourcing performance objectives o Provision of standard reports o Ad hoc report generation o Augment, add, or remove reporting requirements • Technical Support o Interface management o System configurations, customization or enhancements o Release management o Master-file maintenance o Manage development life cycle o Monitor system performance • Vendor Management o Negotiate, monitor and manage expense management system vendor contract o Negotiate, monitor and manage IT outsourcing relationships with respect to the expense manage system o Research and monitor emerging technologies **Corporate Administration Department** The Expense System Management and Technical Support (Oracle iExpense) service is responsible for the technical support and administration of the automated purchasing and employee expense-reporting tool (Oracle iExpense). The Corporate Administration Department supports this service by providing end user administrative support and maintenance services with respect to the two credit card programs. Examples of activities related to the provision of this service include • User support activities o Management and user support of Oracle iExpense system (does not include system support) o Provide back up system support o Manage employee business and travel expense policy and purchasing card agreements o Provide strategic, operational and compliance reporting to management for expense tracking and other objectives • Maintenance services o Manage and maintain cardholder database o Facilitate cardholder / vendor issues o Monitor and follow-up overdue balances
Service Recipient:	Mr. Henry Wong, Director Information Technology, Enbridge Gas Distribution
Cost of Service	

	Department	Service Charge	

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CIO	$35,587	
EFS Strategy and Services	$30,650	
Corporate Admin.	$29,253	
Total	**$95,490**	

Expected Deliverables

- Ensure availability of the infrastructure and Expense System (Oracle iExpense) to support personnel in their claim submission and recovery activities
- Provide user support as required
- Provide an expense management system to ensure adequate tracking, control, and payment of employee expenses.
- Ensuring technical support and management of the Oracle iExpense system to ensure the effective ongoing operation of the system.
- Ensuring alignment with the goals and objectives of EGD which is driven by a relevant governance structure.

Quantity and Quality of Service

- Continuous and uninterrupted access
- Accuracy and integrity of claims and payments.
- On demand user support
- Effective and efficient support for Oracle iExpense.
- Ensuring an effective relationship with the Oracle iExpense vendor
- Ensuring availability of staff that possesses the competencies required to fulfill their job responsibilities.
- Ensuring compliance with all relevant best practices (e.g. ITIL, COSO) to maintain system integrity and reliability.
- Ensuring a diligent process of request prioritization, including assessing cost, resources, systems impacts, and business value to determine which requests will go forward.
- Ensuring EGD is up to date with application market developments external to Enbridge. This includes networking with relevant peer companies to gain knowledge and apply to EGD where appropriate
- Ensuring a relationship with the vendor who supports Oracle iExpense.

Authorized Signature

Mr. Henry Wong
Director Information Technology
Enbridge Gas Distribution

Mar. 7 2012
Date

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15. External Audit Coordination

Service Description	
Service Definition:	The External Audit Coordination service is responsible for coordinating and managing the external auditors and their related supporting activities.
Services Identified by Department	**CFO Department** The External Audit Coordination service is responsible for coordinating and managing the external auditors and their related supporting activities. The CFO Department supports this service by providing senior leadership and overall management guidance. Examples of activities related to the provision of the service include: • Support negotiation of audit fees **Audit Services Department** The External Audit Coordination service is responsible for coordinating and managing the external auditors and their related supporting activities. The Audit Services Department supports this service by assuming responsibility for coordinating internal resources and managing external auditors. Examples of activities related to the provision of the service include: • Coordinate internal resources in the development of the audit plan with external auditors • Participate in the negotiation of external auditor fees and certification outsourcing (PWC, Accenture Business Services) fees on behalf of EGD • Assist in coordinating the external audit in conjunction with EGD to minimize duplication and enhance audit efficiencies • Provide advice on specific audit issues and procedures • Coordinate communications to external auditors • Assess changes in business practices and their impact on the audit plan **Corporate Controller Department** The External Audit Coordination service is responsible for coordinating and managing the external auditors and their related supporting activities. The Corporate Controller Department supports this service by assuming responsibility for coordinating and managing external auditors. Examples of activities related to the provision of the service include: • Coordinate audit plan development with external auditors • Negotiate external auditor fees and certification outsourcing (PWC, Accenture Business Services) fees on behalf of EGD • Coordinate the external audit in conjunction with EGD to minimize duplication and enhance audit efficiencies
Service Recipient:	Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CFO	$84,158
Audit Services (Calgary)	$0
Corporate Controller	$19,241
Total	**$103,399**

Expected Deliverables

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	• Efficient, well managed and timely audit turnarounds
Quantity and Quality of Service	
	• Competitive audit fees (pricing of audits that benefit from economies of scale) • On demand access to financial, accounting and auditing expertise
Authorized Signature	
	Mr. Narin Kishinchandani Vice-President Finance Enbridge Gas Distribution Mar 2, 2012 Date

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16. Financial and Project Accounting System Technical Support (Oracle)

Service Description	
Service Definition:	The Financial and Project Accounting System Technical Support (Oracle) service provides the system support and maintenance, system customization and enhancements for the Enbridge Financial and Project Accounting Management system (Oracle). The Enbridge Financial and Project Accounting Management system (Oracle) includes General Ledger, Accounts Payable, Purchasing, (including i-Procurement), Order Management, Accounts Receivable, Cash Management, Fixed Asset, Projects, Plant Accounting and Inventory modules.
Services Identified by Department	**CIO Department** The Financial and Project Accounting System Technical Support (Oracle) service provides the system support and maintenance, system customization and enhancements for the Enbridge Financial and Project Accounting Management system (Oracle). The CIO Department supports this service by providing leadership and management to IT resources providing services: IT System Analysts, IT DBA resources, IT Infrastructure resources, and IT contract resources. Responsible for overseeing all IT related activities from day-to-day technical support to strategic planning for Enterprise Financial Systems (Oracle Financials). Examples of activities related to the provision of this service include: • Coordinate collaboration and integration across Enbridge IT departments to ensure IT activities support enterprise requirements and to ensure Oracle Financials application is effectively managed • Assist senior business leadership in terms of IT process changes, business process changes, incremental infrastructure, data, and support processes • Establish and maintain effective communication and relationship with systems' vendors to ensure prompt and cost efficient vendors support. • Develop, coach and mentor EFS Strategy and Services employees and contractors • Drive the implementation and compliance to quality assurance procedures, standards for process design, documentation, configuration changes, functionality enhancements, and a release management strategy to protect the integrity and reliability of financial data. • Proactively gather and make recommendations regarding complex intelligence from across Enbridge and externally to assess immediate and future impacts on EFS applications, processes, and priorities. • Establish and maintain an effective external network with appropriate application user groups, industry groups, and business partners to share knowledge, gain intelligence, learn cost avoidance strategies, understand alternatives and trends to anticipate, plan, and ensure continuing operational excellence in the support of EGD's evolving business needs. • Vendor Management o Negotiate, monitor and manage vendor contract o Negotiate, monitor and manage IT outsourcing relationships o Research and monitor emerging technologies o IT Planning and Governance **EFS Strategy and Services Department** The Financial and Project Accounting System Technical Support (Oracle) service provides the system support and maintenance, system customization and enhancements for the Enbridge Financial and Project Accounting Management

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	system (Oracle). The EFS Strategy and Services Department supports this service by providing technical expertise and assuming responsibility for providing the required system support and maintenance, system customization and enhancements for the Enbridge Financial and Project Accounting Management system (Oracle). Examples of activities related to the provision of this service include: • Manage client relationships and communications • Lead the strategic planning process in relation to efficiency and effectiveness of EFS applications • Support & Maintenance o System administration o User support, maintenance & security o User (incl. super user / power user) training & communication o Change management • Reporting & Analysis o Provision of standard reports o Ad hoc report generation / queries o Augment, add, or remove reporting requirements • Technical Support o Interface management o System configurations, customization or enhancements o Release management o Master-file maintenance o Manage development life cycle o Monitor system performance • Vendor Management o Negotiate, monitor and manage vendor contract o Negotiate, monitor and manage IT outsourcing relationships o Research and monitor emerging technologies
Service Recipient:	Mr. Henry Wong, Director Information Technology, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CIO	$192,580
EFS Strategy and Services	$159,581
Total	**$352,161**

Expected Deliverables

- Ensure availability of the financial and other information contained within Oracle System (This system maintains the general ledger and actual transactional data which supports all EGD's requirements for financial reporting and decision making.
- Provide user support as required
- Provide infrastructure, policies and processes for recording financial results
- Ensure availability of a Financial and Project Accounting system to manage the financials for EGD.
- Ensure availability of technical support and management of the Oracle system to ensure the effective ongoing operation of the system.
- Ensuring an Oracle system that is aligned with the goals and objectives of EGD and which is driven by a relevant governance structure
- Ensuring a diligent process of request prioritization, including assessing cost, resources, systems impacts, and business value to determine which requests will go forward.

Quantity and Quality of Service

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	• Continuous and uninterrupted access to financial and other Management information • Accuracy and integrity of data. • On demand user support • Providing an effective relationship with Oracle to ensure timely and effective support from the vendor to business or technical issues. • Ensuring availability of technical staff that possesses the competencies required to fulfill their job responsibilities. • Ensuring compliance with all relevant best practices (e.g. ITIL, COSO) to maintain system integrity and reliability • Ensuring a diligent process of request prioritization, including assessing cost, resources, systems impacts, and business value to determine which requests will go forward. • Ensuring EGD is up to date with application market developments external to Enbridge. This includes networking with relevant peer companies to gain knowledge and apply to EGD where appropriate • Ensuring EGD maintains a relationship with the vendor who supports Oracle Financials.
Authorized Signature	
RB	Mr. Henry Wong Director Information Technology Enbridge Gas Distribution Mar. 7, 2012 Date

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17. Gas Supply, Storage, and Transportation Strategy

Service Description	
Service Definition:	The Gas Supply, Storage and Transportation Strategy service is responsible for supporting the development of the long-term (>5 year) gas supply, storage and transportation strategies. This includes providing forward looking projections on the potential cost of the gas supply, the location of the supply and related industry requirements for storage and transportation.
Services Identified by Department	**CEO Department** The Gas Supply, Storage and Transportation Strategy service is responsible for supporting the development of the long-term (>5 year) gas supply, storage and transportation strategies. This includes providing forward looking projections on the potential cost of the gas supply, the location of the supply and related industry requirements for storage and transportation. The CEO Department provides support to this service by providing leadership support and ensuring alignment to the long-range plan. Examples of activities related to the provision of the service include: • Participate and provide leadership in the development of strategies for alternative gas supply, storage and transportation • Monitor gas supply, storage and transportation activities to ensure alignment to long range plan
Service Recipient:	Mr. Jim Grant, Vice-President, Energy Supply, Storage Development & Regulatory Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$0
Total	**$0**

Expected Deliverables	
	• Support EGD's leadership by identifying issues related to gas supply, storage and transportation and developing a corresponding strategy(s) • Provide EGD's management with guidelines and resources designed to support the successful development and implementation of a Gas Supply, Storage and Transportation strategy

Quantity and Quality of Service	
	• Forward looking Industry information related to gas supply, transportation and storage • Timely access to knowledgeable resources • Executable recommendations for inclusion in Enbridge Gas Distribution's strategy (at a level of detail that allows EGD to execute)

Authorized Signature

Mr. Jim Grant
Vice-President, Energy Supply,
Storage Development & Regulatory
Enbridge Gas Distribution

Date: Feb. 29, 2012

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18. Government Relations

Service Description	
Service Definition:	The Government Relations service ensures EGD's interests are heard by government (federal, Ontario and municipal) officials, departments and committees.
Services Identified by Department	**Public and Government Affairs Department** The Government Relations service ensures EGD's interests are heard by government (federal, Ontario and municipal) officials, departments and committees. The Public and Government Affairs Department supports this service by meeting with government officials and committees and coordinating the use of external expertise. Examples of activities related to the provision of the service include: • Manage federal government liaison and public policy initiatives (specifically climate change/emissions management issues). • Manage government relations consultants in Ottawa. • Maintain relationship with key federal government contacts to keep communications channels open. • Manage and maintain EGD's federal government relations related to climate change and environmental initiatives through contact with government committees, industry associations and the environmental community. • Manage and maintain EGD's involvement with climate change and environmental initiatives through participation in the Corporate Climate Task Force • Analyze climate change issues and identifying risks and opportunities (e.g. regulatory obligations, access to capital, stakeholder relations, and domestic and international credibility) for EGD • Assist EGD in assessing its 'Triple Bottom Line'-based Greenhouse Gases emission projections done on an annual basis. Assist EGD in monitoring and tracking emissions and completing necessary governmental filing for NPRI, LFE frameworks, GHG Registry, etc.) • Monitor climate change obligations • Maintain contact with industry associations, government committees (across all levels of Government) and the environmental community • Ensures EGD provides relevant input into the Corporate Social Responsibility Report (CSR)
Service Recipient:	Ms. Debbie Boukydis, Director, Public & Government Affairs, Enbridge Gas Distribution Mr. Arunas Pleckaitis, Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution
Cost of Service	

Department	Service Charge
Public & Government Affairs	$44,917
Total	**$44,917**

Expected Deliverables	
	• Ensure that EGD's interests are represented to Federal Government Officials and staff
Quality and Quantity of Service	
	• # of Government contacts relevant to EGD • Positive relationships with key government entities

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	• Documented strategies • Comprehensive policies meeting EGD's needs • Investors and customers view EGD as a corporate environmental leader • EGD is well recognized by reporting agencies as having a "best in class" reporting classification • Plan clearly documents EGD's GHG emission levels, sources of emissions, emission reduction objectives and timelines
Authorized Signature	
	Debbie Boukydis Ms. Debbie Boukydis Director, Public & Government Affairs, Enbridge Gas Distribution March 26, 2012 Date

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19. HRIS Program Management and Development

Service Description	
Service Definition:	The HRIS Program Management and Development service provides consulting services for support of the development and management of on-going HRIS and other HR technology system projects, including design, development, implementation, and coordination of project teams. Specific HRIS application include the following PeopleSoft Modules: Human Resources, Payroll for North America, Benefits Administration, Extended Enterprise, eCompensation, ePay, eBenefits, eProfile, eRecruit, eDevelopment, Time and Labour, eCompensation Manager Desktop, eProfile Manager Desktop, Directory Interface, ePerformance, HRMS Warehouse, PeopleSoft Portal. Other HE technology applications include eLMS and workforce planning technologies. And Supporting Infrastructure: Sun, UNIX, Oracle, Web servers, development environments
	CIO Department The HRIS Program Management and Development service provides consulting services for support of the development and management of on-going HRIS and other HR technology system projects, including design, development, implementation, and coordination of project teams. The CIO Department supports this service by providing strategic guidance to the technical support teams. Examples of activities related to the provision of the service include: • Vendor management, • System management services, • Project management services, • Security and IT risk assessment services, • Technical architecture planning services. **Corporate Human Resources Department** The HRIS Program Management and Development service provides consulting services for support of the development and management of on-going HRIS and other HR technology system projects, including design, development, implementation, and coordination of project teams. The Corporate Human Resources Department supports this service by providing HR user expertise and developing the required HR processes and controls. Examples of activities related to the provision of the service include: • Work with EGD to determine immediate and long-term HRIS and other HR technology requirements. • Keep appraised of HRIS service offerings in the HRIS marketplace in North America. • Keep appraised of PeopleSoft offerings. • Work with EGD to match requirements and available services. • Provide expertise required to support the development of business cases for the modifying, expanding or acquiring of new HRIS and other HR technology functionality. • Work with IT HRIS development and business unit human resource staff to plan, execute and implement modifications, expansions or new HRIS and other HR technology functionality.

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	• Work with EGD human resource staff to train users. • Work with EGD human resource staff to ensure maximum benefit is realized from HRIS investments. • Conduct research on additional HRIS modules and other related matters for the purpose of improving support of business operational and strategic objectives • Develop business case, project charter, project plan and other required project documentation; including securing project approval • Organize and coordinate non-IT team resources (both internal and external resources) • Develop business process and non-IT related training materials and provide training to EGD • Advise on change management issues and communication plans • Provide resources to other enterprise projects • Reporting & Analysis o Provision of standard reports o Ad hoc report generation o Augment, add, or remove reporting requirements **HRIS Department** The HRIS Program Management and Development service provides consulting services for support of the development and management of on-going HRIS and other HR technology system projects, including design, development, implementation, and coordination of project teams. The HRIS Department supports this service by assuming technical responsibility for the required user training and support, system maintenance, system customization and enhancements. Examples of activities related to the provision of the service include: • Conduct research on additional HRIS modules and other related matters for the purpose of improving support of business operational and strategic objectives • Work with stakeholders to identify required enhancements or changes to existing systems. • Develop business case, project charter, project plan and other required project documentation; including securing project approval • Organize and coordinate team resources (both internal and external resources) • Manage the vendor selection and RFP process including the negotiation of all fees • Manage and monitor project performance through to completion • Reporting & Analysis o Provision of standard reports o Ad hoc report generation o Augment, add, or remove reporting requirements • Technical Support o Interface management o System configurations, customization or enhancements o Release management o Master-file maintenance o Manage development life cycle o Monitor system performance • Vendor Management o Negotiate, monitor and manage expense management system vendor contract o Negotiate, monitor and manage IT outsourcing relationships with

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	respect to the expense management system o Research and monitor emerging technologies **Pension & Benefits Department** The HRIS Program Management and Development service provides consulting services for support of the development and management of on-going HRIS and other HR technology system projects, including design, development, implementation, and coordination of project teams. The Pension & Benefits Department supports this service by providing HR expertise and project management support. Examples of activities related to the provision of the service include: • Provide project management and definition support for pension and benefit related changes to HRIS system; including, o Develop business case, project charter, project plan and other required project documentation; including securing project approval (i.e. Time and Labour Project) o Organize and coordinate team resources (both internal and external resources) o Advise on change management issues and communication plans **HR Enterprise Business Solutions Department** The HRIS Program Management and Development service provides consulting services for support of the development and management of on-going HRIS and other HR technology system projects, including design, development, implementation, and coordination of project teams. The HR Enterprise Business Solutions Department supports this service by conducting initial business requirements gathering, functional design, data reporting, technical education and post go-live support, providing HR user the functional expertise to developing the required HR processes and controls. Examples of activities related to the provision of the service include: • Work with EGD to determine immediate and long-term HRIS requirements, and how it ties back to the HR Strategy • Keep appraised of HRIS service offerings in the HRIS marketplace in North America (including PeopleSoft) • Work with EGD to match business requirements and available services. • Provide expertise required to support the development of business cases for the modifying, expanding or acquiring of new HRIS functionality. • Work with IT HRIS development and business unit human resource staff to plan, execute and implement modifications, expansions or new HRIS functionality. • Design training materials and work with EGD human resource staff to train users. • Work with EGD human resource staff to ensure maximum benefit is realized from HRIS investments. • Conduct research on additional HRIS modules and other related matters for the purpose of improving support of business operational and strategic objectives • Work with stakeholders to identify required enhancements or changes to existing systems. • Develop testing plans for any new addition to technology • Maintain set-up tables to ensure that data is stored appropriately to deliver data to make decisions • Provide resources to other enterprise projects • Support & Maintenance

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- Functional trouble shooting
- User support
- Provide user (incl. super user / power user) training materials & communication
- Change management
- Ad-hoc and on-going reporting requests
- Business requirements gathering for new functionality and enhancements to existing technology

Service Recipient: Mr. Marc Weil, Director Human Resources, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CIO	$465,956
Corporate HR	$150,591
HRIS	$1,622,414
Pension & Benefits	$0
HR Enterprise Business Solutions	$770,312
Total	**$3,009,273**

Expected Deliverables

- Ensure access to personnel records for all EGD staff as established by company policy
- Provide user support and the development of all HR-related technology applications
- Monitor and maintain the accuracy, integrity and confidentiality of the data contained within the HRIS and other HR technology systems
- Enhancements to the technological supports to maximize efficiencies of HR processes and leverage current and future functionality

Quality and Quantity of Service

- Continuous and uninterrupted access to HRIS system
- Accuracy and integrity of data
- On demand user support
- Efficient/Maximized usage of PeopleSoft system capability
- Expanded functionality achieved cost-effectively due to economies of scale

Authorized Signature

Mr. Marc Weil
Director Human Resources
Enbridge Gas Distribution

March 2, 2012
Date

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20. Human Resource Advice

Service Description	
Service Definition:	The Human Resource Advice service provides research, expertise and support to internal initiatives. This includes support related to policy and systems development, personnel management, and adherence to regulatory and legislative requirements.
Services Identified by Department	**CEO Department** The Human Resource Advice service provides research, expertise and support to internal initiatives. This includes support related to policy and systems development, personnel management, and adherence to regulatory and legislative requirements. The CEO Department supports this service by assuming ultimate responsibility for policy development on Human Resources issues. Examples of activities related to the provision of the service: • Provides ultimate responsibility for all personnel policy issues and adherence to regulatory and legislative requirements • Provides ultimate responsibility for governance of the organization with respect to ensuring the proper procedures, policies, processes, people and culture to be successful **Corporate Human Resources Department** The Human Resource Advice service provides research, expertise and support to internal initiatives. This includes support related to policy and systems development, personnel management, and adherence to regulatory and legislative requirements. The Corporate Human Resource Department supports this service by developing and managing Human Resource systems and processes and providing leadership and expertise on Human Resource issues. Examples of activities related to the provision of the service: • Leader of the corporate Human Resources Leadership Team (HRLT) responsible for o Coordinating HR initiatives across enterprise, including EGD o Providing guidance, advice and coordinating specialist services to EGD o Acting as the ultimate decision making authority for HR initiatives o Developing HR policies and coordinate the delivery with EGD representatives on initiatives and issues • Develop Human Resources systems and processes to ensure that the management and business processes and systems are in place to facilitate effective, efficient and economic benefits. o Identify human resources business issues and define scope of issue o Research and identify alternatives to issue resolution o Design systems and processes to support implementation of issue resolution o Coordinate and facilitate the implementation of the systems and processes o Develop system transition plans for EGD o Provide mentorship and guidance/feedback on individual development plans/performance of EGD HR Director **Enterprise Security Department** The Human Resource Advice service provides research, expertise and support to internal initiatives. This includes support related to policy and systems

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development, personnel management, and adherence to regulatory and legislative requirements. The Enterprise Security Department supports this service by being responsible for gathering, analyzing, and assessing information related to the security and protection risks that can adversely affect the security and safety of personnel.

Examples of activities related to the provision of the service:

- Assists Human Resources in the investigation of allegations of breach of the Business Code of Conduct including harassment and workplace violence
- Develops and maintains the Human Resource Protection Program for International travelers which includes risk assessments, security briefings (Duty to Warn) and security mitigation countermeasures commensurate with the risk (Duty to Protect).

Service Recipient: Mr. Marc Weil, Director Human Resources, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$30,011
Corporate HR	$171,768
Enterprise Security	$0
Total	**$201,779**

Expected Deliverables

- Support EGD's internal HR operations with research, insights and knowledge to support EGD's management in making informed business decisions
- Support EGD's HR Director regarding development planning and performance feedback/coaching

Quantity and Quality of Service

- On demand access to expertise and reliable HR advice to address EGD's business issues
- Executive mentoring/development planning support for EGD's HR Director

Authorized Signature

Mr. Marc Weil
Director Human Resources
Enbridge Gas Distribution

March 2, 2012
Date

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21. Industry Relations & Corporate Social Responsibility (CSR)

Service Description	
Service Definition:	The Industry Relations & CSR service provides the required EGD representation to major energy stakeholders e.g. suppliers, industry associations, and other energy companies in the energy industry.
Services Identified by Department	**People and Partners Department** The Industry Relations & CSR service provides the required EGD representation to major energy stakeholders e.g. suppliers, industry associations, and other energy companies in the energy industry. The People and Partners Department supports this service by providing the required representation with community stakeholder and interest groups, specifically related to, but not exclusive to educational institutions, environmental interest groups, health and safety organizations, officials and committees and various industry associations. Examples of activities related to the provision of the service include: • Responsible for the development, implementation and monitoring of the Corporate Social Responsibility programs and initiatives • Establish, implement and measure the objectives and targets for corporate social responsibility performance including, but not exclusive to o Business ethics and transparency o Environment, health and safety o Stakeholder relations o Employee Relations o Human Rights o Community Investment • Alignment of Corporate Social Responsibility initiatives, strategy and policies to annual and long-range strategic plans • Review and approval of Corporate Social Responsibility project concepts and for funds • Compare and benchmark corporate social responsibility performance against Dow Jones sustainability index • Development and production of the Corporate Social Responsibility report **Public and Government Affairs Department** The Industry Relations & CSR service provides the required EGD representation to major energy stakeholders e.g. suppliers, industry associations, and other energy companies in the energy industry. The Public and Government Affairs Department supports this service by liaising with customers and special interest groups with respect to EGD's position on issues and initiatives in EGD customer communities. Examples of activities related to the provision of the service include: • Coordinate and deliver the company's Corporate Social Responsibility Program of stakeholder relations and production of the CSR annual report which includes: o EGD disclosures on environment, health and safety and social performance o Participating in industry associations such as CEPA and Energy Council of Canada, many of which deal with issues and operations that affect central Canada including Ontario **Industry Associations Department** This relates to the membership of the board members to various external industry associations. The Industry Association Department forms part of the CEO.

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Examples of activities related to the provision of the service include:

- Pay for membership of the board members to various external industry associations

New Ventures Department

The Industry Relations & CSR service provides the required EGD representation to major energy stakeholders e.g. suppliers, industry associations, and other energy companies in the energy industry. The New Ventures Department supports this service by providing the required representation with community stakeholder and interest groups.

Examples of activities related to the provision of the service include:

- Responsible for the development, implementation and monitoring of the Corporate Social Responsibility programs and initiatives
- Attends, and presents at industry and community functions
- Interacts directly with media on consumer and company matters
- Establish, implement and measure the objectives and targets for corporate social responsibility performance including, but not exclusive to
    - Business ethics and transparency
    - Environment, health and safety
    - Stakeholder relations
    - Employee Relations
    - Human Rights
    - Community Investment
- Alignment of Corporate Social Responsibility initiatives, strategy and policies to annual and long-range strategic plans
- Review and approval of Corporate Social Responsibility project concepts and for funds

Enterprise Security Department

The Industry Relations & CSR service provides EGD the representation to major energy stakeholders e.g. suppliers, industry associations, and other energy companies in the energy industry. The Enterprise Security Department supports this service by being an active participant in Industry relation building and is a member of the National Energy Security Practitioners – an association of security professional from major Canadian and US energy companies.

Examples of activities related to the provision of the service include:

- Enterprise Security is responsible for production of the quarterly CSR report related to EGD initiatives and assignments.

Service Recipient:	Ms. Debbie Boukydis, Director Public and Government Affairs, Enbridge Gas Distribution Mr. Arunas Pleckaitis, Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
People and Partners	$22,987
Public & Government Affairs	$360,522
Industry Associations	$856
New Ventures	$0
Enterprise Security	$0
Total	**$384,365**

Expected Deliverables

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	• Support and present EGD's interests to specific external stakeholders groups such as customer, industry and community groups that EGD would not have access to if it was a standalone entity • Provide CSR Report
Quantity and Quality of Service	
	• Access to special interest groups relevant to EGD • Positive interactions with special interest groups
Authorized Signature	
	Debbie Boukydis Ms. Debbie Boukydis Director Government and Public Affairs Enbridge Gas Distribution March 26, 2012 Date

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22. Insurance Claims Support, Strategy and Management

Service Description	
Service Definition:	The Insurance Claims Support, Strategy and Management service is responsible for the general administration of insurance policies for EGD. Insurance policies implemented and managed by this service include liability, property, political risk, automobile, directors and officers liability, fiduciary and crime insurance.
Services Identified by Department	**CFO Department** The Insurance Claims Support, Strategy and Management service is responsible for the general administration of all insurance policies for EGD. Insurance policies implemented and managed by this service include liability, property, political risk, automobile, directors and officers liability, fiduciary and crime insurance. The CFO Department supports this service by providing senior leadership, overall management guidance and advice regarding EGD's financial affairs. Examples of activities related to the provision of the service include: • Further to the insurance policies listed above, insurance specific to EGD includes Control of Well and other insurance policies as may be needed by EGD • Support negotiation of insurance premiums at renewal process of insurance policies **Risk Insurance Department** The Insurance Claims Support, Strategy and Management service is responsible for the provision of claims consulting and processing to ensure all claims are dealt with in an effective manner, as well as for the general administration of all insurance policies for EGD. Insurance policies implemented and managed by this service include, but are not limited to, liability, property, political risk, automobile, directors and officers liability, fiduciary and crime insurance. The Risk Insurance Department supports this service by working with insurance companies and law firms to assist EGD with large claims settlement, as well as by identifying and implementing programs which ensure the insurance requirements are met. Examples of activities related to the provision of the service include: • Provide claims consultation and guidance on material claims • Provide strategic direction to the EGD Operations Risk & Insurance function with respect to claims management • Liaise with EGD and independent legal counsel, and insurance expertise in support of large claim settlement processes • Liaise with insurance companies and law firms to assist EGD with claims settlement processes, as well as claims where the insurance deductible may be reached. • Further to insurance policies listed above, insurance specific to EGD includes Control of Well and other insurance policies as may be needed by EGD • Identify EGD specific insurance requirements, including regulatory compliance issues • Compile EGD data into overall EI insurance submission which is used by insurance companies for calculating insurance premiums costs • Select insurance vendors and negotiation of all insurance policies • Placement and maintenance of policies to ensure material changes to business operations are manifested in the appropriate levels of insurance coverage • Provide proof of insurance documentation to EGD • Provide formal Risk and Insurance Management Policy as available on

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internal portal (E-link)

- Contract review process to establish consistency in standard terms & conditions for all insurance and indemnification clauses for all contracts for service agreements. Assist in the contract review of large contracts on as needed basis
- Liaise with EGD insurance groups on miscellaneous insurance matters
- Coordinate and manage 3rd party periodic loss control and risk control surveys to ensure insurance providers are aware that appropriate health and safety requirements are met
- Provide guidance and oversight to Enbridge off-shore re-insurers utilized to provide EGD with cost effective insurance coverage
- Provide placement of bonds and bonding and specific insurance policies (i.e. Builders' Risk) for construction projects, as required
- Forecast future insurance requirements and related expenditures for long range strategic planning, budgets and annual forecasts

Enterprise Risk Department

The Insurance Claims Support, Strategy and Management service is responsible for the general administration of all insurance policies for Enbridge Inc. and all of its affiliates. Insurance policies procured and managed by this service include general liability, property, political risk, control of well, automobile, aviation liability, directors and officers liability, fiduciary liability, crime coverage, professional liability and bonds. The Enterprise Risk Department supports this service by providing leadership and strategic support.

Examples of activities related to the provision of the service include:

- Support development of overall insurance strategies, including appropriate risk retention levels
- Support negotiation of insurance premiums and coverage terms and conditions
- Manage Risk Management department administratively

Service Recipient:	Mr. Jamie Milner, Vice President Pipeline Integrity & Safety, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CFO	$29,314
Risk Insurance	$50,724
Enterprise Risk	$28,202
Total	**$108,240**

Expected Deliverables

- Minimize denied, delayed or reduced settlements on claims
- Present and manage EGD's insurance claims with the underwriting companies
- Provide advice on how to reduce claims
- Provide advice on policy coverage requirements
- Develop a customized insurance strategy, negotiate with underwriters and ensure a comprehensive policy is in place to maximize coverage at a cost lower than EGD would be able to achieve on its own (Note 1: EGD periodically engages an independent broker to perform an insurance program review for adequacy of coverage and costs competitiveness)
- Provide EGD's management with advice designed to support the successful development and implementation of the Insurance Management strategy

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Quantity and Quality of Service	
	• On demand access to support • Positive Claims experience • Reduced policy costs • Comprehensive policies meeting EGD's needs at a competitive price (see Note 1 above)
Authorized Signature	
	Mr. Jamie Milner Vice President Pipeline Integrity & Safety Enbridge Gas Distribution Mar 2/12 Date

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24. Investor Services

Service Description	
Service Definition:	The Investor Services service ensures that investors are fully informed of EGD's business objectives, strategy, financial performance and condition for the purpose of maintaining confidence in their current investments.
Services Identified by Department	**CEO Department** The Investor Services service ensures that investors are fully informed of EGD's business objectives, strategy, financial performance and condition for the purpose of maintaining confidence in their current investments. It is a critical component of the capital market financing and access processes. The CEO Department supports this service by providing senior leadership representation and support to meetings attended by current and future lenders. Examples of activities related to the provision of the service include: • Maintain institutional investor and investment analyst relationships, as well as with other related agencies (i.e. Exchanges, security commissions, credit rating agencies, etc.) • Communicate EGD's financial condition and strategy to investment community through annual and quarterly reports, the annual general meeting, earnings calls, investor road shows and direct contact with existing and potential investors **CFO Department** The Investor Services service ensures that investors are fully informed of EGD's business objectives, strategy, financial performance and condition for the purpose of maintaining confidence in their current investments. It is a critical component of the capital market financing and access processes. The CFO Department supports this service by providing senior leadership representation and support to meetings such as those related to the annual general meeting and quarterly analyst calls, as well as to meetings and road shows with institutional investors. Examples of activities related to the provision of the service include: • Communicate EGD's financial condition and strategy to investment community through annual and quarterly reports, earning's calls, investor road shows and direct contact with existing and potential investors • Maintain institutional investor and investment analyst relationships, as well as with other related agencies, i.e., exchange (TSX), security commission (OSC), credit rating agencies (S&P, Moody's, Dominion Bond Rating Service and Dun & Bradstreet) • Conduct investor road shows every month except for January • Conduct quarterly analyst calls at which a large percentage of the questions are related to EGD • Report quarterly to credit rating agencies • Provide leverage with the banks to achieve lowest debt pricing, including the cost of short term commercial paper **People and Partners Department** The Investor Services service ensures that investors are fully informed of EGD's business objectives, strategy, financial performance and condition for the purpose of maintaining confidence in their current investments. It is a critical component of the capital market financing and access processes. The People and Partners Department supports this service by maintaining compliance to corporate governance guidelines and standards for exchanges, credit agencies and securities regulations.

Examples of activities related to the provision of the service include:

- Attends and presents at investor relations meetings
- Ensure compliance to guidelines or standards based on the exchanges , credit agencies under which EGD credit worthiness is rated, and the jurisdictions in which EGD operates. Specific entities include
    - TSX
    - Moody's and Standard and Poor's credit agencies
    - Canadian securities regulators

Corporate Secretarial Department

The Investor Services service ensures that investors are fully informed of EGD's business objectives, strategy, financial performance and condition for the purpose of maintaining confidence in their current investments. It is a critical component of the capital market financing and access processes. The Corporate Secretarial Department is responsible for supporting this service by providing legal, paralegal and administrative services.

Examples of activities related to the provision of the service include:

- Activities for Shareholders
    - Report and verify corporate governance and accountability
    - Coordinate the Annual Meeting of Shareholders
    - Manage shareholder business
        - Issue identification and clarification
        - Liaise with transfer agent
        - Maintain shareholder records
        - Voting policies and procedures (traditional and electronically)
- Maintain stock exchange listing on TSE
- Liaise with stock exchange and securities commission regarding compliance

Investor Relations Department

The Investor Services service ensures that investors are fully informed of EGD's business objectives, strategy, financial performance and condition for the purpose of maintaining confidence in their current investments. It is a critical component of the capital market financing and access processes. The Investor Relations Department provides support to this service by acting as the primary point of contact for all investor and analyst related inquiries and is responsible for coordinating and managing all investor communication activities (primarily with investment analysts).

Examples of activities related to the provision of this service include:

- Coordinate annual general meetings
- Coordinate quarterly earnings calls, media calls and other investor related communications; including collection, organization, construction and preparation of all presentation materials
- Monitor compliance with fair disclosure laws of Canada
- Maintain investor analyst, institutional and financial media contacts
- Respond to all customer and analyst inquiries
- Maintain and update investor related information on the Enbridge website on a daily basis. The website is the main portal of information for the investors

Treasury Department

The Investor Services service ensures that investors are fully informed of EGD's business objectives, strategy, financial performance and condition for the purpose

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of maintaining confidence in their current investments. It is a critical component of the capital market financing and access processes. The Treasury Department provides support to this service by maintaining relations with investors and investment analysts (primarily debt investors and investment analysts) to ensure the markets are advised of EGD's current and anticipated financial positions.

Examples of activities related to the provision of the service include:

- Prepare presentations and credit analysis for credit rating agencies, auditors, investments banks, institutional investors, debt holders and fixed income analysts
- Meet with investors and stakeholders to optimally present the financial condition of EGD
- Provide support for fixed income investment road shows and direct investor inquiries

Public and Government Affairs Department

The Investor Services service ensures that investors are fully informed of EGD's business objectives, strategy, financial performance and condition for the purpose of maintaining confidence in their current investments. It is a critical component of the capital market financing and access processes. The Public and Government Affairs Department supports this service by providing advice relating to external financial communications and maintaining media contacts for coordinating news releases and other communications.

Examples of activities related to the provision of the service include:

- Participate in Corporate disclosure process (e.g. CEO and CFO financial statement certification), particularly as it relates to financial communication, material disclosure, news releases, websites and publication of annual and quarterly reports

Service Recipient: Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$475,248
CFO	$69,404
People and Partners	$40,433
Corporate Secretarial	$118,346
Investor Relations	$55,854
Treasury	$60,598
Public & Government Affairs	$63,954
Total	**$883,837**

Expected Deliverables

- Develop and maintain investment community confidence in EGD
- Coordinate the dissemination of relevant business, strategic, financial and operational information

Quantity and Quality of Service

- Timely and relevant disclosures
- Appropriate external stakeholder segmentation
- Relevant messaging to each segment
- Effective communication channels: i.e. conference calls, media releases, investor road shows and general meetings

Authorized Signature

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	Mr. Narin Kishinchandani Vice-President Finance Enbridge Gas Distribution May 2, 2012 Date

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25. Legal Advice

Service Description	
Service Definition:	The Legal Advice service provides access to legal precedents, research material and legal experts providing advice related to matters such as contracts, litigation, regulatory proceedings and various EGD initiatives.
Services Identified by Department	**Corporate Law Department** The Legal Advice service provides access to legal precedents, research material and legal experts providing advice related to contracts, litigation, regulatory proceedings and various EGD initiatives. The Corporate Law Department supports this service by providing expertise and advice on legal issues and assisting with the development of governance related policies. Examples of activities related to the provision of this service include: • Monitoring changes in federal legislation and identifying suggested changes to corporate policies (as noted below) • Drafting and setting EGD policies regarding items such as: o Compliance o Whistleblower procedures o Statement on Business Conduct o Internet policies o Record retention procedures, including electronic records discovery initiatives o Privacy laws o Crisis management • Coordinate and manage the selection process for certain external law firms retained by EGD **Corporate Secretarial Department** The Legal Advice service provides access to legal precedents, research material and legal experts providing advice related to continuous disclosure and securities law compliance, corporate governance, board and board committee matters. The Corporate Secretarial Department supports this service by providing legal expertise, paralegal and administrative services to the EGD Board of Directors and Audit, Finance & Risk Committee ("AFRC"). Examples of activities related to the provision of the service include: • Legal advice in support of press releases, speech and publication review related to the activities of EGD's Board and the AFRC • Disclosure committee – Provide advice to the EGD Disclosure Committee, thereby fulfilling a governance oversight role for EGD's Board and for management • Legal advice and guidance with respect to EGD's continuous disclosure obligations under applicable securities laws (e.g. quarterly and annual Financial Statements and Notes, Management's Discussions and Analysis and the Annual Information Form) **Executive VP Corporate Law Department** The Legal Advice service provides access to legal precedents, research material and legal experts providing advice related to contracts, litigation, regulatory proceedings and various EGD initiatives. The Executive VP Corporate Law Department supports this service by providing executive level expertise and guidance as well as overall direction for significant compliance and governance initiatives.

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	Examples of activities related to the provision of the service include: • Managing the efforts of direct reports, and external legal counsel to reduce costs and risk, to increase functionality of the corporate secretarial services for the benefit of EGD, and to improve and enhance EGD's corporate image and key relationships by a thoughtful and coordinated approach to the public, shareholders, board members, regulators and to other key stakeholders • Support the EGD Board and AFRC in connection with required legal matters for the benefit of EGD (including corporate governance and reporting issuer compliance) • Setting corporate policies for the benefit of EGD regarding items such as: o Compliance o Whistleblower procedures o Statement on Business Conduct o Internet policies o Record retention procedures o Privacy laws o Crisis management • Determine and implement required training programs to enhance EGD's corporate governance and transparency for matters such as whistleblower procedures, fraud awareness and prevention, and privacy protection. • Coordinate and manage the selection process for certain external law firms retained by EGD • Provide advice and counsel to EGD for legal matters related to corporate finance and public disclosure • Monitor the state of compliance with assistance of the relevant departments in EGD, including conducting necessary investigations and reviews into complaints and issues of non-compliance • Chair an enterprise wide committee including EGD and corporate representatives, which identifies and deals with risk mitigation and compliance matters generally to the overall benefit of EGD • Update and revise as necessary the Enbridge Statement on Business Conduct, together with other corporate ethics policies and programs for the benefit of EGD • Provide executive level guidance and advice regarding the structure of EGD's Law Department **Enterprise Security Department** The Legal Advice service provides access to legal precedents, research material and legal experts providing advice related to contracts, litigation, regulatory proceedings and various internal initiatives. The Enterprise Security Department supports this service by providing expertise and advice on mitigation of enterprise security risks and conducting investigations where warranted to ensure the protection of EGD's assets and employees. Examples of activities related to the provision of the service include: • Reports to the Vice President, General Counsel & Chief Compliance Officer on EGD security matters • Accountable for strategic oversight of all security and protection policies and programs including developing, influencing and directing a security and protection strategy for EGD • The security and protection strategy includes the protection of organizational reputation, the uninterrupted reliability of the technical infrastructure and normal business processes, protection of physical and financial assets, and the safety of employees. • In collaboration with EGD's management, develops and implements EGD's security and protection strategy directly related to identified risks.

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	The strategy should outline in detail the plans to prevent and prepare for an adverse event. • Provides advice and guidance to EGD Corporate Security staff with respect to strategies for protection of the physical assets (cash, facilities, equipment), intangible assets (reputation, intellectual property, and trade secrets), and the people (management, directors, employees, customers, contractors and others) of the organization. • Responsible and accountable for ensuring that EGD is prepared for the possibility of a catastrophic event or related significant security incident. This involves the administration of training plans, programs, and exercises. Responsible for regular review and evaluation of the organizational readiness plan in the event of a security related event or emergency. • In case of a security related emergency or an incident, responsible for coordinating efforts to restore the critical systems and provide the facilities required for EGD to function. • Provides leadership and support to EGD's executive team to ensure risks are made known to senior management and the Board of Directors.
Service Recipient:	Mr. Mark R. Boyce, Vice President, Law & Information Technology, Enbridge Gas Distribution
Cost of Service	

Department	Service Charge
Corporate Law	$353,497
Corporate Secretarial	$38,973
Executive VP Corporate Law	$121,926
Enterprise Security	$0
Total	**$514,396**

Expected Deliverables	
	• Support EGD staff with legal research, insights and knowledge leveraging the collective expertise of Enbridge Inc. • Facilitate the acquisition of cost effective external legal services through the negotiation of volume discounts with national law firms utilized by EGD.
Quantity and Quality of Service	
	• On demand access to expertise and reliable legal advice and knowledge • Effective and current legal research, reporting and access to up to date legal precedents.
Authorized Signature	
	Mr. Mark R. Boyce Vice President, Law & Information Technology Enbridge Gas Distribution March 21, 2012 Date

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26. Planning, Management & Execution of Internal Audits

Service Description	
Service Definition:	The Planning, Management and Execution of Internal Audits service is responsible for Audit program development for the execution of internal audits within EGD.
Services Identified by Department	**CFO Department** The Planning, Management and Execution of Internal Audits service is responsible for Audit program development for the execution of internal audits within EGD. The CFO Department supports this service by providing senior leadership, overall management guidance and advice regarding financial affairs. Examples of activities related to the provision of the service include: • Advise on the Annual Audit Plan **Audit Services Department** The Planning, Management and Execution of Internal Audits service is responsible for Audit program development for the execution of internal audits within EGD. The Audit Services Department supports this service by assuming responsibility for developing and coordinating the annual internal audit program. Examples of activities related to the provision of the service include: • Audit program development and execution from a financial, compliance, operational and systems perspective o Ensure audit program alignment to long range plan and risk mitigation plan o Identify depts. and activities to audit o Set and validate audit materiality levels o Identify audit synergies across EGD and coordinate resources to minimize costs o Address issues and gaps in Audit process o Perform audits / tasks, which include • Financial Reporting Certification • Internal Controls Certification • External Audit Assistance Coordination • Statement of Business Conduct Review • D&O Liability Review • Treasury Systems • Cash Management • Debt & Equity Processes • Enterprise-wide Financial Systems • Khalix Consolidation Systems • Corporate Social Responsibility • Provide leadership for policy development • Coordinate functional and department stakeholders for the Audit • Review EGD audit plans and execution o Provide quality assurance o Highlight areas of concern o Recommend mitigation actions o Review audit findings and assist with development of reports • Provide counsel and leadership on internal control, risk management and governance issues and report audit results to the Audit, Finance and Risk committee of EGD
Service Recipient:	Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

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Cost of Service

Department	Service Charge
CFO	$32,426
Audit Services (Calgary)	$159,102
Total	**$191,528**

Expected Deliverables

- Provide guidance to EGD to ensure it has an internal audit plan that aligns with the strategic and risk mitigation plan and leverages the enterprise expertise and supporting resources of the organization
- Ensure alignment of external audit and internal audit to minimize business disruptions and leverage the expertise of available resources
- Provide advice on how to reduce external audit costs
- Provide advice on how to improve controls and efficiencies

Quantity and Quality of Service

- Timely, effective, low cost internal and external audit
- On demand access to financial, accounting and auditing resources, knowledge and expertise
- On demand support and leadership from Audit Services on specific audit mandates

Authorized Signature

Mr. Narin Kishinchandani
Vice-President Finance
Enbridge Gas Distribution

Mar 2, 2012
Date

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27. Portal Suite Operations and Technical Support

Service Description	
Service Definition:	The Portal Suite provides a reliable platform for presenting "web based" content to employees and business partners. The value of this service is: • A central environment for information provided to employees • A central "launch" point for applications, • A central location for content storage and retrieval, • Development standards that ensure reliability and consistency • Consistent and manageable access and security for employee content • The Portal Suite consists of several related applications. The primary applications are the eLink (Sharepoint), eSource (Oracle Portal), Microsoft SharePoint and Open Text Livelink (document and records management service). As well, the Portal Suite consists of a series of supporting connecting services and customized applications. EGD requires this service to enable easy employee access to all relevant data.
Services Identified by Department	**CIO Department** The Portal Suite provides a reliable platform for presenting "web based" content to both employees and business partners. The CIO Department supports the Portal Suite Operations and Technical Support service by providing strategic guidance to the technical support teams. Examples of activities related to the provision of the service include: • Vendor management, • Operational management services, • Systems management services • Project management services, • Security and IT risk assessment services, • Technical architecture planning services • Portal Suite governance. **Corporate IT Operations Department** The Corporate IT Operations Department supports the Portal Suite Operations and Technical Support service by providing the enterprise coordination of projects, governance and performance management for the Portal Suite. Examples of activities related to the provision of the service include: • Supporting the management of support & maintenance service level agreements, • Conducting research on emerging Portal Suite technologies for the purpose of improving support for business operational and strategic objectives, • Working with stakeholders to identify required enhancements or changes to existing systems, • Developing business case, project charter, project plan and other required project documentation; including securing project approval • Development of risk management plans, and coordinating related risk mitigation activities • Developing business cases to modify, expand or acquire functionality, • Working with the EGD Portal Suite departments to ensure proper client training (eLink). • Managing and monitoring Portal Suite projects through to completion • Gathering, analyzing and reporting Portal Suite statistics, to understand current usage and traffic patterns for the portal suite. This will allow for

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	pro-active planning and changes to content and applications based on past usage and trends. • Working with the CIO Department to help manage vendor relations.
Service Recipient:	Mr. Henry Wong, Director Information Technology, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CIO	$167,529
Corporate IT Operations	$163,352
Total	**$330,881**

Expected Deliverables

- Ensure availability of the infrastructure and Portal Suite to support employee access to all relevant data
- Provide user support as required
- Portal Suite statistical reports
- Provide an efficient and effective intranet portal. This portal is used as communications tool and as a robust application delivery and presentation platform.
- Ensuring the following activities are performed to EGD's satisfaction:
- Vendor management,
- Operational management services,
- Project management services,
- Security and IT risk assessment services,
- Technical architecture planning services
- Portal Suite governance.

Quantity and Quality of Service

- Continuous and uninterrupted access to Portal Suite
- Timeliness, accuracy and integrity of data
- On demand user support
- Ensure that SLA's are in place to govern the service delivery commitments associated with the Portal Suite.
- Provide EGD with a portal that it can fully leverage, this includes understanding future technical and functional possibilities and linking them to business direction.
- Ensure users needs and concerns are integrated into future development and enhancement plans.
- Ensure that projects follow a rigorous documentation process.
- All changes to the Portal Suite need to be cost and business value justified.
- Ensure that all users and super-users of the Portal Suite are adequately trained to encourage proper use and adoption of the portal suite platform.

Authorized Signature

RB

Mr. Henry Wong
Director Information Technology
Enbridge Gas Distribution

Mar 7, 2012
Date

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28. Rate Regulated Entity Support

Service Description	
Service Definition:	The Rate Regulated Entity Support service is responsible for supporting EGD's rate regulated entities and unique services pertaining to their regulatory proceedings and rate setting matters.
Services Identified by Department	**Corporate Controller Department** The Rate Regulated Entity Support service is responsible for supporting EGD's rate regulated entities and unique services pertaining to its regulatory proceedings and rate setting matters. The Corporate Controller Department supports this service by managing the rate-regulated cost allocation methodology and ensuring its application according to the governing regulations. Examples of activities related to the provision of this service include: • Coordinate and manage the corporate and regulatory cost allocation process • Attend and provide testimony at regulatory hearings • Provide research and analysis for regulatory support, as required **Treasury Department** The Rate Regulated Entity Support service is responsible for supporting EGD's rate regulated entities and unique services pertaining to their regulatory proceedings and rate setting matters. The Treasury Department supports this service by providing Corporate Treasury expertise in the preparation of rate hearings and planning for corporate finance, cash management, and financial risk related to regulatory issues. Examples of activities related to the provision of this service include: • Prepare rate case testimony and evidence o Address all corporate finance (interest rate, debt financing, etc.), cash management, risk management, access to capital, cost of capital, and transactional support issues through the preparation of evidence, interrogatory responses, and undertaking responses. o Develop any supporting material required or requested and answer general discovery questions. o Research past testimony, coordinate and address changes in policy. o Research and analyze current practices regarding corporate finance (interest rate, debt financing, etc.), cash management, risk management, access to capital, cost of capital, transactional support issues for EGD, both at the provincial and federal level, • Attend and provide testimony at regulatory hearings when required • Provide advice, research and analysis regarding all corporate finance (interest rate, debt financing, etc.), cash management, risk management, access to capital, cost of capital, and transactional support issues for special proceedings as they arise to assess potential impacts on EGD. • Provide any other advice, research and analysis as requested by EGD
Service Recipient:	Mr. Narin Kishinchandani, Vice-President, Finance, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
Corporate Controller	$44,923
Treasury	$208,981

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	Total	**$253,904**	
Expected Deliverables			
	• Support EGD's internal operations staff		
Quantity and Quality of Service			
	• On demand access to expertise and reliable advice • Continuous knowledge of EGD's operations and requirements • Continuous knowledge on topical and current regulatory accounting precedent research • Continuous knowledge on topical and current regulatory financing issues.		
Authorized Signature			
	Mr. Narin Kishinchandani Vice-President, Finance Enbridge Gas Distribution	Mar 2, 2012 Date	

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29. Records and Information Management

Service Description	
Service Definition:	The Records and Information Management service is responsible for the overall development, maintenance and dissemination of policies, procedures, and guidelines for the establishment and maintenance of the Records and Information Management Program.
Services Identified by Department	**Enterprise Content Management Department** The Records and Information Management service is responsible for the overall development, maintenance and dissemination of policies, procedures, and guidelines for the establishment and maintenance of the Records and Information Management Program. The Enterprise Content Management (ECM) Department supports this service by providing strategies, standards, tools, and project management. Specifically as it relates to information technology systems, the ECM department supports this service by developing and maintaining strong, reliable content management systems and solutions that effectively support the business. The systems portfolio that supports the Records and Information Management service includes Livelink, Enterprise Contracts Management and EnCase. Examples of activities related to the provision of the service include: • Provide technical management and support for records and document management systems • Provide functional management and user support for records and document management systems • Develop and maintain system roadmaps for the evolution of document and records management systems in response to changing and emerging business needs • Support negotiation and administration of systems maintenance and consulting third party contracts • Provide assistance and advice to EGD on records and information management matters • Provide consultation and advice to EGD in support of document management system implementation projects • In partnership with business, develop and maintain folder structure following guiding principles as set by ECM and Records Management (RM) • In partnership with RM, link records retention schedule business rules to folder structure • Administer users (i.e. groups, permissions) • Administer the records management module of Livelink • Provide training on document and records management system functionality and business rules to system users **Records Management Department** The Records and Information Management service is responsible for the overall development, maintenance and dissemination of policies, procedures, and guidelines for the establishment and maintenance of the Records and Information Management Program. The Records Management Department is responsible for the overall development, maintenance and dissemination of policies, procedures, and guidelines for the establishment and maintenance of Enbridge (physical and electronic) records. This includes supporting records management requirements by providing strategies, policies, standards, tools, and program management including compliance monitoring. Examples of activities related to the provision of the service include the following

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initiatives:

- Provide leadership and direction in the establishment of the RM Program Roadmap
- Develop, distribute and maintain policies, procedures and guidelines for records and information management
- Maintain the Enterprise Records Retention Schedule which meets business needs as well as applicable laws, regulations and industry standards for the benefit of EGD
- Develop and monitor compliance with records disposition policies and practices
- Communicate, educate and train EGD employees on records management obligations, purpose, principles and minimum compliance requirements
- Provide assistance and advice to EGD on records management matters
- Support negotiation and administration of any records management third party contracts

Records Management Department
In partnership with the ECM team:

- Provide consultation and advice to EGD on document management improvement initiatives prior to implementing records and document management systems, both physical and electronic
- Provide consultation and advice to EGD in support of document management system implementation projects
- Provide functional management and user support of records and document management systems
- In partnership with business, develop and maintain folder structure following guiding principles as set by ECM and RM
- Link records retention schedule business rules to folder structure
- Administer users (i.e. groups, permissions)
- Administer the records management module of records management systems
- Provide training on document management system functionality and document management business rules to system users (electronic documents)
- Provide training on document management system functionality and records management business rules to system users (physical records)
- Develop, maintain and disseminate the document management system Framework to support the Records Management Program objectives in the management of electronic information.

Service Recipient: Mr. Mark R. Boyce, Vice President Law & Information Technology, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
Enterprise Content Management	$395,194
Records Management	$143,158
Total	**$538,352**

Expected Deliverables

- Ensure that all EGD staff have secure storage of, and access to, operational information through a variety of internal sources

Quantity and Quality of Service

- Continuous and uninterrupted access to stored records and documentation;

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	• Ensure access to information technology systems to support records management practices; • Ensure that sound records discovery practices are developed and implemented; • Ensure availability of advice regarding best practices for records and information management
Authorized Signature	
	Mr. Mark R. Boyce Vice President, Law & Information Technology Enbridge Gas Distribution Inc. March 21, 2012 Date

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30. Risk Assessment and Management

Service Description	
Service Definition:	The Risk Assessment and Management service is responsible for identifying corporate risks, supply and demand risks, operational risks, and external risks, understanding their implications and developing mitigation strategies.
Services Identified by Department	**CEO Department** The Risk Assessment and Management service is responsible for identifying corporate risks, supply and demand risks, operational risks, and external risks, understanding their implications and developing mitigation strategies. The CEO Department supports this service by providing senior leadership, overall management guidance and advice regarding EGD's financial and operational affairs. Examples of activities related to the provision of the service include: • Provide guidance and oversight to all risk management policies and monitor financial and non-financial mitigation activities to ensure prudent measures are in place for EGD **CFO Department** The Risk Assessment and Management service is responsible for identifying corporate risks, supply and demand risks, operational risks, and external risks, understanding their implications and developing mitigation strategies. The CFO Department supports this service by providing senior leadership, overall management guidance and advice regarding EGD's financial affairs. Examples of activities related to the provision of the service include: • Provide guidance and oversight to all risk management policies and monitor financial and non-financial mitigation activities to ensure prudent measures are in place for EGD **Corporate Controller Department** The Risk Assessment and Management service is responsible for identifying corporate risks, supply and demand risks, operational risks, and external risks, understanding their implications and developing mitigation strategies. The Corporate Controller Department supports this service by assuming responsibility for coordinating the annual risk assessment exercise with EGD. The corporate risk assessment provides insight into all forms of risk that may be encountered in the course of conducting day-to-day business. Examples of activities related to the provision of the service include: • Develop and coordinate the Corporate Risk Assessment process and all resources required to support the assessment • Develop and coordinate effective internal controls • Identify risk types and collect the required data to describe, measure and rank to determine potential for occurrence and impact • Communicate Corporate Risk Assessment findings to the EGD Executive Management Team and Board of Directors **Audit Services Department** The Risk Assessment and Management service is responsible for identifying corporate risks, supply and demand risks, operational risks, and external risks, understanding their implications and developing mitigation strategies. The Audit Services Department supports this service by identifying, developing and implementing financial risk mitigation controls and strategies.

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	Examples of activities related to the provision of the service include:
	• Develop risk mitigation strategies and control systems
	• Identify and advise on financial compliance and operational risk areas
	• Develop risk mitigation plan
	  o Set and validate risk materiality levels
	  o Quantify risk exposure and develop mitigation strategies and alternatives
	  o Present recommendations to the EGD Audit, Finance and Risk Committee (AFRC) for approval
	• Coordinate implementation of risk mitigation strategies
	• Measure, monitor and report on current or potential future financial compliance and operational risks
	• Update risk mitigation plan based on findings
	
	Enterprise Risk Department
	The Risk Assessment and Management service is responsible for identifying corporate risks, supply and demand risks, operational risks, and external risks, understanding their implications and developing mitigation strategies. The Enterprise Risk Department supports this service by assuming responsibility for assessing, advising on and executing transactions related to mitigating the financial market risk. In addition, the Enterprise Risk Department monitors the credit risk exposure and reports all risk exposures to the EGD Executive Management Team, EGD Executives and EGD's Audit, Finance and Risk Committee.
	
	Examples of activities related to the provision of the service include:
	• Identify and advise on interest rate risk, foreign exchange risk, commodity risk, credit risk, and execution risk
	• Quantify risk exposure and develop mitigation strategies and alternatives
	• Present recommendations to EGD's Audit, Finance and Risk Committee (AFRC) for approval
	• Identify and execute financial contracts (if required) for hedging purposes
	• Measuring, monitoring and reporting on current or future financial risk
	• Research credit rating and financial strength of customers and suppliers
	• Determine and assign credit limits to customers and obtain credit enhancements
	• Monitor credit exposure
	• Measuring, monitoring and reporting on current or future financial risk
	• Review and monitor compliance to risk control policies and procedures including compliance with hedge accounting guidance
	• Calculate the mark-to-market and fair market values of financial instruments used in all financing activities, specifically for hedging purposes
	• Measure, monitor and report compliance findings to Audit, Finance and Risk committee of EGD Board
	• Process the contracts and settlements of financial and physical transactions
	• Manage the on-going maintenance and support of the risk management information technology system

Service Recipient:	Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution
Cost of Service	

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Department	Service Charge
CEO	$30,646
CFO	$17,139
Corporate Controller	$0
Audit Services (Calgary)	$23,728
Enterprise Risk	$806,948
Total	**$878,461**

Expected Deliverables

- Identify all material financial, operational and economic risks associated with EGD's business
- Prepare a Risk Assessment Report
- Develop and execute risk mitigation strategies that support EGD leadership in making informed business decisions

Quantity and Quality of Service

- Low risk profile
- Minimal business interruption

Authorized Signature

Mr. Narin Kishinchandani
Vice-President Finance
Enbridge Gas Distribution

Mar 2, 2012
Date

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

31. Strategic Planning

Service Description

Service Definition:	The Strategic Planning service coordinates the development of EGD's vision and related operational activities and financial impacts delivered through the long-range planning process and document.
Services Identified by Department	**CEO Department** The Strategic Planning service coordinates the development of EGD's vision and related operational activities and financial impacts delivered through the long-range planning process and document. The CEO Department provides support to this service by setting the overall organizational strategy and provides guidance. Examples of activities related to the provision of the service include: • Provide vision, expertise and leadership to the development of the EGD long range plan (5 and 10 year plan) • Advise on all other aspects of the long-range plan including opportunity identification and selection, visioning exercises, tactical planning, etc. • Provide final authority on the long range plan prior to approval by the EGD Board of Directors • Maintain active involvement in securing EGD executive and Board of Directors support for the long range plan **Treasury Department** The Strategic Planning service coordinates the development of EGD's vision and related operational activities and financial impacts delivered through the long-range planning process and document. The Treasury Department provides support to this service by providing analytical financial support. Examples of activities related to the provision of the service include: • Forecast the long-term financing needs based on long range plan and budget plans **Enterprise Risk Department** The Strategic Planning service coordinates the development of EGD's vision and related operational activities and financial impacts delivered through the long-range planning process and document. The Enterprise Risk Department provides support to this service by providing analytical financial support. Examples of activities related to the provision of the service include: • Create a forecast for interest rates, foreign exchange rates and commodity prices for the term of the long range plan
Service Recipient:	Mr. Arunas Pleckaitis, Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$267,256
Treasury	$0
Enterprise Risk	$60,634
Total	**$327,890**

Expected Deliverables

- Senior level oversight and direction provided on long term strategies for EGD including opportunity identification, visioning and financial

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

	projections. This helps to ensure that the financing plan is in place and resources are available to support execution. • Annual strategic plan document for all EGD employees
Quantity and Quality of Service	
	• Availability of Corporate Planning group to produce EGD. Strategic Plan annually and communicated to all EGD employees by November Facilitate Senior Management Strategic Planning Workshop in February to discuss EGD s Strategic Plan issues • Availability of Budgetary and Controller support to ensure that Corporate Planning Standards are available in a timely fashion to support completion of the Long Range Plan in April • Articulate EGD strategic thrusts to the investment community via Enbridge Day, ensuring positive feedback from analysts on EGD documented strategies • Executable strategy (at a level of detail that allows EGD to execute)
Authorized Signature	
	Mr. Arunas Pleckaitis Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution MAR 02/12 Date

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32. Supply Chain Management

Service Description

Service Definition:	The Supply Chain Management service is responsible for coordinating the enterprise-wide initiative to identify and implement procurement cost savings by applying strategic sourcing techniques for the benefit of EGD.
Services Identified by Department	**CFO Department** The Supply Chain Management service is responsible for coordinating the enterprise-wide initiative to identify and implement procurement cost savings by applying strategic sourcing techniques for the benefit of EGD. The CFO Department supports this service by providing senior leadership, overall management guidance and advice regarding supply chain initiatives. Examples of activities related to the provision of the service: • Provide advice and guidance to Supply Chain Steering Committee, in which EGD is a member, in identification and development of supply cost management initiatives **Corporate Administration Department** The Supply Chain Management service is responsible for coordinating the enterprise-wide initiative to identify and implement procurement cost savings by applying strategic sourcing techniques for the benefit of EGD. The Corporate Administration Department supports this service by coordinating the enterprise wide initiative to identify and implement strategic sourcing initiatives through activities performed by the Supply Chain Steering Committee. The Supply Chain Steering Committee consists of procurement specialists from each principal Enbridge business unit, including EGD. Examples of activities related to the provision of this service include: • Assessment of the complete life-cycle of a commodity or service. Total life cycle cost representing the entire value chain, including design, implementation, maintenance, repair, replacement and decommissioning form the basis of the selection process • Identification of opportunities for procurement cost reductions and process efficiencies • Implementation of cost saving and efficiency opportunities • Management of Supply Chain RFP process including team formation, documentation, and vendor selection • Manage enterprise-wide vendor relationships and negotiations
Service Recipient:	Mr. Glenn Beaumont, Senior Vice President Operations, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CFO	$24,915
Corporate Admin.	$14,791
Total	**$39,706**

Expected Deliverables

- Exploitation of identified commodities to reduce the cost of ownership and improve performance, without compromising operational integrity
- Schedule, conduct and report on all results targeted for fiscal year

Quantity and Quality of Service

- Low cost procurement (lower cost structures than industry average)

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	• Measurable cost savings
Authorized Signature	
	Mr. Glenn Beaumont Senior Vice President Operations Enbridge Gas Distribution March 26/12 Date

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33. Tax Reporting & Planning

Service Description	
Service Definition:	The Tax Reporting and Planning service is responsible for ensuring proper reporting of the tax positions in financial statements and tax returns and to ensure initiatives are implemented so that tax is minimized.
Services Identified by Department	**CFO Department** The Tax Reporting and Planning service is responsible for ensuring proper reporting of the tax positions in financial statements and tax returns and to ensure initiatives are implemented so that tax is minimized. The CFO Department supports this service by providing senior leadership, overall management guidance and advice regarding EGD's financial affairs. Examples of activities related to the provision of the service include: • Review tax strategy with respect to past tax related issues. Develop policy in regards to tax issues and tax fund planning • Review tax planning and the adequacy of tax provisions for all Enbridge entities and communicate recommendations to the Board of Directors charged with tax oversight accountability **Tax Services Department** The Tax Reporting and Planning service is responsible for ensuring proper reporting of the tax positions in financial statements and tax returns and to ensure initiatives are implemented so that tax is minimized. The Tax Services Department supports this service by providing tax expertise and assuming responsibility for developing, implementing, and reporting on tax strategies. Examples of activities related to the provision of the service include: • Provide research and information dissemination on certain tax matters including changes in tax policies, changes to GAAP and other issues to tax group and senior management • Review of financial statement disclosures related to tax items including the effective income tax rate reconciliation (oversee changes as appropriate to disclosure) • Providing advice on accounting treatment, related to new issues with a tax impact, in terms of the tax provision recorded in the general ledger • Ensure adequate communication of all tax planning initiatives and tax implications of projects within the tax group and that the tax returns accurately report these items. • Reporting to Audit, Finance & Risk Committee of the EGD Board of Directors regarding tax exposures and quarterly reporting of exposures to senior management in conjunction with provision review. Advise on appropriate provision for exposures in financial statements • Review of EGD tax return and provide advice • Prepare tax assumption memos and provide tax support for budget groups • Provide general tax advice and tax planning • Provide tax assistance re importation of Natural Gas
Service Recipient:	Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Cost of Service		
Department	Service Charge	
CFO	$0	

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	Tax Services	$55,308	
	Total	**$55,308**	
Expected Deliverables			
	• Oversight and leadership provided to the EGD tax team		
Quantity and Quality of Service			
	• On demand access to tax reporting • Effective & topical tax reporting at a level of detail that allows EGD to execute		
Authorized Signature			
	Mr. Narin Kishinchandani Vice-President Finance Enbridge Gas Distribution	Mar 2, 2012 Date	

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

34. Total Compensation and Benefits

Service Description	
Service Definition:	The Total Compensation and Benefits service provides for the establishment of total employee compensation including base pay, performance bonuses (long term and short term incentive programs), benefits programs and job evaluation and performance programs.
Services Identified by Department	**CEO Department** The Total Compensation and Benefits service provides for the establishment of total employee compensation including base pay, performance bonuses (long term and short term incentive programs), benefits programs and job evaluation and performance programs. The CEO Department supports this service by providing senior leadership to compensation policy design and implementation. Examples of activities related to the provision of the service include: • Monitor and guide the compensation system to ensure company competitiveness and skill retention relative to market availability and needs **People and Partners Department** The Total Compensation and Benefits service is responsible for the establishment of total employee compensation including base pay, performance bonuses (long term and short term incentive programs), benefits programs and job evaluation and performance programs. The People and Partners Department supports this service by providing senior leadership to compensation policy design and implementation. Examples of activities related to the provision of the service include: • Identifies and brings forward compensation related recommendations to the EI Board Human Resource Compensation Committee, which set all compensation policies for EGD • Maintains fiduciary responsibility for the design and delivery of EGD's supplementary and regular pension plans and funding **Corporate Human Resources Department** The Total Compensation and Benefits service provides for the establishment of reward policy, strategy and programs including base pay (including job performance), performance based incentives (long term and short term incentive programs), benefits programs, pension programs and recognition programs. The Corporate Human Resources Department supports this service by providing HR expertise to the implementation of total reward programs. Examples of activities related to the provision of the service include: • Developing total rewards strategies for review, input and approval by the Human Resources Leadership Team (HRLT), Corporate Leadership Team and HRC of the Board of Directors • Provide specialized resources for guiding and conducting work for the development of base pay (including job evaluation), short term and long term incentives, benefits, pension perquisites and recognition programs • Provide guidance and advice on broad compensation issues **Pension & Benefits Department** The Total Compensation and Benefits service provides for the establishment of total employee compensation including base pay, performance bonuses (long term and short term incentive programs), benefits programs and job evaluation and performance programs. The Pension & Benefits Department supports this service

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by providing HR expertise and operational support to the development and implementation of pension and benefits programs and employee relations policies.

Examples of activities related to the provision of the service include:

- Coordinate and manage human resources policy issues, with support from legal, tax and corporate communications departments
- Employee pension and benefits plan design and governance
  - Recommend changes to pension and benefits
  - Steward the approval process through the Board of Directors approval process
  - Implement plan changes with carriers
- Managing external consultants (Actuarial and Management Consultants) for pension and benefit matters
- Responsible for the development of communication and education tools related to pension and benefits for dissemination by EGD to their employees
  - Pension and Benefits changes
  - Policy changes related to work hours, Statutory Holidays, Scholarship opportunities and Maternal/Paternal/Sick leave
- Identify and implement new organizational programs (e.g. Web enabled financial planning and retirement tool)
- Manage the collection and analysis of external industry pension and benefit benchmarking data and the use of external consultants
- Manage the administration of executive benefits and retirement programs, including medical assessments
- Provide guidance and support to issues related to pension and benefits and governance for both internal initiatives as well as external relationships such as joint ventures and alliances
- Provide advice to EGD's HR departments related to the efficient design, management, and administration of pension & benefit plans.
- Provide research and support to identify pension plan & benefit alternative to support resolution to EGD issues

Total Compensation Department

The Total Compensation and Benefits service provides for the establishment of total employee compensation including base pay, performance bonuses (long term and short term incentive programs), benefits programs and job evaluation and performance programs. The Total Compensation Department supports this service by providing HR expertise and operational support to the development, design, and implementation of compensation and performance programs.

Examples of activities related to the provision of the service include:

- Coordinate and manage human resources policy issues, with support from legal, tax and corporate communications departments
- Managing external consultants (Actuarial and Compensation Consultants))
- Identify and implement new organizational programs (e.g. Web enabled financial planning and retirement tool)
- Design job evaluation processes
- Manage the collection and analysis of external industry benchmarking data and the use of external consultants
- Design the compensation policies and programs, relating to
  - Base compensation and salary scale
  - Sales / commission based compensation
  - Retention and merit bonuses
  - Non-cash reward programs
- Manage the design and execution of the short term incentive program for executives and non-executives and the long term incentive program for

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executives
    - Identification of enterprise wide financial and EGD specific operating and financial metrics
    - Develop and communicate the policies, process and guidelines for performance program and succession ratings including hot skills identification
    - Oversee the review of performance ratings and approval (through the Board of Directors) and administration of the granting of stock options and performance stock units
- Responsible for the development of supporting processes and policies related to
    - Promotion
    - Transfers
    - Job reclassification
    - Temporary Pay
    - Moving / Transfer
- Manage the administration of executive compensation programs, including stock option and PSU administration and ancillary compensation program administration and parking
- Provide guidance and support to issues related to compensation and governance for both internal initiatives as well as external relationships such as joint ventures and alliances
- Provide employee relocation support and guidance

Corporate Controller Department

The Total Compensation and Benefits service provides for the establishment of total employee compensation including base pay, performance bonuses (long term and short term incentive programs), benefits programs and job evaluation and performance programs. The Corporate Controller Department supports this service by providing the financial analysis and reporting, required to support the determination of short-term, long-term and success sharing bonuses for all EGD employees.

Examples of activities related to the provision of this service include:

- Establish performance metric targets (Enbridge Inc. Return On Equity; Affiliate Earnings, and Total Shareholder Returns)
- Provide annual and quarterly measurement and reporting of current and forecasted performance, including securing approvals from EGD President
- Liaise with Corporate Human Resources group on all matters related to financial performance and bonuses
- Conduct research and report on alternative bonus related performance metrics
- Provide ad hoc performance reporting and analysis

Service Recipient: Mr. Marc Weil, Director Human Resources, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$200,402
Group VP Corp. Resources	$249,040
Corporate HR	$159,379
Pension & Benefits	$0
Total Compensation	$1,108,782
Corporate Controller	$64,206
Total	**$1,781,809**

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Expected Deliverables	
	• Support EGD by developing a competitive and innovative compensation, benefits and performance strategy
Quantity and Quality of Service	
	• Support EGD by developing a competitive and innovative compensation, benefits and performance strategy • Provide EGD management with policies, guidelines and resources designed to support the successful development and implementation of the compensation, benefits and performance strategy • Balance EGD's employee retention and personal development goals with fiscal responsibility and the interests of shareholders
Authorized Signature	
	Mr. Marc Weil Director Human Resources Enbridge Gas Distribution March 2, 2012 Date

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

General Expense

The following tables outline the general expense items directly allocated to EGD. These general expenses are agreed to (by written signature) by a representative of EGD.

A general expense is defined as a significant cost that benefits the Service Recipient, and requires allocation on a basis separate from the Primary Services because the driver of the cost is different, or because the cost is a large, third party cost. A list of the general expenses and the basis of allocation attributable thereto, are set out in RCAM.

Each table provides details on:

- The general expense item definition;
- The EGD representative responsible for agreeing to the service; and
- The EGD cost of the general expense item as calculated in the RCAM model.

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35. Depreciation – Risk Management System

Service Description	
General Expense Definition:	Depreciation – Risk Management System contains the depreciation on the Openlink risk management system. Openlink is used by Treasury and Risk Management to manage risk on all physical commodity deals for EGD. It is also used to track and manage EGD risk on all financial hedges made against these physical commodity deals, including external and internal debt, inter-company loans and Interest Rate and Foreign exchange.
Service Recipient:	Mr. Narin Kishinchandani Vice President Finance, Enbridge Gas Distribution
Cost of Service	
	$64,951
Authorized Signature	
	Mr. Narin Kishinchandani Vice-President Finance Enbridge Gas Distribution Mar 2, 2012 Date

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36. Direct EFS Charge

Service Description	
General Expense Definition:	The costs for supporting the Enterprise Financial Systems (EFS) are directly incurred by multiple affiliates for the purpose of delivering enterprise financial services. For allocation purposes, the participating affiliates' original budget allocations are notionally aggregated and the charges are calculated based on affiliate user count. The difference between this affiliate calculation and the affiliate's original budget allocation (debit or credit) is allocated to the affiliate.
Service Recipient:	Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution
Cost of Service	
	($2,314,784)
Authorized Signature	
	Mr. Narin Kishinchandani Vice-President Finance Enbridge Gas Distribution Mar 2, 2012 Date

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37. Directors Fees and Expenses

Service Description	
General Expense Definition:	The Directors fees and expenses comprises all fees paid to directors of EI's Board, including conducting Board activities and liaisons with members of EI senior executive.
Service Recipient:	Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution
Cost of Service	
	$744,819
Authorized Signature	
	Mr. Narin Kishinchandani Vice-President Finance Enbridge Gas Distribution Mar 2, 2012 Date

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Direct Charges

The following tables outline the direct charge items directly allocated to EGD. These direct charges are agreed to (by written signature) by a representative of EGD.

A direct charge is defined as a service related item separately included in the Service Providers budgets that can be specifically attributed to the service Recipient without loading. A list of the direct charges, and the basis of allocation attributable thereto, are set out in RCAM.

Each table provides detail on:

- The direct charge item definition;
- The EGD representative responsible for agreeing to the service; and
- The cost of the general expense item as calculated in the RCAM model.

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38. EGD Stock Based Compensation

Service Description	
General Expense Definition:	The Stock Based Compensation department contains costs for the expense related to the granting of Long-Term Incentives to Manager-level and above staff within Enbridge Gas Distribution. Long-term incentives are also granted to certain lower level staff on a discretionary basis.
Service Recipient:	Mr. Marc Weil, Director Human Resources, Enbridge Gas Distribution and Mr. Narin Kishinchandani, Vice President Finance, Enbridge Gas Distribution
Cost of Service	
Service Price:	$7,549,229
Authorized Signature	
	Mr. Marc Weil Director Human Resources Enbridge Gas Distribution March 2, 2012 Date
	Mr. Narin Kishinchandani Vice President Finance Enbridge Gas Distribution Mar 2, 2012 Date

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39. Insurance Premiums

Service Description	
General Expense Definition:	Costs include insurance premiums for liability, crime, property, automobile, and fiduciary policies held for Enbridge Inc. and its affiliates.
Service Recipient:	Mr. Jamie Milner, Vice President Pipeline Integrity & Safety, Enbridge Gas Distribution
Cost of Service	
Service Price:	$8,483,868
Authorized Signature	
	Mr. Jamie Miner Vice President Pipeline Integrity & Safety Enbridge Gas Distribution Mar. 2/12 Date

APPENDIX C – MNP INTERVIEW GUIDES

EGD SERVICE RECIPIENT INTERVIEW GUIDE

Date	February 14, 2012	**Time**	3:00pm – 4:30pm
Interviewee	**Arunas Pleckaitis**		
Position	Vice-President, Business Development & Customer Strategy		
Meeting Attendees			
Phone Number			
Email Address			
Service(s) Received	**PRIMARY SERVICES** • Business & Economic Financial Analysis • Business Development • Emerging Energy Technology Research • Government Relations • Industry Relations & Corporate Social Responsibilities • Strategic Planning **DIRECT CHARGES** • N/A		

INTRODUCTION

1. Could you provide us with details on your current role and previous role(s) within EGD and/or other Enbridge affiliates? (Timelines as well if possible)

2. How many employees are in your department(s)?

SERVICE(S) RECEIVED

3. For the services you receive, has the service delivery meaningfully changed over the past four years? How so? Please explain.

4. For each of the services received, what is the process to determine its essentiality?

5. How are the service descriptions developed to ensure they accurately reflect the services provided in terms of completeness and technical specification? Please describe how this process is reviewed.

6. What is the process to determine the level of service required?

7. How is the risk of service provisioning and receipt divided between the service provider and the service recipient (these would include risk related to under and/or over provisioning of services). How is the process to manage this risk reviewed and documented?

8. What is the dispute resolution process for in instances where there is a disagreement such as:
   - Level of service provided
   - Delivery of service (timeliness, quality, etc.)
   - Price charged

9. What is the process to developing business cases, for services received, and how often are they reviewed? What methods are utilized for validation?

10. Have you encountered instances where services were over-provisioned and/or under-provisioned? What is the process to address these cases?

11. What considerations have you given to alternate service provisioning? (i.e. internally, outsourcing, externally, etc.)

CORRELATION OF COST(S) AND SERVICE(S) RECEIVED

12. How does EGD track the correlation between the costs incurred and the shared services received? Is this process documented and how often is it reviewed?

13. Please explain the review process for the allocated cost of each service received, including the approval process.

14. How is the cost/benefit relationship determined for the services received?

    OEB divides benefits into four categories:
    I. **Replacement** – The service cannot be replaced at equal or lower cost.
    II. **Synergistic** – Cost for the service is reduced because it is spread over two or more affiliates. Economy of scale.
    III. **Revenue Enhancement / Cost Recovery** – Cost incurred provide value to other affiliates for which payment is received.
    IV. **Stand-alone** – EI provides the service at a strategic level, which benefits EGD.

SERVICE SPECIFIC QUESTIONS

METHODOLOGY / ALLOCATOR DETERMINATION

- The methodology and allocator for the identified service(s) is/are shown in the table below:

	Methodology / Allocator			
	2007		2011	
Primary Service	External Driver	Allocator	External Driver	Allocator
Business & Economic Financial Analysis	M&A Activity	EGD % of Direct Time	M&A Activity	EGD % of Direct Time
Business Development	M&A Activity	ACER	M&A Activity	ACER
Emerging Energy Technology Research	New technologies	ACER	New technologies	ACER
Government Relations	Regulations	ACER	Regulations	ACER
Industry Relations & Corporate Social Responsibility	Customer base & public interest	ACER	Customer base & public interest	ACER
Strategic Planning	Complexity (company & market)	FCER	Complexity (company & market)	FCER

15. What is your level of understanding of the allocator(s) utilized to determine costs for the service(s) you receive?

16. How comfortable are you with your understanding of the corporate cost allocation methodology? (how the numbers roll up into fully allocated costs)

17. For each of the services received, how is the allocator determined as appropriate and how is it considered representational for the services provisioned? Please describe the review and documentation processes. This includes changes in allocator(s) used.

COST CHANGES

- The costs for the identified service(s) is/are shown in the table below:

	Cost		
Primary Service / Direct Charge	**2007**	**2010**	**2011**
Business & Economic Financial Analysis	$ -	$ -	**$ -**
Business Development	$ 652,513	$ 440,041	**$ 533,671**
Emerging Energy Technology Research	$ 146,966	$ 74,371	**$ 47,593**
Government Relations	$ 119,234	$ 120,509	**$ 34,848**
Industry Relations & Corporate Social Responsibility	$ 245,307	$ 399,487	**$ 465,205**
Strategic Planning	$ 167,834	$ 194,768	**$ 253,879**

Business & Economic Financial Analysis
No costs allocated for this service.

Business Development
18. Comparing the 2007 and 2011 service schedules, the cost for 'Business Development' has decreased. Can you provide us with details for the variance?

Emerging Energy Technology Research
19. Comparing the 2007 and 2011 service schedules, the cost for 'Emerging Energy Technology Research' has decreased. Can you provide us with details for the variance?

Government Relations
20. Comparing the 2007 and 2011 service schedules, the cost for 'Government Relations' has decreased. Can you provide us with details for the variance?

Industry Relations & Corporate Social Responsibility
21. Comparing the 2007 and 2011 service schedules, the cost for 'Industry Relations & Corporate Social Responsibility' has increased. Can you provide us with details for the variance?

Strategic Planning
22. Comparing the 2007 and 2011 service schedules, the cost for 'Strategic Planning' has increased. Can you provide us with details for the variance?

EGD SERVICE RECIPIENT INTERVIEW GUIDE

Date	February 22, 2012	**Time**	10:30am – 12:00pm
Interviewee	**Debbie Boukydis**		
Position	Director, Public & Government Affairs		
Meeting Attendees			
Phone Number			
Email Address			
Service(s) Received	**PRIMARY SERVICES** • Government Relations • Industry Relations & Corporate Social Responsibilities **DIRECT CHARGES** • N/A		

INTRODUCTION

1. Could you provide us with details on your current role and previous role(s) within EGD and/or other Enbridge affiliates? (Timelines as well if possible)

2. How many employees are in your department(s)?

SERVICE(S) RECEIVED

3. For the services you receive, has the service delivery meaningfully changed over the past four years? How so? Please explain.

4. For each of the services received, what is the process to determine its essentiality?

5. How are the service descriptions developed to ensure they accurately reflect the services provided in terms of completeness and technical specification? Please describe how this process is reviewed.

6. What is the process to determine the level of service required?

7. How is the risk of service provisioning and receipt divided between the service provider and the service recipient (these would include risk related to under and/or over provisioning of services). How is the process to manage this risk reviewed and documented?

8. What is the dispute resolution process for in instances where there is a disagreement such as:
    - Level of service provided
    - Delivery of service (timeliness, quality, etc.)
    - Price charged

9. What is the process to developing business cases, for services received, and how often are they reviewed? What methods are utilized for validation?
10. Have you encountered instances where services were over-provisioned and/or under-provisioned? What is the process to address these cases?

11. What considerations have you given to alternate service provisioning? (i.e. internally, outsourcing, externally, etc.)

CORRELATION OF COST(S) AND SERVICE(S) RECEIVED

12. How does EGD track the correlation between the costs incurred and the shared services received? Is this process documented and how often is it reviewed?

13. Please explain the review process for the allocated cost of each service received, including the approval process.

14. How is the cost/benefit relationship determined for the services received?

OEB divides benefits into four categories:

V. **Replacement** – The service cannot be replaced at equal or lower cost.
VI. **Synergistic** – Cost for the service is reduced because it is spread over two or more affiliates. Economy of scale.
VII. **Revenue Enhancement / Cost Recovery** – Cost incurred provide value to other affiliates for which payment is received.
VIII. **Stand-alone** – EI provides the service at a strategic level, which benefits EGD.

SERVICE SPECIFIC QUESTIONS

METHODOLOGY / ALLOCATOR DETERMINATION

- The methodology and allocator for the identified service(s) is/are shown in the table below:

	Methodology / Allocator			
	2007		2011	
Primary Service	External Driver	Allocator	External Driver	Allocator
Government Relations	Regulations	ACER	Regulations	ACER
Industry Relations & Corporate Social Responsibility	Customer base & public interest	ACER	Customer base & public interest	ACER

15. What is your level of understanding of the allocator(s) utilized to determine costs for the service(s) you receive?

16. How comfortable are you with your understanding of the corporate cost allocation methodology? (how the numbers roll up into fully allocated costs)

17. For each of the services received, how is the allocator determined as appropriate and how is it considered representational for the services provisioned? Please describe the review and documentation processes. This includes changes in allocator(s) used.

Cost Changes

- The costs for the identified service(s) is/are shown in the table below:

	Cost		
Primary Service / Direct Charge	2007	2010	2011
Government Relations	$ 119,234	$ 120,509	**$ 34,848**
Industry Relations & Corporate Social Responsibility	$ 245,307	$ 399,487	**$ 465,205**

Government Relations

18. Comparing the 2007 and 2011 service schedules, the cost for 'Government Relations' has decreased. Can you provide us with details for the variance?

Industry Relations & Corporate Social Responsibility

19. Comparing the 2007 and 2011 service schedules, the cost for 'Industry Relations & Corporate Social Responsibility' has increased. Can you provide us with details for the variance?

EGD SERVICE RECIPIENT INTERVIEW GUIDE

Date	February 13, 2012	**Time**	1:00pm – 2:00pm
Interviewee	Mark Sabatini on behalf of **Glenn Beaumont** (Senior Vice-President, Operations)		
Position			
Meeting Attendees			
Phone Number			
Email Address			
Service(s) Received	**PRIMARY SERVICES** • Supply Chain Management **DIRECT CHARGES** • N/A		

INTRODUCTION

23. Could you provide us with details on your current role and previous role(s) within EGD and/or other Enbridge affiliates? (Timelines as well if possible)

24. How many employees are in your department(s)?

SERVICE(S) RECEIVED

25. For the services you receive, has the service delivery meaningfully changed over the past four years? How so? Please explain.

26. For each of the services received, what is the process to determine its essentiality?

27. How are the service descriptions developed to ensure they accurately reflect the services provided in terms of completeness and technical specification? Please describe how this process is reviewed.

28. What is the process to determine the level of service required?

29. How is the risk of service provisioning and receipt divided between the service provider and the service recipient (these would include risk related to under and/or over provisioning of services). How is the process to manage this risk reviewed and documented?

30. What is the dispute resolution process for in instances where there is a disagreement such as:
    - Level of service provided
    - Delivery of service (timeliness, quality, etc.)
    - Price charged

31. What is the process to developing business cases, for services received, and how often are they reviewed? What methods are utilized for validation?
32. Have you encountered instances where services were over-provisioned and/or under-provisioned? What is the process to address these cases?

33. What considerations have you given to alternate service provisioning? (i.e. internally, outsourcing, externally, etc.)

CORRELATION OF COST(S) AND SERVICE(S) RECEIVED

34. How does EGD track the correlation between the costs incurred and the shared services received? Is this process documented and how often is it reviewed?

35. Please explain the review process for the allocated cost of each service received, including the approval process.

36. How is the cost/benefit relationship determined for the services received?

    OEB divides benefits into four categories:

    IX. **Replacement** – The service cannot be replaced at equal or lower cost.
    X. **Synergistic** – Cost for the service is reduced because it is spread over two or more affiliates. Economy of scale.
    XI. **Revenue Enhancement / Cost Recovery** – Cost incurred provide value to other affiliates for which payment is received.
    XII. **Stand-alone** – EI provides the service at a strategic level, which benefits EGD.

SERVICE SPECIFIC QUESTIONS

METHODOLOGY / ALLOCATOR DETERMINATION

- The methodology and allocator for the identified service(s) is/are shown in the table below:

	Methodology / Allocator			
	2007		2011	
Primary Service	External Driver	Allocator	External Driver	Allocator
Supply Chain Management	Raw material volumes	ACER	Raw material volumes	ACER

37. What is your level of understanding of the allocator(s) utilized to determine costs for the service(s) you receive?

38. How comfortable are you with your understanding of the corporate cost allocation methodology? (how the numbers roll up into fully allocated costs)

39. For each of the services received, how is the allocator determined as appropriate and how is it considered representational for the services provisioned? Please describe the review and documentation processes. This includes changes in allocator(s) used.

COST CHANGES

- The costs for the identified service(s) is/are shown in the table below:

	Cost		
Primary Service / Direct Charge	2007	2010	2011
Supply Chain Management	$ 19,504	$ 24,088	**$ 30,414**

Supply Chain Management

40. Comparing the 2007 and 2011 service schedules, the cost for 'Supply Chain Management' has increased. Can you provide us with details for the variance?

EGD SERVICE RECIPIENT INTERVIEW GUIDE

Date	February 14, 2012	**Time**	8:30am – 10:00am
Interviewee	**Henry Wong**		
Position	Director, Information Technology		
Meeting Attendees			
Phone Number			
Email Address			
Service(s) Received	**PRIMARY SERVICES** • Consolidation & Planning System Technical Support • Enterprise IT Program Management • Enterprise IT Strategy Planning & Management • Expense System Management & Technical Support • Financial & Project Accounting System Technical Support • Portal Suite Operations & Technical Support **DIRECT CHARGES** • N/A		

INTRODUCTION

41. Could you provide us with details on your current role and previous role(s) within EGD and/or other Enbridge affiliates? (Timelines as well if possible)

42. How many employees are in your department(s)?

SERVICE(S) RECEIVED

43. For the services you receive, has the service delivery meaningfully changed over the past four years? How so? Please explain.

44. For each of the services received, what is the process to determine its essentiality?

45. How are the service descriptions developed to ensure they accurately reflect the services provided in terms of completeness and technical specification? Please describe how this process is reviewed.

46. What is the process to determine the level of service required?

47. How is the risk of service provisioning and receipt divided between the service provider and the service recipient (these would include risk related to under and/or over provisioning of services). How is the process to manage this risk reviewed and documented?

48. What is the dispute resolution process for in instances where there is a disagreement such as:
    - Level of service provided
    - Delivery of service (timeliness, quality, etc.)
    - Price charged
49. What is the process to developing business cases, for services received, and how often are they reviewed? What methods are utilized for validation?

50. Have you encountered instances where services were over-provisioned and/or under-provisioned? What is the process to address these cases?

51. What considerations have you given to alternate service provisioning? (i.e. internally, outsourcing, externally, etc.)

CORRELATION OF COST(S) AND SERVICE(S) RECEIVED

52. How does EGD track the correlation between the costs incurred and the shared services received? Is this process documented and how often is it reviewed?

53. Please explain the review process for the allocated cost of each service received, including the approval process.

54. How is the cost/benefit relationship determined for the services received?

    OEB divides benefits into four categories:
    XIII. **Replacement** – The service cannot be replaced at equal or lower cost.
    XIV. **Synergistic** – Cost for the service is reduced because it is spread over two or more affiliates. Economy of scale.
    XV. **Revenue Enhancement / Cost Recovery** – Cost incurred provide value to other affiliates for which payment is received.
    XVI. **Stand-alone** – EI provides the service at a strategic level, which benefits EGD.

SERVICE SPECIFIC QUESTIONS

METHODOLOGY / ALLOCATOR DETERMINATION

- The methodology and allocator for the identified service(s) is/are shown in the table below:

	Methodology / Allocator			
	2007		2011	
Primary Service	External Driver	Allocator	External Driver	Allocator
Consolidation & Planning System Technical Support	IT asset usage	System Users	IT asset usage	System Users
Enterprise IT Program Management	IT programs	ACER	IT programs	ACER
Enterprise IT Strategy Planning & Management	IT assets	ACER	IT assets	ACER
Expense System Management & Technical Support	IT asset usage	System Users	IT asset usage	System Users
Financial & Project Accounting System Technical Support	IT asset usage	System Users	IT asset usage	System Users
Portal Suite Operations & Technical Support	Portal IT asset usage	System Users	Portal IT asset usage	System Users

55. What is your level of understanding of the allocator(s) utilized to determine costs for the service(s) you receive?

56. How comfortable are you with your understanding of the corporate cost allocation methodology? (how the numbers roll up into fully allocated costs)

57. For each of the services received, how is the allocator determined as appropriate and how is it considered representational for the services provisioned? Please describe the review and documentation processes. This includes changes in allocator(s) used.

COST CHANGES

- The costs for the identified service(s) is/are shown in the table below:
-

	Cost		
Primary Service / Direct Charge	**2007**	**2010**	**2011**
Consolidation & Planning System Technical Support	$ 375,868	$ 492,550	**$ 606,411**
Enterprise IT Program Management	$ 149,002	$ 413,230	**$ 389,669**
Enterprise IT Strategy Planning & Management	$ 550,749	$ 594,422	**$ 467,282**
Expense System Management & Technical Support	$ 119,526	$ 167,015	**$ 239,394**
Financial & Project Accounting System Technical Support	$ 320,766	$ 254,570	**$ 261,570**
Portal Suite Operations & Technical Support	$ 259,283	$ 156,062	**$ 172,685**

Consolidation & Planning System Technical Support

58. Comparing the 2007 and 2011 service schedules, the cost for 'Consolidation & Planning System Technical Support' has increased. Can you provide us with details for the variance?

Enterprise IT Program Management

59. Comparing the 2007 and 2011 service schedules, the cost for 'Enterprise IT Program Management' has increased. Can you provide us with details for the variance?

Enterprise IT Strategy Planning & Management

60. Comparing the 2007 and 2011 service schedules, the cost for 'Enterprise IT Strategy Planning & Management' has decreased. Can you provide us with details for the variance?

Expense System Management & Technical Support

61. Comparing the 2007 and 2011 service schedules, the cost for 'Expense System Management & Technical Support' has increased. Can you provide us with details for the variance?

Financial & Project Accounting System Technical Support

62. Comparing the 2007 and 2011 service schedules, the cost for 'Financial & Project Accounting System Technical Support' has decreased. Can you provide us with details for the variance?

Portal Suite Operations & Technical Support

63. Comparing the 2007 and 2011 service schedules, the cost for 'Portal Suite Operations & Technical Support' has decreased. Can you provide us with details for the variance?

EGD SERVICE RECIPIENT INTERVIEW GUIDE

Date	February 13, 2012	**Time**	2:30pm – 4:00pm
Interviewee	**Jamie Milner**		
Position	Vice-President, Pipeline Integrity & Safety		
Meeting Attendees			
Phone Number			
Email Address			
Service(s) Received	**PRIMARY SERVICES** • Insurance Claims Support • Insurance Strategy & Management **DIRECT CHARGES** • Insurance Premiums		

INTRODUCTION

64. Could you provide us with details on your current role and previous role(s) within EGD and/or other Enbridge affiliates? (Timelines as well if possible)

65. How many employees are in your department(s)?

SERVICE(S) RECEIVED

66. For the services you receive, has the service delivery meaningfully changed over the past four years? How so? Please explain.

67. For each of the services received, what is the process to determine its essentiality?

68. How are the service descriptions developed to ensure they accurately reflect the services provided in terms of completeness and technical specification? Please describe how this process is reviewed.

69. What is the process to determine the level of service required?

70. How is the risk of service provisioning and receipt divided between the service provider and the service recipient (these would include risk related to under and/or over provisioning of services). How is the process to manage this risk reviewed and documented?

71. What is the dispute resolution process for in instances where there is a disagreement such as:
    - Level of service provided
    - Delivery of service (timeliness, quality, etc.)
    - Price charged

72. What is the process to developing business cases, for services received, and how often are they reviewed? What methods are utilized for validation?
73. Have you encountered instances where services were over-provisioned and/or under-provisioned? What is the process to address these cases?

74. What considerations have you given to alternate service provisioning? (i.e. internally, outsourcing, externally, etc.)

CORRELATION OF COST(S) AND SERVICE(S) RECEIVED

75. How does EGD track the correlation between the costs incurred and the shared services received? Is this process documented and how often is it reviewed?

76. Please explain the review process for the allocated cost of each service received, including the approval process.

77. How is the cost/benefit relationship determined for the services received?

OEB divides benefits into four categories:

XVII. **Replacement** – The service cannot be replaced at equal or lower cost.
XVIII. **Synergistic** – Cost for the service is reduced because it is spread over two or more affiliates. Economy of scale.
XIX. **Revenue Enhancement / Cost Recovery** – Cost incurred provide value to other affiliates for which payment is received.
XX. **Stand-alone** – EI provides the service at a strategic level, which benefits EGD.

SERVICE SPECIFIC QUESTIONS

METHODOLOGY / ALLOCATOR DETERMINATION

- The methodology and allocator for the identified service(s) is/are shown in the table below:

	Methodology / Allocator			
	2007		2011	
Primary Service	External Driver	Allocator	External Driver	Allocator
Insurance Claims Support	Raw material volumes	ACER	Raw material volumes	ACER
Insurance Strategy & Management	Entity Risk	Same as Insurance Premiums	Entity Risk	Same as Insurance Premiums
	2007		2011	
Direct Charge	Driver	Allocator	Driver	Allocator
Insurance Premiums	Risk	Direct	Risk	Direct

78. What is your level of understanding of the allocator(s) utilized to determine costs for the service(s) you receive?

79. How comfortable are you with your understanding of the corporate cost allocation methodology? (how the numbers roll up into fully allocated costs)

80. For each of the services received, how is the allocator determined as appropriate and how is it considered representational for the services provisioned? Please describe the review and documentation processes. This includes changes in allocator(s) used.

COST CHANGES

- The costs for the identified service(s) is/are shown in the table below:

	Cost		
Primary Service / Direct Charge	**2007**	**2010**	**2011**
Insurance Claims Support	$ 2,887	$ 6,301	**$ 7,145**
Insurance Strategy & Management	$ 84,730	$ 120,927	**$ 119,312**
Insurance Premiums	$ 4,905,300	$ 5,179,873	$ 4,338,678

Insurance Claims Support

81. Comparing the 2007 and 2011 service schedules, the cost for 'Insurance Claims Support' has increased. Can you provide us with details for the variance?

Insurance Strategy & Management

82. Comparing the 2007 and 2011 service schedules, the cost for 'Insurance Strategy & Management' has increased. Can you provide us with details for the variance?

Insurance Premiums

83. Comparing the 2007 and 2011 service schedules, the cost for 'Insurance Premiums' has decreased. Can you provide us with details for the variance?

EGD SERVICE RECIPIENT INTERVIEW GUIDE

Date	February 14, 2012	**Time**	10:00am – 11:30am
Interviewee	**Marc Weil**		
Position	Director, Human Resources		
Meeting Attendees			
Phone Number			
Email Address			
Service(s) Received	**PRIMARY SERVICES** • Employee and Labour Relations • Employee Development • HRIS Program Management and Development • Human Resources Advice • Total Compensation and Benefits **DIRECT CHARGES** • EGD Stock Based Compensation		

INTRODUCTION

84. Could you provide us with details on your current role and previous role(s) within EGD and/or other Enbridge affiliates? (Timelines as well if possible)

85. How many employees are in your department(s)?

SERVICE(S) RECEIVED

86. For the services you receive, has the service delivery meaningfully changed over the past four years? How so? Please explain.

87. For each of the services received, what is the process to determine its essentiality?

88. How are the service descriptions developed to ensure they accurately reflect the services provided in terms of completeness and technical specification? Please describe how this process is reviewed.

89. What is the process to determine the level of service required?

90. How is the risk of service provisioning and receipt divided between the service provider and the service recipient (these would include risk related to under and/or over provisioning of services). How is the process to manage this risk reviewed and documented?

91. What is the dispute resolution process for in instances where there is a disagreement such as:
    - Level of service provided
    - Delivery of service (timeliness, quality, etc.)
    - Price charged

92. What is the process to developing business cases, for services received, and how often are they reviewed? What methods are utilized for validation?

93. Have you encountered instances where services were over-provisioned and/or under-provisioned? What is the process to address these cases?

94. What considerations have you given to alternate service provisioning? (i.e. internally, outsourcing, externally, etc.)

CORRELATION OF COST(S) AND SERVICE(S) RECEIVED

95. How does EGD track the correlation between the costs incurred and the shared services received? Is this process documented and how often is it reviewed?

96. Please explain the review process for the allocated cost of each service received, including the approval process.

97. How is the cost/benefit relationship determined for the services received?

OEB divides benefits into four categories:

XXI. **Replacement** – The service cannot be replaced at equal or lower cost.
XXII. **Synergistic** – Cost for the service is reduced because it is spread over two or more affiliates. Economy of scale.
XXIII. **Revenue Enhancement / Cost Recovery** – Cost incurred provide value to other affiliates for which payment is received.
XXIV. **Stand-alone** – EI provides the service at a strategic level, which benefits EGD.

SERVICE SPECIFIC QUESTIONS

METHODOLOGY / ALLOCATOR DETERMINATION

- The methodology and allocator for the identified service(s) is/are shown in the table below:

	Methodology / Allocator			
	2007		2011	
Primary Service	External Driver	Allocator	External Driver	Allocator
Employee and Labour Relations	Employees, Unionized employees	AHC	Employees, Unionized employees	AHC
Employee Development	Employees	AHC	Employees	Non Union EFTE
HRIS Program Management and Development	HRIS IT asset usage	AHC	HRIS IT asset usage	AHC
Human Resources Advice	Employees	AHC	Employees	AHC
Total Compensation and Benefits	Employees	AHC	Employees	AHC
	2007		2011	
Direct Charge	Driver	Allocator	Driver	Allocator
EGD Stock Based Compensation	Usage	AHC - Specific	Usage	Options Granted

98. What is your level of understanding of the allocator(s) utilized to determine costs for the service(s) you receive?

99. How comfortable are you with your understanding of the corporate cost allocation methodology? (how the numbers roll up into fully allocated costs)

100. For each of the services received, how is the allocator determined as appropriate and how is it considered representational for the services provisioned? Please describe the review and documentation processes. This includes changes in allocator(s) used.

COST CHANGES

- The costs for the identified service(s) is/are shown in the table below:

	Cost		
Primary Service / Direct Charge	**2007**	**2010**	**2011**
Employee and Labour Relations	$ 253,529	$ 458,995	**$ 552,430**
Employee Development	$ 255,425	$ 803,140	**$ 1,200,754**
HRIS Program Management and Development	$ 689,995	$ 1,545,942	**$ 2,169,992**
Human Resources Advice	$ 101,190	$ 271,938	**$ 354,073**
Total Compensation and Benefits	$ 865,843	$ 1,313,100	**$ 1,410,246**
EGD Stock Based Compensation	$ 1,663,249	$ 4,842,397	**$ 6,413,231**

Employee and Labour Relations

101. Comparing the 2007 and 2011 service schedules, the cost for 'Employee and Labour Relations' has increased. Can you provide us with details for the variance?

Employee Development

102. Comparing the 2007 and 2011 service schedules, the cost for 'Employee Development' has increased. Can you provide us with details for the variance?

HRIS Program Management and Development

103. Comparing the 2007 and 2011 service schedules, the cost for 'HRIS Program Management and Development' has increased. Can you provide us with details for the variance?

Human Resources Advice

104. Comparing the 2007 and 2011 service schedules, the cost for 'Human Resources Advice' has increased. Can you provide us with details for the variance?

Total Compensation and Benefits

105. Comparing the 2007 and 2011 service schedules, the cost for 'Total Compensation and Benefits' has increased. Can you provide us with details for the variance?

EGD Stock Based Compensation

106. Comparing the 2007 and 2011 service schedules, the cost for 'EGD Stock Based Compensation' has increased. Can you provide us with details for the variance?

EGD SERVICE RECIPIENT INTERVIEW GUIDE

Date	February 14, 2012	**Time**	2:00pm – 3:00pm
Interviewee	**Mark Boyce**		
Position	Vice-President, Law & Information Technology		
Meeting Attendees			
Phone Number			
Email Address			
Service(s) Received	**PRIMARY SERVICES** • Legal Advice • Records & Information Management **DIRECT CHARGES** • N/A		

INTRODUCTION

107. Could you provide us with details on your current role and previous role(s) within EGD and/or other Enbridge affiliates? (Timelines as well if possible)

108. How many employees are in your department(s)?

SERVICE(S) RECEIVED

109. For the services you receive, has the service delivery meaningfully changed over the past four years? How so? Please explain.

110. For each of the services received, what is the process to determine its essentiality?

111. How are the service descriptions developed to ensure they accurately reflect the services provided in terms of completeness and technical specification? Please describe how this process is reviewed.

112. What is the process to determine the level of service required?

113. How is the risk of service provisioning and receipt divided between the service provider and the service recipient (these would include risk related to under and/or over provisioning of services). How is the process to manage this risk reviewed and documented?

114. What is the dispute resolution process for in instances where there is a disagreement such as:
- Level of service provided
- Delivery of service (timeliness, quality, etc.)
- Price charged

115. What is the process to developing business cases, for services received, and how often are they reviewed? What methods are utilized for validation?

116. Have you encountered instances where services were over-provisioned and/or under-provisioned? What is the process to address these cases?

117. What considerations have you given to alternate service provisioning? (i.e. internally, outsourcing, externally, etc.)

CORRELATION OF COST(S) AND SERVICE(S) RECEIVED

118. How does EGD track the correlation between the costs incurred and the shared services received? Is this process documented and how often is it reviewed?

119. Please explain the review process for the allocated cost of each service received, including the approval process.

120. How is the cost/benefit relationship determined for the services received?

OEB divides benefits into four categories:

XXV. **Replacement** – The service cannot be replaced at equal or lower cost.
XXVI. **Synergistic** – Cost for the service is reduced because it is spread over two or more affiliates. Economy of scale.
XXVII. **Revenue Enhancement / Cost Recovery** – Cost incurred provide value to other affiliates for which payment is received.
XXVIII. **Stand-alone** – EI provides the service at a strategic level, which benefits EGD.

SERVICE SPECIFIC QUESTIONS

METHODOLOGY / ALLOCATOR DETERMINATION

- The methodology and allocator for the identified service(s) is/are shown in the table below:

	Methodology / Allocator			
	2007		2011	
Primary Service	External Driver	Allocator	External Driver	Allocator
Legal Advice	Regulation, Contracts, M&A	ACER	Regulation, Contracts, M&A	ACER
Records & Information Management	Transactions, contracts, documents	System Users	Transactions, contracts, documents	System Users

121. What is your level of understanding of the allocator(s) utilized to determine costs for the service(s) you receive?

122. How comfortable are you with your understanding of the corporate cost allocation methodology? (how the numbers roll up into fully allocated costs)

123. For each of the services received, how is the allocator determined as appropriate and how is it considered representational for the services provisioned? Please describe the review and documentation processes. This includes changes in allocator(s) used.

COST CHANGES

- The costs for the identified service(s) is/are shown in the table below:

	Cost		
Primary Service / Direct Charge	2007	2010	2011
Legal Advice	$ 303,414	$ 749,045	**$ 572,710**
Records & Information Management	$ 456,875	$ 298,336	**$ 304,392**

Legal Advice

124. Comparing the 2007 and 2011 service schedules, the cost for 'Legal Advice' has increased. Can you provide us with details for the variance?

Records & Information Management

125. Comparing the 2007 and 2011 service schedules, the cost for 'Records & Information Management' has decreased. Can you provide us with details for the variance?

EGD SERVICE RECIPIENT INTERVIEW GUIDE

Date	February 16, 2012	**Time**	3:00pm – 4:30pm
Interviewee	**Narin Kishinchandani**		
Position	Vice-President, Finance		
Meeting Attendees			
Phone Number			
Email Address			
Service(s) Received	**PRIMARY SERVICES** • Audit & Accounting Advice • Board of Directors Support • Capital Market Financing & Access • Cash Management & Banking • Corporate Compliance • External Audit Coordination • Investor Services • Planning, Management, & Execution of Internal Audits • Rate Regulated Entity Support • Risk Assessment & Management • Tax Reporting & Planning **DIRECT CHARGES** • Audit Fees • Depreciation - Risk Management System • Direct EFS Charge • Directors Fees & Expenses • EGD Stock Based Compensation		

INTRODUCTION

1. Could you provide us with details on your current role and previous role(s) within EGD and/or other Enbridge affiliates? (Timelines as well if possible)

2. How many employees are in your department(s)?

SERVICE(S) RECEIVED

3. For the services you receive, has the service delivery meaningfully changed over the past four years? How so? Please explain.

4. For each of the services received, what is the process to determine its essentiality?

5. How are the service descriptions developed to ensure they accurately reflect the services provided in terms of completeness and technical specification? Please describe how this process is reviewed.

6. What is the process to determine the level of service required?

7. How is the risk of service provisioning and receipt divided between the service provider and the service recipient (these would include risk related to under and/or over provisioning of services). How is the process to manage this risk reviewed and documented?

8. What is the dispute resolution process for in instances where there is a disagreement such as:
   - Level of service provided
   - Delivery of service (timeliness, quality, etc.)
   - Price charged

9. What is the process to developing business cases, for services received, and how often are they reviewed? What methods are utilized for validation?

10. Have you encountered instances where services were over-provisioned and/or under-provisioned? What is the process to address these cases?

11. What considerations have you given to alternate service provisioning? (i.e. internally, outsourcing, externally, etc.)

CORRELATION OF COST(S) AND SERVICE(S) RECEIVED

12. How does EGD track the correlation between the costs incurred and the shared services received? Is this process documented and how often is it reviewed?

13. Please explain the review process for the allocated cost of each service received, including the approval process.

14. How is the cost/benefit relationship determined for the services received?

OEB divides benefits into four categories:

XXIX. **Replacement** – The service cannot be replaced at equal or lower cost.
XXX. **Synergistic** – Cost for the service is reduced because it is spread over two or more affiliates. Economy of scale.
XXXI. **Revenue Enhancement / Cost Recovery** – Cost incurred provide value to other affiliates for which payment is received.
XXXII. **Stand-alone** – EI provides the service at a strategic level, which benefits EGD.

SERVICE SPECIFIC QUESTIONS

METHODOLOGY / ALLOCATOR DETERMINATION

- The methodology and allocator for the identified service(s) is/are shown in the table below:

	Methodology / Allocator			
	2007		2011	
Primary Service	External Driver	Allocator	External Driver	Allocator
Audit & Accounting Advice	Company complexity	FCER	Company complexity	FCER
Board of Directors Support	Company complexity & number of meetings	FCER	Company complexity & number of meetings	FCER
Capital Market Financing & Access	Financing activity	FCER	Financing activity	FCER
Cash Management & Banking	Cash volume	EGD % of Direct Time	Cash volume	EGD % of Direct time
Corporate Compliance	Company complexity	ACER	Company complexity	ACER
External Audit Coordination	Audit size (hence company complexity)	Same as Audit Fees	Audit size (hence company complexity)	Same as Audit Fees
Investor Services	M&A and financing activity	FCER	M&A and financing activity	FCER
Planning, Management, & Execution of Internal Audits	Company complexity	Same as Audit Fees	Company complexity	Same as Audit Fees
Rate Regulated Entity Support	Regulation and company complexity	N/A	Regulation and company complexity	N/A
Risk Assessment & Management	Entity risk	FCER	Entity risk	FCER
Tax Reporting & Planning	Legal Entities, M&A, financing	EGD % of Direct Time	Legal Entities, M&A, financing	EGD % of Direct Time

Direct Charge	2007		2011	
	Driver	Allocator	Driver	Allocator
Audit Fees	Complexity	Direct	Complexity	Direct
Depreciation - Risk Management System	Usage/Transactions	Direct	Usage/Transactions	Direct
Direct EFS Charge	Usage	Direct	Usage	Direct
Directors Fees & Expenses	Company complexity & number of meetings	FCER	Company complexity & number of meetings	FCER
EGD Stock Based Compensation	Usage	AHC - specific	Usage	Options Granted

15. What is your level of understanding of the allocator(s) utilized to determine costs for the service(s) you receive?

16. How comfortable are you with your understanding of the corporate cost allocation methodology? (how the numbers roll up into fully allocated costs)

17. For each of the services received, how is the allocator determined as appropriate and how is it considered representational for the services provisioned? Please describe the review and documentation processes. This includes changes in allocator(s) used.

COST CHANGES

- The costs for the identified service(s) is/are shown in the table below:

Primary Service / Direct Charge	Cost		
	2007	2010	2011
Audit & Accounting Advice	$ 86,095	$ 176,276	**$ 202,937**
Board of Directors Support	$ 511,270	$ 653,787	**$ 512,237**
Capital Market Financing & Access	$ 681,246	$ 857,868	**$ 986,346**
Cash Management & Banking	$ 222,036	$ 346,810	**$ 388,868**
Corporate Compliance	$ 99,725	$ 129,802	**$ 134,323**
External Audit Coordination	$ 43,174	$ 76,248	**$ 63,299**
Investor Services	$ 994,024	$ 685,330	**$ 811,451**
Planning, Management, & Execution of Internal Audits	$ 82,338	$ 228,607	**$ 185,494**
Rate Regulated Entity Support	$ 328,451	$ 128,419	**$ 147,295**
Risk Assessment & Management	$ 541,913	$ 882,571	**$ 1,062,095**
Tax Reporting & Planning	$ 10,196	$ 21,630	**$ 24,894**
Audit Fees	$ 808,955	$ 1,125,631	**$ 1,369,832**
Depreciation - Risk Management System	$ 24,512	$ 13,827	**$ 68,965**
Direct EFS Charge	($ 453,946)	($ 1,174,981)	**($ 1,150,894)**
Directors Fees & Expenses	$ 501,718	$ 517,905	**$ 545,235**
EGD Stock Based Compensation	$ 1,663,249	$ 4,842,397	**$ 6,413,231**

Audit & Accounting Advice

18. Comparing the 2007 and 2011 service schedules, the cost for 'Audit & Accounting Advice' has increased. Can you provide us with details for the variance?

Board of Directors Support

19. Comparing the 2007 and 2011 service schedules, the costs for 'Board of Directors Support' remained relatively unchanged.

Capital Market Financing & Access

20. Comparing the 2007 and 2011 service schedules, the cost for 'Capital Market Financing & Access' has increased. Can you provide us with details for the variance?

Cash Management & Banking

21. Comparing the 2007 and 2011 service schedules, the cost for 'Cash Management & Banking' has increased. Can you provide us with details for the variance?

Corporate Compliance

22. Comparing the 2007 and 2011 service schedules, the cost for 'Corporate Compliance' has increased. Can you provide us with details for the variance?

External Audit Coordination

23. Comparing the 2007 and 2011 service schedules, the cost for 'External Audit Coordination' has increased. Can you provide us with details for the variance?

Investor Services

24. Comparing the 2007 and 2011 service schedules, the cost for 'Investor Services' has decreased. Can you provide us with details for the variance?

Planning, Management, & Execution of Internal Audits

25. Comparing the 2007 and 2011 service schedules, the cost for 'Planning, Management, & Execution of Internal Audits' has increased. Can you provide us with details for the variance?

Rate Regulated Entity Support

26. Comparing the 2007 and 2011 service schedules, the cost for 'Rate Regulated Entity Support' has decreased. Can you provide us with details for the variance?

Risk Assessment & Management

27. Comparing the 2007 and 2011 service schedules, the cost for 'Risk Assessment & Management' has increased. Can you provide us with details for the variance?

Tax Reporting & Planning

28. Comparing the 2007 and 2011 service schedules, the cost for 'Tax Reporting & Planning' has increased. Can you provide us with details for the variance?

Audit Fees

29. Comparing the 2007 and 2011 service schedules, the cost for 'Audit Fees' has increased. Can you provide us with details for the variance?

Depreciation - Risk Management System

30. Comparing the 2007 and 2011 service schedules, the cost for 'Depreciation - Risk Management System' has increased. Can you provide us with details for the variance?

Direct EFS Charge

31. Comparing the 2007 and 2011 service schedules, the cost for 'Direct EFS Charge' has changed. Can you provide us with details for the variance?

Directors Fees & Expenses

32. Comparing the 2007 and 2011 service schedules, the cost for 'Directors Fees & Expenses' has increased. Can you provide us with details for the variance?

EGD Stock Based Compensation

33. Comparing the 2007 and 2011 service schedules, the cost for 'EGD Stock Based Compensation' has increased. Can you provide us with details for the variance?

APPENDIX D – MNP INDIVIDUAL SERVICE ANALYSES

1 – AUDIT AND ACCOUNTING ADVICE

Audit & Accounting Advice – 2012 RCAM Analysis

EGD Service Recipient

Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Service Definition

The Audit and Accounting Advice service is responsible for providing EGD with research and advice related to the company's audit and accounting practices. This includes advising on proposed changes relating to accounting guidance, securities regulation requirements, and the related business impacts.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$1,204,054	4%	**$45,122**	$332,714	FCER	14%	**$46,147**	**$91,270**

Cost by Department

EI Department	*Charges*
Audit Services (Calgary)	$16,636
Corporate Controller	$74,634
Total	**$91,270**

Prong 1 Test
Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Audit & Accounting' function is a necessary component to EGD. Ensuring adherence to the evolving regulatory and statutory requirements is critical to the functional operations of a utility in Ontario, along with remaining abreast of changes within the industry, particularly concerning standards.

EI has been identified as a supplemental provider for this service.

Prong 2 Test
Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Company Complexity' drives the related common costs for this service and dictates the level of service required to provide audit and accounting services to EGD.
- Allocations for common costs use Financing Capital Employed Ratio (FCER) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test
Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Audit Manager	1	$ 119,694	1	$ 155,653
Total	**1**	**$ 119,694**	**1**	**$ 155,653**

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

Audit & Accounting Advice – 2012 RCAM Analysis

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 91,270	$ 119,694	$ 155,653	Below Range

The cost of procuring this service from EI is below the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 500 hours for an external consultant at the associate Partner level (equivalent to a Director of Audit) to provide a comparable on-demand service, which would cost approximately $187,200 to $280,800.
MNP believes that this is a reasonable estimate of effort and cost, which is higher than both the cost incurred via RCAM allocation and internal provisioning estimates. The following table provides a breakdown of the cost estimate:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Associate Partner	$ 468 / hour	1	500	$ 234,000
	Total	**1**	**500**	**$ 234,000**
			Low Range (80% of Total)	$ 187,200
			High Range (120% of Total)	$ 280,800

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost, internally or externally. An alternate source for these stand alone services would result in additional costs to ratepayers.
Synergistic	Economies of scale are achieved as duplicated effort across affiliates is eliminated.
Revenue Enhancement	Not Applicable.
Stand-alone	Not Applicable.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

MNP Conclusion

- Prongs 1, 2, and 3 pass.
- No adjustment to the 2012 EGD allocation is required.

2 – BOARD OF DIRECTORS SUPPORT

Board of Directors Support – 2012 RCAM Analysis

EGD Service Recipient

Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Service Definition

The Board of Directors Support service is responsible for providing lines of communication between EGD Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committees.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$6,789,025	8%	**$541,575**	$1,642,342	FCER	14%	**$227,793**	**$769,368**

Cost by Department

EI Department	*Charges*
CEO	$290,619
CFO	$28,330
People and Partners	$284,584
Corporate Secretarial	$95,023
Corporate HR	$15,380
Total Compensation	$49,879
HR Enterprise Business Solutions	$5,553
Total	**$769,368**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Board of Directors Support' function is a necessary component to EGD. The Board is responsible for ensuring that EGD has a strategic plan in place and that management is executing its responsibilities, as per the strategic plan. Additional responsibilities include the appointment of a qualified Chief Executive, monitoring and setting performance metrics, and ensuring that a rigorous succession plan is in place.

Supporting the Board in successfully executing its responsibilities is essential to EGD due to the strategic nature of their responsibilities.

EI has been identified as the sole provider for this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Company Complexity & number of meetings' drives the related common costs for this service which is representative of the effort required to support the Board.
- Allocations for common costs use Financing Capital Employed Ratio (FCER) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test

Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Board of Directors Support – 2012 RCAM Analysis

Position	MNP Low Range Estimate # of FTE	MNP Low Range Estimate Total Cost	MNP High Range Estimate # of FTE	MNP High Range Estimate Total Cost
Senior-level Finance Executive	1	$ 288,377	1	$ 423,864
Corporate Secretary	1	$ 260,388	1	$ 340,221
Administrative Assistant	1	$ 66,731	1	$ 84,914
Total	**3**	**$ 615,496**	**3**	**$ 849,000**

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 769,368	$ 615,496	$ 849,000	Within Range

The cost of procuring this service from EI is within range of the MNP estimated stand-alone cost.

External Provision

EGD noted that these services cannot be provided by an external service provider. Given the sensitivities of the information handled and developed to support the activities and responsibilities of the EGD Board of Directors, MNP agrees with the EGD assertion and deems it unfeasible to externalize/outsource this function.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost externally. Internal provisioning for this service may be possible, but would result in additional costs to ratepayers in the form of potentially higher direct costs.
Synergistic	Economies of scale are achieved through the avoidance of additional fees and premiums associated with augmenting the current EGD Board with the necessary support required for a stand-alone utility.
Revenue Enhancement	Not Applicable.
Stand-alone	Board of Directors Support requires significant knowledge of the risks, operations, and performance of EGD. The delivery model for this service provides a level of strategic insight that would not be available to EGD through an alternative source.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

MNP Conclusion

- Prongs 1, 2, and 3 pass.
- No adjustment to the 2012 EGD allocation is required.

3 – BUSINESS DEVELOPMENT

Business Development – 2012 RCAM Analysis

EGD Service Recipient

Arunas Pleckaitis, Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution

Service Definition

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects, and partnership formation.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$20,760,284	4%	**$736,918**	$0	ACER	0%	**$0**	**$736,918**

Cost by Department

EI Department	*Charges*
CEO	$291,407
CFO	$38,980
Corporate Law	$88,197
Labour Relations	$125,862
Corporate Controller	$92,071
Public & Government Affairs	$100,401
Total	**$736,918**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Business Development' function is a necessary component to EGD. This service assists EGD in obtaining advice on the evaluation and execution of business improvement, growth, and investment opportunities aligned with EGD's current business model and strategy.

EI has been identified as a supplemental provider for this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates, which in MNP's opinion is an appropriate and industry accepted allocator.

Common Costs

- 'M&A Activity' drives the related common costs for this service, which is representative of opportunity identification and the advising and coordination of opportunity evaluations.
- Allocations for common costs use Adjusted Capital Employed Ratio (ACER) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test

Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Senior-level Business Development Executive	1	$ 232,854	1	$ 365,069
Financial Analysis Manager	1	$ 147,200	2	$ 379,105
Administrative Assistant	1	$ 66,731	1	$ 84,914
Total	**3**	**$ 446,785**	**4**	**$ 829,088**

Business Development – 2012 RCAM Analysis

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 736,918	$ 446,785	$ 829,088	Within Range

The cost of procuring this service from EI is within range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 4,000 hours for an external consulting team to provide a comparable on-demand service, which would cost approximately $790,806 to $1,186,210. The following table provides a breakdown of the cost estimate:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Managing Partner	$ 330 / hour	1	2,000	$ 660,000
Consultant	$ 137 / hour	1	2,000	$ 274,000
Travel Costs				$ 54,508
	Total	**2**	**4,000**	**$ 988,508**
			Low Range (80% of Total)	**$ 790,806**
			High Range (120% of Total)	**$ 1,186,210**

MNP believes that this is a reasonable estimate of effort and cost which is higher than both the cost incurred via RCAM allocation and internal provisioning.

It is also important to note that given the sensitivities of the information handled and developed within this service, it is generally unfavourable to externalize/outsource Business Development. Certain aspects of the service may be augmented by external expertise but core functions should remain internal.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	The service is currently offered at a cost approximately equal to an internal stand-alone EGD team. Any potential cost savings attributed to in-sourcing may be offset somewhat by costs associated with recruitment, training and development.
Synergistic	Economies of scale are achieved through the model's ability to leverage the expertise of multiple EI departments and professional staff for ongoing planning, coordination, and organization of business improvement and investment opportunities.
Revenue Enhancement	Not Applicable.
Stand-alone	Industry expertise and company knowledge, coupled with the scale and scope of the business units providing the services, would be difficult to replicate if service was externalised.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the

Business Development – 2012 RCAM Analysis	
	opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.
MNP Conclusion	• Prongs 1, 2, and 3 pass. • No adjustment to the 2012 EGD allocation is required.

4 – CAPITAL MARKET FINANCING & ACCESS

Capital Market Financing & Access – 2012 RCAM Analysis

EGD Service Recipient

Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Service Definition

The Capital Market Financing and Access service provides support in raising capital (both debt and equity) and maintaining access to capital markets.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$8,648,966	8%	**$668,572**	$2,534,980	FCER	14%	**$351,602**	**$1,020,173**

Cost by Department

EI Department	*Charges*
CEO	$ 157,595
CFO	$ 182,933
Investor Relations	$ 80,379
Treasury	$ 520,278
Corporate Secretarial	$ 78,988
Total	**$1,020,173**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Capital Market Financing & Access' function is a necessary component to EGD. This service assists EGD in attracting and retaining investors to ensure that an adequate amount of capital is available to support its operations and growth plans.

A substantial amount of effort is essential to ensure the availability of capital to support EGD's expenditures. Due to the nature, timing, and amount of capital required, a continuous effort of year-round activities needs to occur. Working with banks, financial institutions, and institutional investors on a continuous basis allows EGD to maintain access to financing to fund the company's capital spending program approved by the OEB.

MNP acknowledges that the costs by department listed above have excluded certain costs of the CFO and Treasury departments due to 'minding the investment' exclusion criteria.

EI has been identified as the sole provider for this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Financing Activity' drives the related common costs for this service, which is representative of the effort and the requirement to maintain investment capital access for all entities in which EI maintains an investment, one of which is EGD.
- Allocations for common costs use Financing Capital Employed Ratio (FCER) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Capital Market Financing & Access – 2012 RCAM Analysis

Prong 3 Test
Do the benefits to ratepayers exceed the costs?

FAIL

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Senior-level Finance Executive	1	$ 288,377	1	$ 423,864
Treasury Director	1	$ 156,364	1	$ 212,687
Financial Analyst II	1	$ 110,407	2	$ 270,405
Administrative Assistant	1	$ 66,731	1	$ 84,914
Total	**4**	**$ 621,880**	**5**	**$ 991,870**

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 1,020,173	$ 621,880	$ 991,870	Above Range

The cost of procuring this service from EI is above the range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 6,500 hours for an external consulting team to provide a comparable on-demand service, which would cost approximately $841,944 to $1,262,916, with a midpoint of $1,052,430. The following table provides a breakdown of the cost estimate:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Senior Consultant	$ 192 / hour	2	2,000	$ 768,000
Consultant	$ 105 / hour	1	2,500	$ 262,500
Travel Costs				$ 21,930
	Total	**3**	**6,500**	**$ 1,052,430**
			Low Range (80% of Total)	**$ 841,944**
			High Range (120% of Total)	**$ 1,262,916**

MNP believes that this is a very conservative estimate of effort, given the amount of time required to perform technical support functions and build/maintain trust in the investment community, and that more time would be required to accomplish the levels of service outlined in EGD's service schedule. The midpoint of EGD estimates is higher that the EI allocation and more realistic levels of effort would yield even higher external costs.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	The service is currently offered by EI at a cost that is higher than the upper range estimated by MNP.
Synergistic	Economies of scale are achieved by through the ability to leverage the expertise of multiple departments across affiliates for the

Capital Market Financing & Access – 2012 RCAM Analysis	
	<table><tr><td></td><td>provision of capital access related support services. Although EGD is assigned interest based on its own credit rating, there may be a synergistic financial benefit to EGD achieved through the avoidance of commission fees on the issuance of commercial paper. These savings amount to between 3 and 5 basis points, which are significant for debt raises of over $100 million.</td></tr><tr><td>Revenue Enhancement</td><td>Not Applicable.</td></tr><tr><td>Stand-alone</td><td>EI can structure financing arrangements to the benefit of EGD in the context of company-wide capital requirements, which is of strategic importance to EGD to secure favourable terms.</td></tr></table> <u>MNP Conclusion</u> Based on the analysis of services required and allocation methodology, MNP is of the opinion that although the services are prudently incurred and appropriately allocated, EGD could lower the costs of this service by assuming the provision of service internally at EGD. Based on this finding, the replacement component of the test is not met. MNP has not considered the costs of switching service providers because these costs are provisional and variable in nature based on specific requirements of alternative provision. Switching costs or quantified synergistic or stand-alone benefits could offset some of the cost savings of alternative provision. In addition, it is unclear if EGD would enjoy basis point savings on commission fees if it were to secure debt financing as a standalone entity, but any savings in this regard would also offset alternative service provision savings.
MNP Conclusion	• Prongs 1 and 2 pass. • Prong 3 fails. • MNP recommends a downward Prong Three adjustment of $28,303 to the 2012 allocation and a corresponding escalated adjustment of $28,924 for 2013.

5 – CASH MANAGEMENT & BANKING

Cash Management & Banking – 2012 RCAM Analysis

EGD Service Recipient

Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Service Definition

The Cash Management and Banking service determines the optimal short-term cash requirements and executes the supporting daily banking transactions. This includes responsibility for managing short-term liquidity and cash holdings.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$3,668,182	8%	**$293,455**	$1,430,591	EGD % of Direct Time	13%	**$187,619**	**$481,073**

Cost by Department

EI Department	*Charges*
Treasury	$ 481,073
Total	**$ 481,073**

Prong 1 Test
Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

The determination of short-term liquidity requirements and cash holdings is extremely important for EGD and is required for a stand-alone gas distribution utility to manage the volatility of working capital and other cash requirements.

EI has been identified as the sole provider for this service.

Prong 2 Test
Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Cash Volume' drives the related common costs for this service, which is representative of the effort to maintain cost effective operating liquidity.
- Allocations for common costs use EGD % of direct time which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test
Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Treasury Director	1	$ 156,364	1	$ 212,687
Financial Analysis Manager	1	$ 147,200	1	$ 189,552
Mid-level Financial Analyst	1	$ 110,407	1	$ 135,203
Total	**3**	**$ 413,971**	**3**	**$ 537,442**

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 481,073	$ 413,971	$ 537,442	Within Range

Cash Management & Banking – 2012 RCAM Analysis

The cost of procuring this service from EI is within range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 4,400 hours for an external consulting team to provide a comparable on-demand service, which would cost approximately $448,640 to $672,906. The following table provides a breakdown of the cost estimate:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Senior Consultant	$ 192 / hour	1	400	$ 76,800
Consultant	$ 137 / hour	1	2,000	$ 274,000
Support Staff	$ 105 / hour	1	2,000	$ 210,000
	Total	**3**	**4,400**	**$ 560,800**
			Low Range (80% of Total)	**$ 448,640**
			High Range (120% of Total)	**$ 672,960**

MNP believes that this is a reasonable estimate of effort and is comparable in cost to both the RCAM allocation and internal provisioning.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	The service is currently offered at a comparable cost to internal and external provisioning. Any potential savings from altering the provision of service would be offset somewhat by switching costs of recruitment or a competitive procurement process and new vendor management.
Synergistic	EGD benefits from having access to the knowledge, expertise and costs savings of the EI treasury department that provides cash management and banking services provided to several EI affiliates.
Revenue Enhancement	Not Applicable.
Stand-alone	Being part of the larger EI entity provides EGD with borrowing strength and banking terms that cannot be achieved by smaller entities. The strategic benefits of having EI provide this service would likely outweigh any potential cost savings of alternatively sourcing these services.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

MNP Conclusion

- Prongs 1, 2, and 3 pass.
- No adjustment to the 2012 EGD allocation is required.

6 – CONSOLIDATION & PLANNING SYSTEM TECH SUPPORT (KHALIX)

Consolidation & Planning System Tech Support (Khalix) – 2012 RCAM Analysis

EGD Service Recipient

Henry Wong, Director Information Technology, Enbridge Gas Distribution

Service Definition

The Consolidation and Planning System Technical Support (Khalix) service is responsible for the technical support and administration of the consolidation and planning system (Khalix).

The Khalix consolidation and planning system consists of three instances used for consolidating the actual results, conducting the enterprise-wide budgeting and forecasting process on an annual basis (ABF), budgeting and forecasting process on a 5 year basis (LRP) and an instance specifically for project budgeting and forecasting (Ensight).

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$790,160	1%	**$5,160**	$712,761	System Users	34%	**$239,929**	**$245,089**

Cost by Department

EI Department	*Charges*
CIO	$ 85,514
EFS Strategy and Support	$ 88,146
Corporate Controller	$ 71,429
Total	**$ 245,089**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the Consolidation and Planning System Technical Support function is a necessary component to EGD to manage system requirements for internal management reporting, budgeting, forecasting, project based budgeting and salary/FTE budgeting. In addition to the system itself, EGD also requires the technical support and administration required to keep the system running and manage and implement system improvements and upgrades.

EI costs went down in 2012, resulting from the completion of major enhancement projects in prior periods

EI has been identified as a supplemental provider for this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'IT Asset Usage' drives the related common costs for this service, which is representative of EGD's level of system usage relative to other affiliates.
- Allocations for common costs are allocated using the 'system users'; the percentage of EGD Khalix system users out of the total user base. In MNP's opinion, this is an appropriate and industry accepted allocator.

Consolidation & Planning System Tech Support (Khalix) – 2012 RCAM Analysis

Prong 3 Test
Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Application Development Manager	1	$ 153,098	1	$ 193,210
Mid-level Business Systems Analyst	1	$ 108,368	1	$ 135,009
Administrative Assistant	1	$ 66,731	1	$ 84,914
Total	**3**	**$ 328,197**	**4**	**$ 542,554**

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 245,089	$ 328,197	$ 542,554	Below Range

The cost of procuring this service from EI is below the MNP estimated stand-alone cost.

External Provision

EGD determined that a reasonably competitive market exists for this service. However, EGD did not provide external cost estimates because EGD would incur significant expense to investigate the costs for this option, and with this investigation an estimate would be unreliable.

Based upon prevailing market rates for technical support services, MNP conservatively estimates that external provision of costs would amount to approximately $560,000, which exceeds both the high range estimate of internal costs and EI allocation. The following table provides a breakdown of the cost estimate:

Consolidation & Planning System Tech Support (Khalix) – 2012 RCAM Analysis

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Partner/Senior Technical Support	$ 250/ hour	1	700	$ 175,000
Senior Consultant Technical Support	$ 165 / hour	1	1,400	$ 231,000
Consultant Technical Support	$ 110 / hour	1	1,400	$ 154,000
	Total	**3**	**3,500**	**$ 560,000**

MNP agrees with the EGD assertion that that an enterprise-wide implementation of IT/Accounting software is extremely costly, especially for organizations the size of EGD. In addition to the support staff identified above, EGD would incur additional costs for system sourcing, planning, design, building, testing, and deployment.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost, internally or externally. An alternate source for these stand alone services would result in incremental expense to rate payers due to the high costs associated to system implementation and upgrade.
Synergistic	Economies of scale is achieved through the model's centralized approach where all affiliates benefiting from the Khalix system share the high fixed costs of implementation, development, planning, annual maintenance, and ongoing support.
Revenue Enhancement	Not Applicable.
Stand-alone	Not Applicable.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

MNP Conclusion

- Prongs 1, 2, and 3 pass.
- No adjustment to the 2012 EGD allocation is required.

7 – CORPORATE COMPLIANCE

Corporate Compliance – 2012 RCAM Analysis

EGD Service Recipient

Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Service Definition

The Corporate Compliance service is responsible for developing the corporate governance structure and policies.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$1,187,441	8%	**$94,191**	$654,037	ACER	16%	**$103,011**	**$197,202**

Cost by Department

EI Department	*Charges*
CEO	$77,565
CFO	$16,626
People and Partners	$35,163
Corporate Controller	$18,331
Corporate HR	$6,540
Total Compensation	$42,977
Total	**$197,202**

Prong 1 Test
Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Corporate Compliance' function is a necessary component to EGD and the associated level of service is required for a stand-alone utility. The legal, economic, and reputational risks of non-compliance to companies, their directors and officers, outweigh any advantages in reducing the level of corporate compliance activity.

EI has been identified as a supplemental provider for this service.

Prong 2 Test
Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Company Complexity' drives the related common costs for this service, which is representative of the effort required to develop effective policies and controls within all entities which EI operates.
- Allocations for common costs use Adjusted Capital Employed Ratio (ACER) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test
Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Senior-level Audit Executive	1	$ 210,351	1	$ 321,812
Administrative Assistant	1	$ 66,731	1	$ 84,914
Total	**2**	**$ 277,083**	**2**	**$ 406,726**

Corporate Compliance – 2012 RCAM Analysis

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 197,202	$ 277,083	$ 406,726	Below Range

The cost of procuring this service from EI is below the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 2,000 hours for an external consulting team to provide a comparable on-demand service, which would cost approximately $197,120 to $295,680. The following table provides a breakdown of the cost estimate:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Senior Consultant	$ 192 / hour	1	200	$ 38,400
Consultant	$ 137 / hour	1	600	$ 82,000
Support Staff	$ 105 / hour	1	1,200	$ 126,000
	Total	**3**	**2,000**	**$ 246,400**
			Low Range (80% of Total)	**$ 197,120**
			High Range (120% of Total)	**$ 295,680**

MNP believes that this is a conservative estimate of effort, yet still falls below the range of costs for RCAM allocation and internal provisioning.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	The service is currently offered by EI at a lower cost than alternative sources.
Synergistic	Economies of scale are achieved through the service delivery model's ability to leverage EI expertise across departments and built through interaction amongst other EI affiliates.
Revenue Enhancement	Not Applicable.
Stand-alone	Trends in governance, accountability, and transparency are evolving quickly in response to various financial and operational challenges in the natural resource and financial sectors. EI's governance contributions benefit EGD at the strategic level to manage risk and bolster corporate citizenship.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

MNP Conclusion

- Prongs 1, 2, and 3 pass.
- No adjustment to the 2012 EGD allocation is required.

8 – EMPLOYEE AND LABOUR RELATIONS

Employee and Labour Relations – 2012 RCAM Analysis

EGD Service Recipient

Marc Weil, Director Human Resources, Enbridge Gas Distribution

Service Definition

The Employee and Labour Relations service provides the development of strategies (overall framework, vision and policies) and tactics for the management of unionized, Joint Industrial Council (JIC) and potentially-unionized employees and supports the development of employee-related principles and policies.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$1,057,416	33%	**$353,457**	$401,261	AHC	31%	**$124,744**	**$478,201**

Cost by Department

EI Department	*Charges*
People and Partners	$13,543
Labour Relations	$428,522
Corporate HR	$36,136
Total	**$478,201**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Employee and Labour Relations' function is a necessary component to EGD and the associated level of service is required for a stand-alone utility. The service is critical to the overall proficiency of EGD's interaction with the labour market and with the firm's employees and contractors.

EI has been identified as the primary provider for this service, although EGD does maintain junior level support staff for this function.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Employees and Unionized Employees' drives the related common costs for this service, which is representative of the effort required to engage and retain employees, as well as comply with both best practices and legislation across all affiliates.
- Allocations for common costs use Affiliate Headcount (AHC) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test

Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Labour Relations Manager	1	$ 152,748	1	$ 205,882
Labour Relations Specialist	2	$ 230,832	2	$ 267,385
Administrative Assistant	1	$ 66,731	1	$ 84,914
Total	**4**	**$ 450,312**	**4**	**$ 558,181**

Employee and Labour Relations – 2012 RCAM Analysis

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 478,201	$ 450,312	$ 558,181	Within Range

The cost of procuring this service from EI is within the range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 4,000 hours for an external consulting team to provide a comparable on-demand service, which would cost approximately $531,200 to $796,800. The following table provides a breakdown of the cost estimate:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Senior Consultant	$ 275 / hour	1	2,000	$ 550,000
Support Staff	$ 57 / hour	1	2,000	$ 114,000
	Total	**2**	**4,000**	**$ 664,000**
			Low Range (80% of Total)	**$ 531,200**
			High Range (120% of Total)	**$ 796,800**

MNP believes that this is a conservative estimate of effort, yielding a cost estimate higher than the cost incurred via RCAM allocation and within the range for internal provisioning.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	Internal provision may be possible at a relatively comparable direct financial cost, although an alternate source for these stand alone services would result in long term incremental expense to ratepayers due to a compromise in the subject matter expertise, familiarity and trust developed within the EI umbrella.
Synergistic	Economies of scale are achieved through the model's centralized approach of service delivery. Example benefits include: • Transferable expertise developed through exposure broader labour relation trends and practices. • Knowledge base of broader labour relations trends and practices that have been applied across EI and its affiliates.
Revenue Enhancement	Not Applicable.
Stand-alone	Sourcing from EI is of strategic benefit to EGD due to EI's familiarity with EGD collective bargaining entities and historical context.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

MNP

- Prongs 1, 2, and 3 pass.

Employee and Labour Relations – 2012 RCAM Analysis	
Conclusion	• No adjustment to the 2012 EGD allocation is required.

9 – EMPLOYEE DEVELOPMENT

Employee Development – 2012 RCAM Analysis

EGD Service Recipient

Marc Weil, Director Human Resources, Enbridge Gas Distribution

Service Definition

The Employee Development service provides long-range planning and the advancement and support of employee development and talent management programs to support business strategies and ensure the supply and development of employees across the enterprise.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$5,216,561	15%	**$763,883**	$2,078,254	Non-Union EFTE	24%	**$496,685**	**$1,260,568**

Cost by Department

EI Department	*Charges*
CEO	$503,231
People and Partners	$41,921
Organizational Effectiveness	$669,944
Corporate HR	$15,017
HR Enterprise Business Solutions	$30,455
Total	**$1,260,568**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Employee Development' function is a necessary component of EGD operations and the associated level of service is required for a stand-alone utility. Employee development is essential to any organization to ensure growth and development of labour, management, and leadership resources with the organization.

In addition to the elements above, EGD is facing challenging conditions in terms of employee development and succession in light of its aging workforce and a strong commitment to employee/customer safety. According to EGD, 18% of its workforce is eligible to retire today and 30% can retire within the next 5 years. In addition, 26% of EGD's leaders can retire today.

EGD is undertaking a rigorous program to address these issues and position itself to continue to meet employee and customer obligations in the future.

EI has been identified as a supplemental provider for this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Employees' drive the related common costs for this service, which is representative of the effort required to engage, retain, and develop non-union employees.
- Allocations for common costs use Non-Union Enterprise Full Time Equivalent (Non-Union EFTE) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Employee Development – 2012 RCAM Analysis

Prong 3 Test
Do the benefits to ratepayers exceed the costs?

FAIL

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Senior-level Human Resources Executive	1	$ 247,330	1	$ 333,171
Training Manager	2	$ 285,263	2	$ 385,568
Mid-level Training Specialist	2	$ 168,017	3	$ 304,906
Administrative Assistant	1	$ 66,731	1	$ 84,914
Program development and third party costs	n/a	$ 137,064	n/a	$ 137,064
Total	**6**	**$ 904,406**	**7**	**$ 1,245,623**

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 1,260,568	$ 904,406	$ 1,245,623	Above Range

The cost of procuring this service from EI is above the range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 8,500 hours for an external consulting team to provide a comparable on-demand service, which would cost approximately $945,651 to $1,418,477. The following table provides a breakdown of the cost estimate:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Senior Consultant	$ 194 / hour	1	2,000	$ 388,000
Consultant	$ 100 / hour	3	2,000	$ 600,000
Support Staff	$ 57 / hour	0.5	2,000	$ 57,000
Program Development Cost				$ 82,238
Provision for loss of economies of scale				$ 54,826
	Total	**4.5**	**8,500**	**$ 1,182,064**
			Low Range (80% of Total)	**$ 945,651**
			High Range (120% of Total)	**$ 1,418,477**

MNP believes that this is a conservative estimate of effort with attribution of hours substantially below those of a full internal team. Even with a low estimate of effort, the external provision estimate of cost is comparable to the RCAM allocated cost, but higher than the lower end of estimated internal provisioning costs. MNP did not evaluate the provision for loss of economies of scale; however, exclusion of the assignment of cost ($54,826) does not alter the analysis.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Employee Development – 2012 RCAM Analysis

Benefit Type	*Reasoning*
Replacement	The service is currently offered by EI at a cost that is higher than the upper range estimated by MNP.
Synergistic	Economies of scale are achieved through the model's centralized approach of service delivery. Example benefits and include: • Leading practices for learning and development programs developed across multiple EI affiliates. • Costs of designing, implementing and administering programs (e.g. annual survey) are reduced by sharing costs among affiliates. • Targeted succession planning for EGD and other affiliates and career development opportunities across the EI umbrella.
Revenue Enhancement	Not Applicable.
Stand-alone	Procuring services from EI provides EGD with strategic benefits through the ability to leverage familiarity, knowledge and expertise of a broad group at EI, attract talent with the prospect of broad opportunities across the network and expand the talent pool from which to draw resources to EGD. Similar experiential benefits may not be available if EGD were to source these services internally.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that although the services are prudently incurred and appropriately allocated, EGD could lower the costs of this service by assuming the provision of service internally at EGD. Based on this finding, the replacement component of the test has not been met.

Synergistic and stand-alone benefits are considered by MNP to be genuine but speculative from a benefits quantification perspective. MNP has also not considered the costs of switching service providers because these costs are provisional and variable in nature based on specific requirements of alternative provision. Switching costs or quantified synergistic or stand-alone benefits could offset some of the cost savings of alternative provision.

MNP Conclusion

- Prongs 1 and 2 pass.
- Prong 3 fails.
- MNP recommends a downward Prong Three adjustment of $14,945 to the 2012 allocation and a corresponding escalated adjustment of $15,274 for 2013.

10 – ENTERPRISE IT PROGRAM MANAGEMENT

Enterprise IT Program Management – 2012 RCAM Analysis

EGD Service Recipient

Henry Wong, Director Information Technology, Enbridge Gas Distribution

Service Definition

The Enterprise IT Program Management service is responsible for the overall coordination, and monitoring of major enterprise projects.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$5,514,246	0%	**$0**	$5,514,246	ACER	16%	**$868,494**	**$868,494**

Cost by Department

EI Department	*Charges*
IT Planning and Governance	$465,106
CIO	$403,388
Total	**$868,494**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Enterprise IT Program Management' function is a necessary component to EGD's modern operations and the associated level of service is required for a stand-alone utility. The service is responsible for the overall coordination and monitoring of major enterprise projects, and is essential for the normal function of the firm and its ability to manage and execute projects.

Costs have increased in 2012 by about $479,000 due to an increase in the number of systems being overhauled, all of which require project management support.

EI has been identified as the sole provider of this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'IT Programs' drives the related common costs for this service, which is representative of the effort required to ensure the delivery of IT project management at a best practices level across all EI affiliates.
- Allocations for common costs use Adjust Capital Employed Ratio (ACER) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test

Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
IT Director	1	$ 240,779	1	$ 319,124
IT Manager	2	$ 313,877	3	$ 657,107
Application Development Manager	2	$ 306,197	3	$ 579,629
Administrative Assistant	1	$ 66,731	2	$ 169,828
Total	**6**	**$ 927,584**	**9**	**$ 1,725,687**

Enterprise IT Program Management – 2012 RCAM Analysis

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 868,494	$ 927,584	$ 1,725,687	Below Range

The cost of procuring this service from EI is below the range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 12,200 hours for an external consulting team to provide a comparable on-demand service, which would cost approximately $1,100,000 to $1,650,000. The following table provides a breakdown of the cost estimate:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Senior Consultant	$ 165 / hour	1	1,600	$ 264,000
Consultant	$ 110 / hour	6	1,600	$ 1,056,000
Support Staff	$ 55 / hour	1	1,000	$ 55,000
	Total	**8**	**12,200**	**$ 1,375,000**
			Low Range (80% of Total)	**$ 1,100,000**
			High Range (120% of Total)	**$ 1,650,000**

MNP believes that this is a reasonable estimate of effort, which is higher than the allocated cost from EI and internal provisioning.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost, internally or externally. An alternate source for these stand alone services would result in incremental expense to rate payers.
Synergistic	Economies of scale are achieved through the centralized approach of service delivery, which leverages the enterprise-wide implementation efforts of projects and shares costs amongst EI affiliates.
Revenue Enhancement	Not Applicable.
Stand-alone	Having central IT professional at EI contributes strategically to the effective management of systems and implementations that benefit EGD. Knowledge of EI integrated systems also allows for more efficient management of resources.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

Enterprise IT Program Management – 2012 RCAM Analysis	
MNP Conclusion	• Prongs 1, 2 and 3 pass. • No adjustment to the 2012 EGD allocation is required.

11 – ENTERPRISE IT STRATEGY PLANNING & MANAGEMENT

Enterprise IT Strategy Planning & Management – 2012 RCAM Analysis

EGD Service Recipient

Henry Wong, Director Information Technology, Enbridge Gas Distribution

Service Definition

The Enterprise IT Strategy Planning and Management service governs the development of enterprise wide strategies, policies and standards for information technologies.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$3,572,546	4%	**$149,655**	$3,012,447	ACER	16%	**$474,460**	**$624,115**

Cost by Department

EI Department	*Charges*
People and Partners	$181,220
CIO	$0
IT Planning and Governance	$442,895
Total	**$624,115**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Enterprise IT Strategy Planning and Management' function is a necessary component to EGD's modern operations and the associated level of service is required for a stand-alone utility. The service provides strategic planning and management guidance in the identification and design of Enterprise IT systems for the benefit of EGD and ratepayers.

MNP acknowledges that the costs by department listed above have excluded certain costs of the CIO and IT Planning and Governance departments due to 'additional management layer' exclusion criteria.

EI has been identified as the sole provider for this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'IT Asset Usage' drives the related common costs for this service, which is representative of EGD's level of system usage relative to other affiliates.
- Allocations for common costs use Adjust Capital Employed Ratio (ACER) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test

Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Senior-level Information Technology Executive	1	$ 257,305	1	$ 353,539
Information Technology Manager	1	$ 156,939	2	$ 438,071
Total	**2**	**$ 414,244**	**3**	**$ 791,610**

Enterprise IT Strategy Planning & Management – 2012 RCAM Analysis

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 624,115	$ 414,244	$ 791,610	Within Range

The cost of procuring this service from EI is within the range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 3,200 hours for an external consulting team to provide a comparable on-demand service, which would cost approximately $702,720 to $1,054,080. The following table provides a breakdown of the cost estimate:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Managing Partner	$ 330 / hour	1	1,600	$ 528,000
Senior Consultant	$ 219 / hour	1	1,600	$ 350,400
	Total	**2**	**3,200**	**$ 878,400**
			Low Range (80% of Total)	**$ 702,720**
			High Range (120% of Total)	**$ 1,054,080**

MNP believes that this is a reasonable estimate of effort, which is higher than the cost incurred via RCAM allocation and comparable at its low end to internal provisioning estimates.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost, internally or externally. An alternate source for these stand alone services would result in incremental expense to ratepayers.
Synergistic	Significant economies of scale are achieved through centralization of the service where assets and annual operating costs are shared amongst affiliates. An additional benefit is added given that EGD is undergoing significant upgrades to its technology environment, where EGD would incur all costs for this service instead of sharing these expenses across affiliates.
Revenue Enhancement	Not Applicable.
Stand-alone	Strategic benefits are derived by leveraging significant and longstanding experience of the EI group of service providers. Utility specific knowledge of systems integration requirements is invaluable for EGD to meet its program objectives.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

Enterprise IT Strategy Planning & Management – 2012 RCAM Analysis	
MNP Conclusion	• Prongs 1, 2, and 3 pass. • No adjustment to the 2012 EGD allocation is required.

12 – EXPENSE SYSTEM MANAGEMENT & TECH SUPPORT (ORACLE IEXPENSE)

Expense System Management & Tech Support (Oracle iExpense) – 2012 RCAM Analysis

EGD Service Recipient

Henry Wong, Director Information Technology, Enbridge Gas Distribution

Service Definition

The Expense System Management and Technical Support (Oracle iExpense) service is responsible for the technical support and administration of the automated purchasing and employee expense reporting tool (Oracle iExpense).

Oracle iExpense is an online system, used in reporting employee expenses, where all expenses incurred via Amex or BMO corporate cards are uploaded automatically. Oracle iExpense contains an approval hierarchy where all expense report approvals are done electronically.

EGD requires this service to ensure efficient and accurate processing of automated purchasing and employee expenses,

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$486,508	0.2%	**$736**	$403,485	System Users	23%	**$94,754**	**$95,490**

Cost by Department

EI Department	*Charges*
CIO	$35,587
EFS Strategy and Services	$30,650
Corporate Admin.	$29,253
Total	**$95,490**

Prong 1 Test
Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review
MNP is of the opinion that the 'Expense System Management and Technical Support' function is a necessary component to EGD's IT infrastructure and the associated level of service is required for a stand-alone utility. The service ensures the availability of the infrastructure and Expense System (Oracle iExpense) to support personnel in their claim submissions and expense recovery activities for EGD; critical to modern business function.

EI has been identified as a supplemental provider for this service.

Prong 2 Test
Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review
Direct Cost
- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs
- 'IT Asset Usage' drives the related common costs for this service, which is representative of EGD's level of system usage relative to other affiliates.
- Allocations for common costs are allocated using the 'system users'; essentially the percentage of Oracle iExpense system users out of the total user base which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test
Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis
<u>EGD Internal Provision of Service</u>
The following table provides a range of cost estimates for the internal provision of services within EGD:

Expense System Management & Tech Support (Oracle iExpense) – 2012 RCAM Analysis

Position	MNP Low Range Estimate # of FTE	MNP Low Range Estimate Total Cost	MNP High Range Estimate # of FTE	MNP High Range Estimate Total Cost
Application Development Manager	1	$ 153,098	1	$ 193,210
Total	**1**	**$ 153,098**	**1**	**$ 193,210**

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 95,490	$ 153,098	$ 193,210	Below Range

The cost of procuring this service from EI is below the range of the MNP estimated stand-alone cost.

External Provision

EGD determined that a reasonably competitive market exists for this service. However, EGD did not provide external cost estimates because EGD would incur significant expense to investigate the costs for this option and with this investigation an estimate would be unreliable.

Based upon prevailing market rates for technical support services, MNP conservatively estimates that external provision of costs would amount to approximately $154,000, which exceeds the EI RCAM allocation. The following table provides a breakdown of the cost estimate:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Senior Consultant Technical Support	$ 165 / hour	1	933	$ 154,000
	Total	**1**	**933**	**$ 154,000**

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost, internally or externally. An alternate source for these stand alone services would result in incremental expense to rate payers.
Synergistic	Economies of scale is achieved through the model's centralized approach where all affiliates benefiting from the Oracle iExpense system share the high fixed costs of implementation, development, planning, annual maintenance, and ongoing support.
Revenue Enhancement	Not Applicable.
Stand-alone	Not Applicable.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of

Expense System Management & Tech Support (Oracle iExpense) – 2012 RCAM Analysis	
	service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.
MNP Conclusion	• Prongs 1, 2, and 3 pass. • No adjustment to the 2012 EGD allocation is required.

13 – EXTERNAL AUDIT COORDINATION

External Audit Coordination – 2012 RCAM Analysis

EGD Service Recipient

Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Service Definition

The External Audit Coordination service is responsible for coordinating and managing the external auditors and their related supporting activities.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$691,874	12%	**$84,158**	$74,896	Audit Fees	26%	**$19,241**	**$103,399**

Cost by Department

EI Department	*Charges*
CFO	$84,158
Corporate Controller	$19,241
Total	**$103,399**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'External Audit Coordination' function is a necessary component to EGD's financial operations and required to uphold compliance with standard business protocol. The level of service is required for a stand-alone utility and is responsible for coordinating and managing external auditors and their activities, including sourcing required audit services, enhancing audit efficiencies, and supporting onsite needs as requested.

EI has been identified as the sole provider for this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Audit size (hence company complexity)' drives the related common costs for this service, which is representative of the effort and financial reporting requirement to support EGD.
- Allocations for common costs are allocated using the 'Audit Fees'; essentially the percentage of cost of the EGD Audit out of the total Audit Fee budget for EI which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test

Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Audit Manager	1	$ 119,694	1	$ 155,653
Total	**1**	**$ 119,694**	**1**	**$ 155,653**

Using salary survey data and the staff complement noted above, MNP estimates a range of costs related to this service within a stand-alone utility as follows:

External Audit Coordination – 2012 RCAM Analysis

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 103,399	$ 119,694	$ 155,653	Below Range

The cost of procuring this service from EI is below the range of the MNP estimated stand-alone cost.

External Provision

EGD claims that external provision of this service is not applicable and did not estimate the cost of external provision. Although it is possible to externalise this function, MNP agrees with the EGD assertion of inapplicability due to inefficiencies associated with retaining an external party to coordinate this activity between EGD and their chosen auditors. Adding an additional external layer to this activity would result in added costs to ratepayers due to unfamiliarity with the internal business processes, internal systems, reporting, source data, and subject matter knowledge.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost, externally or internally without suffering increased costs of alternative sourcing and reduced efficiencies.
Synergistic	Economies of scale is achieved through the model's centralized approach, added negotiating power associated with being part of a multi-affiliate organization versus a sole entity, and inherent knowledge of utility audit requirements.
Revenue Enhancement	Not Applicable.
Stand-alone	Not Applicable.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

MNP Conclusion

- Prongs 1, 2, and 3 pass.
- No adjustment to the 2012 EGD allocation is required.

14 – FINANCIAL & PROJECT ACCOUNTING SYSTEM TECH SUPPORT (ORACLE)

Financial & Project Accounting System Tech Support (Oracle) – 2012 RCAM Analysis

EGD Service Recipient

Henry Wong, Director Information Technology, Enbridge Gas Distribution

Service Definition

The Financial and Project Accounting System Technical Support (Oracle) service provides the system support and maintenance, system customization and enhancements for the Enbridge Financial and Project Accounting Management system (Oracle).

The Enbridge Financial and Project Accounting Management system (Oracle) includes General Ledger, Accounts Payable, Purchasing, (including i-Procurement), Order Management, Accounts Receivable, Cash Management, Fixed Asset, Projects, Plant Accounting, and Inventory modules.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$1,626,360	2%	**$25,397**	$1,391,437	System Users	23%	**$326,764**	**$352,161**

Cost by Department

EI Department	*Charges*
CIO	$192,580
EFS Strategy and Services	$159,581
Total	**$352,161**

Prong 1 Test
Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review
MNP is of the opinion that the 'Financial & Project Accounting System Technical Support' function and level of service is a necessary component to EGD's financial operations and required to ensure the availability of financial and other information within the critical Oracle system infrastructure.

EI has been identified as a supplemental provider for this service.

Prong 2 Test
Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review
Direct Cost
- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs
- 'IT Asset Usage' drives the related common costs for this service, which is representative of EGD's level of system usage relative to other affiliates.
- Allocations for common costs are allocated using the 'system users'; essentially the percentage of Oracle system users out of the total user base which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test
Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis
EGD Internal Provision of Service
The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
IT Manager	1	$ 156,939	1	$ 219,036
Systems Administrator	2	$ 205,837	3	$ 376,751
Total	**3**	**$ 362,776**	**4**	**$ 595,786**

Financial & Project Accounting System Tech Support (Oracle) – 2012 RCAM Analysis

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 352,161	$ 362,776	$ 595,786	Below Range

The cost of procuring this service from EI is below the range of the MNP estimated stand-alone cost.

External Provision

EGD determined that a reasonably competitive market exists for this service. However, EGD did not provide external cost estimates because EGD would incur significant expense to investigate the costs for this option and with this investigation an estimate would be unreliable.

Based upon prevailing market rates for technical support services, MNP conservatively estimates that external provision of costs would amount to approximately $598,500, which exceeds the EI RCAM allocation. The following table provides a breakdown of the cost estimate:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Partner/Senior Technical Support	$ 250 / hour	1	700	$ 175,000
Senior Consultant Technical Support	$ 165 / hour	1	700	$ 115,500
Consultant Technical Support	$ 110 / hour	1	2,800	$ 308,000
	Total	**3**	**4,200**	**$ 598,500**

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost, internally or externally. An alternate source for these stand alone services would result in incremental expense to rate payers due to the high costs associated to system implementation and upgrade.
Synergistic	Economies of scale is achieved through the model's centralized approach where all affiliates benefiting from the Oracle system share the high fixed costs of implementation, development, planning, annual maintenance, and ongoing support.
Revenue Enhancement	Not Applicable.
Stand-alone	Having a centralized service delivery model enables EGD to benefit from a broad knowledge of Oracle and relevant functionality to enable strategic management decisions.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for

Financial & Project Accounting System Tech Support (Oracle) – 2012 RCAM Analysis	
	Ontario ratepayers.
MNP Conclusion	• Prongs 1, 2, and 3 pass. • No adjustment to the 2012 EGD allocation is required.

15 – GOVERNMENT RELATIONS

Government Relations – 2012 RCAM Analysis

EGD Service Recipient

Debbie Boukydis, Director, Public & Government Affairs, Enbridge Gas Distribution
Arunas Pleckaitis, Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution

Service Definition

The Government Relations service ensures EGD's interests are heard by government (federal, Ontario and municipal) officials, departments and committees.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$2,060,059	2%	**$44,917**	$0	ACER	0%	**$0**	**$44,917**

Cost by Department

EI Department	*Charges*
Public & Government Affairs	$44,917
Total	**$44,917**

Prong 1 Test
Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Government Relations' function is a necessary component of service for a stand-alone utility, particularly in a heavily regulated industry like natural gas distribution and service where consumer, environmental, and public policy concerns are all relevant to be engaged in with all levels of government.

EI has been identified as the sole provider for the federal government element of this service, while it provides supplemental support for other services.

Prong 2 Test
Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Regulations' drives the related common costs for this service, which is representative of the effort required to communicate the interests of EI and its affiliates to all levels of government regarding regulation.
- Allocations for common costs use Adjusted Capital Employed Ratio (ACER) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test
Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

GD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Governmental Affairs Director	0.5	$ 80,390	0.5	$ 106,472
Total	**0.5**	**$ 80,390**	**0.5**	**$ 106,472**

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 44,917	$ 80,390	$ 106,472	Below Range

Government Relations – 2012 RCAM Analysis

The cost of procuring this service from EI is below the range of the MNP estimated stand-alone cost.

External Provision
EGD estimates that it would costs approximately $8,223 per month ($98,676 per annum) to receive a comparable service.

MNP believes that this is a reasonable estimate of effort, which is higher than the RCAM and the low range of the internal provision estimate.

OEB Benefits
The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost, internally or externally.
Synergistic	Economies of scale are achieved through elimination of duplicated costs associated with having a stand-alone company. Having a centralized business model and a single point of contact and advocacy for all EI affiliates is conducive to an efficient process.
Revenue Enhancement	Not Applicable.
Stand-alone	There are strong strategic benefits for EGD to being part of a larger entity. The centralized model allows for all affiliates to benefit from all government relations activities conducted by EI service providers.

MNP Conclusion
Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

MNP Conclusion

- Prongs 1, 2, and 3 pass.
- No adjustment to the 2012 EGD allocation is required.

16 – HRIS Program Management & Development Technical Support

HRIS Program Management & Development Technical Support – 2012 RCAM Analysis

EGD Service Recipient

Marc Weil, Director Human Resources, Enbridge Gas Distribution

Service Definition

The HRIS Program Management and Development service provides consulting services for support of the development and management of on-going HRIS and other HR technology system projects, including design, development, implementation, and coordination of project teams.

Specific HRIS applications include the following PeopleSoft Modules:
Human Resources, Payroll for North America, Benefits Administration, Extended Enterprise, eCompensation, ePay, eBenefits, eProfile, eRecruit, eDevelopment, Time and Labour, eCompensation Manager Desktop, eProfile Manager Desktop, Directory Interface, ePerformance, HRMS Warehouse, PeopleSoft Portal.

Other HE technology applications include eLMS and workforce planning technologies. Supporting infrastructure includes Sun, UNIX, Oracle, Web servers, development environments.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$9,679,848	0%	**$0**	$9,679,848	AHC	31%	**$3,009,273**	**$3,009,273**

Cost by Department

EI Department	*Charges*
CIO	$465,956
Corporate HR	$150,591
HRIS	$1,622,414
HR Enterprise Business Solutions	$770,312
Total	**$3,009,273**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'HRIS Program Management & Development Technical Support' function is a necessary component of EGD's operations and the level of service is required for a modern stand-alone utility. The function allows EGD to optimize and leverage workflow, quality and accuracy, and facilitates the collection of key data and metrics which are essential to gas distribution operations.

The factors MNP considered for employee development are also relevant for the HRIS functions. EGD is facing challenging conditions in terms of employee development and succession in light of its aging workforce and a strong commitment to employee/customer safety. According to EGD, 18% of its workforce is eligible to retire today and 30% can retire within the next 5 years. In addition, 26% of EGD's leaders can retire today.

The HRIS system provides support for payroll, employee data, compensation, reporting, recruitment, talent management, workforce requirements, etc. A modern and strong HRIS system will enable EGD to address the challenges of an aging workforce.

EGD is continuing to evolve its HRCore system, and additional post implementation support is required to maintain functionality of the new system.

EI has been identified as the sole provider for this service.

Prong 2 Test

Cost Allocation Review

HRIS Program Management & Development Technical Support – 2012 RCAM Analysis

Determine if EI's charges to EGD are appropriately allocated.

PASS

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'HRIS IT asset usage' drives the related common costs for this service, which is representative of support requirement for a common IT application which benefits all affiliates.
- Allocations for common costs use Affiliate Headcount' (AHC) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test

Do the benefits to ratepayers exceed the costs?

FAIL

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Senior-level HR Executive	1	$ 247,330	1	$ 333,171
Information Technology Manager	2	$ 313,877	2	$ 438,071
Financial Analysis Manager	1	$ 147,200	1	$ 189,552
Mid-level Business Systems Analyst	1	$ 108,368	2	$ 270,018
Mid-level HRIS Clerk	1	$ 74,130	1	$ 85,569
Consulting Fees Related to HRCore	n/a	$ 1,581,217	n/a	$ 1,581,217
Total	**6**	**$ 2,472,121**	**7**	**$ 2,897,598**

Consulting fees related to HRCore of $1,581, 217 are estimated by MNP using the base case estimates provided by EGD of $1,976,521 (see external estimate below). It was assumed by EGD that HRCore consulting fees incurred by EI would be fully incurred by EGD should it implement HRCore as a standalone entity. Based upon MNP's understanding of the system development lifecycle and the nature of the HRCore implementation, it agrees with this principle. While the implementation may apply to a smaller user group, functional requirements of the system would not vary significantly and result in similar implementation effort. To account for any variance associated with the collection and implementation of more limited business requirements, MNP applied a 20% reduction to EGD's estimate.

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 3,009,273	$ 2,472,121	$ 2,897,598	Above Range

The cost of procuring this service from EI is above the range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 12,000 hours for an external consulting team to provide a comparable on-demand service, which would cost approximately $1,304,000 at the mean.

HRIS Program Management & Development Technical Support – 2012 RCAM Analysis

EGD also estimates that it would require the engagement of additional consulting support/assistance of third parties such as PeopleSoft, vendors, and/or external contractors, which would be fully incurred by EGD as a stand-alone entity. The augmented support is estimated to cost approximately $1,976,521.

The combined cost of all involved parties is expected to be between $2,624,417 and $3,936,625. MNP believes that this is a somewhat conservative estimate of cost based on lower than expected rates at the Consultant and Technical Consultant levels. The following table provides a breakdown of EGD cost estimates:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Senior Consultant	$ 194 / hour	1	2,000	$ 388,000
Consultant	$ 79 / hour	2	2,000	$ 316,000
Technical Consultant	$ 100 / hour	3	2,000	$ 600,000
Third Party Consulting	n/a	n/a	n/a	$1,976,521
	Total	**6**	**12,000**	**$ 3,280,521**
			Low Range (80% of Total)	**$ 2,624,417**
			High Range (120% of Total)	**$ 3,936,625**

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	The service is currently offered at a cost that is higher than the upper range estimated by MNP.
Synergistic	Economies of scale are achieved through the model's centralized approach where all affiliates benefiting from the HRIS system share the high fixed costs of planning, development, implementation, sustainment and support.
Revenue Enhancement	Not Applicable.
Stand-alone	The centralized model allows for the development of a robust HRIS system and, without sharing resources, EGD would have been required to incur the full burden of a large-scale implementation, whereby the full burden of a 'smaller' system could cost more than its portion of the 'larger' system. Strategically, EGD is also enjoying the highly specialized knowledge developed by the group of service providers within EI, therefore increasing the quality of the implementation.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that although the services are prudently incurred and appropriately allocated, EGD could lower the costs of this service by assuming the provision of service internally at EGD. Based on this finding, the replacement component of the test is not met.

Synergistic and stand-alone benefits are considered by MNP to be genuine but speculative from a benefits quantification perspective. MNP has also not considered the costs of switching service providers because these costs are provisional and variable in nature based on specific requirements of alternative provision. Switching costs or quantified synergistic or stand-alone benefits could offset some of the cost savings of alternative provision.

HRIS Program Management & Development Technical Support – 2012 RCAM Analysis	
MNP Conclusion	• Prongs 1 and 2 pass. • Prong 3 fails. • MNP recommends a downward Prong Three adjustment of $111,675 to the 2012 allocation and a corresponding escalated adjustment of $114,131 for 2013.

17 – HUMAN RESOURCE ADVICE

Human Resource Advice – 2012 RCAM Analysis

EGD Service Recipient

Marc Weil, Director Human Resources, Enbridge Gas Distribution

Service Definition

The Human Resource Advice service provides research, expertise and support to internal initiatives. This includes support related to policy and systems development, personnel management, and adherence to regulatory and legislative requirements.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$2,839,661	2%	**$60,686**	$453,852	AHC	31%	**$141,094**	**$201,779**

Cost by Department

EI Department	*Charges*
CEO	$30,011
Corporate HR	$171,768
Total	**$201,779**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

EGD is an organization of approximately 1,800 employees, including a significant unionized component. Given the organization's size and inherent complexities, MNP is of the opinion that the 'Human Resources Advice' from leadership and corporate HR is a necessary component of EGD's operations and alignment of strategy, growth, and HR activities across the organization. The level of service is required for a stand-alone utility.

EI has been identified as the sole provider for this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Employees' drives the related common costs for this service, which is representative of effort required to support HR initiatives across EI and its affiliates.
- Allocations for common costs use Affiliate Headcount' (AHC) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test

Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Senior-level HR Executive	1	$ 247,330	1	$ 333,171
Total	**1**	**$ 247,330**	**1**	**$ 333,171**

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment

Human Resource Advice – 2012 RCAM Analysis

$	**201,779**	$ 247,330	$ 333,171	Below Range

The cost of procuring this service from EI is below the range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 2,000 hours for an external consulting team to provide a comparable on-demand service, and result in a cost range from $316,800 to $475,200. EGD's calculation is based on the net effect of the need to replace a management individual with a senior executive, and the external proxies for each. The following table provides a breakdown of the above identified cost estimates:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Managing Partner	$ 385 / hour	1	2,000	$ 770,000
Senior Consultant	$ 187 / hour	-1	2,000	-$ 374,000
	Total	**0**	**-**	**$ 396,000**
			Low Range (80% of Total)	**$ 316,800**
			High Range (120% of Total)	**$ 475,200**

MNP believes that the net effect of the external estimate is a reasonable estimate of effort and cost, which is higher than both the cost incurred via RCAM allocation and internal provisioning estimates.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost, internally or externally. An alternate source for these stand alone services would result in additional costs to ratepayers. The ability to source 'on-demand' executive HR advice results in an overall reduction of costs as full-time employment costs are not incurred.
Synergistic	Economies of scale are achieved through the model's centralized approach where all affiliates realize a level of savings on affiliate-wide initiatives.
Revenue Enhancement	Not Applicable.
Stand-alone	Support through the centralized service model ensures optimal strategic advice, given the understanding of the overall direction, vision, policies, business context, and cultural implications.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

MNP Conclusion

- Prongs 1, 2, and 3 pass.
- No adjustment to the 2012 EGD allocation is required.

18 – INDUSTRY RELATIONS & CORPORATE SOCIAL RESPONSIBILITY

Industry Relations & Corporate Social Responsibility (CSR) – 2012 RCAM Analysis

EGD Service Recipient

Debbie Boukydis, Director Public and Government Affairs, Enbridge Gas Distribution
Arunas Pleckaitis, Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution

Service Definition

The Industry Relations & CSR service provides the required EGD representation to major energy stakeholders e.g. suppliers, industry associations, and other energy companies in the energy industry.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$7,142,956	3%	**$180,972**	$1,291,388	ACER	16%	**$203,394**	**$384,365**

Cost by Department

EI Department	*Charges*
People and Partners	$22,987
Public & Government Affairs	$360,522
Industry Associations	$856
People and Partners	$22,987
Total	**$384,365**

Prong 1 Test
Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Industry Relations & Corporate Social Responsibility' functional departments are necessary components of EGD's operations. The level of service proposed is required for a stand-alone utility to support its interests to key external stakeholder groups and to provide information and CSR reports to consumers and investors that are critical to the competitiveness of firms within the current marketplace.

EI has been identified as a supplemental provider for this service.

Prong 2 Test
Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Customer base and public interest' drives the related common costs for this service, which is representative of the effort required to achieve positive, influential relationships with industry stakeholders for all entities which EI operates.
- Allocations for common costs use Adjusted Capital Employed Ratio (ACER) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test
Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
CSR Director	1	$ 201,656	1	$ 275,830
CSR Manager	1	$ 135,370	1	$ 188,623
CSR Report Development Cost		$ 65,791		$ 65,791
Total	**2**	**$ 402,816**	**2**	**$ 530,244**

Industry Relations & Corporate Social Responsibility (CSR) – 2012 RCAM Analysis

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 384,365	$ 402,816	$ 530,244	Below Range

The cost of procuring this service from EI is below the range of the MNP estimated stand-alone cost.

External Provision

Given the sensitivities of the information handled (such as, knowledge of EGD's business and operating environment, customer base, upstream and downstream activities, and regulatory and political environment) to deliver this service, it is generally inefficient to externalize/outsource Industry Relations & Corporate Social responsibility. Certain aspects of the service may be augmented by external resources/expertise but core functions should remain internal.

MNP's agrees with EGD's assertion that external provision of this service is not applicable and therefore did not estimate the cost of external provision.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost.
Synergistic	EGD enjoys lower costs due to the CSR service being shared among affiliates.
Revenue Enhancement	Not Applicable.
Stand-alone	Benefits are derived from EI's exposure to the upstream and midstream business environments, as well as through leveraging affiliate-wide expertise and reputation in the national and international energy industries.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

MNP Conclusion

- Prongs 1, 2, and 3 pass.
- No adjustment to the 2012 EGD allocation is required.

19 – INSURANCE CLAIMS SUPPORT, STRATEGY AND MANAGEMENT

Insurance Claims Support, Strategy and Management – 2012 RCAM Analysis

EGD Service Recipient

Jamie Milner, Vice President Pipeline Integrity & Safety, Enbridge Gas Distribution

Service Definition

The Insurance Claims Support, Strategy and Management service is responsible for the general administration of insurance policies for EGD. Insurance policies implemented and managed by this service include liability, property, political risk, automobile, directors and officers liability, fiduciary and crime insurance.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$2,139,104	4%	**$77,773**	$214,550	Insurance Premiums	14%	**$30,467**	**$108,240**

Cost by Department

EI Department	*Charges*
CFO	$29,314
Risk Insurance	$50,724
Enterprise Risk	$28,202
Total	**$108,240**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Insurance Strategy and Management' function is a necessary component of EGD's operations and required for a stand-alone utility to support its interests in policy coverage, insurance requirements strategy, and management of claims.

EI has been identified as a supplemental provider for this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Entity Risk' drives the related common costs for this service, which is representative of company complexity and associated risk for EI and its affiliates.
- Allocations for common costs are allocated using the 'Insurance Premiums'; the percentage of cost of the EGD Insurance Premiums out of the total Insurance Premium budget for EI which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test

Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Senior-level Risk Management Executive	1	$ 222,266	1	$ 363,932
Total	**1**	**$ 222,266**	**1**	**$ 363,932**

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

Insurance Claims Support, Strategy and Management – 2012 RCAM Analysis

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 108,240	$ 222,266	$ 363,932	Below Range

The cost of procuring this service from EI is below the range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 1,825 hours for an external consulting team to provide a comparable on-demand service, which would cost approximately between $240,860 and $361,290. The following table provides a breakdown of the above identified cost estimates:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Managing Partner	$ 330 / hour	1	70	$ 23,100
Senior Consultant	$ 192 / hour	1	700	$ 134,400
Consultant	$ 137 / hour	1	1,025	$ 140,425
Support Staff	$ 105 / hour	1	30	$ 3,150
	Total	**4**	**1,825**	**$ 301,075**
			Low Range (80% of Total)	**$ 240,860**
			High Range (120% of Total)	**$ 361,290**

MNP believes that this is a reasonable estimate of effort and cost, which is higher than the cost incurred via RCAM allocation, but is comparable to internal provisioning estimates.

Provisioning of this service through external parties introduced elements of risk due to the potential breach of confidential information, minimal understanding of the company's historic insurance program and policy structure which could result in misalignment with overall company strategy, and the lack of access and understanding of internal risk systems.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost, internally or externally. An alternate source for these stand alone services would result in additional costs to rate payers.
Synergistic	Economies of scale are achieved through EI's negotiating power, which effectively reduces costs while ensuring appropriate coverage and claims risk. In addition, the cost for this service is shared among EI affiliates.
Revenue Enhancement	Not Applicable.
Stand-alone	As an EI affiliate, EGD is able to benefit from expedited management of complex claims due to EI's direct relationship with insurers and underwriters. EI also has a comprehensive understanding of EGD's business risk profile, leading to strategic management of EGD insurance requirements.

Insurance Claims Support, Strategy and Management – 2012 RCAM Analysis	
	MNP Conclusion Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.
MNP Conclusion	• Prongs 1, 2, and 3 pass. • No adjustment to the 2012 EGD allocation is required.

20 – INVESTOR SERVICES

Investor Services – 2012 RCAM Analysis

EGD Service Recipient

Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution.

Service Definition

The Investor Services service ensures that investors are fully informed of EGD's business objectives, strategy, financial performance, and condition for the purpose of maintaining confidence in their current investments.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$12,358,070	6%	**$745,415**	$997,998	FCER	14%	**$138,422**	**$883,837**

Cost by Department

EI Department	*Charges*
CEO	$475,248
CFO	$69,404
People and Partners	$40,433
Corporate Secretarial	$118,346
Investor Relations	$55,854
Treasury	$60,598
Public & Government Affairs	$63,954
CEO	$475,248
Total	**$883,837**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Investor Services' function is a necessary service for EGD's operations. The level of service is required for a stand-alone utility to disseminate important financial and market information to the firm's current and potential investors and must be carried out to meet financial reporting requirements.

EI has been identified as the sole provider for this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'M&A and financing activity' drives the related common costs for this service, which is representative of the effort to maintain adequate investment capital access for all EI affiliates.
- Allocations for common costs use Financing Capital Employed Ratio (FCER) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test

Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Investor Services – 2012 RCAM Analysis

Position	MNP Low Range Estimate # of FTE	MNP Low Range Estimate Total Cost	MNP High Range Estimate # of FTE	MNP High Range Estimate Total Cost
Senior-level Investor Relations Executive	1	$ 259,630	1	$ 353,879
Communications Manager	1	$ 148,950	1	$ 194,701
Public Relations Manager	1	$ 135,370	1	$ 188,623
Administrative Assistant	1	$ 66,731	1	$ 84,914
Stock Registrar Services		$ 109,652		$ 109,652
Total	**4**	**$ 720,333**	**4**	**$ 931,769**

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 883,837	$ 720,333	$ 931,769	Within Range

The cost of procuring this service from EI is within the range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 8,200 hours for an external consulting team to provide a comparable on-demand service, which would cost approximately between $834,922 and $1,252,382. The following table provides a breakdown of the above identified cost estimates:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Managing Partner	$ 330 / hour	1	200	$ 66,000
Senior Consultant	$ 192 / hour	1	2,000	$ 384,000
Consultant	$ 137 / hour	2	2,000	$ 274,000
Support Staff	$ 105 / hour	1	2,000	$ 210,000
Stock Registrar Services				$ 109,652
Total		**5**	**8,200**	**$ 1,043,652**
		Low Range (80% of Total)		**$ 834,922**
		High Range (120% of Total)		**$ 1,252,382**

MNP believes that this is a reasonable estimate of effort and cost, although the cost reflects only one 2,000 hour external party at the Consultant level. An incremental staff member as indicated in the individuals required column would increase the external estimate by $274,000. The incremental cost associated with the additional Consultant yields a result that is higher than the EI allocation and MNP's internal range, while the lower estimate with only one Consultant is comparable to the RCAM allocated cost and internal provisioning estimates. Either scenario results in the same conclusion below.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	It may be possible to provide these services internally and externally at a comparable cost. However, MNP is of the opinion that any potential direct financial benefit from altering the source of provision

Investor Services – 2012 RCAM Analysis	
	<table><tr><td></td><td>may increase the burden on ratepayers due to the cost of switching service providers or initiating an internal provision program.</td></tr><tr><td>Synergistic</td><td>Economies of scale are achieved by sharing these expenses among EI affiliates while benefiting from the expertise of the EI group providing the service.</td></tr><tr><td>Revenue Enhancement</td><td>Not Applicable.</td></tr><tr><td>Stand-alone</td><td>EGD enjoys a strategic benefit by having the EI services group employ a deep understanding of investor expectations within the utilities world and a strong knowledge of EGD and its history. This benefit would not be incurred if sourced externally, and although similar services may be acquired for a comparable cost, MNP feels that the strategic benefits of sourcing from EI outweigh any potential marginal cost savings from external or internal EGD parties.</td></tr></table> MNP Conclusion Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.
MNP Conclusion	• Prongs 1, 2, and 3 pass. • No adjustment to the 2012 EGD allocation is required.

21 – LEGAL ADVICE

Legal Advice – 2012 RCAM Analysis

EGD Service Recipient

Mark Boyce, Vice President, Law & Information Technology, Enbridge Gas Distribution

Service Definition

The Legal Advice service provides access to legal precedents, research material and legal experts providing advice related to matters such as contracts, litigation, regulatory proceedings, and various EGD initiatives.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$8,443,016	5%	**$448,128**	$420,749	ACER	16%	**$66,268**	**$514,396**

Cost by Department

EI Department	*Charges*
Corporate Law	$353,497
Corporate Secretarial	$38,973
Executive VP Corporate Law	$121,926
Total	**$514,396**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'legal advice' function is a necessary service for EGD's operations. The level of service is required for a stand-alone utility to access counsel on litigation, regulatory, contracts, and other legal matters of the firm. These services are essential and provided either internally or externally.

EI has been identified as a supplemental provider for this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Regulation contracts and M&A' drives the related common costs for this service, which is representative of company complexity and the necessary effort to maintain compliance with the regulatory environment.
- Allocations for common costs use Adjusted Capital Employed Ratio (ACER) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test

Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Senior-level Legal Executive	1	$ 247,096	1	$ 330,799
Senior-level Corporate Lawyer	1	$ 183,510	1	$ 218,689
Total	**2**	**$ 430,606**	**2**	**$ 549,488**

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

Legal Advice – 2012 RCAM Analysis

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 514,396	$ 430,606	$ 549,488	Within Range

The cost of procuring this service from EI is within the range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 1,040 hours for an external legal team to provide a comparable on-demand service, which would cost approximately between $423,522 and $635,284. The following table provides a breakdown of the above identified cost estimates:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Senior Consultant	$ 603 / hour	0.33	1350	$ 268,637
Consultant	$ 439 / hour	0.33	1800	$ 260,766
	Total	**0.66**	**1,040**	**$ 529,403**
			Low Range (80% of Total)	**$ 423,522**
			High Range (120% of Total)	**$ 635,284**

MNP believes that this is a conservative estimate of effort and cost due to estimates of internal resourcing would dictate no less than 2,000 hours. This conservative estimate is comparable to the RCAM allocation and internal provisioning estimates and a higher estimate would put costs well above EI costs.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	The EI allocation is comparable to costs incurred via RCAM allocation and internal provisioning estimates. Switching costs would increase costs to ratepayers.
Synergistic	Economies of scale are achieved due to cost sharing among affiliates. If EGD were to in-source these functions, EGD would incur the full costs associated with additional FTEs in the legal department. In addition, being part of the EI and its affiliates allows EGD to take advantage of EI purchasing power in negotiating favourable rates it would not be entitled to as a stand-alone utility.
Revenue Enhancement	Not Applicable.
Stand-alone	Support through the centralized service model ensures optimal strategic advice, given the breadth of EI's legal team and their understanding of legal issues relevant to EGD.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

MNP Conclusion

- Prongs 1, 2, and 3 pass.
- No adjustment to the 2012 EGD allocation is required.

22 – PLANNING, MANAGEMENT & EXECUTION OF INTERNAL AUDITS

Planning, Management, & Execution of Internal Audits – 2012 RCAM Analysis

EGD Service Recipient

Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Service Definition

The Planning, Management and Execution of Internal Audits service is responsible for Audit program development for the execution of internal audits within EGD.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$2,490,771	5%	**$132,879**	$228,297	Same as Audit fees	26%	**$58,648**	**$191,528**

Cost by Department

EI Department	*Charges*
CFO	$32,426
Audit Services (Calgary)	$159,102
Total	**191,528**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Planning, Management, & Execution of Internal Audits' function is a necessary service for EGD's operations, ensuring that strategy aligns with the necessary level of risk mitigation and that the relationship between external audit and internal audit is managed appropriately.

EI has been identified as a supplemental provider for this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Company Complexity' drives the related common costs for this service, which is representative of the financial reporting requirement and risk mitigation required to support EI affiliates.
- Allocations for common costs are allocated using the 'Audit Fees'; essentially the percentage of cost of the EGD Audit out of the total Audit Fee budget for EI which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test

Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Senior-level Audit Executive	1	$ 210,351	1	$ 321,812
Senior-level Internal Auditor	1	$ 119,694	1	$ 155,653
Mid-level Information Systems Auditor	1	$ 92,262	1	$ 112,896
Total	**3**	**$ 422,307**	**3**	**$ 590,362**

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

Planning, Management, & Execution of Internal Audits – 2012 RCAM Analysis

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 191,528	$ 422,307	$ 590,362	Below Range

The cost of procuring this service from EI is below the range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 2,350 hours for an external consulting team to provide a comparable on-demand service, which would cost approximately between $787,261 and $1,180,891. The following table provides a breakdown of the above identified cost estimates:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Managing Partner	$ 623 / hour	1	250	$ 155,750
Senior Consultant	$ 467 / hour	1	1000	$ 467,000
Consultant	$ 296 / hour	1	1000	$ 296,000
Support Staff	$ 105 / hour	1	100	$ 10,500
Travel & IT related Costs				$ 54,826
	Total	**4**	**2,350**	**$ 984,076**
			Low Range (80% of Total)	**$ 787,261**
			High Range (120% of Total)	**$ 1,180,891**

MNP believes that this is a reasonable estimate of effort and cost, which is higher than both the cost RCAM allocated cost and internal provisioning estimates.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost, internally or externally. An alternate source for these stand alone services would result in additional costs to ratepayers.
Synergistic	Economies of scale is achieved through the model's centralized approach where costs associated with coordination of enterprise-wise Audits and Risk Mitigation Strategies are shared amongst affiliates.
Revenue Enhancement	Not Applicable.
Stand-alone	Benefits are achieved through the ability to access on-demand services. Additionally, familiarity with organizational complexity within EI and an understanding EGD's business and risk profile allows for better support and guidance to address business and financial reporting risks.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

Planning, Management, & Execution of Internal Audits – 2012 RCAM Analysis	
MNP Conclusion	• Prongs 1, 2, and 3 pass. • No adjustment to the 2012 EGD allocation is required.

23 – PORTAL SUITE OPERATIONS & TECHNICAL SUPPORT

Portal Suite Operations & Technical Support – 2012 RCAM Analysis

EGD Service Recipient

Henry Wong, Director Information Technology, Enbridge Gas Distribution

Service Definition

The Portal Suite provides a reliable platform for presenting "web based" content to employees and business partners. The value of this service is:

- A central environment for information provided to employees
- A central "launch" point for applications
- A central location for content storage and retrieval
- Development standards that ensure reliability and consistency
- Consistent and manageable access and security for employee content
- The Portal Suite consists of several related applications. The primary applications are the eLink (Sharepoint), eSource (Oracle Portal), Microsoft SharePoint and Open Text Livelink (document and records management service). As well, the Portal Suite consists of a series of supporting connecting services and customized applications. EGD requires this service to enable easy employee access to all relevant data.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$1,064,336	0%	**$0**	$1,064,336	System users	26%	**$330,881**	**$330,881**

Cost by Department

EI Department	*Charges*
CIO	$167,529
Corporate IT Operations	$163,352
Total	**$330,881**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Portal Suite Operations and IT Support' functions are a necessary service for EGD's internal information systems operation, enabling departments, employees, and contractors to communicate effectively and securely to complete day to day activities of the firm.

Incremental costs for 2012 are associated with upgrades to Sharepoint software.

EI has been identified as a supplemental provider for this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Portal IT Asset Usage' drives the related common costs for this service, which is representative of the level of system usage relative to other affiliates.
- Allocations for common costs are allocated using the 'system users'; essentially the percentage of Portal Suite platform users out of the total user base which, in MNP's opinion, is an appropriate and industry accepted allocator.

Portal Suite Operations & Technical Support – 2012 RCAM Analysis

Prong 3 Test
Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Application Development Manager	1	$ 153,098	1	$ 193,210
Systems Administrator	1	$ 102,918	1	$ 125,584
Administrative Assistant	1	$ 66,731	1	$ 84,914
Total	**3**	**$ 322,748**	**3**	**$ 403,707**

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 330,881	$ 322,748	$ 403,707	Within Range

The cost of procuring this service from EI is within the range of the MNP estimated stand-alone cost.

External Provision

EGD determined that a reasonably competitive market exists for this service. However, EGD did not provide external cost estimates because EGD would incur significant expense to investigate the costs for this option, and with this investigation an estimate would be unreliable.

Based upon prevailing market rates for technical support services, MNP conservatively estimates that external provision of costs would amount to approximately $423,500, which exceeds the EI RCAM allocation. The following table provides a breakdown of the cost estimate:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Senior Consultant Technical Support	$ 165 / hour	1	700	$ 115,500
Consultant Technical Support	$ 110 / hour	1	2,800	$ 308,000
	Total	**2**	**3,500**	**$ 423,500**

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced externally at an equal or lower cost.
Synergistic	Economies of scale are achieved through the model's centralized approach where all affiliates benefiting from the Portal Suite platform share the high fixed costs of implementation, development, planning, annual maintenance, and ongoing support.
Revenue	Not Applicable.

Portal Suite Operations & Technical Support – 2012 RCAM Analysis	
	Enhancement | Stand-alone | Not Applicable. MNP Conclusion Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.
MNP Conclusion	• Prongs 1, 2, and 3 pass. • No adjustment to the 2012 EGD allocation is required.

24 – RATE REGULATED ENTITY SUPPORT

Rate Regulated Entity Support – 2012 RCAM Analysis

EGD Service Recipient	Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution.
Service Definition	The Rate Regulated Entity Support service is responsible for supporting EGD's rate regulated entities and unique services pertaining to their regulatory proceedings and rate setting matters.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$656,739	39%	**$253,904**	$19,964	N/A	0%	**$0**	**$253,904**

Cost by Department

EI Department	*Charges*
Corporate Controller	$44,923
Treasury	$208,981
Total	**$253,904**

Prong 1 Test
Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Rate Regulated Entity Support' function is a necessary service to support EGD's regulated service operations. The level of service is required for a utility to ensure compliance with regulatory filing and rate setting practices and proceedings.

EI has been identified as the sole provider for this service.

Prong 2 Test
Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Regulation and company complexity' drives the related common costs for this service, which is representative of the level of effort required to fulfill OEB requirements, conduct research, and financial analysis to support the regulatory filings.
- No common costs have been allocated to EGD.

Prong 3 Test
Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Internal Audit Manager	1	$ 119,694	1	$ 155,653
Financial Analysis Manager	1	$ 147,200	1	$ 189,552
Total	**2**	**$ 266,894**	**2**	**$ 345,206**

Both individuals would require regulatory and financial experience.

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

Rate Regulated Entity Support – 2012 RCAM Analysis

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 253,904	$ 266,894	$ 345,206	Below Range

The cost of procuring this service from EI is below the range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would require a combination of three consultants performing extremely specialized duties; two at the Partner-level and one senior consultant. EGD estimates that this would cost between $504,608 and $723,911. Given that hourly rates and effort were not explicitly provided with EGD's estimate, MNP developed an external cost estimate of its own to validate the result based on anticipated needs.

Based upon prevailing market rates for technical support services, MNP conservatively estimates that external provision of costs would amount to approximately $730,100, which exceeds the EI RCAM allocation and internal provisioning estimates. The following table provides a breakdown of the cost estimate:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Partner Strategy	$ 330 / hour	1	1,050	$ 346,500
Senior Consultant Strategy	$ 219 / hour	1	1,400	$ 306,600
Consultant Technical Support	$ 110 / hour	1	700	$ 77,000
	Total	**4**	**3,153**	**$ 730,100**

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost internally or externally. An alternate source for these stand alone services would result in additional costs to ratepayers.
Synergistic	EGD shares the cost of EI rate regulated entity support staff with other affiliates.
Revenue Enhancement	Not Applicable.
Stand-alone	Ability to leverage expertise built by EI through previous experience within the Ontario (and other) regulatory environment, with specific context to EGD and its processes and objectives.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

MNP Conclusion

- Prongs 1, 2, and 3 pass.
- No adjustment to the 2012 EGD allocation is required.

25 – RECORDS & INFORMATION MANAGEMENT

Records & Information Management – 2012 RCAM Analysis

EGD Service Recipient

Mark Boyce, Vice President Law & Information Technology, Enbridge Gas Distribution

Service Definition

The Records and Information Management service is responsible for the overall development, maintenance and dissemination of policies, procedures, and guidelines for the establishment and maintenance of the Records and Information Management Program.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$10,300,070	0%	**$0**	$10,300,070	System users	5%	**$538,352**	**$538,352**

Cost by Department

EI Department	*Charges*
Enterprise Content Management	$395,194
Records Management	$143,158
Total	**$538,352**

Prong 1 Test
Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Records and Information Management' function is a necessary service for EGD to ensure all EGD employees have secure storage and access to operational and critical business information.

Increased costs for 2012 have to do with an expanded role for Enterprise Content Management in effort to modernize operations and create and coordinate legacy information.

EI has been identified as the primary provider for this service. Although EGD provides supplemental support, EI performs the majority of the work due to EGD's limited internal resources, mainly a Records Advisor and a Records Analyst.

Prong 2 Test
Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- The driver for allocations is 'Transactions, contracts, documents' and the allocator for common costs is 'system users'.
- Allocations for common costs are allocated using the 'system users'; essentially the percentage of Records Management Program users out of the total user base which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test
Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Records & Information Management – 2012 RCAM Analysis

Position	MNP Low Range Estimate # of FTE	MNP Low Range Estimate Total Cost	MNP High Range Estimate # of FTE	MNP High Range Estimate Total Cost
Data Warehousing Manager	1	$ 188,725	1	$ 228,938
Mid-level Business Systems Analyst	1	$ 108,368	2	$ 270,018
Livelink License Fee		$ 226,978		$ 226,978
Total	**2**	**$ 524,070**	**3**	**$ 725,934**

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 538,352	$ 524,070	$ 725,934	Within Range

The cost of procuring this service from EI is within the range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 5,400 hours for an external consulting team to provide a comparable service, which would cost in the range of $810,628 to $982,078 (in this case with a low range of 90% and a high range of 110%). Ranges at the 80% and 120% levels are reflected in the table below. The following table provides a breakdown of the above identified cost estimates:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Senior Consultant	$ 191 / hour	1	1800	$ 343,238
Consultant	$ 127 / hour	1	1800	$ 228,825
Support Staff	$ 54 / hour	1	1800	$ 97,313
Livelink License Fees				$ 226,978
Total		**3**	**5,400**	**$ 896,354**
		Low Range (80% of Total)		**$ 717,083**
		High Range (120% of Total)		**$ 1,075,625**

MNP believes that this is a reasonable estimate of effort and cost, which is higher than both the RCAM allocation and internal provisioning estimates.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost externally.
Synergistic	Economies of scale is achieved through the model's centralized approach where all affiliates benefiting from the Records & Information Management Program system share the high fixed costs of implementation, development, planning, annual maintenance, and ongoing support.
Revenue Enhancement	Not Applicable.

Records & Information Management – 2012 RCAM Analysis	
	Stand-alone: EGD enjoys strategic benefits of having EI perform these services due to EI's intimate knowledge of records and content management requirements of EGD. MNP Conclusion Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.
MNP Conclusion	• Prongs 1, 2, and 3 pass. • No adjustment to the 2012 EGD allocation is required.

26 – RISK ASSESSMENT & MANAGEMENT

Risk Assessment & Management – 2012 RCAM Analysis

EGD Service Recipient

Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Service Definition

The Risk Assessment and Management service is responsible for identifying corporate risks, supply and demand risks, operational risks, and external risks, understanding their implications, and developing mitigation strategies.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$13,052,828	5%	**$685,727**	$1,389,577	FCER	14%	**$192,734**	**$878,461**

Cost by Department

EI Department	*Charges*
CEO	$30,646
CFO	$17,139
Audit Services (Calgary)	$23,728
Enterprise Risk	$806,948
CEO	$30,646
Total	**$878,461**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Risk Assessment & Management' function is a necessary service for EGD to ensure that all financial, operational, economic, and physical risks associated with EGD's business are identified and mitigated.

EI has been identified as a supplemental provider for this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Entity Risk' drives the related common costs for this service, which is representative of the effort required to mitigate risk for all EI affiliates.
- Allocations for common costs use Financing Capital Employed Ratio (FCER) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test

Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Senior-level Risk Management Executive	1	$ 222,266	1	$ 363,932
Financial Analysis Manager	1	$ 147,200	1	$ 189,552
Senior-level Financial Analyst	2	$ 220,815	2	$ 270,405
Administrative Assistant	1	$ 66,731	1	$ 84,914
Total	**5**	**$ 657,012**	**5**	**$ 908,804**

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

Risk Assessment & Management – 2012 RCAM Analysis

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 878,461	$ 657,012	$ 908,804	Within Range

The cost of procuring this service from EI is within the range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 3,530 hours for an external consulting team to provide a comparable service, which would cost approximately $780,698 to $1,171,046. The following table provides a breakdown of the above identified cost estimates:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Managing Partner	$ 467 / hour	1	440	$ 205,480
Senior Consultant	$ 296 / hour	2	620	$ 367,040
Consultant	$ 170 / hour	2	825	$ 280,500
Support Staff	$ 66 / hour	1	200	$ 13,200
Travel and IT costs				$ 109,652
	Total	**6**	**3,530**	**$ 975,872**
			Low Range (80% of Total)	**$ 780,698**
			High Range (120% of Total)	**$ 1,171,046**

MNP believes that this is a conservative estimate of effort and cost based upon the staffing complement required to perform these functions. The conservative estimates are comparable to the cost incurred with the RCAM allocation and internal provisioning estimates.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	The service is currently offered at a comparable cost to external and internal provisioning. Any potential savings of alternate provision may be offset by the high costs of switching and the opportunity cost of lost synergistic and standalone benefits.
Synergistic	Economies of scale are achieved where multiple affiliates benefit from sharing central costs. Additionally, the ability to access on demand services as required allows for further cost efficiencies.
Revenue Enhancement	Not Applicable.
Stand-alone	There is significant strategic benefit to having EI provide risk management services to EGD. Risk management practices and knowledge at EI have been developed in a complex and transparent environment, and EGD enjoys the benefit of this experience in managing its own risks.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for

Risk Assessment & Management – 2012 RCAM Analysis	
	Ontario ratepayers.
MNP Conclusion	• Prongs 1, 2, and 3 pass. • No adjustment to the 2012 EGD allocation is required.

27 – STRATEGIC PLANNING

Strategic Planning – 2012 RCAM Analysis

EGD Service Recipient

Arunas Pleckaitis, Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution.

Service Definition

The Strategic Planning service coordinates the development of EGD's vision and related operational activities and financial impacts delivered through the long-range planning process and document.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$6,953,252	5%	**$327,890**	$0	FCER	0%	**$0**	**$327,890**

Cost by Department

EI Department	*Charges*
CEO	$267,256
Enterprise Risk	$60,634
Total	**$327,890**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Strategic Planning' function is a necessary service of EGD to provide senior and leadership oversight into the long-term direction of the firm, while aligning objectives with internal resource, labour and IT requirements, and partnerships and business collaborations.

EI has been identified as a supplemental provider for this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- 'Complexity (company and markets)' drives the related common costs for this service, which is representative of the effort to identify, develop, and improve overall organizational direction, guidelines, and policies.
- Allocations for common costs use Financing Capital Employed Ratio (FCER) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test

Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD. MNP has incorporated EGD estimates for costs associated with competitive intelligence (e.g. Ziff, PIRA) and distribution of the Strategic Plan to employees. MNP notes that these costs are estimated by EGD to be higher than the same costs with external provisioning due to the loss of a volume or scale-related discount. Estimates using the lower external costs do not change MNP's conclusion.

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Senior-level Strategic Planning Executive	1	$ 238,714	1	$ 345,317
Competitive Intelligence and Production Costs		$ 164,478		$ 164,478
Total	**1**	**$ 403,192**	**1**	**$ 509,795**

Strategic Planning – 2012 RCAM Analysis

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 327,890	$ 403,192	$ 509,795	Below Range

The cost of procuring this service from EI is below the range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 2,160 hours for an external consulting team to provide a comparable service, which would cost approximately $429,434 to $644,150. The following table provides a breakdown of the above identified cost estimates:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Managing Partner	$ 275 / hour	2	540	$ 297,000
Senior Consultant	$ 165 / hour	1	540	$ 89,100
Support Staff	$ 76 / hour	1	540	$ 41,040
Subscription costs for competitive intelligence				$ 54,826
Production Costs for development and distribution				$ 54,826
	Total	**4**	**2,160**	**$ 536,792**
			Low Range (80% of Total)	**$ 429,434**
			High Range (120% of Total)	**$ 644,150**

MNP believes that this is a reasonable estimate of effort and cost, which is higher than the RCAM allocation and the internal provisioning estimates.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost externally or internally.
Synergistic	Economies of scale are evident in sharing strategic planning resources across affiliates and the buying power of EI relating to acquisition of competitive data, without which EGD would incur higher costs.
Revenue Enhancement	Not Applicable.
Stand-alone	There is strategic benefit from using EI for this suite of services, in that EI's size and complexity afford it a broad experience set to share leading practices with its affiliates.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

Strategic Planning – 2012 RCAM Analysis	
MNP Conclusion	• Prongs 1, 2, and 3 pass. • No adjustment to the 2012 EGD allocation is required.

28 – SUPPLY CHAIN MANAGEMENT

Supply Chain Management – 2012 RCAM Analysis

EGD Service Recipient

Jamie Milner, Vice President Pipeline Integrity & Safety, Enbridge Gas Distribution

Service Definition

The Supply Chain Management service is responsible for coordinating the enterprise-wide initiative to identify and implement procurement cost savings by applying strategic sourcing techniques for the benefit of EGD.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$289,899	0%	**$0**	$252,104	ACER	16%	**$39,706**	**$39,706**

Cost by Department

EI Department	*Charges*
CFO	$24,915
Corporate Admin.	$14,791
Total	**$39,706**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Supply Chain Management' function is a necessary service of EGD to optimize the scheduling, conduction, and reporting of the flow of materials, equipment, and commodities through the firm's operational system without compromising integrity or performance.

EI has been identified as the sole provider for this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- The driver for allocations is 'Raw material volumes' and allocations for common costs use Adjusted Capital Employed Ratio (ACER) which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test

Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Supply Chain Management Manager	0.5	$ 68,069	0.5	$ 91,218
Total	**0.5**	**$ 68,069**	**0.5**	**$ 91,218**

Using salary survey data and the staff complement noted above, MNP estimates a range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 39,706	$ 68,069	$ 91,218	Below Range

The cost of procuring this service from EI is below the range of the MNP estimated stand-alone cost.

Supply Chain Management – 2012 RCAM Analysis

External Provision

EGD did not undertake an external estimation for this service.

MNP estimates that it would take approximately 750 hours for an external consultant at the senior manager level to manage and align the procurement efficiencies between EI and EGD. This estimated cost is higher than the RCAM allocation and internal provisioning estimates.

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Senior Manager	$ 240 / hour	1	750	$ 187,500

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost. An alternate source for these stand alone services would result in additional costs to rate payers.
Synergistic	EGD enjoys the buying power offered by its parent EI through preferential pricing on material and service requirements.
Revenue Enhancement	Not Applicable.
Stand-alone	Not Applicable.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

MNP Conclusion

- Prongs 1, 2, and 3 pass.
- No adjustment to the 2012 EGD allocation is required.

29 – TAX REPORTING & PLANNING

Tax Reporting & Planning – 2012 RCAM Analysis

EGD Service Recipient	Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution
Service Definition	The Tax Reporting and Planning service is responsible for ensuring proper reporting of the tax positions in financial statements and tax returns and to ensure initiatives are implemented so that tax is minimized.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$3,132,573	2%	**$54,275**	$58,518	% of Direct Time	2%	**$1,033**	**$55,308**

Cost by Department

EI Department	*Charges*
Tax Services	$55,308
Total	**$55,308**

Prong 1 Test
Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review
MNP is of the opinion that the 'Tax Reporting and Planning' function is a necessary service provided to EGD to optimize the oversight and leadership of tax-related issues of the firm.

EI has been identified as a supplemental provider for this service.

Prong 2 Test
Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review
Direct Cost
- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs
- 'Legal Entities, M&A, financing' drives the related common costs for this service, which is representative of the effort to ensure tax legislation compliance and tax minimization goals.
- Allocations for common costs use EGD % of direct time which, in MNP's opinion, is an appropriate and industry accepted allocator.

Prong 3 Test
Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis
EGD Internal Provision of Service
The following table provides a range of cost estimates for the internal provision of services within EGD:

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Tax Manager	0.5	$ 82,109	0.5	$ 104,242
Total	**0.5**	**$ 82,109**	**0.5**	**$ 104,242**

Using salary survey data and the staff complement noted above, MNP estimates a loaded range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 55,308	$ 82,109	$ 104,242	Below Range

The cost of procuring this service from EI is below the range of the MNP estimated

Tax Reporting & Planning – 2012 RCAM Analysis

stand-alone cost.

External Provision

EGD estimates that it would take approximately 120 hours for an external consultant at the Managing Partner level to provide a comparable and on-demand service, which would cost in the range of $73,728 to $110,592. The following table provides a breakdown of the above identified cost estimates:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Managing Partner	$ 768 / hour	1	120	$ 92,160
	Total	**1**	**120**	**$ 92,160**
			Low Range (80% of Total)	**$ 73,728**
			High Range (120% of Total)	**$ 110,592**

MNP believes that this is a conservative estimate of effort and cost, with the low estimate being higher than the RCAM allocation and the internal provisioning estimates.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Benefit Type	*Reasoning*
Replacement	In MNP's opinion, these services cannot be replaced at an equal or lower cost, internally or externally. An alternate source for these stand alone services would result in additional costs to ratepayers.
Synergistic	Not applicable.
Revenue Enhancement	Not Applicable.
Stand-alone	The ability to access the broad expertise of senior tax advisors within EI provides valuable guidance, advice, and direction that might not otherwise be available to EGD without incurring much higher costs.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

MNP Conclusion

- Prongs 1, 2, and 3 pass.
- No adjustment to the 2012 EGD allocation is required.

30 – TOTAL COMPENSATION & BENEFITS

Total Compensation & Benefits – 2012 RCAM Analysis

EGD Service Recipient

Marc Weil, Director Human Resources, Enbridge Gas Distribution

Service Definition

The Total Compensation and Benefits service provides for the establishment of total employee compensation including base pay, performance bonuses (long term and short term incentive programs), benefits programs, and job evaluation and performance programs.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	C=AxB	D		E	F=DxE	G=C+F
$6,510,852	8%	**$498,199**	$4,128,956	% of Direct Time	31%	**$1,283,611**	**$1,781,809**

Cost by Department

EI Department	*Charges*
CEO	$200,402
Group VP Corp. Resources	$249,040
Corporate HR	$159,379
Total Compensation	$1,108,782
Corporate Controller	$64,206
Total	**$1,781,809**

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

MNP is of the opinion that the 'Total Compensation and Benefits' function is a necessary service provided for EGD to optimize the development of a competitive and innovative compensation and benefits packages that will attract the necessary talent to perform the operations of the firm.

In addition to the elements above, EGD is facing challenging conditions in terms of employee development and succession in light of its aging workforce and a strong commitment to employee/customer safety. According to EGD, 18% of its workforce is eligible to retire today and 30% can retire within the next 5 years. In addition, 26% of EGD's leaders can retire today.

Part of EGD's program to address these and other HR challenges includes a renewed focus on design and administration of competitive compensation. This is required to attract and retain top talent, especially in light of the aging workforce.

EI has been identified as a supplemental provider, performing the majority of activities with EGD managing the administration component of this service.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Direct Cost

- Allocations for direct costs use salary-weighted time estimates which, in MNP's opinion, is an appropriate and industry accepted allocator.

Common Costs

- The driver for allocations is 'Employees' and the allocator for common costs is the 'affiliate headcount' which, in MNP's opinion, is an appropriate and industry accepted allocator.

Total Compensation & Benefits – 2012 RCAM Analysis

Prong 3 Test
Do the benefits to ratepayers exceed the costs?

PASS
With Adjustments

Cost/Benefit Analysis

EGD Internal Provision of Service

The following table provides a range of cost estimates for the internal provision of services within EGD. For comparison purposes, MNP employed EGD's estimates for external consulting costs related to specialized services (e.g. actuarial reports), as these services are currently being provided externally through EI and would be necessary to support an EGD internal provisioning team if it were a stand-alone entity.

Position	MNP Low Range Estimate		MNP High Range Estimate	
	# of FTE	Total Cost	# of FTE	Total Cost
Senior-level HR Executive	1	$ 247,330	1	$ 333,171
Compensation and Benefits Director	0	$ -	1	$ 272,815
Labour Relations Manager	1	$ 152,748	1	$ 205,882
Mid-level Compensation Analyst	2	$ 186,526	1	$ 116,874
Human Resources Assistant	2	$ 135,808	2	$ 163,872
Consulting Costs	n/a	$ 712,736	n/a	$ 712,736
Total	**6**	**$ 1,435,149**	**6**	**$ 1,805,350**

Using salary survey data and the staff complement noted above, MNP estimates a range of costs related to this service within a stand-alone utility as follows:

EI 2012 Allocation	MNP Low Range	MNP High Range	Allocation Assessment
$ 1,781,809	$ 1,435,149	$ 1,805,350	Within Range

The cost of procuring this service from EI is within the range of the MNP estimated stand-alone cost.

External Provision

EGD estimates that it would take approximately 10,000 hours for an external human resources consulting team to provide a comparable service, which would cost in the range of $1,848,589 to $2,772,883. The following table provides a breakdown of the above identified cost estimates:

Position	2012 Market Rate	Individuals Required	Hours per Individual	Estimated Cost
Managing Partner	$ 275 / hour	1	2,000	$ 550,000
Senior Consultant	$ 194 / hour	2	2,000	$ 776,000
Consultant	$ 79 / hour	1	2,000	$ 158,000
Support Staff	$ 57 / hour	1	2,000	$ 114,000
External Consulting Fees				$ 712,736
	Total	**5**	**10,000**	**$ 2,310,736**
			Low Range (80% of Total)	**$ 1,848,589**
			High Range (120% of Total)	**$ 2,772,883**

MNP believes that this is a reasonable estimate of effort and cost, which is higher than both the RCAM allocation and internal provisioning estimates.

OEB Benefits

The following table outlines the benefits achieved by receiving this service from EI:

Total Compensation & Benefits – 2012 RCAM Analysis

Benefit Type	*Reasoning*
Replacement	Provision internally is possible at a comparable cost; however, the switching costs of establishing internal provision of service may offset any potential savings for ratepayers.
Synergistic	Economies of scale are achieved through the model's centralized approach where all affiliates benefit from EI developed programs and resources. EGD also shares the fixed costs of development, planning, implementation, and ongoing support. In addition, EGD enjoys the collective purchasing power achieved by a larger combined business entity to receive preferential pricing on third party services (benefit carriers, pension consultants, etc.).
Revenue Enhancement	Not Applicable.
Stand-alone	There are strategic benefits to EGD that outweigh any perceived potential marginal cost savings of sourcing these services in an alternative form. Due to EI's size and complexity, it has access to a broader knowledge of total rewards, therefore more efficiently meeting EGD objectives with higher quality work products. In addition, the cost of sourcing this basket of services either externally or within EGD would require significant effort and cost.

MNP Conclusion

Based on the analysis of services required and allocation methodology, MNP is of the opinion that the RCAM allocates an appropriate and reasonable cost for the level of service provided and concludes that the benefits of this service outweigh the costs for Ontario ratepayers.

MNP Conclusion

- Prongs 1, 2, and 3 pass.
- No adjustment to the 2012 EGD allocation is required.

31 – DEPRECIATION OF RISK MANAGEMENT SYSTEM

Depreciation of Risk Management System – 2012 RCAM Analysis

EGD Service Recipient	Narin Kishinchandani Vice President Finance, Enbridge Gas Distribution
Service Definition	Depreciation – Risk Management System contains the depreciation on the Openlink risk management system. Openlink is used by Treasury and Risk Management to manage risk on all physical commodity deals for EGD. It is also used to track and manage EGD risk on all financial hedges made against these physical commodity deals, including external and internal debt, inter-company loans, and Interest Rate and Foreign exchange.
Cost of Service	See table below
Cost by Department	Non-departmental direct costs - $64,951
Prong 1 Test Determine if EI's charges to EGD are prudently incurred. **PASS**	**Cost Incurrence Review** MNP is of the opinion that the 'Depreciation – Risk Management System' is a necessary service provided for EGD to manage risk on physical commodity transactions. Use of the Openlink risk management tool would be required to efficiently manage a stand-alone company the size and complexity of EGD. It is therefore within the scope of service required for a utility to assume the capitalized costs and implementation expenses of a risk management system.
Prong 2 Test Determine if EI's charges to EGD are appropriately allocated. **PASS**	**Cost Allocation Review** The depreciation expense for the risk management system is a direct allocation using a system usage factor. In MNP's opinion, this is the appropriate and industry accepted cost allocation method. EGD's usage of the Openlink system is derived from a weighted average of the percentage of the EGD transactions to all enterprise transactions and the percentage of EGD earnings at risk to total enterprise earnings at risk.
Prong 3 Test Do the benefits to ratepayers exceed the costs? **PASS**	**Cost/Benefit Analysis** The benefits related to this general expense exceed the costs due to improved management of risk for the firm. It is MNP's opinion, that the capital cost of acquiring a comparable system on a standalone basis at EGD, would clearly exceed the incremental shared costs of a common system.
MNP Conclusion	• Prongs 1, 2, and 3 pass. • No adjustment to the 2012 EGD allocation is required.

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	Direct Allocation	D		E	F=DxE	G=C+F
$1,278,570	5%	**$64,951**	N/A	N/A	0%	**$0**	**$$64,951**

32 – DIRECT EFS CHARGE

Direct EFS Charge – 2012 RCAM Analysis

EGD Service Recipient

Narin Kishinchandani Vice President Finance, Enbridge Gas Distribution

Service Definition

The costs for supporting the Enterprise Financial Systems (EFS) are directly incurred by multiple affiliates for the purpose of delivering enterprise financial services. For allocation purposes, the participating affiliates' original budget allocations are notionally aggregated and the charges are calculated based on affiliate user count. The difference between this affiliate calculation and the affiliate's original budget allocation (debit or credit) is allocated to the affiliate.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	Direct Allocation	D		E	F=DxE	G=C+F
$(2,314,784)	100%	$(2,314,784)	N/A	N/A	0%	**$0**	$(2,314,784)

Cost by Department

Costs are allocated directly to EGD and are not comprised of individual departmental efforts.

Non-departmental direct credit of $2,314,784.

Prong 1 Test

Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review

It is the opinion of MNP that the charges incurred by EGD for supporting the systems that comprise the Enterprise Financial Systems are prudent and pass the cost incurrence test.

It is justifiable that the Oracle, Khalix and Oracle iExpense, systems are required, respective to the service analyses performed. Therefore, in MNP's opinion, this Direct EFS charge is also appropriate.

Prong 2 Test

Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review

Actual costs incurred by all entities, which support the EFS suite, are allocated to EGD based on a usage factor. This Direct EFS Charge reflects the difference between the usage-based allocation and the costs EGD budgets for EFS support. In MNP's opinion, a usage based allocator for systems support is an appropriate and industry accepted allocation method.

The usage allocator which drives this direct charge is derived from the percentage of EGD's user count for each system (Oracle, Khalix, and Oracle iExpense) to enterprise wide user count.

Prong 3 Test

Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

EGD and other affiliates each incur costs to support these systems on behalf of the EI enterprise. The costs that EGD budgets therefore reflect EGD-specific costs as well as costs incurred to the benefit of the entire enterprise. This general expense (Direct EFS Charge) represents a true-up to ensure that EGD costs allocated through RCAM do not include costs related to other affiliates. In MNP's opinion, this charge is therefore within the scope of the service required for a stand-alone utility and prudently incurred on behalf of ratepayers.

MNP Conclusion

- Prongs 1, 2, and 3 pass.
- No adjustment to the 2012 EGD allocation is required.

33 – DIRECTORS FEES AND CHARGES

Directors Fees and Charges – 2012 RCAM Analysis

EGD Service Recipient

Narin Kishinchandani Vice President Finance, Enbridge Gas Distribution

Service Definition

The Directors fees and expenses comprises all fees paid to directors of EI's Board, including conducting Board activities and liaisons with members of EI senior executive.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	Direct Allocation	D		E	F=DxE	G=C+F
$5,370,000	14% (FCER)	**$744,819**	N/A	N/A	0%	**$0**	**$744,819**

Cost by Department

Costs are allocated directly to EGD and are not comprised of individual departmental efforts.

Non-departmental indirect costs - $744,819

Prong 1 Test
Determine if EI's charges to EGD are prudently incurred.

PASS

Cost Incurrence Review
It is the opinion of MNP that the charges incurred by EGD for the Director's fees and expenses are prudent and pass the cost incurrence test. Given the size and complexity of EGD, industry requirements for board composition, and evolving corporate standards that balance performance, risk management, transparency and corporate citizenship, the fees and expenses would be required for a stand-alone utility.

Prong 2 Test
Determine if EI's charges to EGD are appropriately allocated.

PASS

Cost Allocation Review
Directors' fees and expenses are directly allocated using the Capital Employed Ratio (FCER), which in MNP's opinion is an appropriate and industry accepted allocator.

Prong 3 Test
Do the benefits to ratepayers exceed the costs?

PASS

Cost/Benefit Analysis

For our analysis of Directors Fees and Charges, MNP is relying in part on the logic and data presented in the MNP 2007 Report[1]. Research at that time indicated that the average Canadian board is comprised of twelve members, including the Board Chair. This aligns with our current understanding. In addition, committees are made up of four members, and there are typically four committees on each board. Further to the 2007 MNP Report, costs related to a typical board for a stand-alone organization, using comparable cost ranges could therefore were estimated as:

- Board Chair: $214,000
- Committee Chairs: $79,000 (x 4 committees, additional to flat fee)
- Directors Flat Fee: $73,000 (x 11 regular directors)
- Additional Board Expenses: $199,950 to $333,250 (15-25% of fees)
- Audit Committee Compensation: $15,800 (20% Audit Chair premium)
- Board Chair Compensation: $64,200 (30% Board Chair premium)

The estimated total cost for directors' fees and expenses in 2007 was $1,613,000 to $1,746,000 for a stand-alone organization.

MNP verified the magnitude of Board costs with data acquired from several comparable

[1] MNP Report "Independent Evaluation of Enbridge Gas Distribution Inc.'s Regulatory Corporate Cost Allocation Methodology", February 28, 2007

Directors Fees and Charges – 2012 RCAM Analysis	
	companies with similar Board structure as EI and EGD, listed below. **Company** / **Approximate Employees** / **Cost of Board Compensation** FortisBC Energy Utilities[2] — 1,821 — $ 1,615,985 ATCO Gas[3] — 2,166 — $ 1,756,070 ENMAX Power[4] — 556 — $ 1,258,596 TransCanada[5] — 4,000 — $ 2,358,000 These comparable costs exceed Directors Fees and Charges of $744,819. MNP also compared these costs with the combination of "Directors Fees and Charges" ($744,819) and the primary service "Board of Directors Support" ($769,368). Although MNP was unable to confirm that comparator organizations included Board of Director Support costs (which would increase comparator costs), the combined EI allocation of $1,514,187 is comparable to other similar entities.
MNP Conclusion	• Prongs 1, 2, and 3 pass. • No adjustment to the 2012 EGD allocation is required.

[2] http://www.fortisinc.com/aboutfortis/corporategovernance/BoardCompensation.aspx
[3] http://www.atco.com/Investors/Documents/AIF/ATCODec3107AIFFinal.pdf
[4] http://www.enmax.com/Corporation/About+Enmax/Direction+and+Leadership/Board+Members/default.htm
[5] http://www.transcanada.com/investor/annual_reports/2007/MPCEng.pdf

34 – AUDIT FEES

Audit Fees – 2012 RCAM Analysis

EGD Service Recipient	Narin Kishinchandani Vice President Finance, Enbridge Gas Distribution
Service Definition	The audit fees are established for Enbridge Inc. and its affiliates by the Auditor (PWC) for various audits.
Cost of Service	See table below
Cost by Department	Not Applicable.
Prong 1 Test Determine if EI's charges to EGD are prudently incurred. **PASS**	**Cost Incurrence Review** Audited financial statements are necessary for reporting and regulatory compliance and for achieving fair, responsible and transparent business practices. It is MNP's opinion that the fees associated with the required level of audit are a necessary component of EGD operations and are prudent and therefore pass the cost incurrence test.
Prong 2 Test Determine if EI's charges to EGD are appropriately allocated. **N/A**	**Cost Allocation Review** Effective 2012, audit fees are no longer accounted for under the RCAM. This is reflective of the new direct billing nature agreement between EGD and their auditors.
Prong 3 Test Do the benefits to ratepayers exceed the costs? **N/A**	**Cost/Benefit Analysis** Not Applicable.
MNP Conclusion	Not Applicable.

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	Direct Allocation	D		E	F=DxE	G=C+F
$0	14% (FCER)	$0	N/A	N/A	0%	**$0**	$0

35 – EGD Stock Based Compensation

EGD Stock Based Compensation – 2012 RCAM Analysis

EGD Service Recipient	Marc Weil, Director Human Resources, Enbridge Gas Distribution Narin Kishinchandani, Vice President Finance, Enbridge Gas Distribution
Service Definition	The Stock Based Compensation (SBC) department contains costs for the expense related to the granting of Long-term Incentives to Manager-level and above staff within Enbridge Gas Distribution. Long-term incentives are also granted to certain lower level staff on a discretionary basis.
Cost of Service	See table below
Cost by Department	Non-departmental direct costs - $7,549,229
Prong 1 Test Determine if EI's charges to EGD are prudently incurred. **PASS**	**Cost Incurrence Review** SBC is a standard industry practice for attracting, motivating and retaining senior employees. As a stand-alone entity, EGD would be required to offer comparable compensation to be considered a competitive employer. As has been the case in prior OEB hearings, Stock Based Compensation charges are an appropriate cost incurred on behalf of Ontario Ratepayers.
Prong 2 Test Determine if EI's charges to EGD are appropriately allocated. **PASS**	**Cost Allocation Review** Charges related to the options issued to EGD staff members are employee-specific and allocated directly to EGD which, in MNP's opinion, is an appropriate and industry accepted allocation method.
Prong 3 Test Do the benefits to ratepayers exceed the costs? **PASS**	**Cost/Benefit Analysis** Industry standards and regulatory precedent indicate that stock based compensation is an accepted charge included in total compensation costs. While there are various methods for valuing stock based compensation, MNP in its 2007 report found that over 80% of publicly traded companies on the TSX use the Black-Scholes formula. This is consistent with the CICA Handbook requirement for financial reporting purposes. Black-Scholes is also the leading practice for transfer pricing purposes of shared compensation costs included in rate applications. EGD calculated SBC using the Black-Scholes method. Therefore, the direct calculation of EGD's stock-based compensation costs using the Black-Scholes method is a fair and prudent approach with regards to the interests of Ontario ratepayers. <u>Assessment of the Value of SBC for 2012</u> As discussed with other HR related service areas, EGD is facing significant challenges with employee development and succession in light of its aging workforce and a strong ongoing commitment to employee/customer safety. According to EGD, 18% of its workforce is eligible to retire today and 30% can retire within the next 5 years. In addition, 26% of EGD's leaders can retire today. SBC is considered within EGD to be a valuable tool to attract and retain seasoned talent at the management and supervisorial level.

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	Direct Allocation	D		E	F=DxE	G=C+F
$7,549,229	100%	$7,549,229	N/A	N/A	0%	**$0**	$7,549,229

EGD Stock Based Compensation – 2012 RCAM Analysis	
	An assessment of SBC allocations cannot be considered in isolation or solely in its trending year over year. SBC is just one element of EGD's total compensation system. EGD maintains a target for total rewards at the 50th percentile of the market (P50) within its peer group, plus or minus 10%, and recently contracted Mercer to do a compensation study to assess the reasonableness of EGD's total compensation levels[6]. The result of this study, published on November 30, 2011, showed that EGD total compensation was 2% P50, with its Senior Management and Supervisory/Non-Management groups slightly above P50 by 5% and 1%, respectively. This result is well within EGD's target range of 40th to 60th percentile, and is considered by MNP to be reasonable, especially in light of the aging workforce challenges. Given that SBC is a factor in the total compensation results, MNP finds the value of SBC to be reasonably incurred on behalf of ratepayers of Ontario.
MNP Conclusion	• Prongs 1, 2 and 3 pass. • No adjustment to the 2012 EGD allocation is required.

[6] Mercer Report "Compensation Study Enbridge Gas Distribution Inc.", November 30, 2012.

36 – INSURANCE PREMIUMS

Insurance Premiums – 2012 RCAM Analysis

EGD Service Recipient	Jamie Milner, Vice President Pipeline Integrity & Safety, Enbridge Gas Distribution
Service Definition	Costs include insurance premiums for liability, crime, property, automobile, and fiduciary policies held for Enbridge Inc. and its affiliates.
Cost of Service	See table below
Cost by Department	Non-departmental direct costs - $8,483,868
Prong 1 Test Determine if EI's charges to EGD are prudently incurred. **PASS**	**Cost Incurrence Review** Insurance Premiums are coverage related charges which EGD would require directly to prudently manage business risks on a stand-alone basis. The level of service is reasonable for a utility company with the size and complexity of EGD.
Prong 2 Test Determine if EI's charges to EGD are appropriately allocated. **PASS**	**Cost Allocation Review** Charges related to Insurance Premiums are policy specific and allocated to EGD based on the standard premium drivers used by insurers. These coverage-specific allocators are applied to a 5 year forecast of premiums prepared by EI's Risk Assessment department. In MNP's opinion, insurance premiums are allocated appropriately through an industry accepted allocation method.
Prong 3 Test Do the benefits to ratepayers exceed the costs? **PASS**	**Cost/Benefit Analysis** In MNP's opinion, the benefits related to this charge exceed the cost. MNP's review of independent quotes and a benchmarking undertaken by EGD in October 2008[7], indicate that economies of scale are realized by consolidating insurance programs with EI and that the EGD program does not appear to be out of line with standard industry practice for limits, deductibles and premiums for coverages reviewed. MNP also noted that Insurance Operating and Maintenance costs for Union Gas pursuant to its 2013 Application show Actual for 2010 of $8,506,800, Outlook for 2011 of $8,815,400 and Forecast for 2012 of $8,605,100. These figures are comparable to EI allocated costs of $8,483,868.
MNP Conclusion	• Prongs 1, 2 and 3 pass. • No adjustment to the 2012 EGD allocation is required.

Cost of Service

Direct Costs			Common Costs				EGD Total Allocation
EI Total Cost	EGD Allocation %	EGD Total Cost	All Affiliates	Allocator Type	% Allocation	$ Allocation	
A	B	Direct Allocation	D		E	F=DxE	G=C+F
$59,744,528	14%	$8,483,868	N/A	N/A	0%	**$0**	$8,483,868

[7] Willis Report "Enbridge Gas Distribution Inc. Benchmarking Project", October 2008.

APPENDIX E – EGD INTERCORPORATE SERVICES AGREEMENT

INTERCORPORATE SERVICES AGREEMENT

THIS AGREEMENT made as of the first day of January, 2011

B E T W E E N:

ENBRIDGE INC., a corporation incorporated under the laws of Canada (the "**Service Provider**")

- and -

ENBRIDGE GAS DISTRIBUTION INC., a corporation incorporated under the laws of the Province of Ontario (the "**Service Recipient**")

WHEREAS the above-named parties ("**Parties**") entered into a prior intercorporate services agreement made as of January 1, 2006 (the "**Prior Agreement**");

AND WHEREAS the Affiliate Relationships Code for Gas Utilities rule (the "Code") of the Ontario Energy Board ("**OEB**") prohibits the term of an intercompany services agreement to be greater than five (5) years without OEB approval;

AND WHEREAS the Parties wish to continue the relationship set out in the Prior Agreement whereby the Service Provider provides services to the Service Recipient, in accordance with the terms and conditions of this agreement, and any attached schedules (the "**Agreement**").

NOW THEREFORE THIS AGREEMENT WITNESSES that in consideration of the premises and mutual covenants hereinafter contained, the Parties agree:

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1. Termination of Prior Agreement

Effective as of 11:59 pm EST on December 31, 2010, the Prior Agreement is terminated. Effective as of 12:00 am EST on January 1, 2011 this Agreement shall be in full force and effect.

2. Regulatory Considerations

The Parties acknowledge that this Agreement shall be subject to any rule or order applicable to the Service Recipient made by the OEB pursuant to the Ontario Energy Board Act, S.O. 1998, c. 15, Sch. B., s. 44, including without limitation, the Code, as amended from time to time. The Service Provider agrees to do such things as are reasonably necessary to assist the Service Recipient in complying with these rules, including without limitation:

(a) to comply promptly with all requests either made or authorized by the OEB for information with respect to:

  (i) the Services; and

  (ii) the cost to the Service Provider of providing the Services; and

(b) to include equivalent provisions to those set out in this section in any contracts the Service Provider enters into with another of its affiliates for the purpose of providing any service, resource or product used in the provision of the Services.

3. Regulatory Cost Allocation Methodology

The Parties have developed a regulatory cost allocation methodology ("**RCAM**"), attached hereto as Schedule 1, that has been reviewed and approved by the OEB and may be amended from time to time. RCAM sets out the purpose, objectives, principles, and procedures underlying the identification and costing of the Services for the purpose of determining the amounts which the Service Recipient will request to be recovered in rates from time to time. Where a section of this Agreement is inconsistent with RCAM, RCAM shall prevail to the extent of the inconsistency.

4. Services and Allocation Bases

The Parties shall develop a schedule to describe each individual Service ("**Service Schedules**"), and the applicable quantity and quality indicators, to be provided in any given year. The Services may be comprised of one or more of the following components, as described in further detail in RCAM:

a) **Primary Services:** defined as a service provided by the Service Provider to the Service Recipient either as the sole provider or as a

supplemental provider (where the Service Recipient performs a component of the required activities of the service). A list of the primary services and the bases of allocation attributable thereto, are set out in RCAM.

b) **Support Services:** defined as a service provided by the Service Provider that is necessary to support a primary service to the Service Recipient. Support services are further classified as infrastructural, content, or resource support services, and are listed in RCAM with the applicable allocator.

c) **General Expenses:** defined as a significant cost that benefits the Service Recipient, and requires allocation on a basis separate from a primary service because the driver of the cost is different, or because the cost is a large, third party cost. A list of the general expenses and the basis of allocation attributable thereto, are set out in RCAM.

d) **Direct Charges:** defined as a general expense for services that can be externally priced and specifically attributed to the Service Recipient without loading. A list of the direct charges and the basis of allocation attributable thereto, are set out in RCAM.

e) **Department Costs:** defined as all direct employee and employee-related costs, plus general expenses related to the department, that relate to the primary services and support services.

f) **Return on Invested Capital:** defined as a charge for the Service Recipient's share of the weighted average cost of capital applied to the net book value of property, plant and equipment used to deliver the services. The return on invested capital shall be no higher than the Service Recipient's weighted average cost of capital as approved by the OEB from time to time.

5. Allocation Procedures

Cost allocations shall be made in accordance with the processes and procedures documented in RCAM, which describes how primary services are fully-burdened with department costs, direct charges, general expenses, support services (also fully burdened), and a return on invested capital before being allocated to the Service Provider.

The Service Provider, in consultation with the Service Recipient, shall set the RCAM cost allocations for the Services prior to December 31 each year, or as soon thereafter that the Parties can conclude the relevant budgeting and cost allocation processes, and in any event, prior to March 31 of the year to which the RCAM cost allocations are applicable. The Parties shall execute a confirmation notice ("**RCAM Confirmation Notice**") and Service Schedules to evidence the Parties' agreement to the RCAM cost allocations for that year, which shall be

incorporated into and form part of this Agreement. A copy of the pro forma RCAM Confirmation Notice is attached hereto as Schedule 2, and the executed RCAM Confirmation Notice shall become Schedule 2(a) for 2011, Schedule 2(b) for 2012, and so on.

The RCAM cost allocations shall not be amended within the year to which they apply, except in accordance with section 7 below.

In addition to the determination of the RCAM cost allocations, the Service Provider shall develop cost allocations applicable to the Service Recipient pursuant to an alternate corporate cost allocation methodology ("**CAM**") that is not approved by the OEB. The Service Provider shall determine and apply the CAM cost allocations in accordance with the CAM policies and procedures developed by the Service Provider from time to time.

6. Payment Procedures

The following sets forth the procedure applicable to payments related to Services delivered hereunder:

a) The Service Provider shall prepare monthly recurring journal entries to one or more accounts of the Service Recipient based upon the CAM cost allocations and provide an annual CAM report to the Service Recipient at least thirty (30) days prior to the beginning of the calendar year to which the journal entries relate, or as soon thereafter as reasonably practicable, as a payment notice ("**Payment Notice**") to the Service Recipient.

b) The Service Recipient shall notify the Service Provider immediately of any inaccuracy in each Payment Notice, and failing resolution, the Parties shall endeavor to resolve the dispute in accordance with the dispute resolution mechanism set out in section 15 below.

c) The Service Recipient shall pay the amounts indicated in each Payment Notice on or before the end of each calendar quarter to which the Payment Notice relates, or if there is a dispute about the amount, within thirty (30) days of the date that an amount has been determined by the dispute resolution mechanism. The Service Provider shall apply any payments made hereunder to and in satisfaction of both the CAM and RCAM cost allocations owing.

d) All amounts payable under this Agreement are expressed, and shall be paid, in Canadian dollars unless otherwise stated in the Payment Notices.

e) In the event that the Minister of National Revenue for Canada or any other competent authority at any time proposes to issue or does issue any assessment or assessments that impose or would impose any

liability for tax of any nature or kind whatsoever on the Service Provider or the Service Recipient on the basis that the fair market value of any of the services is different than the amount charged by the Service Provider for the corresponding Services (the "**Services Charge**"), and in the event that the Parties agree that the fair market value of the services is different than the Services Charge, then upon such agreement the Services Charge that the Service Recipient is obligated to pay for the said services shall be varied by increasing or decreasing the amount of the Services Charge as the Service Recipient and the Service Provider may agree.

7. Service Agreement Review and Amendment Process

This Agreement and any related Service Schedules may be amended from time to time upon the approval in writing of the Parties. Version control and archival storage of all amendments shall be the responsibility of the Service Recipient.

8. Term and Termination

8.1 Subject to section 8.3 below, this Agreement shall be effective January 1, 2011, and terminate December 31, 2015 (the "**Term**").

8.2 Each Service Schedule shall have an initial term of one year commencing January 1, 2011 and be automatically renewed for subsequent periods of one year until the end of the Term, subject to any service adjustments agreed to by the Parties in accordance with this Agreement.

8.3 The Parties may terminate this Agreement by mutual consent, in writing, except that the Service Recipient shall have the right to terminate this Agreement immediately in the event that it ceases to be a direct or indirect wholly owned subsidiary of the Service Provider.

9. Indemnification

Each of the Parties (the "**Indemnifier**") shall indemnify and hold the other Party (the "**Indemnified Party**") harmless from and against any loss, damage, claim, liability, debt, obligation or expense (including reasonable legal fees and disbursements) incurred or suffered by the Indemnified Party caused by the Indemnifier, and relating in any way to this Agreement or the provision of the services, including any loss, damage, claim, liability, debt, obligation or expense resulting from or arising from or in connection with a negligent act or negligent omission of the Indemnifier.

10. Confidential Information and Personal Information

Each of the parties hereto agrees to keep all information provided by the other party (the "**disclosing party**") to it (the "**receiving party**") that the disclosing

party designates as confidential or which ought to be considered as confidential from its nature or from the circumstances surrounding its disclosure ("**Confidential Information**") confidential, and a receiving party shall not, without the prior consent of an authorized senior officer of the disclosing party, disclose any part of such Confidential Information which is not available in the public domain from public or published information or sources except:

a) to those of its employees who require access to the Confidential Information in connection with performance of Services hereunder;

b) as in the receiving party's judgement may be appropriate to be disclosed in connection with the provision by the receiving party of Services hereunder;

c) as the receiving party may be required to disclose in connection with the preparation by the receiving party or any of its direct or indirect holding companies, affiliates or subsidiaries of reporting documents including, but not limited to, annual financial statements, annual reports and any filings or disclosure required by statute, regulation or order of a regulatory authority; and

d) to such legal and accounting advisors, valuators and other experts as in the receiving party's judgement may be appropriate or necessary in order to permit the receiving party to rely on the services of such persons in carrying out the receiving party's duties under this Agreement.

The covenants and agreements of the parties relating to Confidential Information shall not apply to any information:

a) which is lawfully in the receiving party's possession or the possession of its professional advisors or its personnel, as the case may be, at the time of disclosure and which was not acquired directly or indirectly from the disclosing party;

b) which is at the time of disclosure in, or after disclosure falls into, the public domain through no fault of the receiving party or its personnel;

c) which, subsequent to disclosure by the disclosing party, is received by the receiving party from a third party who, insofar as is known to the receiving party, is lawfully in possession of such information and not in breach of any contractual, legal or fiduciary obligation to the disclosing party and who has not required the receiving party to refrain from disclosing such information to others; or

d) disclosure of which the receiving party reasonably deems necessary to comply with any legal or regulatory obligation which the receiving party believes in good faith it has.

If in the course of performing services, the receiving party obtains or accesses personal information about an individual, including without limitation, a customer, potential customer or employee or contractor of the disclosing party ("Personal Information") the receiving party agrees to treat such Personal Information in compliance with all applicable federal or provincial privacy or protection of personal information laws and to use such Personal Information only for purposes of providing the services. Furthermore, the receiving party acknowledges and agrees that it will:

a) not otherwise copy, retain, use, modify, manipulate, disclose or make available any Personal Information, except as permitted by applicable law;

b) establish or maintain in place appropriate policies and procedures to protect Personal Information from unauthorized collection, use or disclosure; and

c) implement such policies and procedures thoroughly and effectively.

The Service Recipient shall be entitled periodically to conduct reviews of the procedures implemented by the Service Provider in relation to the obligations described in this Section 10.

Upon the termination of the provision of the services each party shall immediately return to the other party all Confidential Information and Personal Information provided by the disclosing party to the receiving party, and all copies thereof in its possession or control (other than such Confidential Information or Personal Information which continues to be used or relevant to the provision of the services), or destroy such information and copies and certify to the disclosing party that such destruction has been carried out.

11. Audit Rights

The Service Recipient shall have the right, at its own cost and by notice to the Service Provider at reasonable hours to examine and make copies of the books, records and charts of the Service Provider to the extent necessary to verify the accuracy of any statement, charge or computation made pursuant to any of the provisions of this Agreement and to comply with any government filing requirements. Such books, records and charts shall be preserved in accordance with the records retention policies of the Service Provider, provided the books, records or charts related to any matter disputed between the Parties or which is the subject of an outstanding application or proceeding before a government

body shall be preserved until such dispute is settled or such application or proceeding has been finally resolved, whichever is later. The Service Recipient's rights under this Section to view books, records and charts to make copies:

(a) for internal purposes, shall subsist for a period of two (2) years from the end of the calendar year to which such books, records and charts relate, both during the term of this Agreement and for a period of two (2) years after expiration or termination of this Agreement, and

(b) for the purposes of complying with the requirements of governmental bodies, including tax authorities, shall subsist for a period of seven (7) years from the end of the calendar year to which such books, records and charts relate, both during the term of the Agreement and for a period of two (2) years after expiration or termination of this Agreement.

If this Agreement has been terminated or has expired, the Service Provider's obligations to preserve such books, records and charts in accordance with its records retention policy shall continue. The Service Provider may fulfill such obligations by continuing to preserve such books, records, and charts or by delivering them to the Service Recipient.

12. Force Majeure

If either Party is rendered unable by force majeure to carry out its obligations under this Agreement, other than a Party's obligation to make payments to the other Party, that Party shall give the other Party prompt written notice of the event giving rise to force majeure with reasonably full particulars concerning it. Thereupon, the obligations of the Party giving the notice, so far as they are affected by the force majeure, shall be suspended during, but no longer than the continuance of, the force majeure. The affected Party shall use all reasonable diligence to remove or remedy the force majeure situation as quickly as practicable.

13. Quantity and Quality of Service

Quantity and quality indicators are included in each Service Schedule appended to the applicable RCAM Confirmation Notice for the year in which the related service is provided. In accordance with section 14 below, the Parties shall review and update the Service Schedules and the RCAM in each year that services are being provided prior to signing the RCAM Confirmation Notice, to ensure quantity and quality indicators are accurately reflected.

The Service Provider shall perform the services in accordance with the Service Schedules, and shall use reasonable efforts to perform the services in accordance with any additional instructions received from the Service Recipient at any time during a year; provided, however, that the Service Provider shall not be required to incur any additional costs related to the request.

14. Performance Reviews

The Parties will conduct performance review meetings annually, at least four months prior to the end of each year in the Term, between personnel of the Service Recipient who receive the services, and personnel of the Service Provider who provide the services. The purpose of these meetings is to assess and report upon whether the services are being delivered in accordance with the Agreement. Any changes to the operating environments, to the extent that they impact, or could impact, service delivery in any way shall be identified, discussed and monitored.

Personnel conducting the performance review meetings shall provide formal written confirmation whether the services are being delivered in accordance with the Agreement (based on the services descriptions and the quality and quantity indicators in the Service Schedules), and a description of any negotiated changes to the services as a result of this review, to each of the Controller's Groups of the Service Provider and Service Recipient prior to October 1 in the year to which the performance review relates. The Parties shall include all negotiated changes in the updates made to the Service Schedules and the RCAM for the following year in which services are provided.

15. Dispute Resolution Process

In the event that the applicable managers of the Parties cannot resolve an issue related to the nature or performance of services, the amount or bases of the cost allocations, or the interpretation of the Agreement within ten (10) business days of the date that written notice of the disputed issue is received by the non-disputing Party from the disputing Party, then either Party may send a written notice of the dispute to the responsible executives to be escalated upward through the respective organizations of the Parties, to Director, Vice-President and/or President, for resolution within twenty-one (21) business days after the receipt by the applicable executive of the notice. If required, the President of the Service Recipient shall make a final determination. The Director of each of the Parties' Controller's Groups shall facilitate this dispute resolution process and ensure that any negotiated changes resulting from the performance review process be incorporated into the updates made to the Service Schedules and the RCAM for the following year in which the Services are provided.

Upon mutual agreement of the Parties, any dispute or issue of interpretation arising hereunder may be jointly referred for non-binding guidance or arbitration to an external facilitator with recognized expertise in the subject matter of the dispute or issue of interpretation.

16. General

The Service Recipient shall be responsible for and shall pay all applicable federal, provincial, municipal goods and services taxes arising from the provision of Services hereunder, including provincial sales tax if applicable.

A Party shall, from time to time, and at all times, do such further acts and execute and deliver all such further deeds and documents as shall be reasonably requested by the other Party in order to fully perform and carry out the terms of this Agreement.

Any notice, request, demand, direction or other communication required or permitted to be given or made under this Agreement to a Party shall be in writing and may be given by hand delivery to the Party to whom it is addressed or sent by facsimile or electronic mail to such party at its address noted below or at such other address of which notice may have been given by such Party in accordance with the provisions of this section.

Service Provider:	Enbridge Inc.
Address:	#3000, 425 – 1st St. S.W. Calgary, AB T2P 3L8
Attention:	Senior Vice President & Controller
Email:	john.whelen@enbridge.com
Facsimile:	403-231-3944
Service Recipient:	Enbridge Gas Distribution Inc.
Address:	500 Consumers Road North York, ON M2J 1P8
Attention:	Vice President, Finance
Email:	narin.kisinchandani@enbridge.com
Facsimile:	416-495-5998

Any such facsimile or electronic mail shall be deemed to have been received at the opening of business at the premises of such addressee on the first business day following the transmission of such notice.

This Agreement may be executed in counterparts, no one of which needs to be executed by both of the Parties. Each counterpart, including an electronic transmission of this Agreement, shall be deemed to be an original and shall have the same force and effect as an original. All counterparts together shall constitute one and the same instrument.

This Agreement will enure to the benefit of and be binding upon the Parties thereto and their respective successors. This Agreement may not be assigned by either of the Parties thereto without the prior written consent of the other.

The division of this Agreement into articles and sections and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms "this Agreement", "hereof", "hereunder", and similar expressions refer to this Agreement and not to any particular section or other portion hereof. Unless something in the subject matter or context is inconsistent therewith, references herein to articles and sections are to articles and sections of this Agreement. Words importing the singular number shall include the plural and vice versa, words importing the masculine gender shall include the feminine and neuter genders and vice versa, and words importing persons shall include individuals, partnerships, associations, trusts, unincorporated organizations and corporations and vice versa.

In the event that one or more of the provisions contained in this Agreement shall be invalid, illegal or unenforceable in any respect under any applicable law, the validity, legality or enforceability of the remaining provisions hereof shall not be affected or impaired thereby. Each of the provisions of this Agreement is hereby declared to be separate and distinct.

This Agreement constitutes the whole and entire agreement between the Parties respecting the subject matter of the Agreement and supersedes any prior agreement, undertaking, declarations, commitments, representations, verbal or oral, in respect thereof.

ENBRIDGE INC.

Per: _____
J.K. WHELEN – SENIOR VP & CONTROLER

Per: _____
J.R. BIRD – EXECUTIVE VP, CHIEF FINANCIAL OFFICER & CORPORATE DEVELOPMENT

ENBRIDGE GAS DISTRIBUTION INC.

APPROVED AS TO FORM
ENBRIDGE LAW TP

Per: _____
D. Guy Jarvis
President

Per: _____
Mark R. Boyce
Vice President, Law & Information Technology

Schedule 2(a) to the Intercorporate Services Agreement between Enbridge Inc. and Enbridge Gas Distribution Inc., dated January 1, 2011 (the "Agreement")

REGULATORY COST ALLOCATION METHODOLOGY CONFIRMATION NOTICE

SERVICES TO BE PROVIDED DURING 2011 YEAR AND ASSOCIATED COSTS

We have discussed the nature and level of the services to be provided by Enbridge Inc. to Enbridge Gas Distribution Inc. (including Tecumseh Gas Storage) during the year 2011 pursuant to the Agreement, and agree that the services provided, as described in Appendix B hereto, and the costs to be charged as detailed in Appendix A hereto, are acceptable.

TOTAL COST $26,667,504

ENBRIDGE INC.

J.R. Bird, Executive VP, CFO & Corporate Development — Date: February 16, 2012

J. K. Whelen, Senior VP & Controller — Date: February 16, 2012

APPROVED AS TO FORM ENBRIDGE LAW TP

ENBRIDGE GAS DISTRIBUTION INC.

G. Jarvis, President — Date: March 5, 2012

M. Boyce, VP Law & Information Technology — Date: March 5, 2012

ENB LL 24466969

ENBRIDGE™

Regulatory Cost Allocation Methodology

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1 PURPOSE

The Regulatory Cost Allocation Methodology ("RCAM") has been developed to determine the allocation of costs from Enbridge Inc. ("EI") to Enbridge Gas Distribution Inc. ("EGD"). The outputs of RCAM are intended to be an input to the rate filings submitted to the Ontario Energy Board ("OEB"). The methodology has been developed by application of sound costing principles and regulatory precedents and has specifically been aligned with the Affiliate Relationship Code for Gas Utilities, originally issued on July 31, 1999 and as amended from time to time (the "ARC").

This RCAM, however, does not replace the existing Corporate Cost Allocation Methodology ("CAM") which will still be used by EI to transfer costs to all its affiliates, including EGD, for internal management and performance measurement purposes.

1.1 About Enbridge

EI is a leader in energy transportation and distribution in North America and internationally. EI operates the world's longest crude oil and liquids transportation pipeline and Canada's largest gas distribution company. EI also operates natural gas transmission pipelines and midstream businesses in the United States and invests in international energy projects. EI's activities are comprised of regulated and non-regulated businesses. The transportation and distribution activities are regulated by the National Energy Board, the OEB, the Federal Energy Regulatory Commission and various provincial and state regulators.

1.2 Need for a Corporate Cost Allocation Methodology

EI's perspective is that an "integrated" operating model reflects the fact that the corporate office is effectively managed as an integral extension of the decision making and operating activities of its business units and affiliates (for the benefit of the business units and affiliates), rather than as a passive "Holding Company" which merely manages a portfolio of investments (for the benefit of the Holding Company shareholders). The impact of this operating model will result in a decreased overall cost of each respective affiliate's operating and maintenance expenses due primarily to the potential for economies of scale. As various functions shift from an affiliate to the Corporate Shared Service Centre the associated cost will be expected to decrease. The resulting corporate cost allocations back to the affiliate would be offset by this reduction in their own incurred costs. For management purposes, these operating costs and benefits need to be tracked.

1.3 Need for a Regulatory Corporate Cost Allocation Methodology

EI recognizes that the objectives of a cost allocation methodology established for internal management and performance measurement purposes may differ from the objectives of a cost allocation methodology established to meet the needs of a regulator, mandated to protect the interests of various rate paying groups.

In recognition of the needs of the regulator, EI has developed the RCAM with the objective of meeting the regulatory requirements of the OEB (as set out in ARC, OEB decisions, and as reflected in industry).

2 DESIGN OBJECTIVES AND PRINCIPLES

The objective of the RCAM is to establish, in the context of Ontario regulation and OEB precedents, the appropriate charges to be allocated for services delivered by EI to EGD in a given fiscal period. These charges are intended to be included in EGD's rate filings.

The methodology will be service based, focused on the needs of EGD and its usage of the services, understandable and transparent, rigorous and practical to administer and supported by verifiable data and records wherever practicable.

2.1 Regulatory Design Principles

Regulators must review and set rates in accordance with their empowering legislation. However, the legislation seldom contains specific guidance on how to set rates. As a result, regulators frequently refer to established regulatory principles to guide their judgment. These key principles include:

- just and reasonable,
- cost of service; and
- prudence.

Just and Reasonable
The primary regulatory principle, and the one most likely to be incorporated into regulatory legislation, is that rates should be "just and reasonable". "Just and reasonable" applies to both customers and regulated entities. It requires a weighting of the legitimate interests of both parties.

Cost of Service
Under this principle, a regulated entity is permitted to set rates that allow it the opportunity to recover its costs for regulated operations, including a fair rate of return on its investment devoted to regulated operations – no more, no less.

This principle is consistent with what is expected to occur in a competitive market, where the price of services tend towards the cost of providing them, including a fair return- a principle that has been recognized by the OEB:

> *The Board notes that the general role of the regulator is to act as a proxy for competition. In pricing services in a competitive market the relevant costs would be the costs incurred by the service provider in providing the service, plus an appropriate return in order to attract the capital necessary to provide the service.*[1]

It is important to note that this standard only gives the entity the opportunity to earn a fair return; it does not guarantee it. In most cases, rates are set prospectively, based on anticipated future costs. If the entity over-recovers, it usually keeps the excess. If it under-recovers, it bears the deficiency.

The 'cost of service' principle reflects the need for fairness and the necessity to offer adequate incentives for providing regulated services. That is:

- an entity's investors should have the opportunity to recover their costs, including a fair return, just as they would if they were to invest in a non-regulated entity of similar risk.

[1] OEB; RP-2001-0032; Enbridge Consumers Gas Distribution Inc.; December 13, 2002; Sec. 5.11.49.

However, customers should not have to provide investors with the opportunity to earn more than they could expect from investing in non-regulated operations.

- from an incentive viewpoint, unless investors have a reasonable opportunity to recover their costs, it will be difficult to attract the investment necessary to provide regulated operations. However, the opportunity to recover costs, including a fair return, should provide an adequate incentive to attract those funds.

Prudence

The prudence standard modifies the "cost of service" standard. Under this standard, customers should be charged only for prudently incurred costs. This recognizes a regulated entity's responsibility to manage itself in a prudent manner and provide regulated services at the most efficient cost.

Prudence is established by determining what a reasonable person would have done in a similar situation. This should not be done while making use of hindsight. A regulated entity's management can be expected to rely only on information reasonably available to it when it makes its decision.

Normally, there is a presumption of management prudence. However, the OEB has stated that this presumption will not apply to transactions between affiliates:

> *… when transactions occur between or among affiliates, the Board will not presume prudence and the onus is on the utility to establish, to the satisfaction of the Board, that the transaction is prudent and that the corresponding costs to the utility associated with the transactions are fair.*[2]

This reflects the potential conflict of interest with such transactions. As a result, regulated utilities must provide adequate support for their intercorporate charges.

In this regard, the OEB has identified what it has referred to as the "three prong test" for Corporate cost allocations, whereby a utility must demonstrate that the charges meet three tests:

- Cost Incurrence - are the proposed charges prudently incurred by, or on behalf of, the utility for the provision of a service required by Ontario ratepayers – i.e., would the utility have incurred the cost if it were operating as a stand-alone utility?,
- Cost allocation - if properly incurred, are the proposed charges allocated appropriately to the utility, based on the application of cost allocation factors and supported by principles of cost causality?; and
- Cost/Benefit - do the benefits to the utility's Ontario ratepayers equal or exceed the costs?

In meeting the third test – Cost/Benefit – the OEB has stated that it would accept four categories of support as a basis for assessing quantifiable benefits:

- Replacement benefits- the services provided replace an equivalent service at equal or lower cost,
- Synergistic or linkage benefits - the services allow the utility to reduce costs by means of being part of a larger organization and operating in concert for the procurement of products and services,
- Revenue enhancement or cost recovery benefits - the utility's activities and capabilities provide value to other affiliates for which payment in cash or kind is received; and

[2] OEB; RP-2001-0032; Enbridge Consumers Gas Distribution Inc.; December 13, 2001; Sec. 5.11.30.

- Stand-alone benefits- strategic actions and activities instituted by affiliates that produce direct value to the utility.

2.2 Budget-Based Allocations

As EGD's rates are ultimately based upon a cost of service or rebasing proceeding which uses forward year cost estimates, it is appropriate to similarly use EI's estimated costs, namely its Budget, for the RCAM.
. At EI, the budget process is rigorous and the budget is the primary tool managers use for cost control (i.e., the budget process is primarily used to control costs and not the allocation process).

Enbridge budgets costs in three categories based on the notion of grouping cost types:

Department Costs: specific employee and service related costs
General Costs: costs that support several or all business units, but do not relate to one specific affiliate
Direct Costs: costs specifically identifiable to an affiliate

2.3 Regulatory Driven Design Features

Based on regulatory principles and precedents, four key design principles were included in the RCAM design.

- Services Based Approach
- Multi-Step Allocation Process
- Service Description Transparency
- Demand Pull by Recipients

2.3.1 Service Based Approach

The core design principle for the RCAM is the adoption of a service based approach for allocation as required by the OEB and the ARC. The OEB's application of the three-prong test is designed to be applied to service based allocations:

- A utility must demonstrate that all the services associated with the corporate cost allocations are necessary, not just some of the services from a department that charges to the utility or even the majority of the services from a department.
- Where a department supports more than one service and each service has a different causal relationship to affiliates, the services must be broken out so that the most appropriate allocation can de developed for each service provided by that department.
- Cost benefit will be evaluated (wherever possible) by individual service, which requirement is to be discretely defended.

The implication is that each service is fully-burdened with all the costs incurred in delivery. The services costs will therefore include allocations from all applicable department, general and direct budgets. In addition, in some cases certain services may also provide infrastructural or content support to the delivery of other services.

2.3.2 Multi-Step Allocation Process

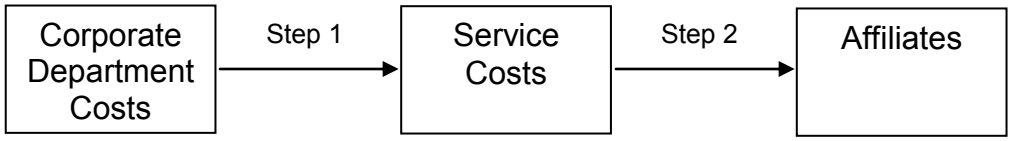
Using a (fully burdened) service based costing approach also implies that a multi-step allocation process is required. The costs are budgeted at the department level and allocated to each

service provided prior to allocation of the fully burdened service cost to the affiliate using the services. Described in its simplest form, the RCAM utilizes a two (composite) step costing approach (See Section 3 for details).

Step 1: At EI, as at most organizations, costs are collected and budgeted in cost centers or departments. Each department offers one or more services. The pool of departmental costs must firstly be allocated to the services provided by the department.

Step 2: Once the services of the department have been costed, a proportion of the cost that represents the actual usage by the affiliate is then allocated to that affiliate.

Figure 1: Two (composite *) Step Allocation Process



* In reality there are a number of sub-steps or sub-allocations that occur. In addition there are a small number of budgeted General Expenses and Direct Charges that are allocated directly as a single step to affiliates.

2.3.3 Service Description Transparency

To enable evaluation of the cost incurrence test, the services provided to the regulated entity must be transparent, both from the recipient, and the provider perspective.

From a recipient perspective, each service must be described in a way that it reflects sub components and the activities involved so that the recipient can evaluate the extent to which the full service is needed.

From a provider perspective, the service must be described in such a way that it is recognizable by every employee delivering the service so that they can assess the relative effort expended and nature of the cost consumed by the service, which will ensure the service can be appropriately costed and will reflect what the provider delivers.

The services provided, and associated expenses (e.g., General Expenses and Direct Charges) and quantity and quality indicators, for any given year are described in detailed Service Schedules appended to the RCAM Confirmation Notice (Schedule 2 to the Agreement), to be signed by both the service provider and service recipient each year.

2.3.4 Demand Pull by Recipients

The RCAM will employ a “demand / pull” approach for allocating service costs. Specifically, the service recipient will pay for only those services required as if it was a stand-alone entity calling for services from an external “arms length” service provider. While both the service recipient and the provider may jointly define the exact nature of those services, ultimately, the recipient will be responsible to confirm the need for the service(s). Through the annual performance review process, the service recipient will confirm that the services being provided meet the service recipient’s requirements, and will ensure that changes are made to those services, if necessary.

2.4 Bases of Allocation

As a general principle, one is seeking to associate and attribute costs (direct and indirect costs) specifically with individual cost objects (in this case, departments, services or affiliates) on the basis of causality.

In reality however, there will be pools of indirect costs that cannot be associated specifically with each one of the cost objects in a group of cost objects. These pools of indirect costs are called "common" costs. In such cases, an allocator that most closely reflects causality must be used.

Allocator definitions for the allocators used in RCAM are included in Appendix A: RCAM Allocator Definitions.

In general, the allocators are selected to reflect:

- the nature of the specific department, service or expense being allocated; and
- the primary drivers of the associated costs.

Primary Cost Drivers

Effort:

Where costs (direct or indirect) have their causal root in effort and can be attributed specifically to each cost object (i.e. departments, service or affiliate) on the basis of time, this allocator (time) will be used, if available.

A quarterly, backward-looking, time study will be used to establish the relative effort expended by EI resources on services provided to EGD and all other affiliates, including EI departments. The time study process will be conducted in a manner consistent with what regulators in earlier regulatory decisions (e.g. Union Gas, TransCanada) have accepted regarding the use of time studies for establishing effort and allocating costs.

In general terms, the time study will be conducted at a detailed level and input sought from each EI staff member within the departments that deliver services to EGD.

For each participating EI department, time estimates are subjected to salary weightings to ensure that departmental costs are appropriately distributed to services and affiliates. Salary weightings are calculated both for the initial allocation to services, as well as for the secondary allocation to affiliates for each service.

The time study will provide an accounting of total time spent by departments on the delivery of services (100 % of staffs' time), as well the proportion of time spent by service on EGD and other affiliates, where identifiable (100% of each staff person's time on a service provided to affiliates). Estimates of the time spent by service will be captured in seven buckets;

- EGD specific;
- EI specific;
- Liquids Pipelines and Major Projects specific;
- Gas Pipelines and Other Distribution specific;
- Sponsored Investments specific;
- International specific; and
- Common time

Usage:

This allocator will be used where costs (direct and indirect) have their causal root in usage and can be attributed specifically to each cost object, on the basis of such usage. The most appropriate allocators include volume metrics such as system users, distance, trips, etc.

Primary Cost Drivers for Common Costs

Where, however, indirect costs cannot be specifically attributed to specific cost objects (which nevertheless provide benefit), the costs may be regarded as "common".

Complexity and Size:

Where these costs have their causal root in effort or usage (and neither specific time nor specific volume metrics can be associated and attributed), allocators will be sought that reflect

- relative complexity of the recipient to be used as a proxy for the likely effort (and hence time) required to service a cost object; or
- relative size of the recipient to be used as a proxy of the likely usage of service (or the likely complexity and hence effort) required to service a cost object.

When indirect costs cannot be attributed to specific cost objects on the basis of time or volume metrics, a relatively small group of allocators will be used. These include derivations of:

- Head Count
- Salaries
- Capital Employed

Relative Benefit:

Where drivers that clearly link to causality are not identifiable, the cost allocators used will be selected to reflect the relative benefit being received by the cost objects in question. The costs incurred were allocated to reflect the benefit experienced by a group of recipients relative to each other.

This is not in conflict with a "cost plus" basis of allocation versus a "market based pricing" mechanism because market based pricing is exactly that; a pricing mechanism, while cost plus is an "apportionment of cost" mechanism.

Stand Alone Principle:

In all cases there will be an underlying intention to allocate costs that are both needed by the recipient (incurrence test) and benefit the recipient (cost benefit test). The costs allocated for the benefit of the service will therefore be equal to or lower than the amount EGD would pay as a stand alone entity for a similar service from an external arms length provider.

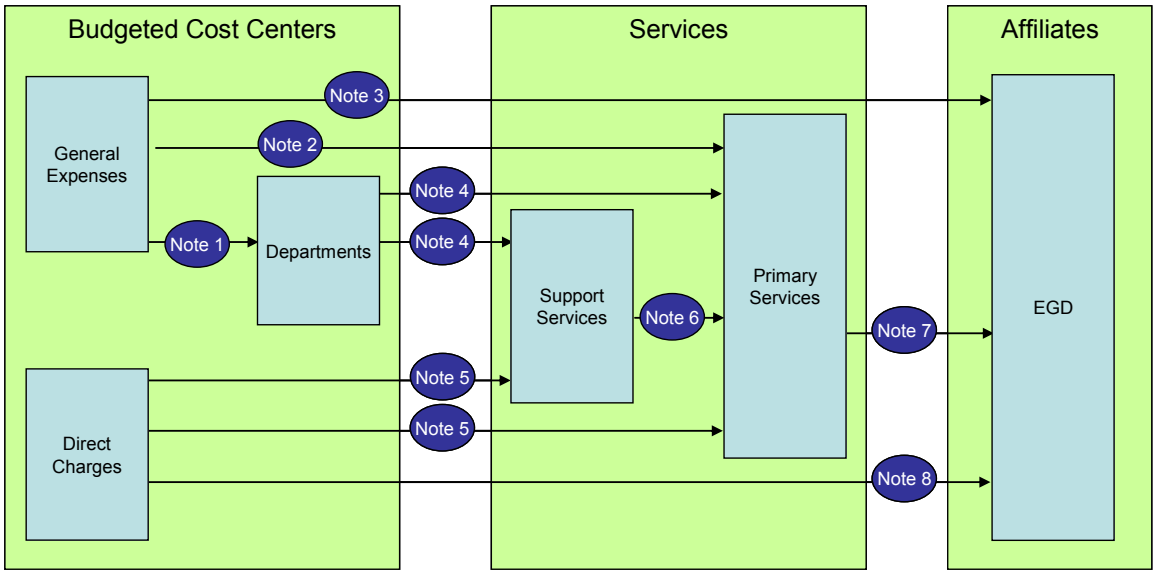
2.5 Currency Usage for Allocations and Direct Charges

Allocations and direct charges will be made in Canadian funds.

3 ALLOCATION

This section reviews the RCAM allocation model. It documents the mechanics and provides a brief rationale for each step.

RCAM Allocation Model



3.1 General Expenses-to-Departments Allocations

Note 1:

EI budgets contain a group of expenses labeled as "General Expenses". These expenses are separately budgeted for management purposes. Some of the General Expenses, however, are incurred for the benefit of Departments (EI only) and some for affiliates. In cases where the General Expenses represent costs incurred by individuals or groups of individuals, the allocation is made to departments in which the individuals reside.

General Expense[1]	Cost Driver	Allocator to Dept
Business Taxes	Usage of facility	Calgary Head Count
Rent & Leases	Usage of facility	Calgary Head Count
Employee Benefits	Usage	Salaries (segmented)
EI's Stock Options (SO), Phantom Stock Units (PSU) and Restricted Stock Units (RSU) Charges[2]	Usage	Head Count - specific
Other Employee Benefits	Usage	Salaries (segmented)
Corporate Law Legal Fees	Staff	Direct
Depreciation - Other Corporate	Direct & Usage	Direct (Plane & IT Projects) Calgary Head Count (other Depreciation)

[1] – General Expenses were not allocated to services provided by EPI and EGD as EI received "fully loaded" allocations from the originating entity.

[2] –

Stock Options (SO) Calc: The fair value of stock options is determined at the date of grant using the Black Scholes model. The number of the SOs vested each year is valued at the market price on the date of vesting, minus the grant price for those vested shares.

Phantom Stock Units (PSU) Calc: PSU holders receive notional units as if one unit was one common share. PSU holders receive cash awards following a three-year performance cycle. Awards are calculated for each outstanding unit at the end of the performance period using the EI weighted average share price and a performance multiplier. The performance multiplier is derived through a calculation of specified performance metrics in relation to a specified peer group of companies, relative to targets established at the time of the grant.

Restricted Stock Units (RSU) Calc: RSU holders receive cash per outstanding unit equal to EI's weighted average EI share price at the time of maturity, 35 months from the date of grant. The outstanding units accumulate notional dividends during their validity.

3.2 General Expenses-to-Primary Services Allocations

Note 2:

In cases where the General Expenses are not incurred based on individuals or groups of individuals and are not affiliate specific, the allocation will be made to the services they support.

General Expense	Cost Driver	Allocator to Service
Industry Associations	Usage	Direct
Corporate Secretarial Legal Fees	Usage	Direct

3.3 General Expenses-to-Affiliate Allocations

Note 3:

In cases where the General Expenses can be specifically identified with an affiliate, the costs will be directed to each affiliate respectively.

General Expense	Cost Driver	Allocator to Affiliate
Directors Fees & Expenses	Effort	Capital Employed
Depreciation - Risk Management System (50%)	Usage	System Usage

3.4 Department-to-Service Allocations

Note 4:

All department costs (loaded with applicable General Expenses) will be allocated to the respective services they provide.

In the majority of cases, staff costs represent a significant portion of the department costs and this clearly links effort to causality as the primary driver of the cost of delivering a service. The primary allocator of costs from Department-to-Services in this situation will be "salary-weighted time". (This will include those non-salary costs required to support the Department that are not material in their own right).

In cases where non-salary costs are significant, allocators other than salary-weighted time will be selected and depending on the nature of the costs are allocated (on the basis of causality), either:

- as a direct charge to the respective service; or
- on the basis of usage.

On this basis, all department costs will be allocated on time estimates to the respective services they provide with two exceptions – the Corporate Administration Department and Enterprise Financial System (EFS) Department, as explained below.

1) Due to the materiality of some of the non-salary related costs, the Corporate Administration Department will use:

   - direct allocation of material office administration costs to the Corporate Office Administration Service;
   - direct allocation of maintenance and licence fees related to the HRIS (PeopleSoft), to the Human Resource Information Systems (HRIS) Program Management and Development Service
   - direct allocation of maintenance and licence fees related to the Records Management System (Livelink) to the Records and Information Management Service;
   - direct allocation of maintenance and licence fees related to the Portal Suite of Applications (elink) to the Portal Suite Operations and Technical Support Service; and
   - the remaining costs are allocated based on time estimates to all services provided by the department. (i.e., Corporate Office Admin. Service, Expense System and Supply Chain Management).

2) The costs for supporting the Enterprise Financial Systems (EFS) will be incurred directly by multiple affiliates for the purpose of delivering enterprise financial services. For allocation purposes, the participating affiliates' original budget allocations are notionally aggregated and the charges are calculated based on affiliate user count. The difference between this affiliate calculation and the affiliate's original budget allocation (debit or credit) is allocated to the affiliate.

3.5 Direct Charges-to-Services Allocations

Note 5:

The "direct charges" will represent expenses incurred directly by EI which can be tracked on an affiliate specific basis. Direct charges of EI also include allocated costs from EGD and EPI for services provided by them to EI. These costs are added directly into the EI Services. These services will then be reallocated to the affiliates (including EGD and EPI). Where a portion of EGD costs allocated to EI would not be incurred for EGD on its own behalf they will not be re-allocated back to EGD.

3.6 Support Service-to-Primary Service Allocations

Note 6:

In establishing the RCAM, all services provided by EI will be identified, costed and made available to EGD for review. EGD will indicate which services are not directly required by them. Where these services are nevertheless regarded by EI as crucial to support the delivery of the services which EGD does need they are added in to those Primary Services that they support (See Appendix F: Support Service Loading for further service definitions). (The rationale underlying this support services loading is that it makes it comparable to an external service provider establishing a basic infrastructure and operational support to conduct a service delivery business. The costs of such support services will be included in the pricing of primary services to

the customers of the external service provider). The distinction between "primary" services and "support" services and the approach to classification is set out below:

Classifying Services as Support vs. Primary:

The following decision chart is used to classify services as either a Primary or Support Service:

Question 1:

Does the affiliate agree that the service is needed directly by them?

- If the answer is "yes" the service is likely to pass the incurrence test as a valid primary service.
- If the answer is "no" a 2nd question will be asked, namely;

Question 2:

Does the affiliate agree that the service is necessary to support the services that are needed directly by them?

- If the answer is "yes" the services is likely to pass the incurrence test to the extent that the service it supports passes the cost incurrence test and is therefore a valid support service.
- If the answer to question 2 "no", then no part of the "support'' service cost will be allocated to the affiliate.

Based on the decision chart established above, the services will be divided into "support" and "primary" services. The nature of each support service will help to determine which primary services receive the costs from each respective support service (i.e., which primary services benefit from the support service). Therefore, the nature of each "support" service is examined and segmented into three groups, namely those that provide "content" based support, those that provide "infrastructural" based support, and those that provide "resource" based support to the primary services.

Loading of Support to Primary Service

Although time estimates were also obtained for determining the extent to which each of the support services were considered to be directly supporting the affiliates, no part of the support service is allocated directly to any affiliate. The full cost of each support service is loaded into the primary services they support. The fully loaded cost of the primary service is then allocated to the affiliate based on the time estimates provided for the respective primary service. Similarly, the common portion would be allocated as determined for the residual of the primary service.

Infrastructural Support Services are considered to be needed by all EI Departments in Calgary providing Primary Services and are therefore allocated across all these Primary Services, based on a Derived Head Count (DHC) of the Primary Service. (Appendix A: RCAM Allocator Definitions)

Content Support Services are allocated to the specific primary services they support based on the relationship of the respective primary service costs. (The DHC of each department is not a reasonable base for allocation for content support services as the volume of people is not the driver of the need for these support services.)

The Resource Support Service is allocated to the services provided by the departments they directly supported as per the time estimation study results.

The summary of support service allocations to Primary Services are listed below:

Support Service	Driver	Allocator
Content Support Services		
Financial Reporting	Complexity & or Usage	Service cost
Certification of Financial Reporting & Internal Controls	Complexity & or Usage	Service cost
Consolidation Accounting	Complexity & or Usage	Service cost
Budgeting & Forecasting	Complexity & or Usage	Service cost
Infrastructure Support Services		
Air Travel for Company Personnel	Usage	Trips[1]
Corporate General Accounting	Usage	Transactions
Corporate Office Administration	Usage	DHC
Environment, Health & Safety	Usage	DHC
Helpdesk, Network, Infrastructure & Hardware Support	Usage	DHC
Information System Support Applications	Usage	DHC
Invoice Processing and Payment	Usage	DHC
IT Project Management & Support	Usage	DHC
IT Software Support & Maintenance	Usage	DHC
Payroll & Benefits Processing	Usage	DHC
Resource Support Service		
Financial Projects	Usage	Direct

[1] Trips – In determining the allocation of the aviation service for transporting company personnel to primary services, the number of flights and the individuals traveling per flight were extracted from the flight logs. With this information and an estimated cost per flight (based on an average cost per km to operate the aircraft and the estimated km traveled per flight) a cost equally shared per individual per flight could be derived. The cost would then track with the individual to their respective affiliate or department and be allocated to the services they support based on the results of the time estimation study. Costs derived in the same manner for each non-Enbridge employee on every flight were treated as a residual corporate cost.

3.7 Service-to-Affiliate Allocations

Note 7:

The link between the basis of allocation and causality is regarded as crucial to the service being able to pass the cost incurrence test. Time is regarded as one of the most supportable causal factors. The methodology therefore seeks to allocate as much of the service cost as possible on the basis of time actually spent delivering the service to affiliates.

Therefore, three broad parameters are considered in the allocation of the cost of the service;

1) How much of the effort spent on delivering the service can be identified and attributable directly to EGD?
2) How much of the effort spent on delivering the service can be identified and attributable directly to other affiliates?
3) How much of the effort spent on delivering the service cannot be identified directly attributable to any affiliate (common cost)?

These proportions have been established by the Time Study.

The effort spent on delivering the Primary Service to EGD versus other affiliates has been identified and used to attribute the portion of the cost of the Primary Service to EGD and other affiliates on the basis of salary-weighted time estimates.

The residual pool of common time is then allocated on a different allocator selected to align as closely as possible to causality.

Not all "common costs" benefit every one of the affiliates. This has specific relevance to the Minority Investments (MIs) which. are sometimes merely financial assets of EI and sometimes fully owned and operated under contracts, etc. The benefiting affiliates will be identified before selecting the allocator which will reflect the most appropriate proxy for causality. See Appendix A for the definition of all acronyms used below.

Service	External Driver	Effort Required by EI to support the acquisition and holding of Financing Minority Interests (FMIs)	Allocator
EGD Required Primary Services Provided Solely by EI (i.e. EGD has no capability to self-serve)			
Board of Directors Support	Company complexity & number of meetings	Yes	FCER
Business Development[1]	Mergers & Acquisitions (M&A) activity	No	ACER
Capital Market Financing & Access	Financing activity	Yes	FCER
Cash Management & Banking	Cash volume	No	EGD % of Direct Time[3]
Enterprise IT Program Management	IT programs	No	ACER
Enterprise IT Strategy Planning & Management	IT assets	No	ACER
External Audit Coordination	Audit size (hence company complexity)	Yes	Same as Audit Fees
Government Relations	Regulations	No	ACER
Human Resource Information Systems (HRIS) Program Management and Development	HRIS IT asset usage	No	AHC
Investor Services	M&A and financing activity	Yes	FCER
Rate Regulated Entity Support	Regulation and company complexity	No	N/A

Service	External Driver	Effort Required by EI to support the acquisition and holding of Financing Minority Interests (FMIs)	Allocator
Records and Information Management	Transactions, contracts, documents	No	System Users
Risk Assessment and Management	Entity risk	Yes	FCER
Supply Chain Management	Raw material volumes	No	ACER
EGD Required Primary Services Provided as a Supplement to EGD's Own Capabilities			
Audit & Accounting Advice	Company complexity	Yes	FCER
Business & Economic Financial Analysis	M&A activity	No	EGD % of Direct Time[3]
Consolidation and Planning System Technical Support (Khalix)	IT asset usage	No	System Users
Corporate Compliance	Company complexity	No	ACER
Emerging Energy Technology Research	New technologies	No	ACER
Employee and Labour Relations	Employees, Unionized employees	No	AHC
Employee Development	Employees	No	Non Union EFTE
Expense System Management & Technical Support (Oracle iExpense)	IT asset usage	No	System Users
Financial and Project Accounting System Technical Support (Oracle)	IT asset usage	No	System Users
Gas Supply, Storage, and Transportation Strategy	Raw material volumes	No	EGD % of Direct Time[3]
Human Resource Advice	Employees	No	AHC
Industry Relations and Corporate Social Responsibility (CSR)	Customer base and public Interest	No	ACER
Insurance Claims Support	Claims	No	EGD % of Direct Time[3]
Insurance Strategy and Management	Entity risk	Yes	Same as Insurance Premiums
Legal Advice	Regulation, Contracts, M&A	No	ACER
Planning, Management & Execution of Internal Audits	Company complexity	Yes	Same as Audit Fees
Portal Suite Operations and Technical Support	Portal IT asset usage	No	System Users
Strategic Planning[2]	Complexity (company & markets)	Yes	FCER

Service	External Driver	Effort Required by EI to support the acquisition and holding of Financing Minority Interests (FMIs)	Allocator
Tax Reporting & Planning	Legal Entities, M&A, financing	No	EGD % of Direct Time[3]
Total Compensation and Benefits	Employees	No	AHC
Primary Services Not Required by EGD			
Aerial Pipeline Surveillance	Not Required by EGD	N/A	N/A
External Communications	Customer base and public interest	No	ACER
Gas Accounting	Not Required by EGD	N/A	N/A
Gas Contract Accounting	Not Required by EGD	N/A	N/A
Internal Employee Communications	Employees	No	AHC
Pension Plan Asset Management and Administration	Already charged separately to EGD	N/A	N/A
Reservoir Engineering	Not Required by EGD	N/A	N/A
Tax Advice	Legal Entities, M&A, financing	No	EGD % of Direct Time[3]

[1] Common Business Development Costs accepted by EGD include only the proportion related to costs incurred by the Ontario Business Development department

[2] Common Strategic Planning costs are not accepted by EGD and are regarded as an EI cost

[3] Where time estimates allocated over 80% of the primary service costs specifically to affiliates, it is deemed reasonable to assume the proportion of effort between EGD specific and "Other" specific affiliates was a fair representation for the allocation of the common (to the benefit of all affiliates) effort.

3.8 Direct Charges-to-Affiliate Allocations

Note 8:

EI budgets contain a group of expenses labeled as "Direct Charges". These charges are separately budgeted for management purposes. They, however, are incurred specifically for affiliates and the details may be tracked directly for the benefit of a particular affiliate.

Direct Charges	Driver	Allocator to Affiliate
Audit Fees	Complexity	Direct
Depreciation – Risk Management System	Usage/ Transactions	Direct
Direct EFS Charge (Credit)	Usage	Direct
Directors Fees and Expenses	Company complexity & number of meetings	FCER
EGD Stock Based Compensation[1]	Usage	AHC – specific
Insurance Premiums	Risk	Direct

[1] Refer to footnote in Note 1

4 RETURN ON INVESTED CAPITAL

ARC allows for a return on "invested capital" as indicated below.

> *2.3.10 Where it can be established that a reasonably competitive market does not exist for a service, product, resource or use of asset that a utility acquires from an affiliate, the utility shall pay no more than the affiliate's fully-allocated cost to provide that service, product, resource or use of asset. The fully-allocated cost may include a return on the affiliate's invested capital. The return on invested capital shall be no higher than the utility's approved weighted average cost of capital.*

A return on invested capital has not been incorporated as a part of each Primary Services' fully allocated cost, but is included as a separate charge in RCAM.

The "invested capital" has been defined as the NBV (net book value) of PPE (property, plant and equipment) assets of EI required to provide the services.

5 UPDATE AND REVIEW PROCESS

The RCAM is a dynamic document which must be reviewed and updated periodically to ensure its relevance to both EI and EGD to reflect organizational changes of the business and any changes to the regulatory environment. There are five key areas that need to be addressed.

5.1 Service Schedule Detail Reviews

The performance review & evaluation and dispute resolution clauses from the Service Agreement (SA) may highlight changes that need to be reflected in the Service Schedules. While performance feedback may occur throughout the life of the SA, a formal discussion shall take place periodically, at least annually, to ensure changes are documented and incorporated into the next SA and rate case filing. Changes may occur in the service definitions, service offerings by department, expected service deliverables and quality & quantity descriptors.

5.2 Service Review for Relevancy to EGD

The second step in the review process is a review for service relevancy to EGD. Reflecting on the performance feedback process and service schedule reviews, services allocated to EGD shall be reviewed, as part of the performance review process, to ensure that they still meet the cost incurrence test. In addition, services that are currently deemed support services or have not in the past been allocated to EGD shall be reviewed to ensure proper treatment. Changes made to the Service Schedules shall be captured within a revised version of the RCAM, updated annually.

5.3 Time Estimation Study

Once the Service Schedules have been updated with changes highlighted from 5.1 and 5.2, the detailed time estimation study will be conducted, if necessary, to estimate the future time that the EI corporate office will provide to the respective services. The results of the time estimation study are used as an input into the allocation model calculation. The time estimation study will be conducted at the end of each quarter.

5.4 Allocator Review

Concurrently with the time estimation study, a review of the cost allocators will be conducted. This review shall include a determination of whether or not the allocator is still appropriate for use with the service or expense in question, an evaluation of whether the information required for its

calculation is available and whether or not the calculation definition needs to be revised based on an organizational change within Enbridge. Changes shall be documented, including the rationale for the change, in a revised version of the RCAM.

5.5 Cost Calculation

Once all Service Schedules are updated, the time estimation study complete and a review of the allocators complete, the cost allocation model shall be revised and run to determine the specific cost allocations from EI to EGD.

APPENDIX F – MNP DETAILED ISA REVIEW

ARC Section		Substantiating Evidence	Opinion	Recommendation(s)
2.2	**Sharing of Services and Resources**			
2.2.1	**Where a utility shares services or resources with an affiliate it shall do so in accordance with a Services Agreement, the length and terms of which may be reviewed by the Board to ensure compliance with this Code. The Services Agreement shall include documentation of:**			
(a)	**the type, quantity and quality of service;**	• **Appendix B of Schedule 2 to the ISA –** "*Regulatory Cost Allocation Methodology Service Schedule*" documents the service definition, breakdown of services as provided by each Service Provider department, EGD representative responsible for agreeing to the service, cost of the service, expected deliverables, and the quantity and quality of the service.	Complies	• None noted.
(b)	**pricing mechanisms, which shall be consistent with section 2.2.5 and section 2.3;**	• The pricing mechanism is detailed within the RCAM, which forms Schedule 1 of the ISA. • Refer to sections 2.2.5 and 2.3 for substantiating evidence on compliance.	Complies	• Recommendations have been made for **Section 2.3.3**
(c)	**cost allocation mechanisms, which shall be consistent with section 2.3.11.3;**	• The cost allocation mechanism is detailed within the RCAM, which forms Schedule 1 of the ISA. • Refer to sections 2.3.11.3 for substantiating evidence on compliance.	Complies	• None noted.
(d)	**information disclosure and confidentiality arrangements, which shall be consistent with section 2.3.1.2;**	• Refer to sections 2.3.1.2(a) and 2.3.1.2(b) for substantiating evidence on compliance.	Complies	• None noted.
(e)	**the apportionment of risks (including risks related to under or over provision of service); and**	• There is no provision in the ISA for the apportionment of risks. • Cost of services is derived from EI's departmental budgets and the respective service's deliverables in terms of quality and quantity. These	Complies; improvement recommended	• Include a section detailing the apportionment of risk.

ARC Section		Substantiating Evidence	Opinion	Recommendation(s)
		costs are detailed in the Service Schedules, which are reviewed and accepted by the Service Recipients annually. • Based on the acceptance of the ISA, EGD bears the risk of under provision, while EI bears the risk of over provision.		
(f)	**a dispute resolution process for any disagreement arising over the terms or implementation of the Services Agreement.**	• **Section 15 of the ISA** documents the dispute resolution process.	Complies	• None noted
2.2.5	**In the event of an emergency situation a utility may share services and resources, without a Services Agreement, with an affiliate which is also a utility. The transfer pricing rules set out in section 2.3 do not apply when a utility and an affiliate share services in an emergency situation; a reasonable fully-allocated cost-related price shall be determined afterwards by the parties.**	• There is no provision in the ISA indicating conduct and/or provision of shared services and resources during an emergency. • **Section 2 of the ISA** implicitly addresses this requirement.	Complies	• None noted
2.3	**Transfer Pricing and Cost Information Disclosure**			
	Terms of Contracts with Affiliates			
2.3.1	**The term of an Affiliate Contract between a utility and an affiliate shall not exceed five years, unless otherwise approved by the Board.**	• **Section 8 of the ISA** (consists of 8.1, 8.2, and 8.3) indicates that the current agreement shall be effective as of January 1, 2011, and terminates on December 31, 2015, which is effectively five years.	Complies	• None noted
2.3.1.A	**Despite section 2.3.1, the term of an Affiliate Contract between a utility and an**	• Based on the OEB's definition of 'qualifying facilities' as set out in document G-2010-0030 dated	Not applicable	• None noted.

ARC Section		Substantiating Evidence	Opinion	Recommendation(s)
	affiliate that is exclusively for the provision of services, products, resources or use of asset related to a qualifying facility may extend to a maximum of 20 years. Where an Affiliate Contract between a utility and an affiliate is for the provision of services, products, resources or use of asset that relates to, among other things, a qualifying facility, only that portion of the Affiliate Contract that relates to a qualifying facility may have a term that extends to a maximum of 20 years.	February 25, 2010, the services provided by EI to EGD do not fall within this category.		
2.3.1.2	**A utility shall not enter into or renew an Affiliate Contract with an affiliate unless it contains provisions which require the affiliate to:**			
(a)	**comply promptly with all requests either made or authorized by the Board for information with respect to: (i) the services, resources or products provided under the contract; and (ii) the cost to the affiliate of providing any service, resource or product under the contract; and**	• **Section 10 of the ISA** details the disclosure and confidentiality agreement between EI and EGD with respect to the shared services arrangement.	Complies	• None noted.
(b)	**include equivalent provisions to those set out in this section in any contracts the affiliate enters into with another of its or the utility's affiliate for the purpose of providing any service, resource or product used in the provision of a**	• **Section 10 of the ISA** details the disclosure and confidentiality agreement between EI and EGD with respect to the shared services arrangement.	Complies	• None noted.

ARC Section		Substantiating Evidence	Opinion	Recommendation(s)
	service, resource or product to the utility.			
	Utility's Internal Costs			
2.3.2	**If a utility intends to enter into an Affiliate Contract for the receipt of a service, product, resource, or use of asset that it currently provides to itself, the utility shall first undertake a business case analysis.**	• EGD conducts individual Business Cases for each service received. "*Business Cases*"	Complies	• None Noted
2.3.2.A	**Despite section 2.3.2, a utility shall not be required to undertake a business case analysis prior to entering into an Affiliate Contract for the receipt of a service, product, resource or use of asset that it currently provides to itself and that pertains exclusively to the ownership and operation of one or more qualifying facilities.**	• Not Applicable	Not Applicable	• None noted.
2.3.3	**For purposes of section 2.3.2, the business case analysis shall contain (a) description of relevant utility needs on a per-service basis, (b) identification of the options available internally or externally from an affiliate or third party, (c) economic evaluation of all available options including the utility's current fully-allocated cost (which may include a return on the utility's invested capital equal to the approved weighted average cost of capital), (d) explanation of the**	• EGD conducts individual Business Cases for each service received. "*Business Cases*"	Complies; requires improvement	• **Consistency amongst business cases** – the level of detail and justification is inconsistent on a case to case basis; some lack in detail, while others were extensive. • **Comparative cost assessments are incomplete in some instances** • **Estimate of benefits to the utility's Ontario ratepayers are incomplete in some instances**.

ARC Section		Substantiating Evidence	Opinion	Recommendation(s)
	selection criteria (including any non-price factors to be taken into account), (e) estimate of any benefits to the utility's Ontario ratepayers from outsourcing, and (f) justification of why any separate items were bundled together when considered for outsourcing.			
2.3.3.2	**If a utility wishes to continue to receive from any affiliate a service, product, resource, or use of asset, the business case analysis described under section 2.3.2 must be repeated at least once every five years.**	• EGD conducts individual Business Cases for each service received. "*Business Cases*"	Complies	• None noted
2.3.3.3	**Section 2.3.3.2 does not apply to a service, product, resource or use of asset that pertains exclusively to the ownership and operation of one or more qualifying facilities.**	• Not Applicable	Not Applicable	• None noted.
	Where a Market Exists			
2.3.4	**Where a reasonably competitive market exists for a service, product, resource or use of asset, a utility shall pay no more than the market price when acquiring that service, product, resource or use of asset from an affiliate.**	• Compliance to this section is not required as EI and EGD have agreed to apply fully-allocated cost-based pricing as per section 2.3.11.2 of the ARC.	Complies	• None noted.
2.3.5	**A fair and open competitive bidding process shall be used to establish the market price before a utility enters into or renews a contract with an affiliate.**	• Compliance to this section is not required as EI and EGD have agreed to apply fully-allocated cost-based pricing as per section 2.3.11.2 of the ARC.	Complies	• None noted.

ARC Section		Substantiating Evidence	Opinion	Recommendation(s)
2.3.6	**Despite section 2.3.5, where satisfactory benchmarking or other evidence of market price is available, a competitive tendering or bidding process is not required to establish the market price for contracts with a value of less than $100,000 or 0.1% of the utility's revenue net of the cost of gas, whichever is greater.**	• Compliance to this section is not required as EI and EGD have agreed to apply fully-allocated cost-based pricing as per section 2.3.11.2 of the ARC.	Complies	• None noted.
2.3.7	**Where the value of a proposed contract exceeds $300,000 or 0.3% of the utility's revenue net of the cost of gas, whichever is greater, a utility shall not award the contract to an affiliate before an independent evaluator retained by the utility has reported to the utility on how the competing bids meet the criteria established by the utility for the competitive bidding process.**	• Compliance to this section is not required as EI and EGD have agreed to apply fully-allocated cost-based pricing as per section 2.3.11.2 of the ARC.	Complies	• Not applicable.
2.3.8	**The Board may, for the purposes of sections 2.3.6 and 2.3.7, consider more than one contract to be a single contract where it has been entered into for the purpose of setting the contract values at levels below the threshold level set out in section 2.3.6 or 2.3.7.**	• Compliance to this section is not required as EI and EGD have agreed to apply fully-allocated cost-based pricing as per section 2.3.11.2 of the ARC.	Complies	• Not applicable.
2.3.9	**Where a reasonably competitive market exists for a service, product, resource or use of asset, a utility shall**	• Compliance to this section is not required as EI and EGD have agreed to apply fully-allocated cost-based pricing as per section 2.3.11.2 of the	Complies	• Not applicable.

ARC Section		Substantiating Evidence	Opinion	Recommendation(s)
	charge no less than the market price of the service, product, resource or use of asset when selling that service, product, resource or use of asset to an affiliate.	ARC.		
	Qualifying Facilities			
2.3.9.A	**For a service, product, resource or use of asset that pertains exclusively to the ownership and operation of one or more qualifying facilities, fully-allocated cost-based pricing (as calculated in accordance with section 2.3.10 or 2.3.11) may be applied between a utility and an affiliate in lieu of applying the transfer pricing provisions of section 2.3.4 or section 2.3.9.**	• Based on the OEB's definition of 'qualifying facilities'[1] as set out in document *G-2010-0030* dated February 25, 2010, the services provided by EI to EGD do not fall within this category.	Not applicable	• None noted.
	Where No Markets Exists			
2.3.10	**Where it can be established that a reasonably competitive market does not exist for a service, product, resource or use of asset that a utility acquires from an affiliate, the utility shall pay no more than the affiliate's fully-allocated cost to provide that service, product, resource or use of asset. The fully-allocated cost may include a return on the affiliate's invested capital. The return on invested capital shall be no higher than the utility's**	• Compliance to this section is not required as EI and EGD have agreed to apply fully-allocated cost-based pricing as per section 2.3.11.2 of the ARC.	Complies	• None noted.

[1] Qualifying facilities or assets: "*the ownership and operation of renewable energy generation facilities, combined power and thermal (heat) energy generation facilities, energy storage facilities and assets in relation to energy conservation*."

ARC Section		Substantiating Evidence	Opinion	Recommendation(s)
	approved weighted average cost of capital.			
2.3.11	**Where a reasonably competitive market does not exist for a service, product, resource or use of asset that a utility sells to an affiliate, the utility shall charge no less than its fully-allocated cost to provide that service, product, resource or use of asset. The fully-allocated cost shall include a return on the utility's invested capital. The return on invested capital shall be no less than the utility's approved weighted average cost of capital.**	• Compliance to this section is not required as EI and EGD have agreed to apply fully-allocated cost-based pricing as per section 2.3.11.2 of the ARC.	Complies	• None noted.
	Shared Core Corporate Services			
2.3.11.2	**Despite sections 2.3.4 and 2.3.9, for shared core corporate services, fully-allocated cost-based pricing (as defined under sections 2.3.10 and 2.3.11) may be applied between a utility and an affiliate.**	• EI and EGD have agreed to apply fully-allocated cost-based pricing as permitted by this section of the ARC. • Since EI and EGD chose to exercise this section, the requirement to comply with sections 2.3.4 and 2.3.9 is superseded.	Complies	• None noted.
2.3.11.3	**Reasonable cost allocation shall be applied to all shared corporate services. The methodology for this calculation shall be documented under section 2.2.1(c).**	• **Section 5 of the ISA** indicates that cost allocations are made in accordance to the processes and procedures documented in the Regulatory Cost Allocation Methodology (RCAM). • The RCAM represents Schedule 1 to the ISA, and details both the pricing and cost allocation mechanisms. • Appendix A to Schedule 1 provides detailed definitions to the RCAM	Complies	• None noted.

ARC Section		Substantiating Evidence	Opinion	Recommendation(s)
		allocators used to determine the cost of services and charges allocated to EGD. • MNP's review of the RCAM indicates that a reasonable cost allocation methodology is being applied.		

APPENDIX G – MNP CURRICULUM VITAES

Jason Hails, MBA
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PROFILE	Jason Hails is a Partner within MNP Consulting based in Toronto and leads the firm's Energy and Utilities Practice nationally. Jason brings over 18 years of business experience, including 8 years consulting primarily to the public, energy and utilities sectors in Canada and the United States. Jason has acquired significant knowledge and experience in the areas of: • Large-scale project management & quality assurance • Performance improvement • Policy and program management • Regulatory and financial compliance • Capital project support (finance and risk) • Business and economic development Jason has worked with numerous utilities, energy-related ministries and regulators across Canada, and with several large integrated utilities in the US. Current and previous clients include Enbridge, the Ontario Power Authority, BC Hydro, ENMAX, EPCOR, SaskPower, Duke Energy, Pacific Gas & Electric (PG&E), FortisBC, the Alberta Department of Energy, the Alberta Utilities Commission and the National Energy Board. Other Firm clients include the IESO, Fortis, Manitoba Hydro and several Local Distribution Companies in Ontario. Jason's utilities experience spans a number of functional areas, including Renewable and Traditional Generation, Transmission and Distribution, Smart Grid, Regulatory and Witness Support, Revenue Management, Supply Chain, Financial Operations, IT and other shared services. Jason's organizational development work in the energy sector has included transaction support and financial due diligence, merger integration, governance and organizational structure reviews and implementations and operations and shared services reviews (e.g. finance, supply chain, facilities, customer services) for regulatory and efficiency mandates. Jason's experience also includes system and process-based performance measure development and implementation for energy companies.
SERVICE LINE	Management Consulting
INDUSTRY FOCUS	Energy & Utilities, Public Sector
OFFICE	Toronto, Ontario and Calgary, Alberta

Selected Assignments:

INDUSTRY	SERVICE LINE	PROJECT DESCRIPTION
Energy, Pipelines	Financial Advisory, Project Management	Pipeline Abandonment Trust Development – Pursuant to the land matters consultation initiative of the National Energy Board, Jason is currently working with a team to manage the development of a pipeline abandonment trust for a major Canadian pipeline company. This project includes project management, financial and process advisory and collaboration with other service groups including valuation, actuarial, regulatory, finance and asset management (ongoing).
Energy &	Cost Consulting	Cost Allocation Review – For a large gas distribution company in Ontario,

Utilities		Jason is conducting an independent review of the allocation of shared services costs from a corporate parent to its subsidiary. The review is being undertaken for submission and defense before the Ontario Energy Board (ongoing).
Energy & Utilities	Process Improvement, Customer Service	Business Process Quality Assurance Review – Jason is currently leading a team of consultants conduct a review for a large electric and natural gas distribution company. The client is implementing SAP CRB (Customer Relationship & Billing for Utilities) concurrently with the development of a greenfield customer service organization to serve over one million customers. The engagement includes review of future state business processes and a risk- based approach to identify and evaluate potential process gaps at go-live (ongoing).
Energy & Utilities	Regulatory Finance, Pipelines	Regulatory Tariff Application – For the third year, Jason is currently leading a team in the development of key components of a General Rate Application for a North American pipeline company. The current application will form the basis for a negotiated settlement, with anticipated submission to the National Energy Board. The applications include development of throughput volume/ toll calculations, and development, analysis and reporting of rate base, rate of return and cost of service filings (ongoing - 7 months over a three year period).
Energy & Utilities	Regulatory, Transmission	Economic Study – Jason recently worked with an intervenor to review the financial assumptions and output relating to the facility application to build a transmission line in Alberta. His team also presented financial scenarios for consideration based upon alternative assumptions, costs and design, and Jason provided Witness Support in AUC Board hearings (4 months).
Energy & Utilities, Public Sector	Economic Analysis for Infrastructure Growth	Financial Analysis and Forecasting – For the Oil Sands Secretariat (Alberta Treasury Board), Jason recently led a team in the development of several extensive financial models (linear regression and forecast) and a report to assist the secretariat plan for infrastructure growth based on a number of key economic, community and population-based indicators (4 months).
Public Sector	Economic Development	ICT Sector Supply Chain Assessment – For a mid-sized Alberta Municipal Economic Development organization, Jason led an assessment of its Information, Communications and Technology sector. They assessment included a current state assessment, including interviews with over 20 ICT companies, a supply chain gap analysis and recommendations to evolve the sector and close priority gaps (2 months).
Energy & Utilities	Regulatory, Valuations, Distribution and Transmission	Benchmark Study (Affiliate Transactions) – Jason led the development of benchmark study to assess the relative value of services provided by an unregulated entity of the large regulated utility. The project includes a fair market value assessment, a benchmark study for comparison purposes, and the development of a cost-build-up to value of internal service provision at the regulated entity (4 months - ongoing).
Energy, Public Sector	Regulatory, Process Improvement, Oil & Gas	Department of Energy Oil & Gas Regulatory Framework – The Government of Alberta recently announced a competitiveness report "Energizing Investment: A Framework to Improve Alberta's Natural Gas and Conventional Oil Competitiveness". The report introduced a new Royalty framework and a high-profile initiative to enhance and streamline the Oil & Gas regulatory system. Led by Jason, MNP acted as the Project Manager for the Regulatory Enhancement Project and helped guide the development of system-wide recommendations for implementation. The Project involved multiple Alberta Government Ministries and a significant group of stakeholders (9 months).

Energy & Utilities, Public Sector	Internal Controls, Reporting	National Energy Board – Jason recently provided subject matter expertise in conjunction with MNP's Enterprise Risk group in performing a review of operational and financial controls. The focus of the Project is on the Procure-to-Pay, Financial Reporting, Payroll and Revenue processes, and will improve reporting standards for the Auditor General and other stakeholders (3 months).
Public Sector	Process Improvement	Alberta Pensions Services (APS) – Jason recently provided subject matter expertise and quality assurance for an engagement with APS to streamline customer service and operational functions for pension estimates and annual statements for over 500 participating employers and about 300,000 members and pensioners. The project result is for APS to improve effectiveness and efficiency in meeting its mandate (4 months).
Energy & Utilities	Markets and Tax	Valuations Opinion – Jason recently supported the MNP valuations team conduct a review and assessment of a large electric industry infrastructure sale for the Canada Revenue Agency. The review specifically focused on the valuation methodology recorded by the seller for accounting and tax purposes. The review included an assessment of previous similar transactions in the industry and commonly accepted accounting treatment(s) (1 month).
Energy & Utilities	Performance Measurement & Management	Alberta Utilities Commission – Jason led a team to review and make recommendations to improve business plan objectives and performance measures, developed and implemented a performance measure tracking system, and reviewed alignment between corporate performance measures and executive contracts and compensation (7 months over 3 years).
Energy & Utilities	Revenue Management	Functional Advisor – Jason recently worked with a large integrated provincial utility to provide functional quality assurance for several business transformation project teams. The projects incorporate improvements to systems, processes and performance management related to Customer Services, Billing, Collections, Metering, with a focus on billing systems, telephony and key performance indicators (scorecards) (5 months).
Public Sector	Revenue Management, Process & Controls	Alberta Sustainable Resource Development (ASRD) – MNP completed a project in early 2009 to assess and make recommendations for improvement to ASRD revenue management processes and controls. The project included identification of key revenue streams, mapping revenue processes and documenting current and proposed controls. Jason is currently leading a large project to implement these recommendations to improve efficiency, embed a robust control environment and meet requirements of the Alberta Auditor General (12 months).
Energy & Utilities	Regulatory, Finance, Generation	Electric Utilities Act (Section 95 – Independent Assessment) – MNP is appointed by the Alberta Department of Energy as an Independent Assessor to assess the relative benefits derived by a municipality (or its subsidiary) through ownership of an interest in a generating unit. Jason and his MNP colleagues have conducted about a dozen assessments for the last 10 years (2-year appointment period – ongoing).
Energy & Utilities	Business Development	Business Case Development for a proposed Wind Generation Project – MNP recently developed a business case to support the capital investment requirements for a 250MW+ wind farm. The business case included technical feasibility, detailed phased economics, risk assessment, regulatory and other key project considerations (3 months).

Energy & Utilities	Supply Chain Optimization	Procurement and Vendor Management – Jason recently led an MNP team to evaluate and make recommendations to improve the procurement and vendor management practices for a large integrated provincial utility. The review includes an assessment of current state, visioning for future state, identification of gaps in procurement practices and recommendations to fill these gaps with industry best practices (3 months).
Public Sector	Sustainability and Land Use	Recreation Management Strategy – Jason recently led a project with ASRD to assist in the development of a Recreation Management Strategy for public lands in Alberta. The strategy involves consultation with numerous stakeholder groups and includes multiple dimensions for analysis, including environmental sustainability, recreation land uses and land types; all supported by a cohesive vision and guiding principles (3 months).
Public Sector	Sustainability & Land Reclamation	ASRD – Jason recently led a project with ASRD to review current land reclamation requirements and develop viable options for non-legislated reclamation incentives for industry. Project includes a multi-jurisdictional review, stakeholder consultation, and development of criteria for evaluating incentive options (3 months).
Energy & Utilities	Municipal Finance	Municipal Tax & Utility Cost Comparison – Jason led the development of a report for a Municipality that compares the cost of doing business among 10 Alberta municipalities, including municipal tax and utilities costs. The report will be used to generate economic (1 month).
Energy & Utilities	Regulatory, Finance	Shared Services Cost Allocation Review – MNP deconstructed and documented the shared services allocation model for an integrated Alberta electric utility (1 month).
Energy	Systems Implementation, Finance & Manufacturing	Systems Implementation – For a highly successful downhole tools manufacturer based in Alberta, conducted a fit/gap assessment for a full-scale ERP implementation with a focus on Finance and Manufacturing. The assessment resulted in a 'go' decision for the client, and MNP provided project management and quality assurance support for the 10-month implementation (12 months).
Construction	Finance, Business Development	Business Case Development - Worked with a major industrial, commercial and residential construction company based in Fort McMurray to develop a business case to support their request for financing to build a large-scale multi-unit residential project. The business case includes a financial model, capacity and vendor analysis, market analysis and financing terms and conditions (3 months).
Energy/ Pipelines	Funding, Finance	Funding Evaluation – Led a funding evaluation project for INAC to support continued Federal government agency operational funding to a pipeline company so that it may continue representing its large-scale interest in the Mackenzie Valley Gas Project (3 months).
Utilities	Regulatory, Finance	Regulatory Cost Allocation - Developed a cost allocation model and framework for Alberta Utilities Commission to recover its costs from industry participants (2 months).
Public Sector & Energy	Process & Controls, Performance Management and Reporting	Alberta Royalties – Process and Controls - Worked with the Alberta Department of Energy, project manager for advisory services related to the processes and controls currently in use to collect data, calculate and report on the performance of Alberta's Royalty Regime for oil and gas revenues. Project includes an assessment of current practices and recommendations to improve process, controls and reporting for the New Royalty Framework (announced October 25, 2007) (Consulting - 3 months).

Public Sector & Healthcare	Supply Chain, Policy and Process	Supply Chain - For a major GoA department, conducted a review of contracting and expenditures practices for one of its Commissions, including a review of Finance and Administration policies, the control environment and processes in place for efficient and effective purchasing (Consulting - 3 months).
Utilities	Finance Function Effectiveness	Finance Function Effectiveness - Conducted a Finance Function Effectiveness diagnostic for an Alberta electric utility. Engagement included an extensive survey of Finance leaders, and evaluation of current practices, and recommendations for improvement. Findings led to reorganization of the department (1 month).
Utilities	Process and Controls, Finance	SOX – Top-Down Risk-Based Approach - For several large U.S. utilities, managed and executed client programs to implement a top-down risk-based approach to SOX 404 compliance, including evaluation of financial statement line item and assertion risk, identification of entity-level controls (ELC) and relevant business controls, and an assessment of the degree to which ELCs mitigated risk. Managed control upgrades to further improve sustainment requirements. Efforts resulted in client savings in the $Millions (5 months).
Energy	Capital Projects, Project Management	Capital Project Lifecycle Management - For a pre-IPO Alberta venture building an Upgrader, led a team in doing an assessment of capital project lifecycle management with the company's EPCM, focusing on high risk areas within the cycle and making recommendations to improve the project management office and control environment (3 months).
Energy	Supply Chain	Inventory Management/Supply Chain - For an integrated supplier of wellbore products and services to the oil & gas industry, completed an assessment of the company's full-cycle inventory management processes within a decentralized manufacturing and sales/service environment. The evaluation included touch points with Purchasing, Finance and IT, resulting in client selection of scalable ERP software (1 month).
Utilities	Business Intelligence, Performance Reporting	Business Intelligence - For a BC electric transmission company, co-managed the implementation of a Cognos business intelligence software solution to enhance managerial decision-making, financial reporting and regulatory scenario analysis (3 months).
Utilities	Revenue Assurance, IT Customer Service	Revenue Assurance - For a large integrated Alberta electric utility, led a team of analysts and developers with several projects to evaluate and implement process and system (UIS, CRM) upgrades for the Customer Services division, resulting in a direct and indirect NPV benefit to the client in excess of $12Million (11 months).
Energy & Transporta-tion	Merger Integration, Process Improvement	Merger Integration - As a member of the core integration team for a major national propane distribution company, subsequent to the merger, Jason developed and fully implemented a progressive sales and field customer service organization in alignment with the integrated Company's new business model. Built a 70-person national sales & customer service organization with new roles, responsibilities, and performance expectations that improved sales effectiveness. The new structure resulted in an increased number of customer calls and better-quality calls while generating and realizing $3.6Million in annual cost-savings, representing over $25Million in NPV. Full implementation included business case development, senior leadership approval, analysis and design, communication and project management, technology rollout, CRM evaluation, candidate selection, training and ongoing performance management. Prior to the merger, responsible for collection, coordination and delivery of undertakings related to Tribunal hearings before the

		Competition Bureau to facilitate approval of the pending merger (1 year).
Energy	M&A, Finance, Business Development	Financial Due Diligence (M&A) –Jason has actively participated in numerous (10+) financial due diligence projects for private equity, energy trusts and operating entities to support acquisitions in the oil & gas and other industries. Due diligence focused on quality assessments of earnings and assets, identifying and quantifying transaction issues and evaluating closing/post-closing adjustments. This work systematically resulted in favourable acquisition price adjustments for clients (Throughout an 18 month period).
Utilities	Business Development	Service Level Agreements - For a large integrated Alberta electric utility, led a team in the development of inter-company and external service level agreements to better structure the provision of customer-related services. In addition, created a Master Service Agreement and related schedules to facilitate and add value to the sale of a retail book of assets (2 months).
Utilities	Business Development and Analysis	Business Development Leadership – Responsible for the development and evaluation of business growth opportunities, including acquisitions, partnerships, and service level agreements for both regulated and unregulated business. Supervised a team of 4 technical staff in developing and presenting business cases and analysis to senior management on the economic and operational viability of transactions.
Utilities	M&A, Business Development	Acquisition Management - Performed and managed a variety of intensive transaction, due diligence and integration planning activities for a $1.3Billion acquisition process, including synergy valuation and development of key provisions of the Purchase and Sale Agreement, resulting in a competitive bid that presented a rate of return and risk profile within desired limits.
Utilities	Business Development, Capital Projects	Development Projects - Negotiated and supported a variety of electric utility initiatives, including municipal operating agreements, EPCM projects, infrastructure investment and distributed generation projects. Projects included wind generation, landfill gas, district heating in downtown Calgary, and a detailed Northern Lights generation and transmission assessment.
Energy, Utilities	Process and Control, Regulatory, Finance, IT	CSOx - For 3 Canadian companies, managed and executed client programs for compliance with Multilateral Instrument 52-109 requirements, focusing on high-risk processes and efficient sustainment (Consulting – 8 months).Governance, disclosure controls and procedures and entity-level controls. Business process, ITGC and application controls. Prioritization of control remediation and optimization activities (10 months).
Utilities	Regulatory, Project Management	Regulatory Project Management - Worked in an advisory and project management capacity with a consortium of Alberta electricity wires owners to initiate the impact assessment phase for the implementation of a Uniform System of Accounts to meet pending regulated Minimum Filing Requirements (Consulting – 2 months).
Utilities	Regulatory, Finance	Regulatory Analysis - Financial analysis and valuation of a telecommunications network and network services for an Alberta-based electric utility to support a rate case application with the EUB (Consulting – 2 months).

EDUCATION	• B.A. (Hons) – Economics and Political Science – York University – 1991 • M.B.A. – University of British Columbia – 1993 Course Completion Electric System Operation for the Non-Engineer – 2003 (Northwest Public Power Association)

Ysobella Phillipe
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PROFILE	Bella is currently a Senior Manager with MNP Consulting based in Calgary, focusing on Process and Systems alignment and integration. Ysobella Phillipe brings a strong IT business background with more than 5 years industry experience and 10 years consulting to public, energy, oil and gas, mining, sales and manufacturing, banking and finance, transportation and telecommunications sectors. Ysobella has significant expertise in delivering large-scale multifaceted and complex, interdependent business solutions with demonstrated delivery in formulating innovative strategies, streamlining processes and successful solution delivery to enhance business operations, manage risks and improve profitability. Ysobella has a proven track record in process improvement, re-engineering and business alignment including experience in whole scale assessment of manufacturing processes and formulating innovative strategies to enable performance improvement, quality control and assurance, improving product inventory management and complex multidepartment controls. Ysobella is ITIL and Six Sigma Green Belt Certified with more than 6 years industry experience and over 10 years consulting to public, energy, oil and gas, mining, sales and manufacturing, banking and finance, transportation and telecommunications sectors. Ysobella worked for IBM as a Data and Enterprise Architect for 6 years, and has worked in both industry and Big 4 environments with a focus on IT and Business alignment, system implementation and optimisation, and process improvements. Prior to joining MNP Ysobella worked as the Director of Information Technology for a very successful international Oil and Gas completions corporation. In this position, she defined strategic direction and provided IT leadership to support the company's mission and core objectives. Oversaw the design and development of the IT infrastructure and related programs, software development initiatives, policies, and procedures and continually evaluated same to enhance delivery to corporate business goals. There she implemented an ERP for Finance, Engineering and Manufacturing while delivering over 7 other major programs (e.g. data centres, VPLS, engineering database, hardware infrastructure upgrades). Ysobella is currently working with two of the largest gas distribution companies in Canada and she has consulted to numerous utility companies including ENMAX, TransAlta, AltaLink and recently with the Utilities Consumer Advocate as an technology specialist and intervenor/assessor for various Alberta-based rate applications and the Alberta Smart Grid inquiry.
SERVICE LINE	Management Consulting
INDUSTRY FOCUS	Energy & Utilities, Public Sector
OFFICE	Toronto, Ontario and Calgary, Alberta

Selected Assignments:

INDUSTRY	SERVICE LINE	PROJECT DESCRIPTION
Public Sector	Program Management	Evaluated and provided technical and strategic recommendations on the Alberta Smart Grid Inquiry of the Alberta Utilities Commission. Assessed

		all technical implication of the Smart Grid initiative including, implementation, program management, compliance to governance, frameworks and standards. Highlighted potential operational effectiveness opportunities through technology solutions, highlighting risks and issues (The Office of The Utilities Consumer Advocate).
Public Sector	Technical Review	Provided technical assessments of the various participants' admissions on the Alberta Smart Grid Inquiry of the Alberta Utilities Commission. The scope of admissions varied from individual parties, Smart Grid technology vendors, Energy Utilities and consumers. (The Office of The Utilities Consumer Advocate).
Energy & Utilities	Project Management Business Process Improvement	Managed the Business Process Quality Assurance engagement for the Customer Care Enhancement Project. Assessed the development methodology and business processes for all aspects of this SAP and related technology implementation. Performed a comprehensive review examining 3 critical criteria, risk to outcomes, fit for purpose, capacity to fulfill, and developed mitigation strategies for critical risks. Provided overall Program Management.
Energy & Utilities	Technical Review	Managed the Regulatory Cost Allocation Model Review engagement for a major gas distributor. Lead a team of analysts to assess, in accordance to the Ontario Board of Energy's directive, the client and the clients shared services business cases and cost allocators.
Public Sector	Operational Review Business Process Improvement	Identified control gaps between legislation, operational policies, processes/procedures, discrepancies between policy and legislation and operational improvements to increase business process efficiencies and compliance.
Energy & Utilities	Program Management	Provided Program Management expertise to complex high-value, multi-stakeholder project initiatives including RPF management, IFRS and ERP high level Project Plan and PMO Tools.
Energy & Utilities	Project Management	Assessed planned approach, assessed program management methodology and provided gap analysis identifying control gaps between TBC (Tariff Bill Code) initiative and regulatory requirements.
Mining	Business Continuity	Developed Business Continuity Program Management Plan (BCP) for one of the world's largest uranium producers.
Energy & Utilities	Technology Review	Evaluated Enterprise Architecture, Information/Data Management, Security, Infrastructure, Integration and SOE. Assessed implementation and compliance to governance, frameworks, and standards. Determined the operational effectiveness of IT Architecture, highlighting issues and root causes. Provided strategic roadmap with recommendations and remediation to improve operational efficiencies.
Energy & Utilities	Operational Review	Assessed effectiveness of IT Enterprise Architecture group, included evaluation of implementation and compliance to governance, frameworks and standards, communication and relationship with stakeholders, and effectiveness within the organization. Produced assessment report highlighting issues and root causes and provided strategic roadmap with recommendations and remediation.
Oilfield Services	Strategic Direction / IT Management	Defined strategic direction and provided IT leadership to support the company's mission and core objectives. Oversaw the design and development of the IT infrastructure and related programs, software development initiatives, policies, and procedures and continually evaluated same to enhance delivery to corporate business goals. Assembled and mentored highly skilled IT technical and management

		team to achieve established objectives. • Negotiated increase in IT "out-sourced" support services while reducing per head desktop support operating costs by over 40%. • Program managed a multi-million dollar ERP development and integration. Delivered without any financial write downs after deployment and data migration from existing ERP. • Directed design and implementation of leading edge Infrastructure program encompassing comprehensive upgrade of all technology elements - storage, server technology (Blades/VM), network communications. Delivered ahead of schedule and under budget. • Developed strategic integrated global data management program and implemented North American Infrastructure solution. • Managed department expansion of over 500% in 1 year, to respond to rapid organisational growth in order to provide efficient, effective and leading edge IT service. • Served as key leader in effectively initiating and controlling IT budget. • Analysed current state IT and employed Enterprise Architecture methodology to align all aspects of IT to enable projected business growth over medium to long term. • Negotiated and directed Virtual Private LAN Service (VPLS) deployment across 12 sites throughout Canada and the US including multiple Data Centres. For the majority of sites this required full server room build out including cooling, security, servers, routers and switches, building data cabling, secure wireless access points and network integration. • Streamlined internal IT department including governance, standards, internal business processes and resource management improving service delivery and implementing best practices.
EDUCATION	• Graduate Certificate of Management (Masters of Management - Information Technology) Charles Sturt University, Australia (In Progress) • Six Sigma – Green Belt • ITIL F Certified	

STORAGE COST ALLOCATION STUDY

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PREPARED FOR

Enbridge Gas Distribution Inc.

1 MAY 2012

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INTRODUCTION AND SUMMARY

In the Natural Gas Electricity Interface Review ("NGEIR") Decision in EB-2005-0551[1], the Ontario Energy Board (the "Board") determined that the market for the ex-franchise storage services of Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") and Union Gas Limited ("Union") was a competitive market and that Enbridge and Union would no longer be subject to rate regulation for those services. The Board stated that it would cease regulating the prices charged for the following storage services:

- All storage services offered by Union and Enbridge to customers outside their franchise areas;
- New storage services offered by Union and Enbridge to their in-franchise customers; and
- All storage services offered by other storage operators, including storage operators affiliated with Union and Enbridge.[2]

This decision permitted Enbridge to develop new storage services within the competitive market under rates and revenues that would not be regulated by the Board. The Board stated that Enbridge could develop new storage capacity to serve both its in-franchise and ex-franchise customers, however, the Board would not regulate the prices for any of the new storage services developed and offered by Enbridge.

A key element of the Board's decision was that it did not require Enbridge to functionally separate its regulated and unregulated storage operations. At page 73 of its Decision in EB-2005-0551, it was stated that:

> "The Board finds that functional separation is not necessary. The evidence before the Board is that it would be costly and difficult to establish a functional separation of utility and non-utility storage, and there was no evidence to suggest that there would be significant benefits from such a separation. To the extent there may be concerns regarding the integrated operations, these will be addressed through the reporting requirements set out in section 5.4."

Of particular note was that the Board also recognized that all of Enbridge's then existing storage investment was required to serve its in-franchise customers. Therefore, unlike the more complicated situation that existed at that time for Union, it was not necessary for Enbridge to undertake a study of the storage assets that it owned at the time of the NGEIR Decision to determine the portion of its integrated storage operations that was to be allocated to the unregulated storage business.

In response to the Board's Decision, Enbridge established a separate set of books, and implemented a specific accounting and cost allocation process to identify and separate costs between regulated and unregulated storage operations. Enbridge's separate books and cost allocation and accounting

[1] EB-2005-0551 Decision With Reasons issued on November 7, 2006
[2] EB-2005-0551 Decision With Reasons, Page 3.

process accommodate all of the cost elements which support its integrated storage operation, including capital expenditures, Operating & Maintenance ("O&M") expenses, overhead expenses, fuel expenses, and the cost of lost and unaccounted for volumes.

In view of the relative complexities of the process, its level of detail, and its impact upon rate levels, the allocation of costs between Enbridge regulated and unregulated storage operations has been an issue in its recent regulatory proceedings before the Board. In accordance with the provisions of the Settlement Agreement in its 2009 Earnings Sharing Mechanism ("ESM") proceeding (EB-2010-0042), Enbridge agreed to submit as part of its 2010 ESM filing, "an analysis of the appropriate allocation of the costs of regulated and unregulated storage operations."[3] In EB-2011-0008, Enbridge submitted a narrative explanation of the allocation of costs for its regulated and unregulated storage activities.[4] Parties in that proceeding had the opportunity to review Enbridge's submission and to file interrogatories to better understand the nature of its cost allocation process and methods.

One of the provisions of Enbridge's ESM Settlement Agreement in its 2010 ESM proceeding was to address the allocation of costs between its regulated and unregulated storage operations. Specifically, part s, item 3 of the Agreement stated that:

> "For the purpose of reaching an overall settlement, no party opposes Enbridge's allocation of costs between regulated and unregulated storage activities for the purpose of determining the 2010 ESMDA amount. There is no agreement as to whether Enbridge's continued use of its current approach to allocating costs between regulated and unregulated storage is appropriate for future years. Enbridge agrees that, as part of the evidence in support of its 2013 application, it will file a study, prepared by an external expert, evaluating the appropriateness of the allocation of costs between Enbridge's regulated and unregulated storage activities. It is expected that the expert will provide a professional assessment of the methodologies used and recommendations for alternate approaches if, in their opinion, improvements can be made."[5]

Based on Enbridge's review of the proposals submitted in response to its Request for Proposal ("RFP"), Enbridge retained Black & Veatch Corporation ("Black & Veatch") to conduct the required study.

The purpose of this report is to present the results of Black & Veatch's review and evaluation of Enbridge's cost allocation process for its regulated and unregulated storage operations.

SCOPE OF THE REVIEW

Black & Veatch understands that Enbridge required a review of the cost allocation process and methods for its unregulated and regulated underground storage operations.

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[3] EB-2010-0042 Decision and Procedural Order, Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, Page 9 of 14, dated July 10, 2010

[4] EB 2011-0008, Exhibit B, Tab 1, Schedule 6 and Appendices, filed on April 20, 2011

[5] EB-2011-0008, Decision and Order, Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, Page 15 of 16, dated July 22, 2011.

Based on this requirement, Black & Veatch structured its review to include the following work tasks:

1. Review and evaluate Enbridge's current cost allocation methodology (and supporting accounting process) for its regulated and unregulated underground storage operations and make recommendations on any changes to the underlying assumptions and/or methodologies.
2. Prepare a written report which sets forth in detail the findings and recommendations of the review with respect to all material issues and methodologies, and which is structured in an appropriate format for submission to the Board and Enbridge's external stakeholders.

Finally, Black & Veatch's particular focus was on the level of storage-related costs that Enbridge incurred, and that were allocated to its two storage businesses, during 2011. This focus was taken because Enbridge's 2011 costs will be the subject of its 2011 ESM filing before the Board and because the allocation of costs presented by Enbridge in past ESM proceedings have already been accepted by the Board for ratemaking purposes. At the same time, however, Black & Veatch did review Enbridge's cost allocation methods and accounting results from prior years for continuity purposes and to better understand to what extent Enbridge's cost allocation treatment has evolved over time.

GUIDING CONSIDERATIONS AND AREAS OF CONCENTRATION

In conducting our review of Enbridge's cost allocation process for its unregulated and regulated storage operations, we were guided by the following considerations:

1. The fundamental and underlying philosophy applicable to every utility cost of service study pertains to the concept of cost causation for purposes of allocating costs to customer groups or service types.
2. Cost causation (or cost causality) addresses the question – *Which customer or groups of customers cause the utility to incur particular types of costs?* To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers.
3. *A Key Consideration* – the ability to establish operating relationships between customer service requirements and the costs incurred by the utility in meeting those requirements (e.g., satisfying a customer's peak demand requirements through the incurrence of capacity-related costs to provide the required level of gas delivery service).
4. The three broad steps most often followed to perform utility cost of service studies: (1) cost functionalization; (2) cost classification; and (3) cost allocation will be utilized for this review as a framework for evaluating the various steps involved in Enbridge's current cost allocation process.
5. A utility's cost allocations should stand on their own objective merits (i.e., costs should be assigned to the classes or categories of service based on the design and operational considerations of the utility's system rather than on achieving results that support a desired outcome for the allocation of revenues to classes and/or rate design).
6. Consistency of structure, methodology, and computational details between Enbridge's cost allocation process used for separating its storage-related assets and expenses and the cost

allocation study it utilizes to evaluate the costs of serving its in-franchise customers and service offerings.

7. The Board's findings in the NGEIR Decision (EB-2005-0551).

8. The storage cost allocation methodology used by Union, and any decision made by the Board with respect to that methodology in the EB-2011-0038 proceeding.

We saw our primary roles and responsibilities in this project as follows:

- To understand the system planning, operation, and utilization of Enbridge's underground storage facilities to confirm that cost causation is properly reflected in its cost allocation and accounting processes;
- To understand the differences between the cost accounting for Enbridge's unregulated and regulated storage operations;
- To understand the cost transactions that comprise Enbridge's unregulated and regulated storage operations, including the allocation of costs of its current integrated storage system and its incremental storage facilities; and
- To provide sufficient commentary on our recommendations and supporting information pertaining to alternative cost allocation process and the related treatment of costs so that Enbridge can adequately evaluate our findings and decide whether or not to propose changes in its subsequent rate and regulatory filings with the Board.

These above-described elements defined the focus areas in which Black & Veatch concentrated its review and evaluation in this project. In our review of Enbridge's cost allocation process for its storage lines of business, Black & Veatch conducted its work in a manner so that it could determine:

- If Enbridge's cost allocation methodology for the allocation of costs between its regulated and unregulated storage operations had a conceptual basis that was grounded in sound and acceptable utility costing principles and the operational realities of its gas utility system.
- If there were certain regulatory precedents established by the Board that Enbridge recognized and incorporated into its cost allocation method.
- If Enbridge's cost allocation and accounting methods provided analytical and computational transparency (i.e., did it create a sufficient and verifiable audit trail - identification of input data sources, traceable information flows, identification of each computational step).

OVERALL ASSESSMENT

Based on the results of our review, Black & Veatch's overall assessment consists of the following observations:

1. The conceptual underpinnings and resulting methodologies upon which Enbridge's cost allocation process is based are generally well-conceived and reasonable in their treatment of storage-related plant and expenses. However, there are a few components of Enbridge's current cost allocation methods that Black & Veatch believes should be changed to better recognize the underlying cost causative factors of Enbridge's storage operations.

2. The manner in which Enbridge has presented its separation of costs between its regulated and unregulated storage operations in its past ESM Filings before the Board does not in all cases provide a sufficient level of detail and explanation to allow an outside party to understand, trace, and verify the underlying assumptions of the cost allocation methodology, computational processes, and to independently confirm the results.

RECOMMENDATIONS

Enbridge has considered Black & Veatch's discussions related to the first overall assessment item above and has proposed to revise certain of its current cost allocation methods for the following cost elements:

- **New General Storage Plant**
    1. Enbridge proposes to adopt the cost allocation treatment for new general plant depicted in Schedule 5 and to apply this method to the cost of its Sombra warehouse facility once it is completed and placed into service.

- **Storage Operations**
    1. Enbridge proposes to change its cost allocation factor for fixed storage costs to reflect a proper weighting of the cost drivers of annual capacity and deliverability, and has made minor modifications to the portion of costs it classifies as variable in nature.

    2. Enbridge proposes to eliminate from its current cost allocation process the use of an "Applicable Share" adjustment to certain costs included in the Storage Administration Cost Center (see page 2 of Schedule 6).

As a result of the second overall assessment item above, Black & Veatch recommends the following enhancements to Enbridge's computational process and evidentiary presentation:

1. Establish more robust documentation that readily allows the reader to clearly trace how Enbridge's regulated and unregulated storage costs are developed, which should include providing clear references for the cost allocation methods used in the calculation of the costs of Enbridge's unregulated storage operations. Black & Veatch believes that certain of the Schedules presented in this report should be incorporated into Enbridge's future evidentiary presentations before the Board on this subject.

2. Provide additional details to be able to trace Enbridge's elimination from its Utility Income of each particular expense item (e.g., gas costs, O&M expenses, property taxes, and depreciation expense) associated with Enbridge's unregulated storage operation, and the computational details to derive each eliminated amount.

3. The manner in which Enbridge splits the cost of new storage assets that replace existing storage assets with a capacity enhancement component between its regulated and unregulated storage operations (e.g., Enbridge's "Pool Metering Upgrades" project) should be detailed so that the basis for the determination of the cost split can be readily understood by an outside party.

BACKGROUND PERSPECTIVES

As a backdrop and to provide sufficient context to our subsequent detailed review of Enbridge's costing method for its storage lines of business, Black & Veatch initiated its work effort with a review of the operational characteristics and service offerings of Enbridge's integrated storage facilities. Specifically, our review addressed the following activities:

- The physical attributes and operations of Enbridge's Tecumseh storage facilities; and
- The nature and level of storage services available to Enbridge's ex-franchise customers.

In addition, we reviewed the relevant regulatory, ratemaking, and accounting aspects of Enbridge's regulated and unregulated storage operations to better understand the evolution of the issues, regulatory decisions, and implementation processes required to allocate costs to these activities and to account for them in Enbridge's financial statements and ratemaking filings before the Board.

OPERATIONAL

Enbridge's Tecumseh underground storage facilities are located in Southwestern Ontario, near the Dawn Hub, and have been in operation since the 1960s. Enbridge's storage operations consist of 11 storage pools with a total working capacity[6] of approximately 110 Bcf, with a peak deliverability of about 2.5 Bcf per day. In addition, Enbridge owns and operates the Crowland storage facility, which is a small gas storage field with a capacity of 0.4 Bcf located in the Niagara Region that is directly connected to Enbridge's gas distribution system. Included in the 110 Bcf capacity level, Enbridge also operates a 6.7 Bcf storage operation on behalf of, and for use by, Union (the Dow Moore and Black Creek storage pools). Enbridge's Tecumseh gas storage system is depicted in Figure 1. In addition, a summary listing of the operational characteristics of Enbridge's gas storage facilities is presented in Schedule 1.

Enbridge's storage facilities are directly connected to four (4) pipeline systems: the Vector Pipeline, Niagara Gas Transmission-Link Pipeline, TransCanada PipeLines Limited ("TCPL"), and Union. These pipeline interconnections enable Enbridge to provide gas storage services to markets in Eastern Canada, the Midwest U.S., and the Northeast U.S. Figure 2 shows the pipeline interconnections with Enbridge's Tecumseh storage operations. To reach Enbridge's gas utility franchise area in Central and Eastern Ontario, gas stored in the Tecumseh facilities flows over Union's Dawn-Trafalgar gas transmission system, and then through the TCPL system.

Regarding Enbridge's storage operations, its various storage pools are operated as an integrated system with each pool affecting the operation of the other pools throughout the injection and withdrawal periods.

[6] Also referred to as storage space

Figure 1
Enbridge's Gas Storage Facilities

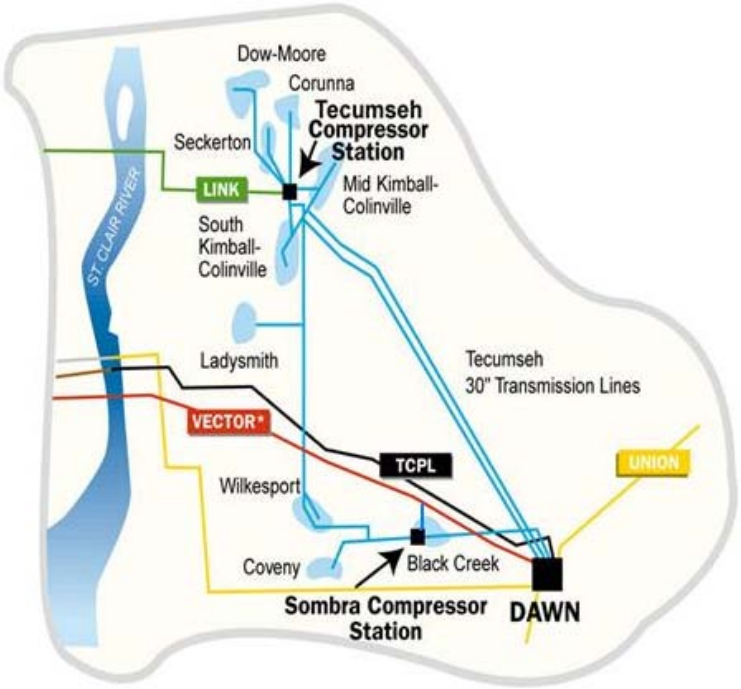
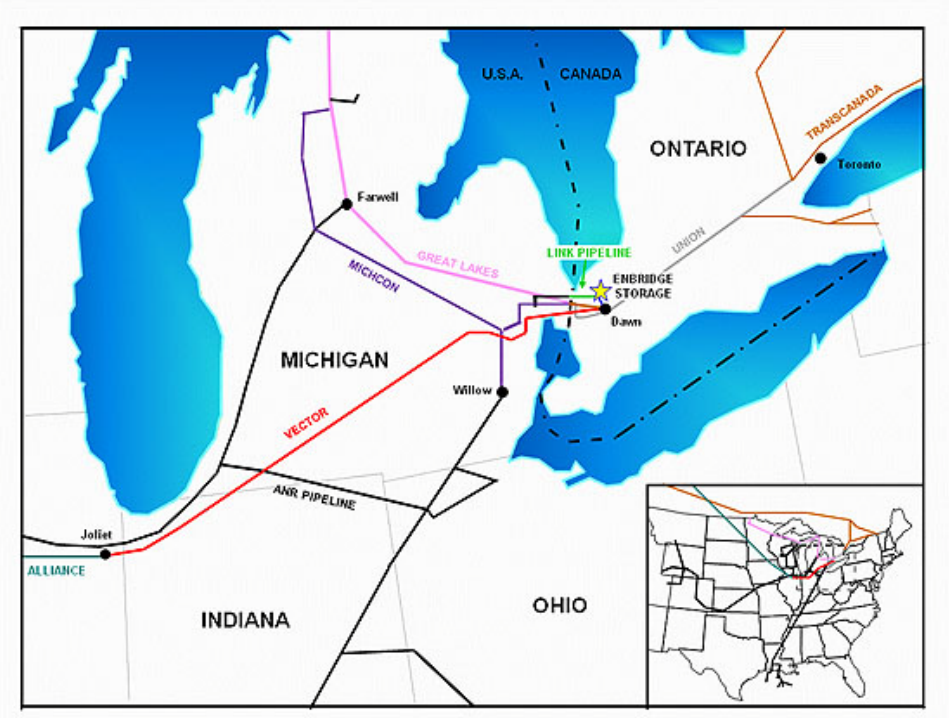


Figure 2
Gas Pipelines Interconnected with Enbridge's Gas Storage Facilities



STORAGE SERVICE CHARACTERISTICS

At the time of the NGEIR Decision, Enbridge required all of its owned storage capacity, in addition to approximately 20 Bcf of storage under multi-year contracts with Union, to serve its in-franchise customers (i.e., regulated utility customers) on a bundled basis. This situation continues to be the case today. In addition, Enbridge has certain larger customers who have chosen to opt out of bundled service by contracting with Enbridge for delivery and storage services on an unbundled basis. Due to the growth of these services over the years, Enbridge now requires approximately 21 Bcf of storage capacity from third-parties to meet its total in-franchise storage requirements.

Enbridge's in-franchise customers, and certain ex-franchise customers, are offered unbundled storage services under its Rates 315, 316, and 325, which are described below.

- Rate 315 – Gas Storage Service (for customers taking service under Rate 125 – Extra Large Firm Distribution Service and Rate 300 – Firm or Interruptible Distribution Service)
- Rate 316 – Gas Storage Service at Dawn (for customers taking service under Rates 125 and 300)
- Rate 325 – Transmission, Compression, and Pool Storage Service (with Union)

Enbridge also offers short-term storage services or Transactional Services ("TS") to third-party customers through the temporarily unused regulated utility storage assets that are considered surplus to its current in-franchise needs. These services have been offered in the marketplace by Enbridge since 1997. TS customers (who are typically more active in the gas market) have the ability to utilize Enbridge's storage services to create supply optimization opportunities premised upon the prevailing natural gas prices. Typical services consist of "park and loan" transactions that are of a short-term nature. "Parks" are services where a third-party injects gas into Enbridge's storage facilities through a TS arrangement for withdrawal at a later time, and "loans" are where the third-party first receives gas out of Enbridge's storage for redelivery to Enbridge at a future time.

To utilize Enbridge's storage resources in this manner, we understand that it is not uncommon for some of Enbridge's short-term storage service customers to cycle their storage inventory 2-3 times in one year (which results in storage transactional volumes equal to 4-6 times the physical storage space).[7] With such high cycling rates (i.e., high inventory turnover ratios), it is not unusual for Enbridge to experience volumetric activity levels for these customers that are much higher than the level of the underlying contracted storage space. In contrast, Enbridge' customers who contract for long-term storage services sometimes cycle their storage space less than once in a particular year (see Schedule 1 for Enbridge's storage turnover rates).

Based on the operational particulars of Enbridge's TS activities, the overall net impact of such transactions can act to offset the traditional seasonal operations of Enbridge's regulated storage activities. As a result, TS activities can serve to reduce the volume of gas that is physically injected into and withdrawn from storage which can generally increase the efficiency of Enbridge's

[7] A customer that contracts for 10 PJ of storage space would be expected to have about 20 PJ of activity to complete one full storage cycle (10 PJ of injections to fill the contracted storage space and 10 PJ of withdrawals to empty the space).

integrated storage operations. At the same time, Enbridge generates incremental revenue from these transactions which is shared between its utility customers and Enbridge's shareholders under a Board approved sharing arrangement.

Enbridge has also been offering competitive storage services at market-based prices since 2008 to gas utilities, wholesale market participants, and power generation customers. These customers comprise Enbridge's unregulated storage market. To accommodate the needs of these customers, Enbridge has been investing since that time in its existing storage operation at Tecumseh to add incremental storage capacity and deliverability beyond the level that existed at the time of the NGEIR Decision. Currently, Enbridge has 12.2 Bcf of unregulated storage capacity. Enbridge also has plans to expand its existing storage facilities based on market demand to take advantage of other market opportunities as they arise such as U.S. Shale gas and gas-fired power generation needs. The level of Enbridge's incremental capital investments in storage for its unregulated operations and the accounting treatment of these investments will be discussed in detail later in this report.

The characteristics of the unregulated storage services offered by Enbridge include:

- Services are offered on a firm and interruptible basis and range from high deliverability (10 or 20 day service)to seasonal storage;
- Customers pay a monthly demand charge, as well as variable charges including the gas commodity and fuel;
- Contract terms that range from 1 to 20 years;
- Customers have the option to cycle gas volumes within their contractual parameters and pay variable charges on the cycled volumes; and
- Overrun services are available on a request basis for an additional fee and must be authorized by Enbridge in advance.

Schedule 1 also provides the annual level of activity for Enbridge's unregulated storage services from 2008 through 2011.

ACCOUNTING FOR STORAGE

To implement a separation model for Enbridge's regulated and unregulated storage operations, as required by the NGEIR Decision, there were three options available to Enbridge: (1) a functional separation; (2) an accounting separation; or (3) an asset divestiture. As pointed out earlier, the Board found that functional separation of the storage assets of Enbridge and Union was not necessary, nor was an asset divestiture a desired alternative in light of their integrated storage operations. Therefore, implementation of an accounting separation process was the only viable alternative for Enbridge to consider.

While the adoption of that approach created the need for the establishment of cost allocation methods to be applied to Enbridge's storage assets, direct expenses, and other indirect costs, the same type of comprehensive process required by Union at that time was not required by Enbridge because: (1) Enbridge required all of its storage assets to satisfy the storage service needs of its in-franchise customers; and (2) Enbridge was not providing unregulated storage services to the natural gas marketplace. A one-time asset separation, therefore, was not required by Enbridge to

implement the Boards' findings in the NGEIR Decision. In addition, Enbridge's cost allocation study[8] that it had conducted on or around the time of the NGEIR Decision did not have to be directly relied upon (as was required in Union's case) because there were no storage-related costs that had to be assigned to Enbridge's unregulated storage operations - since the operation did not exist in late 2006.

Enbridge was required, however, on a going forward basis to structure an operational process to identify storage-related investments that were required to support its unregulated storage operations, an accounting process to maintain separate plant records, and an allocation process to assign storage-related expenses to its regulated and unregulated storage operations. The various processes established by Enbridge that have evolved over time have, in our opinion, been greatly influenced by the fact that Enbridge did not have to initially separate by the end of 2007 any of its storage-related assets between regulated and unregulated storage operations.

It is apparent to Black & Veatch that Enbridge's unregulated storage operations has been created in recent years to function as an integral part of an integrated storage operation that served the entirety of its regulated storage requirements on a standalone basis at the time of the NGEIR Decision. On that basis, Enbridge has chosen to utilize an incremental costing approach as a foundation for its identification and assignment of new storage assets to either the regulated or unregulated storage operations. The appropriateness of utilizing this type of a costing approach (in light of Enbridge's specific business situation) compared to a fully allocated costing method that recognizes the common plant characteristics of an integrated utility operation in the derivation of cost allocation methods will be discussed in more detail later in this report.

[8] Used as a guide to evaluate and determine Enbridge's regulated utility revenues and rates for its in-franchise customers.

COST ALLOCATION FOR ENBRIDGE'S STORAGE OPERATIONS

The purpose of this section is to detail the findings and recommendations of Black & Veatch's review and evaluation of Enbridge's cost allocation methods for its regulated and unregulated storage operations. With a basic operational foundation established, a review of Enbridge's cost allocation process structure and framework was conducted. The following areas were reviewed in detail:

- Phases or steps included in the cost allocation process.
- Organizational layout of and interrelationship between filed information and schedules which present Enbridge's cost allocation results.
- Flow of data and sequencing of steps within the cost allocation process.
- Degree to which the cost allocation process is presented on a "self-contained" basis (i.e., analyses and supporting data are an integral part of Enbridge's evidentiary presentation).
- Basis for the total storage cost of service reflected in the cost allocation results.
- The interrelationship and methodological consistency between Enbridge's cost allocation process for its storage operations and its 2007 Board-approved cost allocation study to derive the cost of service for its in-franchise (rate regulated) customers.

Black & Veatch evaluated each element of Enbridge's cost allocation process to determine if its methods and underlying computations were: (1) reflective of how the costs were incurred; (2) fair and equitable; (3) transparent and replicable by an outside party; and (4) consistently applied to each of Enbridge's investment and expense components.

PURPOSE

Enbridge's cost allocation process for its storage operations is used for the following purposes:

1. To separate the costs of Enbridge's unregulated storage operations from its regulated utility operations to properly account for the unregulated operations and to identify regulated storage costs for the purpose of setting Enbridge's regulated utility rates.
2. To identify and compile the results of Enbridge's unregulated storage operations to determine standalone utility financial results for earnings sharing purposes.

The results of Enbridge's cost allocation process for its storage operations are presented each year in its ESM proceeding (e.g., EB-2011-0008), and it is expected that the results will also be submitted in its 2013 rates application, where Enbridge will re-compute the underlying costs of its in-franchise customers to rebase its regulated delivery rates under incentive regulation.

STRUCTURE

Schedule 2 presents a high-level view of the overall functional process Enbridge follows to separate its regulated and unregulated storage costs. Enbridge's overall cost allocation process addresses nine (9) separate cost elements related to its underground storage operations, including:

1. New storage assets;
2. New general plant;
3. Other plant-related costs
4. Operating & maintenance expenses
5. Corporate administrative and general overheads
6. Unregulated business development and administrative costs
7. Cost of gas (fuel gas expenses and lost and unaccounted for gas)
8. Depreciation expense
9. Property tax

Each of these elements requires Enbridge to identify and compile the required input cost data, to select the direct assignment and/or cost allocation methods that are to be applied to the relevant costs, and to derive the costs associated with Enbridge's unregulated storage operations. As will be discussed in the next section, certain of these cost elements are allocated to Enbridge's unregulated storage operations on a one-time basis (as each new storage asset is added) while other cost elements are allocated to that business line on a monthly or annual basis using allocation factors that are updated periodically.

DATA SOURCES AND THE TIMING OF ENBRIDGE'S COST ALLOCATION PROCESS

Enbridge's on-going allocation of costs to its unregulated storage operations is premised upon, for the most part, the same sources of data that it utilizes to derive its total cost of service for regulated operations.

The timing of Enbridge's cost allocation process is presented in Schedule 3. There are two categories reflected in this Schedule, with costs allocated on: (1) an annual or monthly basis; and (2) a periodic basis. Schedule 3 presents the particular cost elements that comprise Enbridge's unregulated storage cost of service grouped according to these two categories. Details of the timing associated with Enbridge's cost allocation process are discussed in subsequent sections of this report.

FOUNDATIONAL ASPECTS OF ENBRIDGE'S COST ALLOCATION METHODS

As discussed earlier, Enbridge's unregulated storage operation has been created in recent years to function as an integral part of an integrated storage operation that served the entirety of its regulated storage requirements on a standalone basis at the time of the NGEIR Decision. On that

basis, Enbridge has chosen to utilize an incremental costing approach as a foundation for its identification and assignment of new storage assets to either the regulated or unregulated storage operations. Under this approach, Enbridge reviews each of its asset additions to determine the cost drivers that explain the need for the new asset. These costs drivers include replacement or enhancement of existing assets, development of incremental capacity and/or deliverability, or some combination of these costs drivers. Because Enbridge has the specific operational knowledge of its storage operation to make this type of project-specific determination for each of its asset additions, it is unnecessary for Enbridge to rely upon a more generalized cost allocation method, such as a fully allocated costing approach, that presumes such assets cannot be directly attributed to either one of Enbridge's storage operations. More generally, a fully allocated costing approach is regularly relied upon in utility cost allocation studies to allocate the costs of common or joint-used assets because the utility does not have the knowledge or data to identify which specific assets should be assigned to particular rate classes over the life of the utility's gas system.

If a fully allocated costing approach was applied to Enbridge's total storage assets (regulated and unregulated businesses), its unregulated storage operation would be allocated between approximately $32 million (using an Annual Capacity factor) and $49 million (using a Daily Deliverability factor), or about $41 million if those two allocation factors were weighted equally in the allocation process. However, Black & Veatch does not view this result as properly reflecting the cost causative factors associated with Enbridge's asset additions over the 2007-2011 timeframe. As will be discussed in greater detail later in this report, under Enbridge's current cost allocation method for its new storage assets, its unregulated storage operation has been assigned about $84.4 million in net storage plant through the end of 2011. In Black & Veatch's view, it is appropriate for Enbridge to utilize an incremental costing approach for its new storage assets because it best reflects the cost causative factors which drive the level of asset costs incurred by Enbridge to serve its unregulated storage market.

STORAGE-RELATED ASSETS

This section describes the evolution of Enbridge's storage operations since the NGEIR Decision and the treatment of Enbridge's new asset additions and asset retirements within its cost allocation process for storage operations.

Enbridge's Regulated Storage Assets

At the time of the NGEIR Decision, the 2007 gross value of the storage assets supporting Enbridge's existing regulated storage operation was approximately $261 million, with a net plant investment of about $175 million. Since 2007, Enbridge has made modest investments in its regulated storage operations primarily to replace or recondition facilities that have through age, use, or obsolescence, come to the end of their useful lives. In addition to these "maintenance-related" projects, Enbridge also has had to make capital expenditures for its regulated storage operations to ensure continued compliance with safety, environmental, and technical requirements. Examples of such expenditures recently made by Enbridge include: noise and exhaust emission enhancements to compressor facilities and improvements to its gas measurement and gas inventory observation facilities.

Table 1 below presents Enbridge's net plant in service for its regulated storage operations for the years 2007 through 2011.

Table 1
Enbridge Gas Storage Assets – Regulated Operation
Net Plant Balances at Year End
($ millions)

ASSET DESCRIPTION	PLANT ACCOUNT	2007	2008	2009	2010	2011
Land & Land Rights	450/451	22.5	21.4	20.4	21.1	20.2
Structures & Improvements	452	6.5	6.5	6.5	9.6	9.5
Wells	453	12.4	12.4	13.4	20.7	22.5
Well Equipment	454	3.8	4.0	4.3	4.6	4.3
Field Lines	455	27.6	26.8	26.7	25.9	38.4
Compressor Equipment	456	54.3	56.7	59.4	60.8	61.5
Measuring & Regulating Equipment	457	7.3	7.0	6.8	6.6	6.2
Base Pressure Gas	458	40.8	40.8	40.8	40.9	40.9
Total		$175.2	$175.6	$178.3	$190.2	$203.5

The costs of any other investments made by Enbridge over the 2007-2011 timeframe that were designed to add storage capacity and deliverability to its existing gas storage system were all assigned to Enbridge's unregulated storage operations.

Enbridge's Unregulated Storage Assets

In 2007, Enbridge began its investment program to add capacity and deliverability to support its newly created unregulated storage operation. From that time through 2011, Enbridge has invested approximately $88 million in gross plant additions in four major storage-related capital programs. These programs have included the drilling of additional wells into Enbridge's existing storage pools and the installation of additional pipelines, compression, gas dehydration, and measurement capacity. Some of the additional metering capacity has been added at the custody transfer point into Union's gas transmission system at Dawn and some has been created at a new custody point into the Vector pipeline system.

As a result of these capital programs, Enbridge has created new storage capacity and deliverability that it has offered to the competitive gas market. In total, these projects have resulted in the development of about 12.2 Bcf of total storage capacity and incremental withdrawal capability of 400 MMcfd at the end of 2011 (see Schedule 1). Without these capital investments made by Enbridge, none of its new storage capacity would be available to provide services to its unregulated storage market.

Table 2 below presents Enbridge's net plant in service for its unregulated storage operations for the years 2007 through 2011.

Table 2
Enbridge Gas Storage Assets – Unregulated Operation
Net Plant Balances at Year End
($ millions)

ASSET DESCRIPTION	PLANT ACCOUNT	2007	2008	2009	2010	2011
Land & Land Rights	450/451			0.4	1.1	1.1
Structures & Improvements	452			0.0	0.0	0.0
Wells	453		3.9	7.2	10.0	9.6
Well Equipment	454		0.0	0.0	0.0	0.0
Field Lines	455	1.3	8.5	14.6	14.6	14.2
Compressor Equipment	456	7.1	9.9	11.9	20.1	20.6
Measuring & Regulating Equipment	457		0.0	0.4	0.3	0.3
Plant Not Classified (1)	458		14.1	12.8	3.6	38.6
Total		$8.4	$36.4	$47.3	$49.7	$84.4

(1) 2011 amount related to the capitalization of Project Nexus – a gas storage expansion project

Based on Enbridge's cost allocation method and the results reflected in Tables 1 and 2, approximately 29% of Enbridge's total net storage plant (as of December 31, 2011) has been assigned to its unregulated storage operation.

To understand and verify the manner in which these plant account balances were derived, Black & Veatch reviewed Enbridge's detailed plant accounting data for its gross plant and accumulated depreciation reserve entries from 2007 through 2011. Schedule 4 presents the annual derivation of Enbridge's net plant balances for its unregulated storage operations. This analysis verified that Enbridge's net plant balances presented in Table 2 were accurate and that they could be replicated from the more detailed plant information.

New Storage Assets

Enbridge has developed and implemented a cost allocation process that assigns the cost of its storage investments to its regulated and unregulated storage operations. The method is premised upon the proper reflection of cost causative principles. Specifically, Enbridge has developed the following investment categories to facilitate the grouping of its storage-related investment according to the factors which cause each investment to be made:

1. Replacement of Existing Storage Assets
2. Development of Incremental Storage Capacity
3. Replacement of Existing Storage Assets with a Capacity Enhancement Component

4. General Storage Plant

Each of these investment categories are described in further detail below. It should be noted that the above-described process requires the allocation of individual assets in order for Enbridge to create and maintain on a going forward basis the proper plant accounting records at the individual asset level for its unregulated storage operations.

Replacement or Enhancement of Existing Storage Assets

These projects consist of storage-related assets that are installed to replace Enbridge's existing assets supporting its storage operations. The nature of these projects serve to maintain the facilities and service capabilities whether they completely replace the asset, recondition the asset, or bring the asset into regulatory or environmental compliance. In all cases, the capital costs of these new facilities are directly assigned to Enbridge's accounts and/or entity of the original assets.

Black & Veatch reviewed Enbridge's projects in this category and confirmed that the capital costs of each asset addition were treated in a manner consistent with its current cost allocation methods. As an example, Enbridge's "K708 Compressor Power Cylinder Liner Replacement" project was undertaken in 2011 to replace the cylinder liners on one of its compressor engines at Tecumseh. These liners deteriorate over time from wear and must be replaced, which means that this is a "maintenance capital" type project. Since this compressor engine was originally installed to meet the storage needs of Enbridge's regulated storage operation, Enbridge concluded that it was appropriate to directly assign the cost of this new asset to the regulated utility business.

Another example of an asset replacement or enhancement project is Enbridge's drilling of the Tecumseh Seckerton #20 pressure observation well in a location adjacent to the Seckerton storage pool. The drilling of this well, and others, was recommended by reservoir consultants to Enbridge. The well may confirm the presence of porous rock zones in proximity to the storage pool, and the presence of gas volumes in those zones that would indicate communication with the pool. The well enhances Enbridge's understanding of the Seckerton storage pool and helps to raise the quality of its gas inventory management to a standard that is consistent with storage industry practice. Because the well enhances Enbridge's understanding of the Seckerton storage pool, which is a regulated asset, its cost has been charged to the regulated storage operation.

Based on its review of these projects, Black & Veatch agrees with the costing treatment of these assets.

Development of Incremental Storage Capacity

These projects consist of storage-related assets that are installed to provide Enbridge with new storage capacity or deliverability. Since the storage needs of Enbridge's regulated utility business continue to be fully satisfied by the storage-related assets (and third-party storage) that existed at the time of the NGEIR Decision, the capital costs of these new facilities are directly assigned to Enbridge's unregulated storage operation.

Black & Veatch reviewed Enbridge's projects in this category and confirmed that the capital cost of each asset addition was treated in a manner consistent with its current cost allocation methods. As an example, Enbridge's "Drilling of TKC 61H" project was undertaken to drill a new storage injection/withdrawal well. This well was a relatively high cost, horizontal well drilled into

Enbridge's Mid-Kimball storage pool. Since this well was drilled to satisfy the incremental storage capacity needs of Enbridge's unregulated storage operation, Enbridge concluded that it was appropriate to directly assign the cost of this new asset to its unregulated storage business.

Another example is Enbridge's "Ladysmith Gathering Pipeline" project which was undertaken to provide greater gas flow capabilities into and out of the Ladysmith storage pool, while making available some capacity on the Wilkesport gathering pipeline. This project optimized Enbridge's storage system, thereby, creating a greater level of storage capacity at Enbridge's custody transfer points to serve its unregulated storage market. As a result, Enbridge concluded that it was appropriate to directly assign the cost of this new asset to its unregulated storage business.

Based on our review of these projects, Black & Veatch agrees with the costing treatment of these assets.

Replacement of Existing Assets with a Capacity Enhancement Component

These projects consist of storage-related assets that are installed to replace Enbridge's existing assets and to provide incremental storage capacity or deliverability. For example, it may be necessary for Enbridge to replace a utility asset at the end of its useful life, but where the replacement asset is sized to provide additional capacity beyond that of the original asset. Importantly, the replacement of the asset is driven by the fact that it is no longer technically capable of providing the service for which it was intended and that Enbridge needs to replace the asset to maintain the level of storage service required by its regulated utility customers.

Under this scenario, Enbridge's regulated utility operation would be charged the portion of the capital costs that it would have incurred if it were to have replaced the asset on a like-for-like basis. And, on that basis, its unregulated storage operation would be charged for the incremental costs that would have resulted from the higher capacity asset. This would include both the cost of the incremental capacity and the cost of any of the system design changes that might have been required to accommodate the different asset. In other words, the portion of the total asset cost that will be booked to Enbridge's regulated storage operation will be no more, and may be less, than would have been incurred had the replacement asset been sized simply to replace the original asset.

Conversely, in a scenario where the asset is not at the end of its useful life, but where its replacement is driven by the operational needs of Enbridge's unregulated storage operation, then it would be charged for the entire cost of the replacement. Finally, we understand that the relative proportions of the replacement assets will be noted by Enbridge in the asset accounts of both its storage operations.

Black & Veatch reviewed Enbridge's projects in this category and confirmed that the capital cost of each asset addition was treated in a manner consistent with its current cost allocation methods. As an example, Enbridge's "Replace Corunna and Seckerton Pool Gathering Pipelines" project was undertaken after a review of the existing wellhead and gathering line facilities of the Corunna and Seckerton storage pools to determine their appropriateness for the delta pressuring of the pools to create additional unregulated capacity. This review revealed that those facilities would have to be replaced to allow for the needs of Enbridge's higher pressure, unregulated storage service. Since this replacement would not have otherwise occurred because the existing facilities were suitable to

continue to provide storage services to Enbridge's regulated utility customers, Enbridge concluded that the entire cost of this replacement should be assigned to its unregulated storage operation. Based on our review of this project, Black & Veatch agrees with the costing treatment of these assets.

Another example is Enbridge's "Pool Metering Upgrades" project which was undertaken to provide more accurate measurement of total pool volumes, energy content, and injection/withdrawal volumes. Enbridge was required to replace its older metering technology with current technology metering equipment. At the same time, certain gathering line changes were required to accommodate the storage capacity and deliverability needs of the unregulated storage operation, so the total cost of the project was much higher than if only the metering facilities were replaced.

To reflect the cost consequences of this configuration of facilities, Enbridge designed and estimated the cost of this project assuming two design scenarios – with and without the incremental asset requirements of the unregulated storage business. The incremental costs of the project were caused by higher pressure-rated materials, additional growth elements in the facilities design, and the different physical configuration of the gathering facilities supporting the unregulated storage operation. As a result, Enbridge concluded that it was appropriate to assign the replacement cost of the metering facilities to its regulated storage business, with all other costs of the project assigned to its unregulated storage operation.

Although there are still certain project costs that have yet to be incurred, the estimated cost at completion is expected to be about $36.2 million. Of this amount, approximately $21.0 million or 58% of the total project costs will be charged to Enbridge's regulated utility business with the balance of approximately $15.2 million or 42% of the total project costs to be assigned to its unregulated storage operation. Black & Veatch agrees with Enbridge's expected costing treatment of these assets.

General Storage Plant

General plant assets consist predominantly of structures such as office and utility buildings, warehouses, sheds, and parking lots that do not directly support the capacity and deliverability of Enbridge's storage operations. Under Enbridge's current cost allocation process, if the general storage plant asset is designed to meet an incremental need of either of its two storage operations, Enbridge will assign the entire cost of that asset addition to the particular operation that had the direct need for that asset. If the project is driven more by the general needs of its integrated storage operation, Enbridge will allocate the cost of that asset to both operations based on an allocation factor that best reflected the cost causative characteristics of the facility's design and intended purpose.

During the course of this project, Black & Veatch had a number of discussions with Enbridge staff who are involved in the day-to-day operations, asset investment evaluations and decisions, and accounting treatment of its unregulated storage operations. One of the discussion topics was the appropriate cost allocation treatment of Enbridge's general storage plant. Enbridge has not had an asset addition to its general storage plant since the NGEIR Decision so it did not have any real world examples to consider for cost allocation purposes. From our discussions, we were of the view initially that Enbridge would likely directly assign to its regulated storage operation the cost of any

replacement of, or enhancement to, its general storage facilities simply because the original asset had existed previously to only support the regulated storage operations.

Our further discussions also indicated that Enbridge does have under construction currently a storage (warehouse) building located at its Sombra Compressor Station. The Sombra Storage Building project will support Enbridge's integrated storage operation and will be used to store Glycol, compressor parts, and other storage-related materials. Black & Veatch understands that this planned asset addition was originally viewed by Enbridge as a facility which solely supported its regulated storage operation. On that basis, Enbridge intended to assign the entire capital cost of this asset to its regulated storage operation. After further evaluation of the purpose and expected utilization of this facility, Enbridge has revisited the assignment of capital costs for this project. The Sombra facility is not an asset replacement project and it has been sized to provide some additional space to house certain materials that are required for the unregulated storage operation. As a result, the capital cost of this facility should be assigned to both storage businesses using an allocation basis that reflects the joint use of the facility.

More generally, the treatment of the Sombra facility for cost allocation purposes has caused Enbridge to consider revising its current cost allocation process for storage-related assets. One option would be to assign a portion of the asset to each of Enbridge's two storage businesses by developing an allocation factor which is based upon the amount of storage space required for each storage business. Another option would be to treat the capital costs as an overhead item and to allocate those costs on a corporate-wide basis as a function of each cost center's direct costs. Enbridge has proposed to treat such assets as "Corporate General Plant" as other similar assets are treated within the Enbridge organization. We understand that Enbridge normally treats Corporate General Plant as an overhead cost element and apportions such costs across its various cost centers through its A&G overhead factors. Under that method, Enbridge's unregulated storage operation would share in the cost of this facility in the same way it does for all of Enbridge's other general plant facilities. Based on our understanding of that process, Black & Veatch believes that Enbridge's proposed method is a reasonable basis for the cost allocation treatment of general storage plant.

Enbridge's Capital Project Assessment Process

Schedule 5 presents a flowchart of the assessment process that Enbridge follows to assign the costs of storage-related capital projects to its regulated and unregulated storage operations. The decision criteria in this flowchart reflects the cost attribution characteristics described above for each category of Enbridge's storage assets, including its proposed treatment of general storage plant. Black & Veatch recognizes that the process reflected in Schedule 5 has become more formalized in recent times as Enbridge has invested in each type of storage asset and gained greater insights into the factors causing the investments to be made in these assets. One proposed addition that Black & Veatch recommends to Enbridge's capital project assessment process is to include the gas storage characteristic of deliverability in the description of projects that should be charged directly to Enbridge's unregulated storage business.

Based on our review of individual new storage assets added by Enbridge since 2007 to support its regulated and unregulated storage operations, Black & Veatch concludes that Enbridge has applied its cost attribution process to new storage assets in a consistent manner. This conclusion was

based upon our evaluation of the examples of storage assets presented above (and others) within the context of Enbridge's current capital project assessment process reflected in Schedule 5.

Other Plant-Related Costs

For each of its storage-related projects, Enbridge reflects a total cost level that includes all of the materials and third-party service costs that are incurred in the design, construction, and commissioning of the facility. In most cases, the project will also require time and effort from Enbridge staff, with much of that being provided from its Gas Storage Operations staff located near its Tecumseh storage operation. In addition to these costs, each project also is charged for Interest during Construction ("IDC") and administration and general corporate overheads.

These cost components are described below:

Internal Labor

All Enbridge staff members working directly on each capital project maintain time sheets that accumulate the time spent on the project. Those time sheets are processed on a regular basis, and the time is charged at the hourly equivalent rate for that staff member.

Corporate Administrative and General ("A&G") Overheads

Enbridge charges corporate A&G costs to the new storage assets of its unregulated storage operation in the same manner as it does for its O&M costs (as will be described later). The hourly salary rates for Enbridge staff working on those projects are grossed-up to include corporate A&G and an amount associated with the expected performance-based payout inherent in Enbridge's employee compensation plan. Together, these amounts result in an overhead factor of approximately 65% to 70% which is applied to each staff member's base salary level.

Contractor and Materials

All third-party services and materials costs related to Enbridge's unregulated storage projects are charged directly to its unregulated storage accounts.

Interest During Construction ("IDC")

Enbridge assesses an IDC charge to all unregulated storage projects in the same manner that it does for its utility capital projects.

STORAGE-RELATED EXPENSES

With the commencement of its unregulated storage operations, and the operation of its larger, integrated storage facilities, Enbridge's total O&M costs have increased over time as its unregulated storage operation has grown. There are additional storage-related facilities to operate and maintain, and more gas volumes being transacted. Some specific O&M costs have increased generally, more or less in proportion to the increase in storage activity; while others have increased only marginally, or not at all. As additional capacity and deliverability is added to Enbridge's integrated storage operations in the future, it is understood that these costs may increase in a stair step manner in recognition of the added manpower requirements that could be caused by Enbridge reaching a higher level of storage activity.

Table 3 below presents Enbridge's total storage O&M costs for its regulated storage operations for the years 2007 through 2011. Table 4 which follows presents Enbridge's total storage O&M costs

for its unregulated storage operations for the years 2007 through 2011.

Table 3
Enbridge Gas Storage – O&M Costs
Regulated Storage Operation

EXPENSE CATEGORY (1)	2007	2008	2009	2010	2011
Labor	$3,361,251	$3,574,771	$3,607,253	$3,835,016	$4,299,598
Supplies	$1,061,065	$1,152,423	$1,022,099	$1,348,299	$1,365,079
Consulting Services	$1,480,086	$1,416,565	$1,468,205	$2,146,386	$1,482,801
Other Operating Expenses	$2,314,434	$2,223,109	$2,501,334	$2,653,088	$2,355,530
Property Taxes	$1,321,560	$1,180,933	$1,331,352	$1,425,708	$1,611,240
Labor Credits and Other	($1,044,216)	($1,279,375)	($1,400,056)	($2,036,650)	($2,358,964)
Total	$8,494,180	$8,268,426	$8,530,187	$9,371,847	$8,755,284

(1) Excludes A&G Overhead amounts

Table 4
Enbridge Gas Storage – O&M Costs
Unregulated Storage Operation

EXPENSE CATEGORY (1)	2007	2008	2009	2010	2011
Labor	$143,821	$117,253	$506,108	$491,619	$391,669
Supplies	$136	$483	$19,652	$165	$2,687
Consulting Services	$85,016	$19,413	$166,735	$183,663	$180,294
Employee Expenses	$10,058	$14,965	$27,785	$752	$29,314
Other Operating Expenses	$6,667	$41,593	$404,052	$1,083,138	$1,401,631
Property Taxes (1)		$156,000	$73,656		
Subtotal	$245,698	$349,707	$1,197,988	$1,759,337	$2,005,595
Labor Credits and Other	($8,895)	$10,995	($75,167)	($51,740)	($59,114)
Total	$236,803	$360,702	$1,122,821	$1,707,597	$1,946,481
Direct Assignment	$230,136	$319,109	$718,769	$624,459	$544,850
Allocated Amount	$6,667	$41,593	$404,052	$1,083,138	$1,401,631
Total	$236,803	$360,702	$1,122,821	$1,707,597	$1,946,481

(1) An allocated amount is included in Other Operating Expenses in 2010 and 2011

To determine an appropriate cost allocation basis for its O&M costs, Enbridge evaluated each of its cost categories to establish a relationship between the various service requirements of storage and the costs incurred by Enbridge in serving those requirements (i.e., what are the cost drivers?). Unlike the asset side of Enbridge's storage operations, where a clearer determination could be made of which of Enbridge's two storage operations caused the new asset addition, O&M expenses are more generalized in nature, and in many cases, they support the entirety of Enbridge's integrated storage operation. This fact makes it difficult to determine with certainty which of Enbridge's two storage operations cause these costs to be incurred. As a result, most of Enbridge's O&M expenses are allocated and shared on the basis of the relative proportions of the total storage capacities and, in some cases, the actual storage activity of its regulated and unregulated storage operations.

Enbridge derives storage-related expenses for its unregulated storage operations on a monthly basis to reflect the latest operating activity supporting that business. Enbridge first identifies the costs of certain storage-related activities that can be directly attributed or assigned to its unregulated storage operations. Enbridge's unregulated storage business has an Unregulated Storage Group that is dedicated to managing and administering all aspects of that business. All other activities and associated costs which support Enbridge's integrated storage operations must be allocated between its regulated and unregulated storage operations. An assessment of the appropriate costing treatment was made by Enbridge for each of the various cost elements that supports Enbridge's storage operations. Each of Enbridge's cost elements that support (either directly or indirectly) its unregulated storage operations, and the associated allocation methods, is described below.

Storage Operations

Enbridge incurs certain operating costs that can be directly identified with its unregulated storage operations. These activities consist of staff time and a variety of other expenses associated with Enbridge's Unregulated Storage Group described earlier. The costs of these activities are charged to a cost center that is specific to the unregulated storage business.[9]

For cost allocation purposes, Enbridge has determined that the costs of its storage operations can either be classified as fixed or variable in nature. Enbridge has defined fixed costs as those that do not vary with the levels of storage activity, and variable costs as those that do vary with activity. This approach is similar to the designation of demand and commodity costs as used in a utility's traditional cost allocation study. This cost classification process is dependent upon the degree to which the particular cost is observed to vary with Enbridge's storage activity. If a particular cost does not change materially with the level of actual storage activity, then Enbridge classifies that cost as 100% fixed. Conversely, for costs that do vary materially as the level of actual storage activity changes, Enbridge classifies these costs as 100% variable. Examples of variable costs are other materials such as compressor and crankcase oil, glycol, and outside services such as electricity.

Enbridge has evaluated each of its cost elements to determine how the particular cost should be classified. In most cases, it was a straightforward process for Enbridge to determine definitively

[9] Enbridge Gas Distribution - Cost Centre 25371 – Unregulated Storage

that the cost element was fixed in nature. For certain other cost elements, Enbridge was required to apply management judgment by those staff members closest to the underlying activities to determine the relative proportion of costs that were fixed and variable in nature.

The operating expenses that are deemed to be relatively fixed are allocated between Enbridge's regulated and unregulated storage operations based upon their relative share of Enbridge's total available storage capacity. This means that, as the unregulated storage business grows, the unregulated business will be charged for an increasing share of Enbridge's fixed storage operating costs.

For those operating costs that vary with the levels of storage activity, Enbridge allocates such costs using the actual costs incurred in each month, and the relative share of the total actual storage activity for the regulated and unregulated storage operations for that same month. In that way, Enbridge's unregulated storage business, which may exhibit a more volatile activity profile than the more traditional use of storage by the regulated utility customer, would pay a higher share of these variable costs in months when its customers required a disproportionately greater level of storage activity.

To better understand and verify how Enbridge conducts its above-described cost allocation process, Black & Veatch analyzed the storage-related expenses incurred by Enbridge each month during calendar year 2011 and the level of costs that was directly assigned or allocated to its unregulated storage operations. To illustrate the cost allocation process that Enbridge follows, Schedule 6 presents a series of detailed storage cost accounting sheets for calendar 2011 and for the month of November 2011 (which reflect expenses that are charged in December). Page 1 of Schedule 6 presents a summary of the allocation of O&M costs to Enbridge's unregulated storage operation for 2011. There are four Cost Centers associated with Enbridge's gas storage operations: (1) Storage Administration - 25121; (2) Storage Operations - 25122; (3) Storage Maintenance - 25123; and (4) Field Maintenance - 25124. The total allocated amount of $1,401,567 presented on page 1 of Schedule 6 is brought forward to Table 4 presented above.[10]

For each month, there are four (4) Operating Cost Reports by Cost Center that reflect the allocation of costs between Enbridge's regulated and unregulated storage operations (see Pages 2-5 of Schedule 6). Each sheet details the allocation of costs by individual cost element, the derivation of the fixed and variable allocation factors based on the shares of storage capacity and storage activity, respectively, and the resulting total costs to be charged to Enbridge's unregulated storage operation.

At the end of each month, Enbridge charges the total allocated costs for each of these Cost Centers to its unregulated storage operation through adjustments to its General Ledger Journal, which results in the inclusion of these costs in the December 2011 Operating Cost Report[11] for Enbridge's

[10] An unexplained discrepancy of $64 exists between the amounts recorded in Enbridge's Monthly Operating Cost Reports for 2011 (see page 1 of Schedule 6) and the total amount recorded in the "Other Operating" line entry (70899) in its Operating Cost Report for 2011 for Cost Center 25371 – Unregulated Storage (see page 6 of Schedule 6).

[11] There is a one-month lag in the booking of the allocated storage costs in the Operating Cost Report of Enbridge's unregulated storage operation.

unregulated storage operation. Page 6 of Schedule 6 is a copy of the Operating Cost Report for December 2011 for Enbridge's unregulated storage operation, which shows the inclusion of the allocated storage costs for calendar 2011 in the line identified as "70899 Other Operating" under the column "Year to Date – Actual."

Black & Veatch believes that the manner in which Enbridge allocates costs in this category to its two storage operations should be reflective of the cost causative factors that give rise to these costs. While Black & Veatch agrees that storage capacity (or space) and storage activity are two important attributes of a utility's storage operations, storage deliverability also is an important cost driver. In its past filings, Enbridge has not explicitly recognized storage deliverability in its cost allocation methods. When Black & Veatch questioned Enbridge concerning why it did not classify storage-related O&M costs according to the cost classification categories of Deliverability and Space that were used in its Fully Allocated Cost Study, Enbridge responded as follows:

> "Because of the nature of the unregulated storage services, and the likelihood that gas volumes for unregulated customers would be cycled several times in a year, it was felt that activity was a fairer basis for cost allocation. A deliverability classification, as used for the more traditional, single cycle needs of the utility customers, would have recognized the higher deliverability characteristics of the current unregulated storage business but would not have recognized the multiple-cycling nature of the unregulated storage contracts. It is felt that basing the allocation on activity, and not deliverability, would capture both the higher deliverability and multiple-cycling cost implications of these services."

Black & Veatch understands Enbridge's response and agrees with the view that it is more appropriate to allocate certain of these costs using an allocation factor based on storage activity because it better reflects the storage requirements of its unregulated storage operations. However, Black & Veatch does not agree with the conclusion that storage activity also serves as a good proxy for storage deliverability. In Enbridge's most recent fully allocated cost study, it classified Tecumseh Gas' storage-related costs, and the costs based on contract arrangements with Union, according to three distinct types of service:

1. An annual component for space or capacity
2. A variable component (activity) for each unit of gas injected into or withdrawn from storage
3. A peak component (deliverability) for the maximum daily rate at which the gas may be withdrawn from storage.[12]

Enbridge classified approximately 40% of its total storage-related cost of service of Tecumseh Gas (excluding its commodity-related costs) as capacity ("Annual Demand") and 60% of these costs as deliverability ("Daily Demand").[13] Enbridge's subsequent allocation of these costs was performed recognizing the same 40/60 proportion of Annual Demand and Daily Demand. In contrast, Enbridge has allocated a much smaller percentage of costs to its unregulated storage operation

[12] EB-2006-08-25, Exhibit G2, Tab 1, Schedule 1, Page 16 of 26.
[13] EB-2006-08-25, Exhibit G2, Tab 7, Schedule 3, page 1.

using an allocation factor based on actual monthly storage activity compared to the 60% of costs described above which are allocated on a daily deliverability basis. Referring to pages 2 through 5 of Schedule 6, the total costs in November 2011 allocated on the basis of actual monthly storage activity equaled only about 6%, while the remaining 94% of the total costs were allocated on storage capacity. In Black & Veatch's opinion, this comparison shows that Enbridge's current cost allocation method which assigns storage O&M costs to its unregulated storage operation underemphasizes the cost driver of storage deliverability and overemphasizes the cost driver of storage capacity. As a result, Black & Veatch believes that this allocation method does not reflect the cost causative factors that are relied upon by Enbridge when classifying and allocating these same costs in its fully cost allocation study. Based on this situation, Black & Veatch conveyed to Enbridge during our discussions related to this study that it should consider changing its allocation factor for fixed storage costs to reflect a proper weighting of the cost drivers of capacity and deliverability.

As a result of Black & Veatch's discussions on this subject, Enbridge has re-examined each of the operating and maintenance expense categories for the four cost centers reflected in Schedule 6 and has determined that certain allocation factors should be revised to recognize storage deliverability as a distinct cost driver. As part of this re-examination, Enbridge also made minor revisions to the allocation treatment for certain costs that it believed were impacted differently by storage activity based on the nature of the business activity and with the recognition of deliverability as a cost allocation factor. Schedule 7 presents Enbridge's detailed storage cost accounting sheets for the month of August 2011 (which reflect expenses that are charged in September) with the revised allocation factors it proposes to establish for the assignment of fixed and variable expenses incurred to support its regulated and unregulated storage operations.

Black & Veatch has reviewed the revised cost allocation methods established by Enbridge for its storage operating expenses and concludes that they are reasonable and appropriate. Enbridge's cost allocation methods and cost allocation factors are reflective of the manner in which similar types of costs are treated in its fully allocated cost of service study and the judgments of the staff who are regularly involved in the day-to-day management and operations of its gas storage businesses.

One additional minor issue that was identified by Black & Veatch pertained to Enbridge's use of an "Applicable Share" adjustment to certain costs included in the Storage Administration Cost Center (see page 2 of Schedule 6). Enbridge first reduces the actual total labor costs in this area by 5% (a 95% Applicable Share amount) to recognize that one FTE in the business group does not provide any services to the unregulated storage business. As discussed earlier, Enbridge's Unregulated Storage Group provides dedicated managerial and administrative support to the unregulated storage business. As such, Enbridge views an allocation of 100% of the labor costs of the Storage Administration Cost Center as creating an over-allocation of these costs to its unregulated storage operation.

Our concern is that if Enbridge relies upon a fully allocated costing basis to assign O&M costs to its unregulated storage operation, it is inappropriate to first eliminate certain costs from the allocation process. This is because the validity in utilizing a generalized allocation factor is premised upon it being applied to all costs being assigned. The application of the particular allocation factor (e.g.,

11% for storage capacity) presumes that a portion of the time spent by all staff represents a fair allocation of total costs between the two storage businesses, irrespective of the specific activities on any one staff member. While Enbridge believes that a particular staff member does not spend 11% of the workday supporting its unregulated storage operation, its use of a fully allocated costing method also means that Enbridge has implicitly accepted the premise that staff may spend a greater or lesser amount of time than the 11% level inherent in the allocation factor, but that overall, each of the staff spends an average of 11% on unregulated storage activities.

While Black & Veatch understands that this particular element of Enbridge's current cost allocation process causes a slight reduction in the level of costs assigned to its unregulated storage operation, it does compromise the conceptual basis for adopting a fully allocated costing method for these costs. As a result, Black & Veatch believes that this minor exception to the cost allocation process should be addressed by Enbridge on a going-forward basis by eliminating its "Applicable Share" adjustment. Based on this situation, Black & Veatch conveyed to Enbridge during our discussions related to this study that its use of an "Applicable Share" adjustment to certain costs included in the Storage Administration Cost Center should be eliminated from its current cost allocation process on a going-forward basis.

We understand that Enbridge has reviewed our explanation of this situation and has proposed to eliminate this adjustment from its current allocation treatment of storage-related operating expenses. Schedule 7 shows that the "Applicable Share" adjustment will no longer appear in Enbridge's monthly Operating Cost Reports.

Corporate Administrative and General Overheads

Enbridge also allocates A&G overhead costs to its unregulated storage operations in the same way that it does for the operating costs incurred by its regulated storage activities. An hourly A&G overhead amount is determined for each Full-Time Equivalent ("FTE") staff member, with those costs treated as a premium to the hourly cost of the FTEs involved in Enbridge's unregulated storage activities.

These overhead costs include a broad range of corporate costs and services such as finance and business services, customer support, regulatory, legal and corporate services, human resources, and engineering, as well as a rate of return on, and the depreciation expenses for, buildings, office furniture and equipment, telecom equipment, and information technology/software assets. In addition to these overhead costs, Enbridge's cost allocation process also includes the expected cost of its performance-based pay incentive for storage operations staff.

The allocation of these overhead costs to Enbridge's unregulated storage operation has the effect of increasing the base labor costs by 65% to 70%, which is reflected on page 2 of Schedule 6 under the "Overhead Rate" column. The calculation and inclusion of these overhead amounts is an integral part of Enbridge's monthly allocation process for its Tecumseh storage operations.

Unregulated Business Development and Administration Costs

As a participant in the unregulated storage industry, Enbridge incurs other costs that are specific to the strategic development, management and operation of the business. These costs are charged directly to the set of accounts that are kept for the unregulated business. Among these is the cost of

the dedicated management and staff of the unregulated storage business, the cost of Gas Control services in Edmonton and the cost of any professional services required, such as legal counsel and third party technical consultants.

These resources are necessary to stay current with gas storage markets, identify storage service opportunities and their feasibility and to manage the contractual relationships that underlie the commercial basis for the un-regulated storage business. These costs are charged directly to the accounts of the unregulated storage business through the normal payroll, financial and A/P systems of Enbridge. As such, there are no business development and administrative costs in this category that is incurred on behalf of Enbridge's regulated storage operations.

Fuel Gas

Enbridge assigns a portion of the cost of gas it incurs to operate its gas storage operations at Tecumseh to its unregulated storage operations. This is accomplished by determining the actual storage activity for Enbridge's unregulated storage operations and applying that amount to the previous October's Quarterly Rate Adjustment Mechanism ("QRAM") reference price of gas. Enbridge's current Fuel Ratio charged to its unregulated storage customers is 0.35%.

Lost and Unaccounted For Gas

Enbridge assigns the cost of Lost and Unaccounted for Gas ("LUF") to its unregulated storage operations by applying an "in-kind" charge to its unregulated storage customers' capacity and activity levels. This charge uses the same LUF replacement factor that has been approved by the Board for Enbridge's regulated utility customers. We understand that Enbridge maintains a separate LUF factor that is specific to its gas storage operations.

Schedule 8 summarizes the cost allocation treatment for Enbridge's cost of gas components.

Depreciation Expense

Annual depreciation rates for Enbridge's underground storage assets were approved by the Board in RP-2002-0133. Table 5 below presents the annual depreciation rates for Enbridge's unregulated underground storage operations.

Table 5
Enbridge's Annual Depreciation Rates for Unregulated Storage Assets

ACCOUNT NUMBER	ACCOUNT DESCRIPTION	ANNUAL DEPRECIATION RATE
451	Land Rights	2.10%
452	Structures & Improvements	2.60%
453	Wells	4.60%
454	Well Equipment	3.10%
455	Field Lines	2.60%
456	Compressor Equipment	2.20%
457	Regulating Equipment	3.60%

Depreciation expense (and the associated accumulated depreciation reserve) is calculated at the individual asset level using the annual rate that is applicable to the entire asset class. Enbridge's depreciation expense is posted to a separate general ledger account. The 2011 depreciation expense for Enbridge's unregulated storage assets was approximately $1.37 million.

Property Taxes

Enbridge currently assigns a portion of its storage-related property taxes to the unregulated storage business through the cost allocation process utilized in its Storage Administration Cost Center (25121). As shown on page 1 of Schedule 7, under the line "70701 – Property Taxes," Enbridge proposes to assign this cost element to its unregulated storage operation on the basis of its Annual Capacity allocation factor (40%) and its Deliverability allocation factor (60%).

Schedule 9 summarizes the cost allocation treatment for Enbridge's depreciation expense and property taxes.

FINDINGS AND RECOMMENDATIONS

Based upon Black & Veatch's review of Enbridge's storage allocation process, methodology, and results, the conceptual underpinnings and resulting methodologies upon which Enbridge's cost allocation process are generally well-conceived and reasonable in their treatment of storage-related plant and expenses. However, there are a few components of Enbridge's current cost allocation methods that Black & Veatch believes should be changed to better recognize the underlying cost causative factors of Enbridge's storage operations. As described previously, Enbridge has considered Black & Veatch's discussions on this topic and has proposed to revise certain of its current cost allocation methods for the following cost elements:

- **New General Storage Plant**
    1. Enbridge proposes to adopt the cost allocation treatment for new general plant depicted in Schedule 5 and to apply this method to the cost of its Sombra warehouse facility once it is completed and placed into service.

- **Storage Operations**
    1. Enbridge proposes to change its cost allocation factor for fixed storage costs to reflect a proper weighting of the cost drivers of annual capacity and deliverability, and has made minor modifications to the portion of costs it classifies as variable in nature.

    2. Enbridge proposes to eliminate from its current cost allocation process the use of an "Applicable Share" adjustment to certain costs included in the Storage Administration Cost Center (see page 2 of Schedule 6).

In addition, the manner in which Enbridge has presented its separation of costs between its regulated and unregulated storage operations in its past ESM Filings before the Board[14] does not in all cases provide a sufficient level of detail and explanation to allow an outside party to understand,

[14] See Enbridge's evidence filed in EB-2010-0042 and EB-2011-0008.

trace, and verify the underlying assumptions of the cost allocation methodology, computational processes, and to independently confirm the results.

As a result of this finding, Black & Veatch recommends the following enhancements to Enbridge's computational process and evidentiary presentation:

1. Establish more robust documentation that readily allows the reader to clearly trace how Enbridge's regulated and unregulated storage costs are developed, which should include providing clear references for the cost allocation methods used in the calculation of the costs of Enbridge's unregulated storage operations. Black & Veatch believes that certain of the Schedules presented in this report should be incorporated into Enbridge's future evidentiary presentations before the Board on this subject.

2. Provide additional details to be able to trace Enbridge's elimination from its Utility Income of each particular expense item (e.g., gas costs, O&M expenses, property taxes, and depreciation expense) associated with Enbridge's unregulated storage operation, and the computational details to derive each eliminated amount.[15]

3. The manner in which Enbridge splits the cost of new storage assets that replace existing storage assets with a capacity enhancement component between its regulated and unregulated storage operations (e.g., Enbridge's "Pool Metering Upgrades" project) should be detailed so that the basis for the determination of the cost split can be readily understood by an outside party.

[15] See EB-2011-0008, Exhibit B, Tab 1, Schedule 4, pages 1-4.

ENBRIDGE GAS DISTRIBUTION INC. **Schedule 1**

Underground Storage Facilities - Operational Characteristics (1)

	2007	2008	2009	2010	2011
Annual Capacity (Bcf)					
In-Franchise (2)	91.7	91.7	91.7	91.7	91.7
Ex-Franchise (3)	6.7	6.7	6.7	6.7	6.7
Subtotal	98.4	98.4	98.4	98.4	98.4
Unregulated	0.0	2.2	4.2	8.7	12.2
Total	98.4	100.6	102.6	107.1	110.6
Daily Withdrawal Commitments (Bcfd)					
In-Franchise (2)	1.74	1.74	1.74	1.74	1.74
Ex-Franchise (4)	0.19	0.19	0.19	0.19	0.19
Subtotal	1.93	1.93	1.93	1.93	1.93
Unregulated	0.0	0.157	0.269	0.359	0.401
Total	1.93	2.09	2.20	2.29	2.33
Injection/Withdrawal Activity (Bcf)					
Regulated	0	140.11	179.02	163.85	173.28
Unregulated	0.0	11.97	28.28	13.65	15.49
Total	0.00	152.08	207.30	177.50	188.77
Storage Turnover Rate (5)					
Regulated	0	1.4	1.8	1.7	1.8
Unregulated	0.0	5.4	6.7	1.6	1.3
Total	0.0	1.5	2.0	1.7	1.7

Notes:

(1) Includes Crowland Storage

(2) Includes Transactional Services

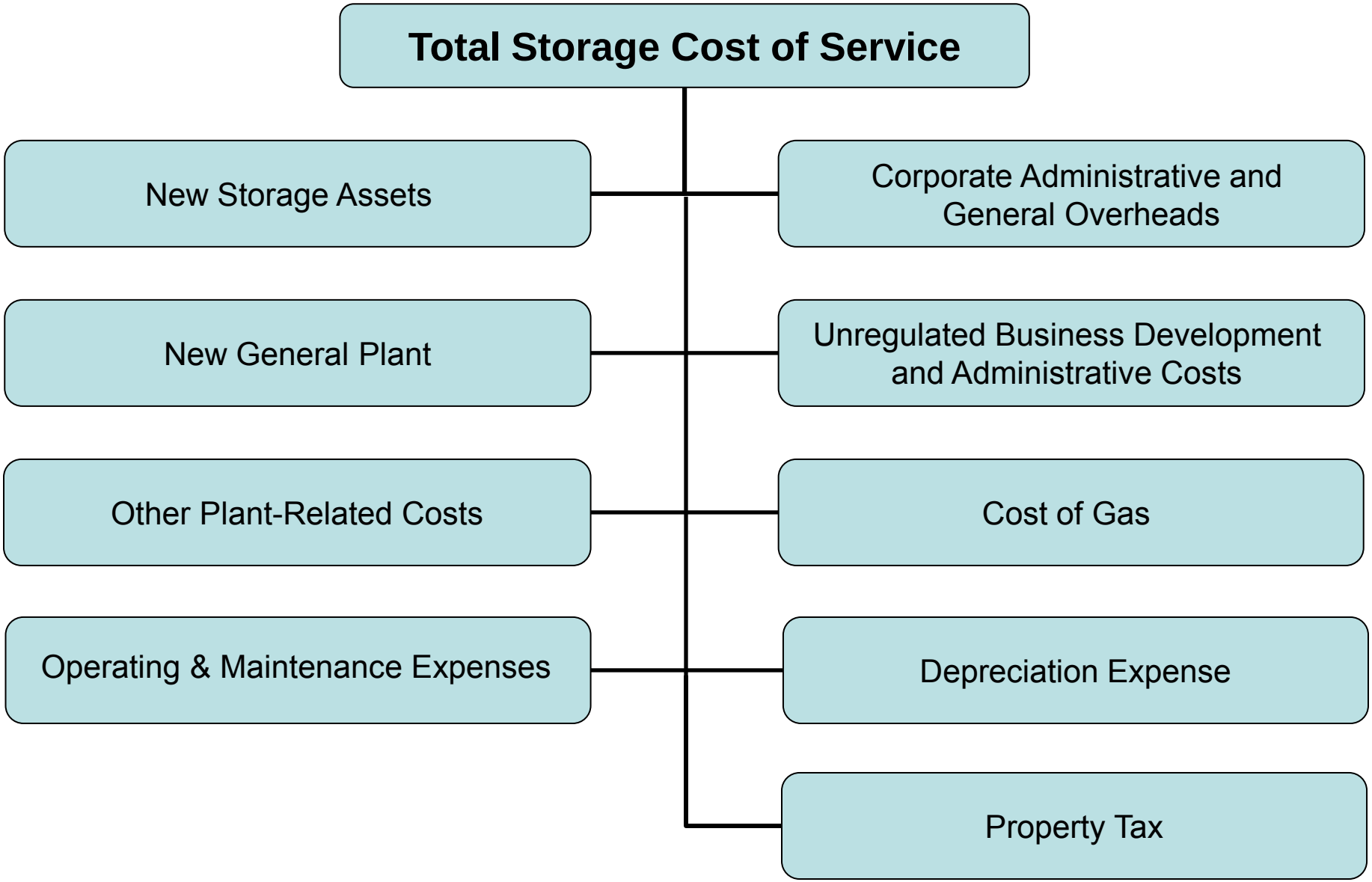
(3) Regulated contract storage services for Union Gas Limited

(4) Regulated contract storage services for Union Gas Limited (0.11 Bcfd) and transmission deliverability services for Niagara Gas Transmission Ltd. (0.08 Bcfd)

(5) Unregulated storage operations started in May 2008

ENBRIDGE GAS DISTRIBUTION INC.
Allocation of Regulated and Unregulated Storage Costs
Functional Process Flowchart

Schedule 2



ENBRIDGE GAS DISTRIBUTION INC. **Schedule 3**
Allocation of Regulated and Unregulated Storage Costs
Timing of the Cost Allocation Process

Monthly/Annual	Periodic
•Storage Asset Additions and Retirements –Direct Assignments –Allocations	•New Depreciation Rates
•General Plant Additions and Retirements –Direct Assignments –Allocations	
•Operating and Maintenance Expenses –Direct Assignments –Allocations	
•Corporate Administrative and General Overheads –Loading Rates	
•Unregulated Business Development and Administrative Costs –Direct Assignment	
•Cost of Gas –Lost and Unaccounted for Gas –Allocations	
•Property Tax –Allocations	

ENBRIDGE GAS DISTRIBUTION INC.
Unregulated Gas Storage Assets
Net Plant - Year End Balances

Asset Description	Plant Account	2007 Opening Balance	2007 Additions	2007 Provisions	2007 Ending Balance
Gross Plant					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453				
Field Lines	455		$1,307,846		$1,307,846
Compressor Equipment	456		$7,043,209		$7,043,209
Measuring & Regulating Equipment	457				
Plant Not Classified					
Totals			$8,351,055		$8,351,055
Accumulated Depreciation Reserve					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453				
Field Lines	455				
Compressor Equipment	456				
Measuring & Regulating Equipment	457				
Plant Not Classified					
Totals					
Net Plant					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453				
Field Lines	455		$1,307,846		$1,307,846
Compressor Equipment	456		$7,043,209		$7,043,209
Measuring & Regulating Equipment	457				
Plant Not Classified					
Totals			$8,351,055		**$8,351,055**

ENBRIDGE GAS DISTRIBUTION INC.
Unregulated Gas Storage Assets
Net Plant - Year End Balances

Asset Description	Plant Account	2008 Opening Balance	2008 Additions	2008 Provisions	2008 Ending Balance
Gross Plant					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453		$3,929,319		$3,929,319
Field Lines	455	$1,307,846	$7,230,279		$8,538,125
Compressor Equipment	456	$7,043,209	$2,878,383		$9,921,592
Measuring & Regulating Equipment	457				
Work-In-Progress			$14,152,941		$14,152,941
Plant Not Classified					
Totals		$8,351,055	$28,190,922		$36,541,977
Accumulated Depreciation Reserve					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453			($24,912)	($24,912)
Field Lines	455			($25,473)	($25,473)
Compressor Equipment	456			($53,053)	($53,053)
Measuring & Regulating Equipment	457				
Plant Not Classified					
Totals				($103,438)	($103,438)
Net Plant					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453		$3,929,319	($24,912)	$3,904,407
Field Lines	455	$1,307,846	$7,230,279	($25,473)	$8,512,652
Compressor Equipment	456	$7,043,209	$2,878,383	($53,053)	$9,868,539
Measuring & Regulating Equipment	457				
Work-In-Progress			$14,152,941		$14,152,941
Plant Not Classified		$8,351,055	$28,190,922	($103,438)	**$36,438,539**
Totals					

ENBRIDGE GAS DISTRIBUTION INC.
Unregulated Gas Storage Assets
Net Plant - Year End Balances

Asset Description	Plant Account	2009 Opening Balance	2009 Additions	2009 Provisions	2009 Ending Balance
Gross Plant					
Land & Land Rights	450/451		$405,933		$405,933
Structures & Improvements	452				
Wells	453	$3,929,319	$3,608,934		$7,538,253
Field Lines	455	$8,538,125	$6,452,305		$14,990,430
Compressor Equipment	456	$9,921,592	$2,279,289		$12,200,881
Measuring & Regulating Equipment	457		$368,439		$368,439
Work-In-Progress		$14,152,941	($4,917,233)		$9,235,708
Plant Not Classified			$3,801,257		$3,801,257
Totals		$36,541,977	$11,998,924		$48,540,901
Accumulated Depreciation Reserve					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453	($24,912)		($295,644)	($320,556)
Field Lines	455	($25,473)		($398,656)	($424,129)
Compressor Equipment	456	($53,053)		($287,662)	($340,715)
Measuring & Regulating Equipment	457			($13,264)	($13,264)
Plant Not Classified				($118,473)	($118,473)
Totals		($103,438)		($1,113,699)	($1,217,137)
Net Plant					
Land & Land Rights	450/451		$405,933		$405,933
Structures & Improvements	452				
Wells	453	$3,904,407	$3,608,934	($295,644)	$7,217,697
Field Lines	455	$8,512,652	$6,452,305	($398,656)	$14,566,301
Compressor Equipment	456	$9,868,539	$2,279,289	($287,662)	$11,860,166
Measuring & Regulating Equipment	457	$0	$368,439	($13,264)	$355,175
Work-In-Progress		$14,152,941	($4,917,233)		$9,235,708
Plant Not Classified			$3,801,257	($118,473)	$3,682,784
Totals		$36,438,539	$11,998,924	($1,113,699)	**$47,323,764**

ENBRIDGE GAS DISTRIBUTION INC.
Unregulated Gas Storage Assets
Net Plant - Year End Balances

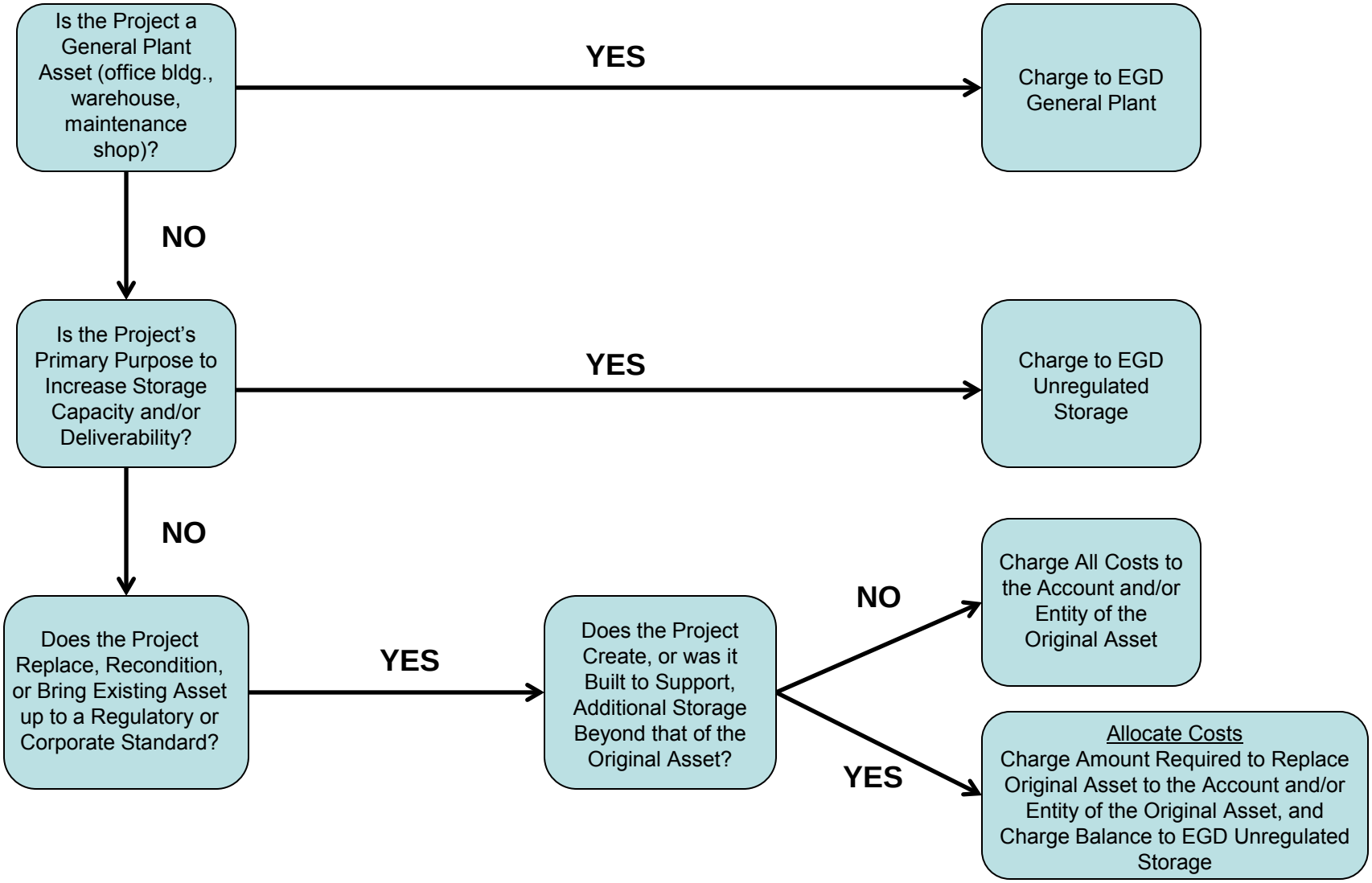
Asset Description	Plant Account	2010 Opening Balance	2010 Additions	2010 Provisions	2010 Ending Balance
Gross Plant					
Land & Land Rights	450/451	$405,933	$1,132,577	($411,207)	$1,127,303
Structures & Improvements	452				
Wells	453	$7,538,253	$3,071,174	$103,903	$10,713,330
Field Lines	455	$14,990,430	$89,821	$404,718	$15,484,969
Compressor Equipment	456	$12,200,881	$4,628,296	$4,072,396	$20,901,573
Measuring & Regulating Equipment	457	$368,439			$368,439
Work-In-Progress		$9,235,708	$8,574,447	($14,214,255)	$3,595,900
Plant Not Classified		$3,801,257		($3,801,257)	
Totals		$48,540,901	$17,496,315	($13,845,702)	$52,191,514
Accumulated Depreciation Reserve					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453	($320,556)	($438,062)		($758,618)
Field Lines	455	($424,129)	($410,897)		($835,026)
Compressor Equipment	456	($340,715)	($485,789)		($826,504)
Measuring & Regulating Equipment	457	($13,264)	($13,264)		($26,528)
Plant Not Classified		($118,473)		$118,473	
Totals		($1,217,137)	($1,348,012)		($2,446,676)
Net Plant					
Land & Land Rights	450/451	$405,933	$1,132,577	($411,207)	$1,127,303
Structures & Improvements	452				
Wells	453	$7,217,697	$2,633,112	$103,903	$9,954,712
Field Lines	455	$14,566,301	($321,076)	$404,718	$14,649,943
Compressor Equipment	456	$11,860,166	$4,142,507	$4,072,396	$20,075,069
Measuring & Regulating Equipment	457	$355,175	($13,264)		$341,911
Work-In-Progress		$9,235,708	$8,574,447	($14,214,255)	$3,595,900
Plant Not Classified		$3,682,784		($3,682,784)	
Totals		$47,323,764	$16,148,303	($13,727,229)	**$49,744,838**

ENBRIDGE GAS DISTRIBUTION INC.
Unregulated Gas Storage Assets
Net Plant - Year End Balances

Asset Description	Plant Account	2011 Opening Balance	2011 Additions	2011 Provisions	2011 Ending Balance
Gross Plant					
Land & Land Rights	450/451	$1,127,303			$1,127,303
Structures & Improvements	452				
Wells	453	$10,713,330		$129,191	$10,842,521
Field Lines	455	$15,484,969			$15,484,969
Compressor Equipment	456	$20,901,573	$13,275	$978,362	$21,893,210
Measuring & Regulating Equipment	457	$368,439			$368,439
Work-in-Progress		$3,595,900		($3,331,979)	$263,921
Plant Not Classified				$38,289,245	$38,289,245
Totals		$52,191,514	$13,275	$36,064,819	$88,269,608
Accumulated Depreciation Reserve					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453	($758,618)	($492,867)	($112)	($1,251,597)
Field Lines	455	($835,026)	($402,609)		($1,237,635)
Compressor Equipment	456	($826,504)	($465,330)	($40,190)	($1,332,024)
Measuring & Regulating Equipment	457	($26,528)	($13,264)		($39,792)
Plant Not Classified					
Totals		($2,446,676)	($1,374,070)	($40,302)	($3,861,048)
Net Plant					
Land & Land Rights	450/451	$1,127,303			$1,127,303
Structures & Improvements	452				
Wells	453	$9,954,712	($492,867)	$129,079	$9,590,924
Field Lines	455	$14,649,943	($402,609)		$14,247,334
Compressor Equipment	456	$20,075,069	($452,055)	$938,172	$20,561,186
Measuring & Regulating Equipment	457	$341,911	($13,264)		$328,647
Work-in-Progress		$3,595,900		($3,331,979)	$263,921
Plant Not Classified				$38,289,245	$38,289,245
Totals		$49,744,838	($1,360,795)	$36,024,517	**$84,408,560**

ENBRIDGE GAS DISTRIBUTION INC.
Allocation of Regulated and Unregulated Storage Costs
Capital Project Assessment Process

Schedule 5



ENBRIDGE GAS DISTRIBUTION INC.
Unregulated Storage Operation
2011 Operating and Maintenance Costs - Allocated

Expense Category	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Administration	$6,394	$23,453	$41,846	$44,704	$41,278	$62,262	$72,798	$42,707	$52,862	$54,260	$57,640	$107,571	$607,775
Storage Operations	$15,574	$10,841	$11,369	$25,164	$16,909	$32,057	$23,492	$35,151	$23,608	$40,176	$46,564	$50,204	$331,109
Storage Maintenance	$30,981	$14,098	$6,420	$21,465	$21,030	$20,072	$6,428	$24,152	$33,442	$23,738	$55,684	$63,499	$321,009
Field Maintenance	$42,183	($1,993)	$4,062	$21,132	$7,284	($17,655)	$438	$5,150	$36,041	$15,268	$16,108	$13,656	$141,674
Total	$95,132	$46,399	$63,697	$112,465	$86,501	$96,736	$103,156	$107,160	$145,953	$133,442	$175,996	$234,930	**$1,401,567**

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: NOV-11 Currency: CAD

	Annual Capacity Bcf	Annual Capacity % of Total	Commodity Bcf	Commodity % of Total
Regulated	98.00	88.93%	1.95	42.94%
Un-regulated	12.20	11.07%	2.59	57.06%
	110.2	100.00%	4.54	100.00%

COST CENTRE=25121 (STORAGE ADMINISTRATION)

	Actual	Applicable Share		Annual %	Annual $	Commodity %	Commodity $	Overhead Rate	
CONTROLLABLE COSTS									
60101 BASE PAY	150,645	95%	242,148	100%	242,148	0%	-	69.2%	
60109 TEMPORARY PAYRO	9,370	95%	15,061	100%	15,061	0%	-	69.2%	
60117 VACATION PAY	10,414	95%	16,740	100%	16,740	0%	-	69.2%	
60129 SCHEDULED OVERTIME	940	95%	1,511	100%	1,511	0%	-	69.2%	
60131 STATUTORY HOLID	0	95%	-	100%	-	0%	-	69.2%	
60133 SICK PAY	450	95%	723	100%	723	0%	-	69.2%	
60141 VACANCY CREDIT	0	95%	-	100%	-	0%	-	69.2%	
60145 OTHER SALARY EX	0	95%	-	100%	-	0%	-	69.2%	
TOTAL LABOUR	**171,819**		**276,183**		**276,183**		**0**		**30,576**
60401 EMPLOYEE TRAINI	12	95%	11	100%	11	0%	-		
60411 AWARDS AND ALLO	(446)	95%	(424)	100%	(424)	0%	-		
61105 COPIER AND OTHE	2,570	100%	2,570	100%	2,570	0%	-		
61116 COMPUTER SOFTWA	25,009	100%	25,009	100%	25,009	0%	-		
61511 PROFESSIONAL CO	0	100%	-	100%	-	0%	-		
61505 FILING FEES	725	100%	725	100%	725	0%	-		
61707 JANITORIAL SERVICES	9,496	100%	9,496	100%	9,496	0%	-		
61709 OFFICE REPAIRS	122	100%	122	100%	122	0%	-		
61715 POSTAGE COURIER	392	100%	392	100%	392	0%	-		
61717 REPRODUCTION SE	136	100%	136	100%	136	0%	-		
61910 SITE WORK	0	100%	-	100%	-	0%	-		
61999 OTHER OUTSIDE S	25,518	100%	25,518	100%	25,518	0%	-		
62301 VEHICLE / FLEET	10,193	100%	10,193	90%	9,174	10%	1,019		
70001 LAND LEASES	485,029	100%	485,029	100%	485,029	0%	-		
70409 OTHER TELECOM S	0	100%	-	100%	-	0%	-		
70501 AIRFARE	641	95%	609	100%	609	0%	-		
70503 GROUND TRANSPOR	1,278	95%	1,214	100%	1,214	0%	-		
70505 ACCOMMODATION	1,942	95%	1,845	100%	1,845	0%	-		
70507 MEALS AND ENTER	2,933	95%	2,786	100%	2,786	0%	-		
70509 OTHER TRAVEL EX	328	95%	312	100%	312	0%	-		
70511 CONFERENCE AND	421	95%	400	100%	400	0%	-		
70701 PROPERTY TAXES	128,706	100%	128,706	100%	128,706	0%	-		
70809 TRADE AND CIVIC	1,797	100%	1,797	100%	1,797	0%	-		
NON-LABOUR COST CENTRE COSTS	**696,802**		**696,446**		**695,427**		**1,019**		**77,571**
INTERNAL COST RECOVERIES									
79966 VARIABLE INTERN	(5,200)	100%	(5,200)	100%	(5,200)	0%	-		
79967 OTHER RECOVERIE CAPITAL	0	100%	0	100%	0	0%	-		
TOTAL COST RECOVERIES	**(5,200)**		**(5,200)**		**(5,200)**		**-**		**(576)**
TOTAL NET COST CENTRE COSTS	**863,420**		**967,429**		**966,410**		**1,019**		
CHARGES TO UN-REGULATED					106,989		582		
							107,571		

OPERATING COST REPORT - DETAIL CADSEP

		Annual Capacity		Commodity	
CADDEC		Bcf	% of Total	Bcf	% of Total
Period: NOV-11 Currency: CAD	Regulated	98.00	88.93%	1.95	42.94%
	Un-regulated	12.20	11.07%	2.59	57.06%
		110.2	100.00%	4.54	100.00%

COST CENTRE=25122 (STORAGE OPERATIONS)

	Actual	Applicable Share	Annual %	Annual $	Commodity %	Commodity $	Overhead Factor
CONTROLLABLE COSTS							
60101 BASE PAY	14,057	100%	100%	23,204	0%	0	65.1%
60105 HOURLY PAYROLL	70,747	100%	100%	116,786	0%	0	65.1%
60117 VACATION PAY	5,570	100%	100%	9,195	0%	0	65.1%
60129 SCHEDULED OVERT	50,903	100%	80%	67,222	20%	16,806	65.1%
60131 STATUTORY HOLID	0	100%	100%	0	0%	0	65.1%
60133 SICK PAY	6,350	100%	100%	10,482	0%	0	65.1%
60145 OTHER SALARY EX	0	100%	100%	0	0%	0	65.1%
TOTAL LABOUR	**147,627**			**226,889**		**16,806**	
61009 SAFETY RELATED	4,995	100%	100%	4,995	0%	0	
61299 OTHER MATERIALS	7,504	100%	40%	3,002	60%	4,503	
61601 CONTRACT SERVIC	0	100%	100%	0	0%	0	
61805 ENVIRONMENTAL C	2,427	100%	100%	2,427	0%	0	
61999 OTHER OUTSIDE S	30,710	100%	40%	12,284	60%	18,426	
NON-LABOUR COST CENTRE COSTS	**45,635**			**22,707**		**22,929**	
INTERNAL COST RECOVERIES							
79966 VARIABLE INTERN	(906)	100%	100%	(906)	0%	0	100%
79967 OTHER RECOVERIE CAPITAL		100%	100%	0	0%	0	100%
TOTAL COST RECOVERIES	**(906)**			**(906)**		**0**	
TOTAL NET COST CENTRE COSTS	**192,356**			**248,690**		**39,734**	
CHARGES TO UN-REGULATED				27,532		22,672	
						50,204	

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: NOV-11 Currency: CAD

	Annual Capacity		Commodity	
	Bcf	% of Total	Bcf	% of Total
Regulated	98.00	88.93%	1.95	42.94%
Un-regulated	12.20	11.07%	2.59	57.06%
	110.2	100.00%	4.54	100.00%

COST CENTRE=25123 (STORAGE MAINTENANCE)

	Actual	Applicable Share	Annual %	Annual $	Commodity %	Commodity $	Overhead Factor
CONTROLLABLE COSTS							
60101 BASE PAY	64,726	100%	100%	110,046	0%	0	70.0%
60105 HOURLY PAYROLL	0	100%	100%	0	0%	0	70.0%
60117 VACATION PAY	1,692	100%	100%	2,877	0%	0	70.0%
60129 SCHEDULED OVERT	8,419	100%	40%	5,726	60%	8,588	70.0%
60131 STATUTORY HOLID	0	100%	100%	0	0%	0	70.0%
60133 SICK PAY	9,839	100%	100%	16,728	0%	0	70.0%
60145 OTHER SALARY EX	0	100%	100%	0	0%	0	70.0%
TOTAL LABOUR	**84,676**			**135,376**		**8,588**	
60401 EMPLOYEE TRAINI	10,862	100%	40%	4,345	60%	6,517	
61299 OTHER MATERIALS	65,786	100%	40%	26,314	60%	39,472	
61601 CONTRACT SERVIC	40,964	100%	40%	16,385	60%	24,578	
NON-LABOUR COST CENTRE COSTS	**117,612**			**47,045**		**70,567**	
INTERNAL COST RECOVERIES							
79951 CAPITAL PROJECT	(12,022)	100%	100%	(12,022)	0%	0	100%
79966 VARIABLE INTERN	(4,800)	100%	100%	(4,800)	0%	0	100%
79967 OTHER RECOVERIE CAPITAL		100%	100%	0	0%	0	100%
TOTAL COST RECOVERIES	**(16,822)**			**(16,822)**		**0**	
TOTAL NET COST CENTRE COSTS	**185,466**			**165,599**		**79,155**	
CHARGES TO UN-REGULATED				**18,333**		**45,166**	
						63,499	

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: NOV-11 Currency: CAD

	Annual Capacity		Commodity	
	Bcf	% of Total	Bcf	% of Total
Regulated	98.00	88.93%	1.95	42.94%
Un-regulated	12.20	11.07%	2.59	57.06%
	110.20	100.00%	4.54	100.00%

COST CENTRE=25124 (FIELD MAINTENANCE)

	Actual	Applicable Share	Annual %	Annual $	Commodity %	Commodity $
CONTROLLABLE COSTS						
61299 OTHER MATERIALS	0	100%	100%	0	0%	0
61511 PROFESSIONAL CO	2,060	100%	100%	2,060	0%	0
61601 CONTRACT SERVIC	112,493	100%	100%	112,493	0%	0
61805 ENVIRONMENTAL C	8,803	100%	100%	8,803	0%	0
DIRECT COST CENTRE COSTS	**123,356**			**123,356**		**0**
TOTAL NET COST CENTRE COSTS	**123,356**			**123,356**		**0**
CHARGES TO UN-REGULATED				13,656		0
						13,656

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: DEC-11 Currency: CAD
Submitted: 10-JAN-12 10:46:28

LOB=25104 (ENBRIDGE GAS DISTRIBUTION - UNREGULATED), COST CENTRE=25371 (UNREGULATED STORAGE)

	Current Month			Year To Date			Full Year
	Actual	Budget	Variance	Actual	Budget	Variance	Budget
CONTROLLABLE COSTS							
60101 BASE PAY	38,151.00	31,770.00	(6,381.00)	563,996.00	379,324.00	(184,672.00)	379,324.00
60109 TEMPORARY PAYRO	10,080.00	0.00	(10,080.00)	121,480.00	0.00	(121,480.00)	0.00
60117 VACATION PAY	9,328.00	0.00	(9,328.00)	45,571.00	0.00	(45,571.00)	0.00
60131 STATUTORY HOLID	4,261.00	0.00	(4,261.00)	27,143.00	0.00	(27,143.00)	0.00
60133 SICK PAY	0.00	0.00	0.00	3,139.00	0.00	(3,139.00)	0.00
60401 EMPLOYEE TRAINI	300.00	0.00	(300.00)	375.00	0.00	(375.00)	0.00
60412 EMPLOYEE RECOGN	0.00	0.00	0.00	179.00	0.00	(179.00)	0.00
61105 COPIER AND OTHE	0.00	50.00	50.00	285.00	600.00	315.00	600.00
61116 COMPUTER SOFTWA	0.00	3,000.00	3,000.00	0.00	36,000.00	36,000.00	36,000.00
61299 OTHER MATERIALS	0.00	0.00	0.00	496.00	0.00	(496.00)	0.00
61503 LEGAL FEES	149.00	0.00	(149.00)	1,885.00	0.00	(1,885.00)	0.00
61511 PROFESSIONAL CO	3,452.00	25,000.00	21,548.00	17,717.00	300,000.00	282,283.00	300,000.00
61601 CONTRACT SERVIC	(6,433.00)	21,550.00	27,983.00	40,692.00	258,600.00	217,908.00	258,600.00
61715 POSTAGE COURIER	0.00	25.00	25.00	278.00	300.00	22.00	300.00
61717 REPRODUCTION SE	0.00	0.00	0.00	1,540.00	2,500.00	960.00	2,500.00
61999 OTHER OUTSIDE S	10,000.00	280,000.00	270,000.00	120,000.00	1,360,000.00	1,240,000.00	1,360,000.00
70407 IT TELECOM SERV	0.00	0.00	0.00	88.00	0.00	(88.00)	0.00
70501 AIRFARE	(12,518.00)	1,250.00	13,768.00	8,066.00	15,000.00	6,934.00	15,000.00
70503 GROUND TRANSPOR	(4,242.00)	375.00	4,617.00	6,230.00	4,500.00	(1,730.00)	4,500.00
70505 ACCOMMODATION	4,274.00	1,000.00	(3,274.00)	10,258.00	12,000.00	1,742.00	12,000.00
70507 MEALS AND ENTER	(1,070.00)	500.00	1,570.00	2,261.00	6,000.00	3,739.00	6,000.00
70509 OTHER TRAVEL EX	0.00	200.00	200.00	0.00	2,400.00	2,400.00	2,400.00
70511 CONFERENCE AND	0.00	0.00	0.00	2,279.00	10,100.00	7,821.00	10,100.00
70809 TRADE AND CIVIC	0.00	0.00	0.00	220.00	0.00	(220.00)	0.00
70899 OTHER OPERATING	314,888.00	89,137.00	(225,751.00)	1,401,631.00	1,069,645.00	(331,986.00)	1,069,645.00
DIRECT COST CENTRE COSTS	370,620.00	453,857.00	83,238.00	2,375,809.00	3,456,969.00	1,081,160.00	3,456,969.00
ACCOUNTABLE COSTS							
74002 FIXED INTERNAL	11,561.00	19,127.00	7,566.00	138,732.00	229,522.00	90,790.00	229,522.00
74007 GENERAL EXPENSE	3,613.00	0.00	(3,613.00)	43,356.00	0.00	(43,356.00)	0.00
TOTAL ACCOUNTABLE COSTS	15,174.00	19,127.00	3,953.00	182,088.00	229,522.00	47,434.00	229,522.00
GROSS OPERATING COSTS	385,794.00	472,984.00	87,190.00	2,557,897.00	3,686,491.00	1,128,594.00	3,686,491.00
INTERNAL COST RECOVERIES							
79951 CAPITAL PROJECT	(46,145.00)	0.00	46,145.00	(552,302.00)	0.00	552,302.00	0.00
79966 VARIABLE INTERN	0.00	(2,490.00)	(2,490.00)	(59,114.00)	(29,880.00)	29,234.00	(29,880.00)
TOTAL INTERNAL COST RECOVERIES	(46,145.00)	(2,490.00)	43,655.00	(611,416.00)	(29,880.00)	581,536.00	(29,880.00)
TOTAL NET OPERATING COSTS	339,649.00	470,494.00	130,845.00	1,946,481.00	3,656,611.00	1,710,130.00	3,656,611.00

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: AUG-11 Currency: CAD

	Annual Capacity		Deliverability		Commodity	
	Bcf	% of Total	Bcf	% of Total	Bcf	% of Total
Regulated	98.00	**88.93%**	1.94	**82.91%**	11.82	**95.51%**
Un-regulated	12.20	**11.07%**	0.40	**17.09%**	0.56	**4.49%**
	110.20	**100.00%**	2.34	**100.00%**	12.38	**100.00%**

COST CENTRE=25121 (STORAGE ADMINISTRATION)

	Actual	Applicable Share	Overhead Factor	Allocable Amount	Comm.	Split of the Balance Cap	Split of the Balance Deliv	Resulting Allocations Capacity %	Capacity $s	Deliverability %	Deliverability $s	Commodity %	Commodity $s
CONTROLLABLE COSTS													
60101 BASE PAY	137,178	100%	69.2%	232,107	5%	75%	25%	71%	165,376	24%	55,125	5%	11,605
60109 TEMPORARY PAYRO	9,767	100%	69.2%	16,526	5%	75%	25%	71%	11,775	24%	3,925	5%	826
60117 VACATION PAY	16,068	100%	69.2%	27,187	5%	75%	25%	71%	19,371	24%	6,457	5%	1,359
60129 SCHEDULED OVERTIME	2,860	100%	69.2%	4,839	5%	75%	25%	71%	3,448	24%	1,149	5%	242
60131 STATUTORY HOLID	7,331	100%	69.2%	12,404	5%	75%	25%	71%	8,838	24%	2,946	5%	620
60133 SICK PAY	0	100%	69.2%	-	5%	75%	25%	71%	-	24%	-	5%	-
60141 VACANCY CREDIT	0	100%	69.2%	-	5%	75%	25%	71%	-	24%	-	5%	-
60145 OTHER SALARY EX	0	100%	69.2%	-	5%	75%	25%	71%	-	24%	-	5%	-
TOTAL LABOUR	**173,204**			**293,063**									
60401 EMPLOYEE TRAINI	1,275	100%		1,275	5%	75%	25%	71%	908	24%	303	5%	64
60403 EXECUTIVE DEVELOPMENT	(1,275)	100%		(1,275)	5%	75%	25%	71%	(908)	24%	(303)	5%	(64)
60405 RECRUITMENT ADV	(1,155)	100%		(1,155)	5%	75%	25%	71%	(823)	24%	(274)	5%	(58)
60411 AWARDS AND ALLO	11	100%		11	5%	75%	25%	71%	8	24%	3	5%	1
61009 SAFETY RELATED	(942)	100%		(942)	5%	75%	25%	71%	(671)	24%	(224)	5%	(47)
61105 COPIER AND OTHE	1,477	100%		1,477	5%	75%	25%	71%	1,052	24%	351	5%	74
61116 COMPUTER SOFTWA	25,392	100%		25,392	0%	75%	25%	75%	19,044	25%	6,348	0%	-
61511 PROFESSIONAL CO	0	100%		-	0%	75%	25%	75%	-	25%	-	0%	-
61601 CONTRACT SERVICES	(8,925)	100%		(8,925)	0%	75%	25%	75%	(6,694)	25%	(2,231)	0%	-
61707 JANITORIAL SERVICES	4,854	100%		4,854	0%	75%	25%	75%	3,641	25%	1,214	0%	-
61709 OFFICE REPAIRS	252	100%		252	0%	75%	25%	75%	189	25%	63	0%	-
61715 POSTAGE COURIER	2,237	100%		2,237	0%	75%	25%	75%	1,678	25%	559	0%	-
61717 REPRODUCTION SE	1,952	100%		1,952	0%	75%	25%	75%	1,464	25%	488	0%	-
61910 SITE WORK	0	100%		-	0%	75%	25%	75%	-	25%	-	0%	-
61999 OTHER OUTSIDE S	23,305	100%		23,305	5%	75%	25%	71%	16,605	24%	5,535	5%	1,165
62301 VEHICLE / FLEET	7,726	100%		7,726	10%	75%	25%	68%	5,215	23%	1,738	10%	773
70001 LAND LEASES	14,558	100%		14,558	0%	90%	10%	90%	13,102	10%	1,456	0%	-
70409 OTHER TELECOM S	0	100%		-	0%	75%	25%	75%	-	25%	-	0%	-
70501 AIRFARE	1,301	100%		1,301	5%	75%	25%	71%	927	24%	309	5%	65
70503 GROUND TRANSPOR	1,613	100%		1,613	5%	75%	25%	71%	1,149	24%	383	5%	81
70505 ACCOMMODATION	1,134	100%		1,134	5%	75%	25%	71%	808	24%	269	5%	57
70507 MEALS AND ENTER	2,597	100%		2,597	5%	75%	25%	71%	1,850	24%	617	5%	130
70509 OTHER TRAVEL EX	38	100%		38	5%	75%	25%	71%	27	24%	9	5%	2
70511 CONFERENCE AND	3,377	100%		3,377	0%	75%	25%	75%	2,533	25%	844	0%	-
70701 PROPERTY TAXES	128,706	100%		128,706	0%	40%	60%	40%	51,482	60%	77,224	0%	-
70707 VEHICLE LICENSI	(11)	100%		(11)	0%	75%	25%	75%	(8)	25%	(3)	0%	-
70801 CORPORATE DONAT	0	100%		-	0%	75%	25%	75%	-	25%	-	0%	-
70807 SPONSORSHIPS	0	100%		-	0%	75%	25%	75%	-	25%	-	0%	-
70809 TRADE AND CIVIC	747	100%		747	0%	75%	25%	75%	560	25%	187	0%	-
NON-LABOUR COST CENTRE COSTS	**210,244**			**210,244**									
INTERNAL COST RECOVERIES													
79966 VARIABLE INTERN	(1,000)	100%		(1,000)	0%	75%	25%	75%	(750)	25%	(250)	0%	-
79967 OTHER RECOVERIE CAPITAL	(9,137)	100%		(9,137)	0%	75%	25%	75%	(6,853)	25%	(2,284)	0%	-
TOTAL COST RECOVERIES	**(10,137)**			**(10,137)**									
TOTAL NET COST CENTRE COSTS	**373,311**			**493,170**					**314,343**		**161,932**		**16,895**
									63.7%		32.8%		3.4%
									34,800		**27,681**		**759**
										Allocation to Unregulated Storage			**63,240**

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: AUG-11 Currency: CAD

	Annual Capacity		Deliverability		Commodity	
	Bcf	% of Total	Bcf	% of Total	Bcf	% of Total
Regulated	98.00	**88.93%**	1.94	**82.91%**	11.82	**95.51%**
Un-regulated	12.20	**11.07%**	0.40	**17.09%**	0.56	**4.49%**
	110.20	**100.00%**	2.34	**100.00%**	12.38	**100.00%**

COST CENTRE=25122 (STORAGE OPERATIONS)

	Actual	Applicable Share	Overhead Factor	Allocable Amount	Comm.	Split of the Balance Cap	Split of the Balance Deliv	Resulting Allocations Capacity %	Capacity $s	Deliverability %	Deliverability $s	Commodity %	Commodity $s
CONTROLLABLE COSTS													
60101 BASE PAY	11,566	100%	65.1%	19,093	0%	75%	25%	75%	14,319	25%	4,773	0%	0
60105 HOURLY PAYROLL	81,044	100%	65.1%	133,783	0%	75%	25%	75%	100,337	25%	33,446	0%	0
60117 VACATION PAY	3,155	100%	65.1%	5,208	0%	75%	25%	75%	3,906	25%	1,302	0%	0
60129 SCHEDULED OVERT	27,028	100%	65.1%	44,616	10%	75%	25%	68%	30,116	23%	10,039	10%	4,462
60131 STATUTORY HOLID	4,613	100%	65.1%	7,615	0%	75%	25%	75%	5,711	25%	1,904	0%	0
60133 SICK PAY	0	100%	65.1%	-	0%	75%	25%	75%	-	25%	-	0%	0
60145 OTHER SALARY EX	0	100%	65.1%	-	0%	75%	25%	75%	-	25%	-	0%	0
TOTAL LABOUR	**127,406**			**210,315**									
61009 SAFETY RELATED	1,929	100%		1,929	0%	75%	25%	75%	1,447	25%	482	0%	0
61299 OTHER MATERIALS	38,603	100%		38,603	60%	40%	60%	16%	6,176	24%	9,265	60%	23,162
61601 CONTRACT SERVIC	31,071	100%		31,071	0%	75%	25%	75%	23,303	25%	7,768	0%	0
61805 ENVIRONMENTAL C	646	100%		646	0%	40%	60%	40%	258	60%	388	0%	0
61999 OTHER OUTSIDE S	43,161	100%		43,161	60%	40%	60%	16%	6,906	24%	10,359	60%	25,897
NON-LABOUR COST CENTRE COSTS	**115,410**			**115,410**									
INTERNAL COST RECOVERIES				-									
79966 VARIABLE INTERN	(78,009)	100%		(78,009)	0%	75%	25%	75%	(58,507)	25%	(19,502)	0%	0
79967 OTHER RECOVERIE CAPITAL	0	100%		-	0%	75%	25%	75%	-	25%	-	0%	0
TOTAL COST RECOVERIES	**(78,009)**			**(78,009)**									
TOTAL NET COST CENTRE COSTS	**164,807**			**247,716**					**133,974**		**60,222**		**53,520**
									54.1%		24.3%		21.6%
									14,832		**10,294**		**2,404**
										Allocation to Unregulated Storage			**27,530**

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: AUG-11 Currency: CAD

	Annual Capacity		Deliverability		Commodity	
	Bcf	% of Total	Bcf	% of Total	Bcf	% of Total
Regulated	98.00	**88.93%**	1.94	**82.91%**	11.82	**95.51%**
Un-regulated	12.20	**11.07%**	0.40	**17.09%**	0.56	**4.49%**
	110.20	**100.00%**	2.34	**100.00%**	12.38	**100.00%**

COST CENTRE=25123 (STORAGE MAINTENANCE)

	Actual	Applicable Share	Overhead Factor	Allocable Amount	Comm.	Split of the Balance Cap	Split of the Balance Deliv	Resulting Allocations Capacity %	Capacity $s	Deliverability %	Deliverability $s	Commodity %	Commodity $s
CONTROLLABLE COSTS													
60101 BASE PAY	56,108	100%	70.0%	95,394	0%	75%	25%	75.0%	71,545	25%	23,848	0%	-
60105 HOURLY PAYROLL	0	100%	70.0%	-	0%	75%	25%	75.0%	-	25%	-	0%	-
60117 VACATION PAY	6,436	100%	70.0%	10,942	0%	75%	25%	75.0%	8,207	25%	2,736	0%	-
60129 SCHEDULED OVERT	692	100%	70.0%	1,177	60%	75%	25%	30.0%	353	10%	118	60%	706
60131 STATUTORY HOLID	2,597	100%	70.0%	4,415	0%	75%	25%	75.0%	3,312	25%	1,104	0%	-
60133 SICK PAY	0	100%	70.0%	-	0%	75%	25%	75.0%	-	25%	-	0%	-
60145 OTHER SALARY EX	0	100%	70.0%	-	0%	75%	25%	75.0%	-	25%	-	0%	-
TOTAL LABOUR	**65,833**			**111,928**									
60401 EMPLOYEE TRAINI	8,742	100%		8,742	60%	75%	25%	30.0%	2,623	10%	874	60%	5,245
61299 OTHER MATERIALS	110,429	100%		110,429	60%	40%	60%	16.0%	17,669	24%	26,503	60%	66,257
61601 CONTRACT SERVIC	70,091	100%		70,091	60%	40%	60%	16.0%	11,215	24%	16,822	60%	42,055
NON-LABOUR COST CENTRE COSTS	**189,262**			**189,262**									
INTERNAL COST RECOVERIES													
79951 CAPITAL PROJECT	(9,870)	100%		(9,870)	0%	75%	25%	75.0%	(7,403)	25%	(2,468)	0%	-
79966 VARIABLE INTERN	78,672	100%		78,672	0%	75%	25%	75.0%	59,004	25%	19,668	0%	-
79967 OTHER RECOVERIE CAPITAL	0	100%		-	0%	75%	25%	75.0%	-	25%	-	0%	-
TOTAL COST RECOVERIES	**68,802**			**68,802**									
TOTAL NET COST CENTRE COSTS	**323,897**			**369,992**					**166,524**		**89,205**		**114,263**
									45.0%		24.1%		30.9%
									18,435		**15,249**		**5,132**
											Allocation to Unregulated Storage		**38,816**

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: AUG-11 Currency: CAD

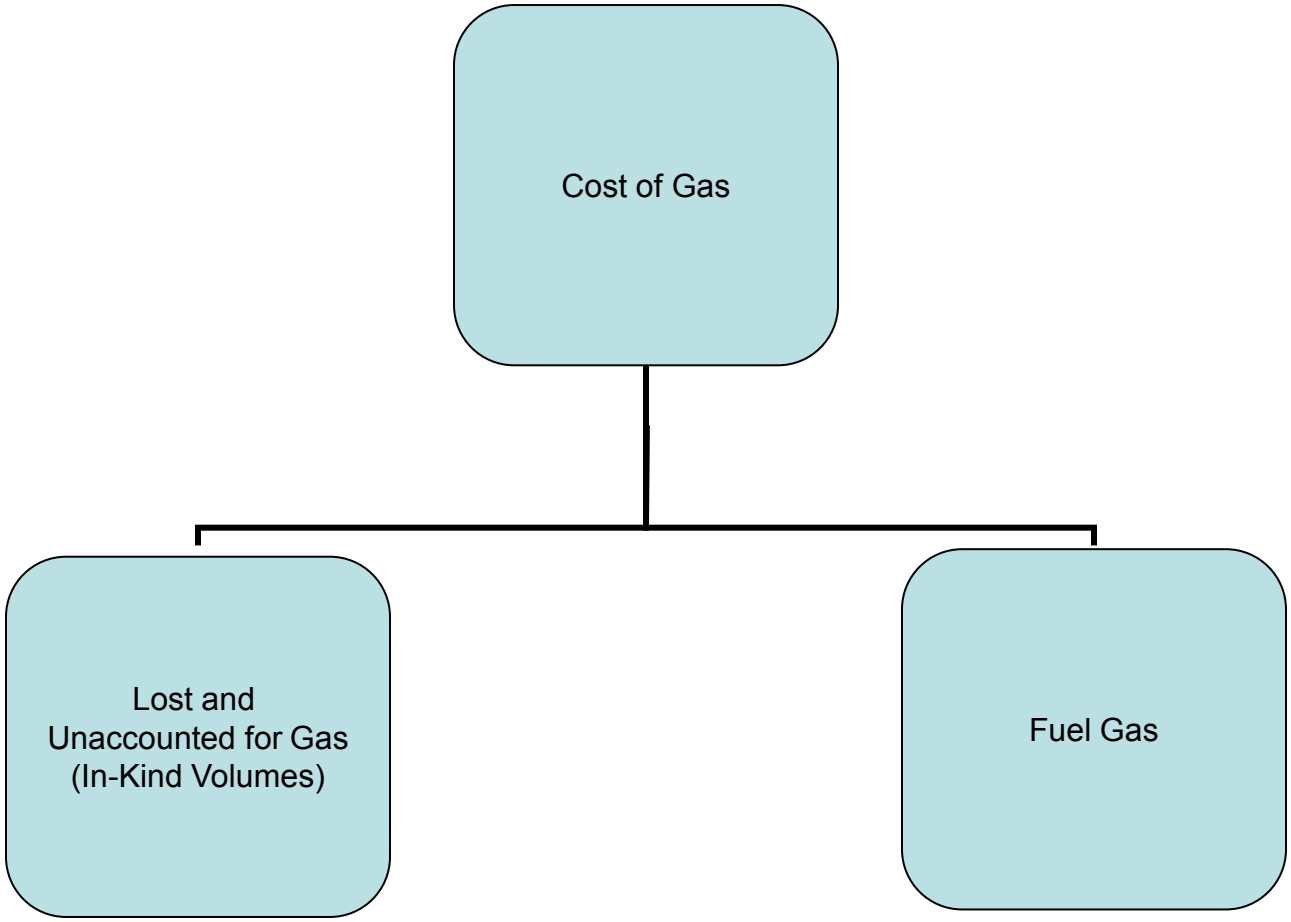
	Annual Capacity		Deliverability		Commodity	
	Bcf	% of Total	Bcf	% of Total	Bcf	% of Total
Regulated	98.00	**88.93%**	1.94	**82.91%**	11.82	**95.51%**
Un-regulated	12.20	**11.07%**	0.40	**17.09%**	0.56	**4.49%**
	110.20	100.00%	2.34	100.0%	12.38	100.00%

COST CENTRE=25124 (FIELD MAINTENANCE)

	Actual	Applicable Share	Overhead Factor	Allocable Amount	Comm.	Split of the Balance Cap	Split of the Balance Deliv	Resulting Allocations: Capacity %	Capacity $s	Deliverability %	Deliverability $s	Commodity %	Commodity $s
CONTROLLABLE COSTS													
61299 OTHER MATERIALS	8,859	100%	0	8,859	0%	40%	60%	40.0%	3,544	60.0%	5,315	0.0%	-
61511 PROFESSIONAL CO	11,772	100%	0	11,772	0%	90%	10%	90.0%	10,595	10.0%	1,177	0.0%	-
61601 CONTRACT SERVIC	304,920	100%	0	304,920	0%	40%	60%	40.0%	121,968	60.0%	182,952	0.0%	-
61805 ENVIRONMENTAL C	0	100%	0	-	0%	40%	60%	40.0%	-	60.0%	-	0.0%	-
DIRECT COST CENTRE COSTS	**325,551**			**325,551**									
TOTAL NET COST CENTRE COSTS	**325,551**			**325,551**					**136,106**		**189,445**		**0**
									41.8%		58.2%		0.0%
									15,068		32,384		-
										Allocation to Unregulated Storage			**47,452**

ENBRIDGE GAS DISTRIBUTION INC.
Allocation of Regulated and Unregulated Storage Costs
Cost of Gas Components

Schedule 8



•Actual storage capacity and activity

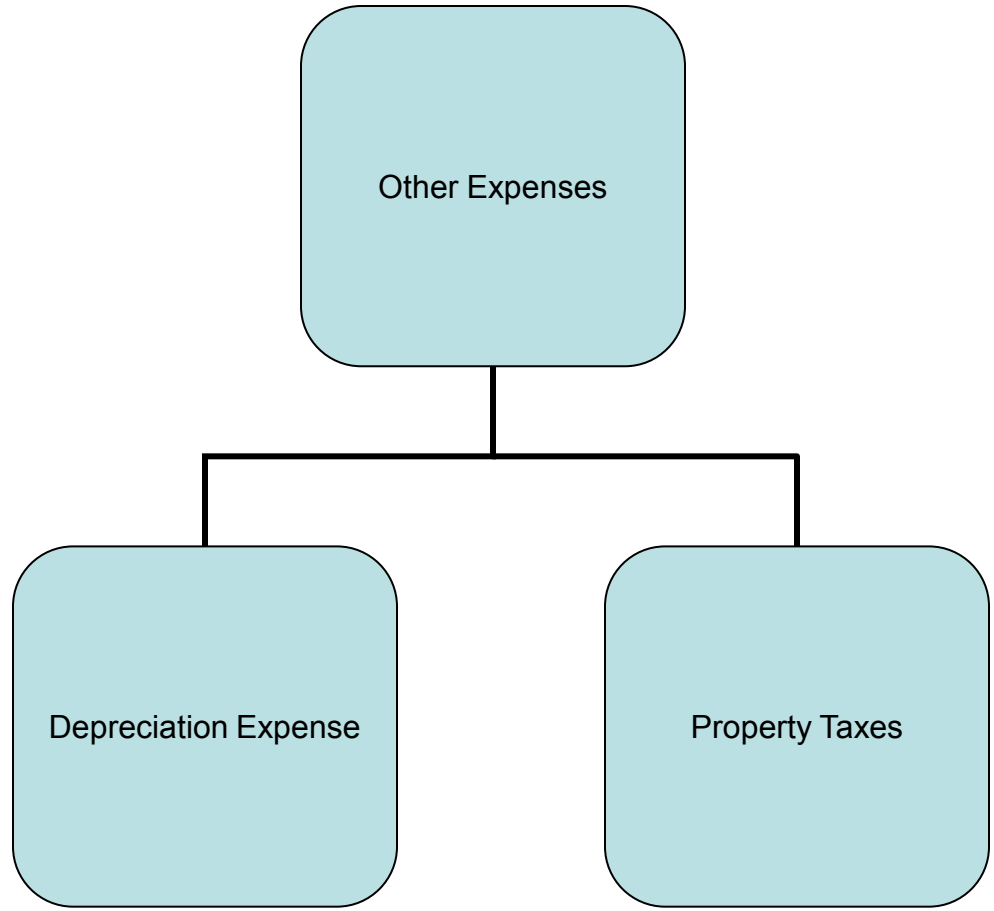
•LUF replacement factor

•Actual monthly storage activity

•Previous October QRAM reference price of gas

ENBRIDGE GAS DISTRIBUTION INC.
Allocation of Regulated and Unregulated Storage Costs
Other Expenses

Schedule 9



•Depreciation rates for Unregulated storage assets

•Actual property tax for storage assets – allocated between regulated and unregulated storage operations based on the annual storage capacity and deliverability of each storage operation