November 2, 2017

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2017-0306 – Enbridge Gas Distribution Inc. and Union Gas Limited – MAAD Application – Application and Evidence

Please see the attached for the Application and Evidence to the Ontario Energy Board ("OEB") seeking approval to effect the amalgamation of Enbridge Gas Distribution Inc. ("EGD") and Union Gas Limited ("Union"), under Section 43(1) of the *Ontario Energy Board Act, 1998*.

In preparing the Application, the Applicants have been guided by the OEB's January 19, 2016 Handbook to Electricity Distributor and Transmitter Consolidations ("Consolidation Handbook"), which provides guidance on applications for mergers, acquisitions and divestitures ("MAAD"). The mapping of the Application's contents to the Consolidation Handbook's Filing Requirements is provided in Exhibit A, Tab 3.

To assist the OEB, EGD and Union have included a draft issues list in Exhibit A, Tab 4.

The evidence is organized as follows:

<u>Exhibit A</u>

Tab 1: Exhibit List
Tab 2: Application
Tab 3: Mapping of Filing Requirements in Consolidation Applications to the Applicants Evidence
Tab 4: Draft Issues List

<u>Exhibit B</u>

Tab 1: MAAD Application and Evidence

If you have any questions on this matter, please contact me at 519-436-5275.

Sincerely,

[*original signed by*]

Mark Kitchen
Director, Regulatory Affairs

cc: Andrew Mandyam, EGD
Fred Cass, Aird & Berlis
Crawford Smith, Torys
EB-2016-0245 and EB-2016-0215 Intervenors

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED
MAAD APPLICATION
EXHIBIT LIST

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. and Union Gas Limited, pursuant to section 43(1) of the *Ontario Energy Board Act, 1998*, for an order or orders granting leave to amalgamate as of January 1, 2019.

APPLICATION

1. Enbridge Gas Distribution Inc. ("EGD") is an Ontario corporation with its head office in the City of Toronto. It carries on the business of selling, distributing, transmitting, and storing natural gas within Ontario.

2. Union Gas Limited ("Union") is a business corporation incorporated under the laws of the Province of Ontario, with its head office in the Municipality of Chatham-Kent. Union conducts both an integrated natural gas utility business that combines the operations of distributing, transmitting and storing natural gas, and a non-utility storage business.

3. EGD is operating under a five year Incentive Regulation ("IR") plan approved by the Ontario Energy Board ("Board") in EB-2012-0459. The Board Decision with Reasons in that proceeding establishes a Custom IR framework to set EGD's rates over the period from 2014 to 2018.

4. Union is operating under a five year Incentive Rate Mechanism ("IRM") approved by the Board in EB-2013-0202. The Board's Decision with Reasons in that proceeding approved

a price cap IRM to set Union's rates for the regulated distribution, transmission and storage of natural gas over the period from 2014 to 2018.

5. EGD and Union (collectively "the Applicants") hereby apply to the OEB, pursuant to section 43 of the Act for an order or orders granting leave to amalgamate effective January 1, 2019.

6. This application is supported by written evidence and may be amended from time to time as circumstances require.

7. The persons affected by this application are the customers resident or located in the municipalities, police villages and First Nations reserves served by the Applicants, together with those to whom the Applicants sell gas, or on whose behalf the Applicants distribute, transmit or store natural gas. It is impractical to set out in this application the names and addresses of such persons because they are too numerous.

8. The address of service for the Applicants is:

Enbridge Gas Distribution

Address for personal service:
500 Consumers Road
Willowdale, Ontario M2J 1P8

Mailing address:
P. O. Box 650
Scarborough, Ontario M1K 5E3

Attention:	Andrew Mandyam Director, Regulatory Affairs
Telephone:	(416) 495-5499
Fax:	(416) 495-6072

- and -

Union Gas Limited

P.O. Box 2001
50 Keil Drive North
Chatham, Ontario N7M 5M1

Attention:	Mark Kitchen Director, Regulatory Affairs
Telephone:	(519) 436-5275
Fax:	(519) 436-4641

- and -

Aird & Berlis LLP
Suite 1800, P.O. Box 754
Brookfield Place, 181 Bay Street
Toronto, Ontario M5J 2T9

Attention:	Fred Cass
Telephone:	(416) 865-7742
Fax:	(416) 863-1515

DATED November 2, 2017.

ENBRIDGE GAS DISTRIBUTION INC.
UNION GAS LIMITED

Fred W. Cass

Fred Cass
Aird & Berlis LLP

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

MAAD APPLICATION

CONSOLIDATION HANDBOOK FILING REQUIREMENTS MAPPED TO APPLICATION

Filing Requirements Reference	**Filing Requirements for Consolidation Applications**[1]	**Application Reference**
1.0	Certification of Evidence	Exhibit B, Tab 1, Attachment 1
2.1.0	Index	Exhibit A, Tab 1
2.2.0	Application	Exhibit B, Tab 1
2.2.1	Administrative	
	Legal name of the applicant or applicants	Exhibit B, Tab 1, Section 1.2
	Details of the authorized representative of the applicant/s, including the name, phone and fax numbers, and email and delivery addresses	Exhibit B, Tab 1, Section 1.2
	Legal name of the other party or parties to the transaction, if not an applicant	n/a
	Details of the authorized representative of the other party or parties to the transaction, including the name, phone and fax numbers, and email and delivery addresses	Exhibit B, Tab 1, Section 1.3
	Brief description of the nature of the transaction for which approval of the OEB is sought by the applicant or applicants	Exhibit B, Tab 1, Section 1.1
2.2.2	Description of the Business of the Parties to the Transaction	
	Describe the business of each of the parties to the proposed transaction	Exhibit B, Tab 1, Section 2.1 and 2.2
	Describe the geographic territory served by each of the parties to the proposed transaction, including each of their affiliates, if applicable, noting whether service area boundaries are contiguous or if not the relative distance between service boundaries	Exhibit B, Tab 1, Section 2.3
	Describe the customers, including the number of customers in each class, served by each of the parties to the proposed transaction	Exhibit B, Tab 1, Section 2.1 and 2.2
	Describe the proposed geographic service area of each of the parties after completion of the proposed transaction	Exhibit B, Tab 1, Section 2.3
	Provide a corporate chart describing the relationship between each of the parties to the proposed transaction and each of their respective affiliates	Exhibit B, Tab 1, Attachment 4.
	If the proposed transaction involves the consolidation of two or more distributors, please indicate the current net metering thresholds of the utilities involved in the proposed transaction. The OEB will, in the absence of exceptional circumstances, add together the kW threshold amounts allocated to the individual utilities and assign the sum to the new or remaining utility. Applicants must indicate if there are any special circumstances that may warrant the OEB using a different methodology to determine the net metering threshold for the new or remaining utility	n/a
2.2.3	Description of the Proposed Transaction	
	Provide a detailed description of the proposed transaction	Exhibit B, Tab 1, Section 3

[1] OEB Handbook to Electricity Distributor and Transmitter Consolidations, January 19, 2016.

	Provide a clear statement on the leave being sought by the applicant, referencing the particular section or sections of the Ontario Energy Board Act, 1998	Exhibit B, Tab 1, Section 1.1
	Provide details of the consideration (e.g. cash, assets, shares) to be given and received by each of the parties to the proposed transaction	Exhibit B, Tab 1, Section 3
	Provide all final legal documents to be used to implement the proposed transaction	Exhibit B, Tab 1, Attachment 6
	Provide a copy of appropriate resolutions by parties such as parent companies, municipal council/s, or any other entities that are required to approve a proposed transaction confirming that all these parties have approved the proposed transaction	Exhibit B, Tab 1, Attachment 7
2.2.4	Impact of the Proposed Transaction	
	Objective 1 – Protect consumers with respect to prices and the adequacy, reliability and quality of electricity service	
	Indicate the impact the proposed transaction will have on consumers with respect to prices and the adequacy, reliability and quality of electricity service.	Exhibit B, Tab 1, Section 4
	Provide a year over year comparative cost structure analysis for the proposed transaction, comparing the costs of the utilities post transaction and in the absence of the transaction.	Exhibit B, Tab 1, Section 4.3
	Provide a comparison of the OM&A cost per customer per year between the consolidating distributors.	Exhibit B, Tab 1, Section 2.5
	Confirm whether the proposed transaction will cause a change of control of any of the transmission or distribution system assets, at any time, during or by the end of the transaction.	Exhibit B, Tab 1, Section 3
	Describe how the distribution or transmission systems within the service areas will be operated.	Exhibit B, Tab 1, Section 4.4
	Objective 2 – Promote economic efficiency and cost effectiveness and to facilitate the maintenance of a financially viable electricity industry	
	Indicate the impact that the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity), identifying the various aspects of utility operations where the applicant expects sustained operational efficiencies (both quantitative and qualitative).	Exhibit B, Tab 1, Section 4.6
	Identify all incremental costs that the parties to the proposed transaction expect to incur which may include incremental transaction costs (e.g. legal, regulatory), incremental merged costs (e.g. employee severances), and incremental on-going costs (e.g. purchase and maintenance of new IT systems). Explain how the consolidated entity intends to finance these costs.	Exhibit B, Tab 1, Section 4
	Provide a valuation of any assets or shares that will be transferred in the proposed transaction. Describe how this value was determined.	Exhibit B, Tab 1, Section 3
	If the price paid as part of the proposed transaction is more than the book value of the assets of the selling utility, provide details as to why this price will not have an adverse effect on the financial viability of the acquiring utility.	n/a
	Provide details of the financing of the proposed transaction.	Exhibit B, Tab 1, Section 4.1
	Provide financial statements (including balance sheet, income	Exhibit B, Tab 1, Attachment 10

	statement, and cash flow statement) of the parties to the proposed transaction for the past two most recent years.	
	Provide pro forma financial statements for each of the parties (or if an amalgamation, the consolidated entity) for the first full year following the completion of the proposed transaction.	Exhibit B, Tab 1, Attachment 11
2.2.5	Rate considerations for consolidation applications	
	Indicate a specific deferred rate rebasing period that has been chosen.	Exhibit B, Tab 1, Section 5.1
	For deferred rebasing periods greater than five years: • Confirm that the ESM will be as required by the 2015 Report and the Handbook • If the applicant's proposed ESM is different from the ESM set out in the 2015 Report, the applicant must provide evidence to demonstrate the benefit to the customers of the acquired distributor	Exhibit B, Tab 1, Section 5.2.
2.2.6	Other Related Matters	
	Applicants are required to provide justification for these types of requests [other related matters] and for any other requests for which a determination is being sought from the OEB as part of a consolidation application.	n/a

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

MAAD APPLICATION

DRAFT ISSUES LIST

PRICE, COST EFFECTIVENESS AND ECONOMIC EFFICIENCY:

1. Does the proposed consolidation protect the interests of consumers with respect to price?
2. Have the Applicants clearly identified the specific number of years for which they have chosen to defer the rebasing?
3. If the Applicants have identified a deferred rebasing period greater than five years, have they identified an Earnings Sharing Mechanism (ESM), and does it follow the form set out in the OEB's 2015 Report – Rate-Making Associated with Distributor Consolidation and the OEB's 2016 Handbook to Electricity Distributor and Transmitter Consolidations?
4. Does the ESM, as defined in the application, achieve the objective of protecting customer interests during the deferred rebasing period?

RELIABILITY AND QUALITY OF GAS SERVICE:

5. Does the proposed consolidation protect the interests of consumers with respect to adequacy, reliability, and quality of gas service?

FINANCIAL VIABILITY:

6. Does the proposed consolidation maintain the financial viability of the consolidated entity in the delivery of the ongoing investment and maintenance of the distribution system?

7. What is the effect of the consolidation on the cost structures of the consolidating distributors?
8. What is the impact of the financing of incremental costs (transaction and integration costs) on the consolidating entities?

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

MAAD APPLICATION

TABLE OF CONTENTS

1. ADMINISTRATIVE

1.1 APPLICATION OVERVIEW

This is an application ("Application") to the Ontario Energy Board ("OEB" or "the Board") under Section 43(1) of the *Ontario Energy Board Act, 1998* ("OEB Act") for approval to effect the amalgamation of Enbridge Gas Distribution Inc. ("EGD") and Union Gas Limited ("Union") including a 10 year deferred rebasing period ("deferred rebasing period"). Collectively EGD and Union are referred to as the "Applicants" and the amalgamated company is referred to as "Amalco".

Both EGD and Union have a long and proud history of serving Ontario residents, delivering the energy they want and need, and Amalco will best position the utilities to continue this strong history of service. The amalgamation of EGD and Union will provide significant and sustainable benefits to current and future ratepayers in Ontario. The goals of the OEB, as articulated in the Renewed Regulatory Framework ("RRF"), are that utilities are expected to provide services that bring value for money to customers, demonstrate continuous improvement while delivering safe, reliable service, be responsive to public policy initiatives and have the ability to earn a fair rate of return while demonstrating sustainable improvements in efficiency. Delivering on these goals is best enabled through the amalgamation and integration of EGD and Union.

While each individual utility has successfully delivered benefits to Ontario ratepayers over the past 15 years under their respective Incentive Regulation ("IR") frameworks, both utilities have limited individual opportunities to continue to deliver similar benefits under a new five year IR framework for rates. As detailed in the Application, the deferred rebasing period will allow the integrated utility to tackle larger, more complex systems and processes, including Customer Care and Work Management Systems. In addition, the formation of an integrated Amalco senior leadership team will allow for an efficient and effective management structure for the new integrated utility.

EGD and Union have been under common ownership since February 27, 2017 when Enbridge Inc. merged with Spectra Energy Corp. Amalco under its parent, Enbridge Inc., will be part of the fourth largest company in Canada and the largest infrastructure company in North America. Amalco will benefit from strong governance and support of the combined Enbridge company. Amalgamation allows for greater operating efficiencies, including potential economies of scale as well as continuous improvement through best practices. These efficiencies provide direct and enduring benefits for both customers and Amalco. The amalgamation also provides an opportunity to allow for greater strategic focus and capability to face the challenges and opportunities of market developments in the Ontario energy sector. These challenges and opportunities will come from technology change, government policy (including climate change policy), and rising customer expectations. An amalgamation positions Amalco to deliver benefits to customers and strengthens its ability to respond to market evolution going forward.

In preparing the Application, the Applicants have been guided by the OEB’s Handbook to Electricity Distributor and Transmitter Consolidations (“Consolidation Handbook”), which provides guidance on applications for mergers, acquisitions, amalgamations and divestitures

("MAADs"). Although the Consolidation Handbook is directed to the electricity sector, the underlying principles are the same in the gas sector. These principles include incenting greater efficiency and positioning utilities to address future changes and market evolution. In the Handbook to Utility Rate Applications[1], the Board outlines how the RRF and the underpinning principles apply to all regulated utilities going forward.

As with electricity sector transactions, the OEB must be satisfied that the proposed transaction meets the "no harm" test. The Board also recently confirmed the use of the no harm test in the natural gas sector in its August 2017 Decision approving Natural Gas Resource Limited's application to sell its distribution system.

To satisfy the no harm test, the cumulative effects of the proposed transaction must not negatively impact the attainment of the OEB's statutory objectives or the OEB's goals and objectives under its key policies (in particular, the RRF). The evidence supporting this application demonstrates that the proposed amalgamation meets the no harm test and would have a positive effect on the attainment of the OEB's statutory and policy objectives. In financial terms, the Applicants estimate the cumulative benefit to customers of amalgamation to be $410 million over the deferred rebasing period.

[1] OEB Handbook to Utility Rate Applications, October 13, 2016.

In accordance with the Consolidation Handbook, the Applicants are seeking an Earnings Sharing Mechanism ("ESM") consistent with the MAADs policy framework, specifically an ESM for years six through ten of the deferred rebasing period. There are risks and costs associated with amalgamation. To ensure a successful amalgamation and enduring benefits, significant costs and efforts must be expended in the planning and execution of the amalgamation. Amalco will integrate many systems and business processes, but management must schedule this work to ensure that Amalco continues to deliver safe, reliable service. For these reasons, the Applicants have chosen to defer rebasing for 10 years. The evidence details the types of capital and operating cost investments that Amalco will make to support system and process integration, as well as the estimated net benefit that will result from these investments. Complex processes and system applications, like those required to support Customer Care, must be both well planned and executed and require a longer payback period to recover the investment.

EGD and Union are currently under multi-year incentive rate frameworks. In the absence of amalgamation, each of EGD and Union would be required to apply separately for new multi-year rate setting parameters (including rebasing) to establish new rates to be effective January 1, 2019. Under the MAADs policy framework, rate setting during the deferred rebasing period is based on the price cap IR adjustment mechanism beginning in 2019 (when current IR plans have expired). However, there is no established productivity factor for natural gas utilities similar to what exists for electric utilities. EGD and Union will therefore file a separate Rate Setting

Mechanism Application (EB-2017-0307) which will propose an annual index mechanism that would be used for Amalco and each of the rate zones[2].

The evidence supporting this Application follows the Consolidation Handbook filing requirements and includes the following sections:

1. **Administration**: names of the applicants and authorized representatives, contact information, and a brief description of the transaction;
2. **Description of the Business of the Parties to the Transaction**: descriptions of EGD and Union, including lines of business, geographic territories, customers, and corporate organizations (including affiliates);
3. **Description of the Proposed Transaction**: detailed information regarding the amalgamation, including associated legal documents, corporate resolutions, valuation information and effects on the EGD and Union Undertakings;
4. **Impact of the Proposed Transaction**: quantitative and qualitative analysis of the transaction in terms of its impact on the OEB's statutory objectives and key policies, including financial statements and other information;
5. **Rate considerations**: support for and explanation of the rate rebasing deferral period and the ESM; and
6. **Other Related Matters**: There are no other related matters to be addressed in this Application so the Applicants have not included a section on this topic.

[2] The three rate zones are EGD, Union North and Union South.

1.2 Name of Applicants and Authorized Representatives

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

Authorized Representative:

Andrew Mandyam
Director, Regulatory Affairs
Tel: 416-495-5499
Fax: 416-495-6072
egdregulatoryproceedings@enbridge.com

Union Gas Limited
P.O. Box 2001, 50 Keil Drive North
Chatham, ON N7M 5M1

Authorized Representative:

Mark Kitchen
Director, Regulatory Affairs
Tel: 519-436-5275
Fax: 519-436-4641
unionregulatoryproceedings@uniongas.com

1.3 Counsel to the Applicants

Fred Cass
Aird & Berlis LLP
Suite 1800, P.O. Box 754
Brookfield Place, 181 Bay Street
Toronto ON M5J 2T9
Tel: 416-865-7742
Fax: 416-863-1515
fcass@airdberlis.com

1.4 Certification of Evidence

The Applicant's evidence is accurate, consistent and complete. Please see Exhibit A, Tab 1 for a table mapping the Application's contents to the Consolidation Handbook Filing Requirements.

The certification of evidence is provided at Exhibit B, Tab 1, Attachment 1.

2. DESCRIPTION OF THE BUSINESS OF THE PARTIES TO THE TRANSACTION[3]

2.1 ENBRIDGE GAS DISTRIBUTION

EGD is a rate-regulated natural gas distribution utility in Ontario, with over 165 years of experience, serving over 2.1 million residential, commercial and industrial customers in 121 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 and Barrie. EGD also owns and operates regulated and unregulated natural gas storage facilities in Ontario.

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

EGD's head office and registered office are located at 500 Consumers Road, North York, Ontario, M2J 1P8.

As of December 31, 2016 EGD:

- owned and operated a network of approximately 80,000 kilometers of mains and services to carry natural gas to customers' premises;

[3] All of the information provided in this section is as of 2016.

- owned and operated storage facilities in Ontario, with a total working capacity of approximately 3.2 billion cubic metres (115 billion cubic feet) of which 2.6 billion cubic metres (92 billion cubic feet) is available for utility customers at cost-based rates;
- delivered approximately 11.8 billion cubic metres of natural gas to approximately 2.1 million residential, commercial and industrial customers; and
- had approximately 2,100 employees.

2.2 UNION GAS LIMITED

Union is a rate-regulated natural gas storage, transmission and distribution company based in Ontario with over 100 years of experience and service to customers. The distribution business serves approximately 1.5 million residential, commercial and industrial customers in more than 400 communities across northern, southwestern and eastern Ontario. The storage and transmission business offers a variety of storage and transportation services to customers at the Dawn Hub and for Union's Dawn-Parkway transmission system which runs from the Dawn Hub to Toronto.

Union's common stock is held by Great Lakes Basin Energy L.P. a wholly-owned limited partnership of Westcoast Energy Inc. ("Westcoast"). Westcoast is an indirect wholly-owned subsidiary of Spectra Energy Corp ("Spectra Energy"). On February 27, 2017 Enbridge acquired all of the common stock of Spectra Energy, making Spectra Energy, and therefore Union, a wholly owned subsidiary of Enbridge.

Union's head and registered office is located at 50 Keil Drive North, Chatham, Ontario N7M 5M1.

As of December 31, 2016 Union:

- owned and operated approximately:
    - 65,000 km of distribution system main and service pipelines to carry natural gas from the point of local supply to customers;
    - 4,900 km of high-pressure transmission pipeline and five mainline compressor stations; and
    - 4.6 billion cubic metres (162 billion cubic feet) of storage capacity in 23 underground facilities located in depleted gas fields, of which approximately 2.7 billion cubic metres (95 billion cubic feet) is reserved for utility customers at cost-based rates.
- delivered approximately 13.4 billion cubic metres of natural gas through the distribution and transmission systems to approximately 1.5 million residential, commercial and industrial customers and ex-franchise customers consisting of downstream utilities and marketers;
- transported approximately 20.8 billion cubic metres through the transmission system to over 100 counter parties; and
- had approximately 2,300 employees.

2.3 GEOGRAPHIC SERVICE AREA

EGD and Union have contiguous franchise areas in various adjacent municipalities and in many instances individual municipalities within the province. Please see Exhibit B, Tab 1, Attachment 2 for the list of franchise areas.

Upon completion of the proposed amalgamation, the geographic service area of the merged entity would encompass all of the regions in Ontario previously served by the individual merging entities. A map outlining the combined service areas is provided at Exhibit B, Tab 1, Attachment 3.

2.4 CORPORATE RELATIONSHIP

A simplified organizational chart outlining the corporate relationships between each of EGD and Union, their respective affiliates and their parent Company, Enbridge Inc., before and after the proposed transaction is provided at Exhibit B, Tab 1, Attachment 4.

2.5 COMPARATIVE COST STRUCTURE

The audited financial statements for the utilities for the year ended December 31, 2016 with comparable results for 2015 are publicly filed and can be found on the SEDAR filing system[4] or in the Financial Viability evidence in Section 4.5.

[4] http://www.sedar.com/homepage_en.htm

The results for the utility operations are filed with the OEB as part of the annual deferral and variance account disposition and earnings sharing applications.[5]

Table 1 below shows a comparison of the 2016 revenues and costs for each utility and the respective shares of the combined total.

Table 1
Comparison of Costs and Revenues as at December 31, 2016[6]

$ millions	EGD		Union		Combined
Rate Base	5,909	*55%*	4,758	*45%*	10,667
Operating Revenue	1,164	*53%*	1,022	*47%*	2,186
O&M	450	*53%*	398	*47%*	848
Customers	2,124,683	*59%*	1,458,720	*41%*	3,583,403

Overall, the Applicants are of similar size; differences in costs and revenues reflect the differences in operations, service territory and customer mix. EGD is a distribution utility with limited transmission assets and Union has transmission and distribution operations. Union has fewer customers in a larger geographic area.

Pursuant to the Consolidation Handbook, Applicants are required to provide O&M costs per customer. Table 2 below summarizes O&M and customers from the Applicants' annual utility regulatory filings.

[5] EGD's 2016 utility results are filed in EB-2017-0102, Union's 2016 utility results are filed in EB-2017-0091.
[6] Ibid.

Table 2
Comparison of O&M per Customer

	EGD			Union		
	O&M $ millions	Customers	$ O&M per Customer	O&M $ millions	Customers	$ O&M per Customer
2014[7]	408	2,063,837	198	380	1,419,499	268
2015[8]	431	2,094,681	206	383	1,436,924	267
2016[9]	450	2,124,683	212	398	1,458,720	273

3. DESCRIPTION OF THE PROPOSED TRANSACTION

In late October and early November, 2017, the boards of directors of each of Enbridge Inc., EGD and Union and the common shareholders of EGD and Union approved an amalgamation of EGD and Union to form a single regulated gas distribution, transmission and storage company ("Amalco"). This approval is subject to those same entities determining that it is prudent to proceed with the amalgamation upon consideration of the OEB Decisions on this Application and the related price cap Rate Setting Mechanism Application ("OEB Decisions"). Also subject to such a determination, each of EGD and Union propose to take steps to simplify their capital structures such as redeeming their respective issued and outstanding preference shares prior to amalgamation.

EGD and Union currently intend that the amalgamation will be effective January 1, 2019 (the

[7] EGD O&M and customer numbers are filed in EB-2015-0122. Union O&M and customer numbers are filed in EB-2015-0010.
[8] EGD O&M and customer numbers are filed in EB-2016-0142. Union O&M and customer numbers are filed in EB-2016-0118.
[9] EGD O&M and customer numbers are filed in EB-2017-0102. Union O&M and customer numbers are filed in EB-2017-0091.

"Effective Date"), upon which each of the common shares of EGD and Union will be converted into issued and outstanding shares of Amalco. The debt of EGD and Union will become debt of Amalco by operation of law. The common shareholders of each of EGD and Union will receive Amalco common shares which represent the relative fair market valuations of the common shares of each of EGD and Union as of the Effective Date. The relative fair market valuations are currently estimated to be as set out at Exhibit B, Tab 1, Attachment 5, according to a preliminary equity valuation of EGD and Union based upon estimated enterprise value derived from multiple methods, including a ten year discounted cash flow analysis and precedent transaction multiples applied to 2017 forecast financial earnings and rate bases. Additional equity required to balance the capital structure for Union in 2018 will be provided through EGD's shareholder, Enbridge Energy Distribution Inc., and is not expected to result in a material change to the preliminary valuation.

The only consideration for the proposed amalgamation is conversion of the existing common shares of EGD and Union into common shares of Amalco and there will be no change of control as Amalco will be an indirect subsidiary of Enbridge Inc. (as each of EGD and Union is currently). As a subsidiary of Enbridge Inc., a multi-national publicly traded entity subject to thorough public disclosure requirements, Amalco will follow the same rigorous governance practices as EGD and Union have followed in the past.

The draft Amalgamation Agreement is set out at Exhibit B, Tab 1, Attachment 6. After the board of directors of Enbridge Inc. and the boards of directors and common shareholders of EGD and

Union have determined that it is prudent to proceed with the amalgamation upon consideration of the OEB Decisions, the Amalgamation Agreement will be finalized and executed.

Approvals by the board of directors of Enbridge Inc. and the boards of directors and common shareholders of EGD and Union are required for the proposed amalgamation. Copies of the resolutions authorizing the filing of this Application and the Rate Setting Mechanism Application are included at Exhibit B, Tab 1, Attachment 7.

3.1 UNDERTAKINGS TO THE LIEUTENANT GOVERNOR IN COUNCIL FOR ONTARIO

EGD and Union and their then parent affiliate companies provided undertakings ("Undertakings") to the Lieutenant Governor in Council for Ontario, approved by Order in Council 2865/98 on December 9, 1998 and made effective March 31, 1999. The Undertakings set out certain restrictions on the business activities of EGD and Union, as amended and expanded by Ministerial Directives dated August 10, 2006 and September 8, 2009 ("Business Activities Restrictions"). Copies of the existing Undertakings and Ministerial Directives are provided in Exhibit B, Tab 1, Attachment 8.

The substance of the EGD and Union Undertakings are almost identical except for the following:

a) section 4.1 of the EGD Undertakings states that the head office shall remain within the franchise area whereas the Union Undertakings state that the head office shall remain in the Municipality of Chatham-Kent; and

b) section 5.2 of the EGD Undertakings states that the June 23, 1994 British Gas PLC and Consumers undertakings remain in full force and effect. These 1994 Undertakings, included in Exhibit B, Tab 1, Attachment 9, were satisfied by December 31, 2000 and are no longer relevant.

Section 10.1 of the Union Undertakings provides that the signatories are released from the Undertakings "on the day that Westcoast no longer holds, either directly or through its affiliates, more than 50% of the voting securities of Union…" With the creation of Amalco as contemplated in this Application, Westcoast Energy Inc. will no longer hold, directly or through its affiliates, more than 50% of the voting securities of Union and hence the Union Undertakings will cease to have effect. The EGD Undertakings, however, will continue to survive. Amalco and its parent affiliates set out in Exhibit B, Tab 1, Attachment 4 would assume the obligations of EGD and such obligations would also be applicable to the former businesses of Union within Amalco. Those obligations include the Business Activities Restrictions, the maintenance of common equity at the OEB approved level and the head office covenant.

With respect to the head office covenants under section 4.1 of the Undertakings, Amalco would assume the commitment in the EGD Undertakings that the Amalco head office shall remain within the franchise area of Amalco. All franchise areas are within the Province of Ontario. The head office of EGD is currently located at 500 Consumers Rd. North York, Ontario. The head office of Union is currently located at 50 Keil Dr. North, Chatham, Ontario. The location of the head office of Amalco and what functions will reside in either location remains under consideration. Amalco will continue to serve hundreds of Ontario municipalities and will maintain local offices (many of which will continue to be staffed locally) as required to manage those operations and continue to provide safe, reliable service to its customers.

Union has had several communications with the Municipality of Chatham-Kent in relation to the head office covenant in section 4.1 of the Union Undertakings. Union has indicated that post amalgamation, Amalco will continue to maintain a significant presence in Chatham-Kent. This is evidenced by the fact that Union recently invested $17 million to renovate its Bloomfield Road facility into a new Information Technology Centre, and in the fall of 2017, construction of a new multi-million dollar Powerhouse facility commenced at the 50 Keil Drive location. Amalco will fulfill the commitments made by Union to the Municipality of Chatham-Kent to maintain a significant presence in the area, post-amalgamation.

4. IMPACT OF THE PROPOSED TRANSACTION

4.1 TRANSACTION COSTS

The Applicants do not expect the transaction costs related to the amalgamation to be material. As related parties, the Applicants engaged joint legal and financial advisors to assist with the transaction. All transaction costs will largely be incurred, paid for and financed prior to January 1, 2019 and hence will be borne by the EGD and Union shareholders and not by ratepayers.

4.2 NO HARM TEST CONTEXT

The Consolidation Handbook was developed to provide guidance to applicants and stakeholders on applications to the OEB for approval of MAADs transactions and subsequent rate applications. Specifically, the Consolidation Handbook states that the Board will assess MAADs applications using the no harm test. The no harm test considers whether or not the transaction has an adverse effect on meeting the Board's statutory objectives. The Board recently affirmed the use of the no harm test for natural gas utilities in its EB-2016-0351 Decision and Order on Natural Resource Gas Limited's application to sell its natural gas distribution system to EPCOR.

In the EB-2016-0351 Decision and Order, the Board summarized the no harm test by stating:

> *"In the assessment of consolidation transactions in the electricity sector, the OEB has consistently applied the "no harm" test since 2005. The no harm test considers whether the proposed transaction will have an adverse effect on the attainment of the OEB's statutory objectives; where a proposed transaction has a positive or neutral effect on the attainment of these objectives, the OEB will approve the application."*[10]

The Board applied the no harm test in EB-2016-0351 using the statutory objectives for the gas sector set out in section 2 of the OEB Act, 1998:

1. To facilitate competition in the sale of gas to users.
2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.
3. To facilitate rational expansion of transmission and distribution systems.

[10] EB-2016-0351 Decision and Order on Natural Resource Gas Limited Application to sell natural gas distribution system to EPCOR, August 3, 2017, p.3.

4. To facilitate rational development and safe operation of gas storage.

5. To promote energy conservation in accordance with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

5.1. To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

6. To promote communication within the gas industry and the education of consumers.

The Board stated it:

> *"focused on the objectives that are of most direct relevance to the impact of the proposed sale transaction; namely, price, reliability and quality of gas service, and financial viability."*[11]

The Board also recognizes in the Consolidation Handbook that the primary focus of the no harm test is as noted above. Specifically, the Board states:

> *"The OEB has implemented a number of instruments, such as codes and licences that ensure regulated utilities continue to meet their obligations with respect to the OEB's statutory objectives relating to conservation and demand management, implementation of smart grid and the use and generation of electricity from renewable resources. With these tools and the ongoing performance monitoring previously discussed, the OEB is satisfied that the attainment of these objectives will not be adversely effected by a consolidation and the "no harm" test will be met following a consolidation. There is no need or merit in further detailed review as part of the OEB's consideration of the consolidation transaction.*"[12]

Accordingly, the Applicants address price, reliability and quality of gas service and financial viability in the following three sections of evidence.

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[11] Ibid.
[12] OEB Handbook to Electricity Distributor and Transmitter Consolidations, January 19, 2016, p.6.

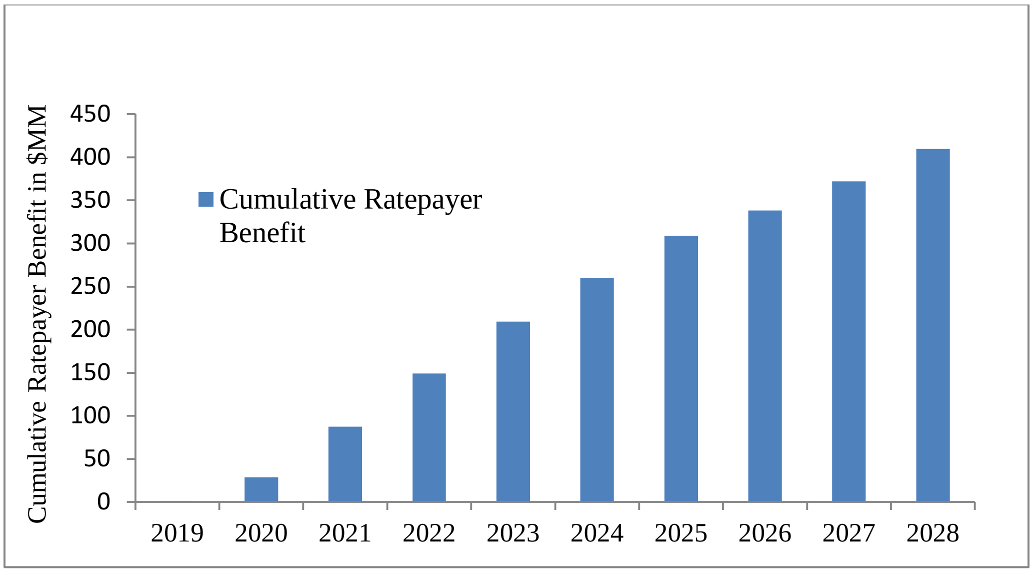
4.3 PRICE

The transaction provides greater benefits to customers than the continued stand-alone operations of EGD and Union. Table 3 provides a comparison between annual revenue requirement for EGD and Union were they to continue to operate as stand-alone utilities as compared to the proposed revenue as an amalgamated entity operating under a price cap mechanism over the deferred rebasing period. The cumulative benefit to customers over the deferred rebasing period is $410 million. The same information is provided in graphical form in Figure 1.

Table 3
Comparison of Revenue Requirement of Stand-alone Utilities to Revenue of Amalco
($ millions)

Line No.		2019	2020	2021	2022	2023
	Stand-alone					
1	EGD	1,300	1,357	1,428	1,473	1,516
2	Union	1,231	1,300	1,340	1,377	1,416
3	Total	2,531	2,657	2,767	2,850	2,932
4	Amalco	2,530	2,630	2,709	2,788	2,872
5	Ratepayer benefit	1	28	59	62	60
6	Cumulative benefit	1	29	87	149	209
		2024	**2025**	**2026**	**2027**	**2028**
	Stand-alone					
1	EGD	1,546	1,592	1,629	1,693	1,738
2	Union	1,468	1,511	1,545	1,575	1,614
3	Total	3,014	3,103	3,174	3,268	3,351
4	Amalco	2,964	3,054	3,144	3,234	3,314
5	Ratepayer benefit	50	49	30	34	38
6	Cumulative benefit	259	309	338	372	410

Figure 1
No Harm Test - Cumulative Ratepayer Benefit



The revenue requirement for the stand-alone utilities shown at lines 1 through 3 in Table 3 represents status-quo operations for the deferred rebasing period based on the following assumptions:

- EGD and Union would rebase in 2019 and 2025 and rates are set using a Custom IR framework during the 2020 to 2024 and 2026 to 2028 periods;
- Capital expenditures are based on the utilities' Asset Management Plans to support growth and replacement and maintenance of existing assets. The combined growth reflects customer attachments of an average of 45,000 per year consistent with historic trends.
- Operating costs increase for inflation and growth, pension and other programs related to asset management.

The proposed revenue of Amalco at line 4 in Table 3 reflects customer growth and rate adjustments under the price cap mechanism for setting rates during the deferred rebasing period and assumes:

- 2018 approved rates, adjusted for EGD's CIS and customer care costs[13] and Union's deferred tax drawdown[14], are increased annually using the price cap formula plus adjustments for the recovery of incremental capital expenditures, subject to OEB approval. The price cap formula includes inflation offset by a productivity factor (I-X), certain approved pass-through items (Y-factors) and potential adjustments for cost increases outside of management's control (Z-factors); inflation is 1.73%, which is the 5-year average ending 2017 of GDP IPI FDD and the productivity factor (X) is zero. The Total Factor Productivity Study supporting the proposed X-factor will be filed as part of EB-2017-0307.
- Revenue includes the cost related to incremental capital projects to be passed through to customers using the Incremental Capital Module ("ICM").

Based on the above, customers are better off by $410 million than they otherwise would have been if the utilities had continued to operate on a stand-alone basis. Accordingly, the

[13] As a result of the EB-2011-0226 Settlement Agreement, EGD's 2018 rates include $131 million associated with CIS and customer care costs while the Board approved costs amount to only $126 million. Accordingly, EGD is seeking a base rate adjustment to reduce rates by $5 million as part of the Rate Setting Mechanism proceeding (EB-2017-0307).
[14] Union's rates currently include a credit of approximately $17 million related to the deferred tax drawdown. The deferred tax drawdown expires at the end of 2018. Accordingly, Union will be seeking a base rate adjustment to remove the credit in rates as part of the Rate Setting Mechanism proceeding (EB-2017-0307).

amalgamation of EGD and Union into Amalco meets the no harm test with respect to price. The estimated efficiencies as a result of amalgamation are discussed in more detail in Section 4.6.

4.4 RELIABILITY AND QUALITY OF SERVICE

Amalco will continue to maintain the safety, reliability and quality of service to EGD and Union customers, both in-franchise and ex-franchise, that currently exists. Amalco will continue to be subject to and report on all existing Service Quality Requirements ("SQR") applicable to gas utilities. The Applicants also provide a proposed scorecard for review and approval as part of the Rate Setting Mechanism Application.

4.5 FINANCIAL VIABILITY

The amalgamation is expected to have no impact on the financial viability of Amalco as there is only a conversion of EGD and Union shares into shares of Amalco and no change of control, as described above in Section 3.

As will be described more fully in the Rate Setting Mechanism Application, however, it is also important that Amalco be given the opportunity to earn the allowed Return on Equity ("ROE") in order to allow Amalco to continue to invest in natural gas infrastructure to the benefit of customers and the Province of Ontario. In addition, Amalco will face risks associated with the changing economic environment with respect to interest rates and the move to a lower carbon economy. The Applicants have assumed that over the deferred rebasing period, Amalco will be subject to a price cap mechanism that will allow for inflationary increases and the pass-through of discrete capital projects using the ICM. This pricing mechanism will provide Amalco a reasonable opportunity to earn its allowed ROE while at the same time producing integration savings that will provide the opportunity for the applicants to take on and manage the risks of implementation costs and integration activities that will ultimately benefit ratepayers upon rebasing.

As indicated above, there are risks that Amalco will bear over the deferred rebasing period that are outside of management's control and that may impact Amalco's ability to earn its allowed ROE. The most significant risks outside of management's control are interest rates and government policy. These risks and the Applicants' proposals in relation to them will be addressed in the Rate Setting Mechanism Application.

In accordance with the Consolidation Handbook, the financial statements of EGD and the annual report of Union for the years ended December 31, 2015 and 2016 are provided at Exhibit B, Tab 1, Attachment 10. The pro forma financial statements of the combined entity for the first full year of operations following the completion of the proposed amalgamation are provided at Exhibit B, Tab 1, Attachment 11.

4.6 ESTIMATED COST EFFICIENCY OPPORTUNITIES

The following evidence provides the assumptions underpinning the estimated synergy opportunities for Amalco. Opportunities to generate efficiencies and synergies over the deferred rebasing period through workforce restructuring and alignment, as well as system and process integration exist in the following areas:

- Customer Care
- Distribution Work Management
- Utility Shared Services
- Storage and Transmission, Gas Supply and Gas Control
- Management Functions
- Other Functions

The estimated cost efficiencies and associated capital costs are summarized in Table 4 below. Annual impacts of the estimated cost efficiency opportunities showing both required capital investments and related O&M savings for the 10 year period from 2019 to 2028 are provided in Exhibit B, Tab 1, Attachment 12. Field Operations have been excluded from the scope of the analysis at this time to reflect that service areas for each utility do not directly overlap.

The estimated capital investment required for the integration of systems and technology to support the amalgamation of EGD and Union is estimated to be between \$50 million and \$250 million to deliver potential cost synergies of between $350 million and $750 million over the 10 year deferred rebasing period.

Table 4
High Level Minimum and Maximum Cost and Savings Estimate ($ Millions)

Item	Potential Capital Investment		Potential O&M Savings	
	Minimum	Maximum	Minimum	Maximum
Customer Care	$25	$110	$120	$250
Distribution Work Management	$10	$90	$30	$150
Utility Shared Services	$5	$20	$15	$50
Storage & Transmission	$5	$10	$15	$50
Management Functions & Other	$5	$20	$170	$250
Total	$50	$250	$350	$750

While the groups and functional areas that will generate synergies have been identified, the detailed implementation plans will be developed and implemented following the Board's Decision in the EB-2017-0306 and EB-2017-0307 proceedings. EGD and Union have only recently been able to share and discuss integration opportunities post the closing of the merger transaction between Enbridge and Spectra Energy in February, 2017. As such, it has not been feasible to develop an extensive and detailed integration plan. Many of the synergy opportunities are tied to the ability to align systems processes, procedures, standards and specifications.

Multiple Large Scale Software Implementations

Significant software system costs and implementations will take place over the deferred rebasing period from 2019 to 2028 to support the integration. Large scale system implementations will be planned to allow for staff to be resourced to these projects and to support change management and the adoption of the new systems and processes by employees and vendors. The timing of these system implementations will also need to consider corporate Enterprise Resource Planning ("ERP") system initiatives that will be happening concurrently during 2019 and 2020. The estimated cost efficiencies related to system implementations is based on a moderate to aggressive timeline, as two large system implementations are projected to be completed by 2024 in order to deliver the estimated synergies.

The ERP migration will be supported by Amalco and some Amalco system implementations will need to interface with the ERP. The first large system implementation is the Distribution Work Management system integration. The second large system implementation is the migration to one Customer Care software application. Each of these projects has a two to three year project duration and each large system implementation carries both timeline and cost risks. Management will ensure no harm to the customer experience through these multiple system changes by balancing quality outcomes with cost and timeline risks. The Applicants have recent experience with large software implementations including SAP, Contrax, Oracle, SCADA and Maximo and will be supported by the Enbridge enterprise support teams and external expert resources as required.

Business Process Transformations

Integration of the Applicants' business processes is expected to largely take place over the first six years but will occur over the full 10 year deferred rebasing period. The breadth of this integration and the associated business process transformation is significant. To provide context for the breadth and potential complexity of the integration consider the following examples:

- Alignment of engineering policies, standards, specifications and procedures for pipeline and facilities construction, inspection, maintenance including distribution, transmission and storage operations, etc.
- Common processes for supply chain procurement
- Alignment of safety policies and practices
- Common work management processes including estimating, planning, scheduling, and execution practices and policies
- Consistent accounting practices and policies including consolidated financial forecasting and reporting
- Alignment of various management systems (asset, emergency response, safety, etc.)
- Alignment of the 10 year asset management plans including risk identification and mitigation practices

In addition to the operational processes that will be integrated, one of the most significant undertakings will be to integrate EGD's and Union's Customer Care operations. A comprehensive review and plan will be established and executed that will address the differences between the existing two utility methods and approaches. This integration of the customer care operations is forecasted to deliver savings five years after the legal amalgamation in 2019.

Given the inter-dependencies and breadth of integration between systems and business transformation there is a risk to the moderate to aggressive timeline and therefore a 10 year deferred rebasing period was selected and deemed necessary to provide sufficient time for management to achieve a fully aligned and stabilized integrated utility prior to rebasing in 2029.

Customer Care

Management will begin Customer Care integration efforts subsequent to the Board's Decision in this proceeding and the EB-2017-0307 proceeding. Management will evaluate the costs and benefits of the various alternatives in order to identify the optimal solutions to implementing a common approach and supporting software. A major long term contributor to achieving further efficiencies in the Customer Care function is the integration of the customer care software platform. Integration of the software is currently targeted to be in-service by 2024.The principal metric used to evaluate and implement efficiencies will be cost per customer with the goal being to reduce the cost per customer while maintaining service quality to customers. To achieve a reduction in the cost per customer, management expects to incur costs to achieve savings in this area.

Currently EGD and Union have different customer care software applications and approaches. EGD currently uses SAP software for billing. Union contracts with Vertex to use the Banner Billing system. Amalco will integrate Customer Care operations under a single system and supporting software platform. A detailed analysis will be completed to determine the best customer care solutions to deliver quality services to Amalco's customers. The range of solutions includes migration of Union data into the EGD SAP software, migration of EGD to the Union platform or implementation of a new system. The estimate of $65 million represents migration to one of the current existing software platforms and structures. The estimate is approximately 50% of the original EGD SAP software implementation costs.

EGD's and Union's Customer Care groups also have differences in operations and practices that drive different operating costs. Projected savings (prior to any system changes and alignment) are based on a medium to aggressive schedule with planning work commencing in the latter part of 2018 after the OEB Decisions, and implementation starting in 2019. The goal is to target the delivery of the first tranche of savings in the 2020 to 2023 timeframe. Savings in this first tranche are targeted at a 10% reduction to the combined utilities' customer care services costs, which are currently approximately $150 million in total. This reduction is based on an estimated reduction of approximately $4 per customer across the combined 3.5 million customer base. These efficiencies could be the result of activities such as a digitization campaign to increase e-bill customers, increase collections efficiencies, and workforce alignment.

Integration onto a single CIS software platform is expected to accompany the implementation of processes that take advantage of that single software platform. Moving to a single software platform is expected to improve customer service offerings and reduce the workload required to process customer interactions and service requests. The expected total cost of operations for customer care services in 2024 is projected to be approximately $135 million per year ($150 million net of $15 million annual savings). An estimated additional $10 million savings per year from 2024 to 2028 is to be achieved from a combination of increased number of e-bill customers through better customer care web services, integration of the customer care software system onto a single platform and rationalization of processes that support some workforce optimization.

A key consideration related to the timing of the customer care efficiencies is related to project execution, specifically, the dependency on other system transformations that Enbridge Inc. and Amalco will undertake. Enbridge Inc. is undertaking a transformation which will implement a common ERP system. This timing will impact the ultimate timing and delivery of an integrated customer care software system given the customer care software system will be the "cash register" for the integrated utility revenues. In addition, timing of software migrations undertaken by Amalco such as the work management system, gas supply and commercial market and transmission software systems will impact the delivery of customer care integration plan. Finally, the scope and size of the software implementation is uncertain at this time given that no final decisions on the current options for the final software and customer care approach have been made. Table 4 highlights the cost and savings range uncertainty.

Distribution Work Management

Distribution work management consists of the planning, scheduling, compliance, work management systems, work management systems support, asset information, records and support related to the work required to maintain assets.

EGD completed an implementation of a new software platform (Maximo) to support work management systems in 2016 at an approximate cost of $85 million. The current software supporting the Union platform (Advantex) is nearing end of life and will not be supported in the near future. While a detailed analysis of options is required, the estimated cost efficiencies are based on integrating Union and EGD into a Maximo software system. Management estimates that a potential range of implementation costs could be between $30 million for data and business process migration to $85 million for full implementation. The estimate for migrating Union processes and data into Maximo is approximately $50 million.

With respect to potential savings opportunities in the Distribution Work Management function, there is an opportunity to align existing systems, improve worker efficiencies in the planning and scheduling of field work by adopting the best practices from both utilities and to consider under what model Amalco will deliver the best outcome in terms of customer service and cost. Related savings have been estimated at $11 million per year. The estimated savings increase to $16 million per year in 2024 to 2028 due to optimizing third party contracts and consolidating the workload planning and dispatching functions.

EGD recently implemented the Maximo software platform in conjunction with the eGIS software and Click Mobile software as its end-to-end distribution work management system. The Maximo platform has established a solid base for future optimization of this business function. The primary area of integration focus for this business function is the back-office activities, integration with customer care services to improve offerings and delivery times to customers and software integration. EGD and Union have different approaches to how the distribution work management function is undertaken. An integration plan where each distribution work management process is evaluated to implement the best practice at the lowest cost level will be developed. Given that EGD and Union have optimized workforces and optimized internal processes on a standalone basis and have forecasted an average of approximately 45,000 new customer additions per year, an estimate of 10% further reduction in costs and workforce planning is seen as moderate to aggressive.

Utility Shared Services

The Enbridge corporate office functions began to integrate and optimize at the close of the Enbridge Inc. and Spectra Energy merger in Q1, 2017. Initiatives to align these functions across the enterprise are ongoing and are part of the overall corporate merger integration and not managed directly by the Applicants. There are, however, a number of shared services such as Finance, Law, Human Resources, Information Technology, Supply Chain Management, Real Estate Services, Government Relations and Enterprise Safety & Operational Reliability that are resident at EGD and Union, which provide utility-specific shared services.

The utility specific shared services rely on several smaller systems and software. The initial review has identified applications such as utility billing financial analysis, IT service requests and real estate services as potential integration opportunities.

The preliminary estimate to implement a common software platform for those areas of shared services is $13 million. This cost estimate reflects implementation of between 5 to 10 systems resulting with an average implementation cost range of $2.6 million for 5 systems and $1.3 million for 10 systems. Overall, management estimates that the range of costs for these shared services systems is between $5 million and $20 million.

The potential savings from the utility shared service functions will be addressed by management as part of detailed integration planning. This assessment will review the impact of implementing a range of harmonization and standardization within the utility shared service functions that are performed at the utilities. The savings for these functions are estimated to be an average of $4 million per year over the deferred rebasing period.

Storage and Transmission Operations and Gas Supply and Control

The Storage and Transmission Operations business function include operations and maintenance of the transmission pipeline systems, storage wells and reservoirs. Gas Supply and Gas Control includes the gas control room operations for both EGD and Union, gas supply and upstream transportation contracting and settlement processes and associated systems and software for both utilities.

The integration opportunity for Amalco is the consolidation of the Gas Control and Gas Supply functions. EGD has its gas control SCADA system in Edmonton and Union has its gas control SCADA system in Chatham with a backup system at the Dawn Hub. EGD and Union use different software applications for their gas supply settlement processes (EGD uses OpenLink, EnCore and Entrac and Union uses CONTRAX and other smaller systems). A high level preliminary estimate to integrate the SCADA system and selection of software for gas supply operations to a common platform ranges from $5 million to $10 million. The midpoint of this cost range is approximately $8 million.

There are some opportunities to apply best practices across Amalco and to determine if there are operational benefits available related to the combination of these functions. The integration and alignment of the SCADA systems will also yield a potential benefit. The primary cost savings are expected to come from harmonizing the SCADA systems, process changes to optimize maintenance costs and alignment of contracts. The savings are estimated to be an average of $3 million per year over the 10 years, or approximately 10% of the annual $30 million in cost.

Other Functions

Other functions include business areas such as Engineering, Asset Management and Integrity, Public Affairs, Demand Side Management, Cap-and-Trade and other Low Carbon Business Development. These groups have opportunities to integrate and pursue productivity initiatives associated with elimination of smaller software systems, assessing sourcing models to reduce internal system support costs, implementing efficiencies through vendor contract management and process optimization cost savings opportunities. The annual savings estimate from this area is approximately $14 million per year. Given the majority of the savings will come from the rationalizing of information technology systems costs, the savings are expected to be generated in 2024 through 2028.

With respect to Asset Management, both EGD and Union have progressed with the implementation of Asset Management processes and practices in the development of their 10 year Asset Management Plans. To further refine the prioritization of individual projects, EGD has invested in new systems, including the use of PowerPlan (formerly RIVA) software. The associated processes support the long term optimization of asset investments to balance cost, risk, and performance. Management expects to integrate EGD and Union into a single set of asset management processes and software as part of the integration.

EGD and Union also have several systems that facilitate day to day operation of the utilities. Examples of different systems include: GIS, extranet websites, different meter-reading based software, several data warehouses that facilitate data analytics and reporting. Integration of these utility systems would begin in 2019, with preliminary initial cost estimates ranging from $5 million to $20 million. An average range of per system capital costs between $0.5 million and $2 million has been used to migrate or replace a range of 7 to 30 systems. An estimate of $14 million has been used as a baseline capital cost estimate for the Other Functions/systems.

Management Functions

There are opportunities to align the management structure and other functions within Amalco. Identifying a single management structure and Executive Management Team is one of the first integration efforts that will be conducted. The savings estimate for aligning the management structure is $20 million per year with an offset in year one for severance costs of $20 million. The estimated $20 million cost reduction will come from a mix of roles at EGD and Union. The total savings from this initiative is estimated to be $180 million over 10 years. Broader workforce alignment efforts are expected to occur at a much more gradual pace as various integration initiatives are undertaken over the deferred rebasing period.

4.7 RRF OUTCOMES

The key principles of the RRF include an expectation of continuous improvement, robust integrated planning and asset management, incentives to enhance utility performance, ongoing monitoring of performance against targets and customer engagement to ensure utility plans are informed by customer expectations.[15]

Table 5 provides more detail on the RRF outcomes identified by the OEB and how this Application to amalgamate supports those outcomes.

[15] OEB Handbook to Utility Rate Applications, October 12, 2016, p. 2.

Table 5
OEB Outcomes and Relationship to Application

OEB Outcome	Relationship to Application
Customer Focus *The OEB expects utilities to develop a genuine understanding of customers' interests and preferences and expects each utility to develop business plans that are informed by the utility's engagement with its customers*	Amalco will serve the vast majority of natural gas customers in Ontario. Amalco will use the information on customer interests and preferences through ongoing customer research within EGD and Union to inform its business plans going forward. In preparation for their respective 2019 rate applications both EGD and Union undertook extensive customer engagement activities in an effort to understand customer preferences. For example, both utilities learned that customers are willing to accept modest annual rate increases and that customers prefer that capital spending be managed over time to avoid large spends in any single year. Amalco will continue to engage customers over the deferred rebasing period to ensure that customer preferences are known and acted upon. Further, during the deferred rebasing period, Amalco will conduct a comprehensive customer engagement process every two years. The results of the customer engagement process will provide input into Amalco's business plans. In addition to bi-annual comprehensive customer engagement, Amalco will conduct a bi-annual stakeholder meeting to review Amalco's integration results and plans going forward with stakeholders and the Board. The proposed amalgamation will not impact the competition in the sale of gas to users. Amalco will continue to be the default supplier and purchase natural gas on behalf of customers choosing utility gas supply and to accommodate the direct purchase options for those customers choosing to purchase their gas supply directly. Harmonization changes in the administration of gas supply and direct purchase will be considered as part of the review of Gas Supply and Customer Care processes, with appropriate customer consultation and/or OEB approvals depending on the nature of the changes proposed.
Operational Effectiveness *The OEB expects utilities to demonstrate*	The proposed amalgamation creates the opportunity to increase operational efficiency in several areas.

ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives *The OEB will assess performance trends and look for evidence of strong system planning and good corporate governance* *The OEB will use benchmarking to assess a utility's performance over time and to compare its performance against other utilities*	During the deferred rebasing period, Amalco will provide annual financial reporting and will continue to report on Board approved Service Quality Requirements. In addition, EGD and Union have developed a utility scorecard similar to that used by electric distributors. The utility scorecard is provided as part of the Rate Setting Mechanism Application.
Public Policy Responsiveness *The OEB expects utilities to consider public policy objectives in their business planning and to deliver on the obligations required of regulated utilities* *Natural gas utilities are expected to identify investments or programs that have been planned to meet obligations under Ontario's cap and trade program*	Amalco will continue to provide cost effective Demand Side Management programs to all in-franchise customer classes across the former EGD and Union franchises. Amalco will demonstrate its commitment to support Ontario's Climate Change Action Plan and the associated carbon reduction targets. Through its annual compliance filing under Ontario's Cap-and-Trade program, Amalco will meet its obligations. Amalco will also demonstrate its commitment to helping customers manage their carbon emissions through carbon abatement programs (e.g. renewable natural gas, compressed natural gas). The larger size of Amalco's combined customer base presents a unique opportunity to support government policy on a larger scale.
Financial Performance *The OEB expects utilities to demonstrate sustainable improvements in their efficiency and in doing so will have the opportunity to earn a fair return*	Under the proposed price cap approach for rate-setting with a deferred rebasing period, Amalco expects to achieve efficiencies that will benefit both the ratepayer and the company and recover the shareholders cost to achieve with a fair and reasonable return on invested capital. Ratepayers will pay an estimated $410 million less under the proposed amalgamation over the deferred rebasing period and will benefit from a lower cost structure at rebasing. To demonstrate the impact of the proposed amalgamation on the company's financial viability during the deferred rebasing period, Amalco will provide annual financial reporting to stakeholders and the Board. The proposed earnings sharing mechanism addresses the potential of excess returns.

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4.8 EXISTING CONTRACTS BETWEEN EGD AND UNION

One consequence of the proposed amalgamation is that the existing contracts between EGD and Union will cease to have effect as they will be contracts between the same party. These contracts apply to various gas supply (storage and transportation) and operating services arrangements.

Gas Supply (Storage and Transportation) Contracts

EGD relies on long-term contracts with Union for transportation and storage of natural gas to meet the gas supply requirements of customers in EGD's franchise areas. Transportation services are provided at regulated rates and storage services are provided at market prices. The cost consequences of these contracts are passed through to customers in rates.

The amalgamation will not change the price, quality or reliability of these services for customers. Amalco will continue to have access to existing storage and transportation capacity to meet the gas supply requirements of customers. Despite the fact that the contracts will cease to have effect upon amalgamation, Amalco will treat current contractual arrangements as continuing services for the existing term of the pre-amalgamation contracts. After this time, Amalco will evaluate service options. Amalco's own unregulated storage capacity and regulated transportation capacity will continue to be an option to meet customers' requirements. Internal processes will be developed to maintain the fairness and confidentiality of the bidding process used for Amalco procurement of storage services either from third parties or from the unregulated assets of Amalco. Transportation services provided with legacy Union assets for the purpose of legacy EGD customers will be priced consistent with the approved regulated rate-setting mechanism.

The cost consequences of these contracts will continue to be passed through to customers in rates in the same way these are costs treated currently. Treating storage and transportation services in this way will result in no harm to ratepayers.

Operating and Other Contracts

EGD and Union also have existing contracts in place that address operating requirements where existing systems interconnect, and contracts to address shared storage assets. Amalco will develop operating procedures as required to replace operating agreements and ensure a consistent level of reliable service. Any costs related to operating services or shared storage assets will be managed as part of Amalco's overall operating expenses consistent with the current treatment of those costs, resulting in no harm to ratepayers.

5. RATE CONSIDERATIONS FOR CONSOLIDATION APPLICATIONS

5.1 RATE REBASING PERIOD

The Applicants have selected 10 years for the deferred rate rebasing period, which results in rebasing occurring in 2029 rather than 2019. The deferred rebasing period of 10 years is necessary to allow Amalco to integrate and have sufficient time to support making the capital and system investments necessary to generate integration synergies across the combined EGD and Union operations. The Applicants will use the 10 year deferred rebasing term to generate efficiencies through system and process integration as well as workforce alignment as described at a high level in Section 4.6. Many of the opportunities are tied to the ability to align systems, processes, procedures, standards and specifications. Such alignment will take time while ensuring continued safe and reliable operations. In addition, as significant software system implementations occur, time is required to allow for staff to be resourced to these projects, and support change management and adequate adoption of the new systems and processes by employees and vendors.

EGD and Union will continue to follow their 2014-2018 Incentive Rate Mechanisms to set rates for 2018. Subject to OEB approval, beginning in 2019 Amalco will set rates annually for the three rate zones (EGD, Union North and Union South) using a price cap. During the deferred rebasing period, Amalco may apply for rate adjustments using the Board's ICM.

5.2 EARNINGS SHARING MECHANISM

Consistent with the OEB's requirements for consolidating entities requesting a deferred rebasing period of greater than five years to present an earnings sharing mechanism ("ESM"), Amalco will have an ESM beginning in year six (2024).

If, in any calendar year from 2024 to 2028, the actual utility ROE is greater than 300 basis points above the allowed ROE as set out under the OEB's policy, the excess earnings above 300 basis points will be shared 50/50 between the ratepayers and the shareholders. For the purposes of the ESM, the utility earnings will be calculated using generally accepted accounting principles

("GAAP") consistent with the combined entities external reporting, including regulatory accounting provisions as prescribed by the OEB from time to time. All revenues and costs included in the utility earnings calculation will be consistent with those allowable in a cost-of-service regulatory filing.

As a result of the corporate merger and the amalgamation of EGD and Union, the integration of policies, processes and procedures could result in accounting changes. Any changes in accounting will continue to comply with GAAP and will be subject to review by the company's external auditors.

6. Conclusion

The evidence above supports the Applicants' request to the OEB under Section 43(1) of the OEB Act for approval to effect the amalgamation of EGD and Union including a 10 year deferred rebasing period.

The Application has been prepared based on the Consolidation Handbook which provides guidance on MAADs applications. Central to the OEB's evaluation of MAADs applications is the no harm test. To satisfy the no harm test, the cumulative effects of the proposed transaction must not negatively impact the attainment of the OEB's statutory objectives or the OEB's goals and objectives under its key policies (in particular, the RRF). The evidence above demonstrates that the proposed amalgamation meets the no harm test and would have a positive effect on the attainment of the OEB's statutory and policy objectives. In financial terms, the Applicants estimate the cumulative benefit to customers of amalgamation to be $410 million over the deferred rebasing period.

As detailed in the evidence above, over the deferred rebasing period Amalco will integrate a number of systems and processes and by doing so will deliver significant and sustainable benefits to ratepayers. Amalgamation allows for greater operating efficiency, including potential economies of scale as well as continuous improvement through best practices. These efficiencies provide direct and enduring benefits for both customers and the utilities. The amalgamation also provides an opportunity to allow for greater strategic focus and capability to face the challenges and opportunities of market developments in the Ontario energy sector. These challenges and opportunities will come from technology change, government policy (including climate change policy), and rising customer expectations. An amalgamation positions Amalco to deliver benefits to customers and strengthens its ability to respond to market evolution going forward.

Accordingly, the Applicants respectfully request that the OEB approve the Application as filed.

uniongas
An Enbridge Company

Certification of Evidence

The undersigned, the President of Union Gas Limited, in my capacity as an officer of that corporation and without personal liability, hereby certify, to the best of my knowledge, as at the date of certification, that the evidence in the Application is accurate, consistent and complete.

Steve Baker, President, Union Gas Limited

Certification of Evidence

The undersigned, the President of Enbridge Gas Distribution Inc., in my capacity as an officer of that corporation and without personal liability, hereby certify, to the best of my knowledge, as at the date of certification, that the evidence in the Application is accurate, consistent and complete.

Jim Sanders, President, Enbridge Gas Distribution Inc.

Enbridge Gas Distribution Inc. and Union Gas Limited Franchise Areas

Enbridge Gas Distribution Inc. Franchise Areas

Municipality Type	Municipality Name
Township of	ADJALA-TOSORONTIO
Township of	ADMASTON/BROMLEY
Town of	AJAX
Township of	ALFRED AND PLANTAGENET
Township of	AMARANTH
Town of	ARNPRIOR
Township of	ASPHODEL-NORWOOD
Township of	ATHENS
Town of	AURORA
City of	BARRIE
Township of	BECKWITH
Town of	BRADFORD WEST GWILLIMBURY
City of	BRAMPTON
Municipality of	BRIGHTON
Township of	BROCK
City of	BROCKVILLE
Town of	CALEDON
Town of	CARLETON PLACE
Village of	CASSELMAN
Township of	CAVAN MONAGHAN
Township of	CHAMPLAIN
City of	CLARENCE-ROCKLAND
Municipality of	CLARINGTON
Township of	CLEARVIEW
Town of	COLLINGWOOD
Town of	DEEP RIVER
Township of	DOURO-DUMMER
Township of	DRUMMOND/NORTH ELMSLEY
County of	DUFFERIN
Regional Municipality of	DURHAM
Township of	EAST GARAFRAXA
Town of	EAST GWILLIMBURY
Township of	ELIZABETHTOWN-KITLEY
Town of	ERIN
Township of	ESSA
Town of	FORT ERIE
Town of	GEORGINA
Town of	GRAND VALLEY
County of	GREY
Township of	GREY HIGHLANDS
Town of	GRIMSBY
Township of	HAVELOCK-BELMONT-METHUEN
Town of	HAWKESBURY
Township of	HORTON
Town of	INNISFIL
County of	KAWARTHA LAKES
Township of	KING
County of	LANARK
Town of	LAURENTIAN HILLS
Township of	LAURENTIAN VALLEY
United Counties of	LEEDS AND GRENVILLE
Township of	LEEDS AND THE THOUSAND ISLANDS
Town of	LINCOLN
Town of	MARKHAM
Township of	MCNAB/BRAESIDE
Township of	MELANCTHON
Village of	MERRICKVILLE-WOLFORD
Town of	MIDLAND
City of	MISSISSAUGA
Town of	MISSISSIPPI MILLS
Town of	MONO
Township of	MONTAGUE
Township of	MULMUR
Town of	NEW TECUMSETH

Town of	NEWMARKET
Regional Municipality of	NIAGARA
City of	NIAGARA FALLS
Town of	NIAGARA-ON-THE-LAKE
Township of	NORTH GLENGARRY
Township of	NORTH GRENVILLE
Township of	NORTH STORMONT
County of	NORTHUMBERLAND
Town of	ORANGEVILLE
Township of	ORO-MEDONTE
City of	OSHAWA
Township of	OTONABEE-SOUTH MONAGHAN
City of	OTTAWA
Regional Municipality of	PEEL
Town of	PELHAM
City of	PEMBROKE
Town of	PENETANGUISHENE
Town of	PERTH
Town of	PETAWAWA
County of	PETERBOROUGH
City of	PETERBOROUGH
City of	PICKERING
City of	PORT COLBORNE
United Counties of	PRESCOTT AND RUSSELL
County of	RENFREW
Town of	RENFREW
Town of	RICHMOND HILL
Township of	RIDEAU LAKES
Township of	RUSSELL
Township of	SCUGOG
Township of	SEVERN
Town of	SHELBURNE
County of	SIMCOE
Township of	SMITH-ENNISMORE-LAKEFIELD
Separated Town of	SMITHS FALLS
Township of	SOUTH GLENGARRY
Township of	SOUTHGATE
Township of	SPRINGWATER
City of	ST. CATHARINES
United Counties of	STORMONT, DUNDAS & GLENGARRY
Township of	TAY
Township of	TAY VALLEY
Municipality of	THE NATION
City of	THOROLD
Township of	TINY
City of	TORONTO
Municipality of	TRENT HILLS
Township of	UXBRIDGE
City of	VAUGHAN
Township of	WAINFLEET
Town of	WASAGA BEACH
City of	WELLAND
Township of	WEST LINCOLN
Town of	WHITBY
Town of	WHITCHURCH-STOUFFVILLE
Township of	WHITEWATER REGION
Regional Municipality of	YORK

Union Gas Limited Franchise Areas
Adelaide Metcalfe, Township
Alberton, Township
Alnwick/Haldimand, Township
Amherstburg, Town
Armour, Township
Armstrong, Township
Arran-Elderslie (Arran Township)
Arran-Elderslie (Tara, Village)
Ashfield-Colborne-Wawanosh, Township

Atikokan, Township
Augusta, Township
Baldwin, Township
Bayham, Municipality
Belleville, City
Black River-Matheson, Township
Blandford-Blenheim, Township
Blind River, Town
Bluewater, Municipality
Bonfield, Township
Bracebridge, Town
Brant, County
Brantford, City
Brighton, Municipality
Brockton, Municipality
Brooke-Alvinston, Township
Bruce Mines, Town
Bruce, County
Burk's Falls, Village
Burlington, City
Callander, Municipality
Calvin, Township
Cambridge, City
Central Elgin, Municipality
Central Huron, Municipality
Centre Hastings, Municipality
Centre Wellington, Township
Chapple, Township
Charlton and Dack, Municipality
Chatham-Kent, Municipality
Chatsworth, Township
Cobalt, Town
Cobourg, Town
Cochrane, Town
Coleman, Township
Cornwall, City
Cramahe, Township
Dawn-Euphemia, Township
Dawson, Township
Deseronto, Town
Dryden, City
Dutton-Dunwich, Municipality
Ear Falls, Township
East Ferris, Township
East Zorra – Tavistock, Township
Edwardsburgh/Cardinal Township
Elgin County
Elliot Lake, City
Emo, Township
Englehart, Town
Enniskillen, Township
Espanola, Town
Essex, County
Essex, Town
Evanturel, Township
Fauquier-Strickland, Township
Fort Frances, Town
Gananoque, Town
Georgian Bluffs, Township
Goderich, Town
Gravenhurst, Town
Greater Napanee, Town
Greater Sudbury, City
Greenstone, Municipality
Grey Highlands, Municipality
Grey, County
Guelph, City
Guelph/Eramosa, Township

Haldimand County
Halton Hills, Town
Halton, Regional Municipality (was County)
Halton, Regional Municipality
Hamilton, City
Hamilton, Township
Hanover, Town
Harris, Township
Hastings, County
Hearst, Town
Howick, Township
Huntsville, Town
Huron East, Municipality
Huron Shores, Municipality
Huron, County
Ignace, Township
Ingersoll, Town
Iroquois Falls, Town
Johnson, Township
Kapuskasing, Town
Kenora, City
Kingston, City (Kingston Township)
Kingston, City (Pittsburgh Township)
Kingsville, Town
Kirkland Lake, Town
Kitchener, City
Lakeshore, Town
Lambton Shores, Municipality
Lambton, County
LaSalle, Town
La Vallee, Township
Leamington, Municipality
Leeds & Grenville, United Counties
Leeds & Thousand Islands, Township
Lennox & Addington, County
London, City
Loyalist, Township
Lucan-Biddulph, Township
MacDonald, Meredith & Aberdeen Additional, Township
Machar, Township
Machin, Township
Madoc, Township
Mapleton, Township
Markstay-Warren, Municipality
Marmora and Lake, Municipality
Mattawa, Town
Mattawan, Township
Mattice – Val Côté, Township
McMurrich-Monteith, Township
Meaford, Municipality
Middlesex Centre, Municipality
Middlesex, County
Milton, Town
Minto, Town
Mississauga, City
Moonbeam, Township
Morley, Township
Morris-Turnberry, Municipality
Muskoka, District Municipality
Nairn and Hyman, Township
Neebing, Municipality
Newbury, Village
Nipigon, Township
Norfolk County
North Bay, City
North Dumfries, Township
North Dundas, Township
North Huron, Township

North Middlesex, Municipality
North Perth, Municipality
North Stormont, Township
Northumberland, County
Norwich, Township
Oakville, Town
Oil Springs, Village
Oliver Paipoonge, Municipality
Opasatika, Township
Orillia, City
Oro-Medonte, Township
Owen Sound, City
Oxford, County
Papineau-Cameron, Township
Parry Sound, Town
Peel, Regional Municipality
Perry, Township
Perth East, Township
Perth South, Township
Perth, County
Petrolia, Town
Plummer Additional, Township
Plympton-Wyoming, Town
Point Edward, Village
Port Hope, Municipality
Powassan, Municipality
Prescott, Town
Prince, Township
Prince Edward, County
Puslinch, Township
Quinte West, City
Rainy River, Town
Ramara, Township
Red Lake, Municipality
Red Rock, Township
Sarnia, City
Saugeen Shores, Town (Port Elgin, Town)
Saugeen Shores, Town (Saugeen, Township)
Saugeen Shores, Town (Southampton, Town)
Sault Ste. Marie, City
Seguin, Township
Severn, Township
Shuniah, Municipality
Simcoe, County
Smooth Rock Falls, Town
South Bruce Peninsula, Town (Hepworth, Village)
South Bruce Peninsula, Town (Wiarton, Town)
South Bruce Peninsula, Town (Amabel, Township)
South Bruce, Municipality
South Dundas, Township
South Huron, Municipality
South River, Village
South Stormont, Township
Southgate, Township
Southwest Middlesex, Municipality
South-West Oxford, Township
Southwold, Township
St. Charles, Municipality
St. Clair, Township
St. Marys, Town
St. Thomas, City
Stirling-Rawdon, Township
Stone Mills, Township
Stormont, Dundas & Glengarry, United Counties
Stratford, City
Strathroy-Caradoc, Township
Strong, Township
Sundridge, Village

Tecumseh, Town
Temagami, Municipality
Temiskaming Shores, City
Thames Centre, Municipality
The Blue Mountains, Town
Thessalon, Town
Thunder Bay, City
Tillsonburg, Town
Timmins, City
Tweed, Municipality
Tyendinaga, Township
Val Rita – Harty, Township
Warwick, Township
Waterloo, City
Waterloo, Regional Municipality
Wellesley, Township
Wellington North, Township
Wellington, County
West Elgin, Municipality
West Grey, Municipality
West Nipissing, Municipality
West Perth, Township
Wilmot, Township
Windsor, City
Woodstock, City
Woolwich, Township
Zorra, Township

Unorganized / Unincorporated Townships

Ashmore Township
Aurora Township (near Iroquois Falls)
Boston Township (near Kirkland Lake)
Broder Township
Bruce Lake - Griffith Mine
Buller Township
Cargill Township (near Kapuskasing)
Commanda Township (near North Bay)
Cumming Township (near Kapuskasing)
Eby Township
Errington Township
Freeborn Township
Grenfell Township
Guibord and Munro
Hanniwell Township
Hutchinson Township
Kendall Township (near Mattice-Val Cote)
Kenora District - Unsurveyed
Langton Township
Laurier Township
Lorrain Valley
McCaul Township
McKenzie-Portage Township
O'Brien Township
Poitras Township (incl Thorne)
Pyramid Township
Rainy River - Unsurveyed District
Ramsay-Wright Township
Redvers Township
Sapawe Township
Schwenger Township
Stirling Township (near Nipigon)
Studholme Township (near Mattice-Val Cote)
Wabigoon Township (near Dryden)
Wainwright Township (near Dryden)
Van Horne Township (near Dryden)
Zealand Township (near Dryden)

Produced October 2017
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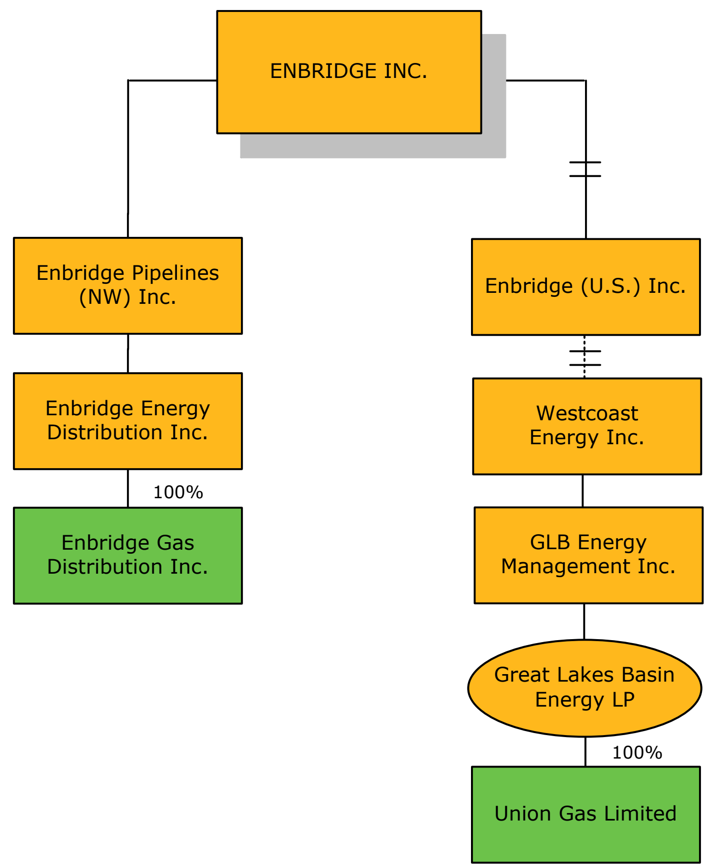
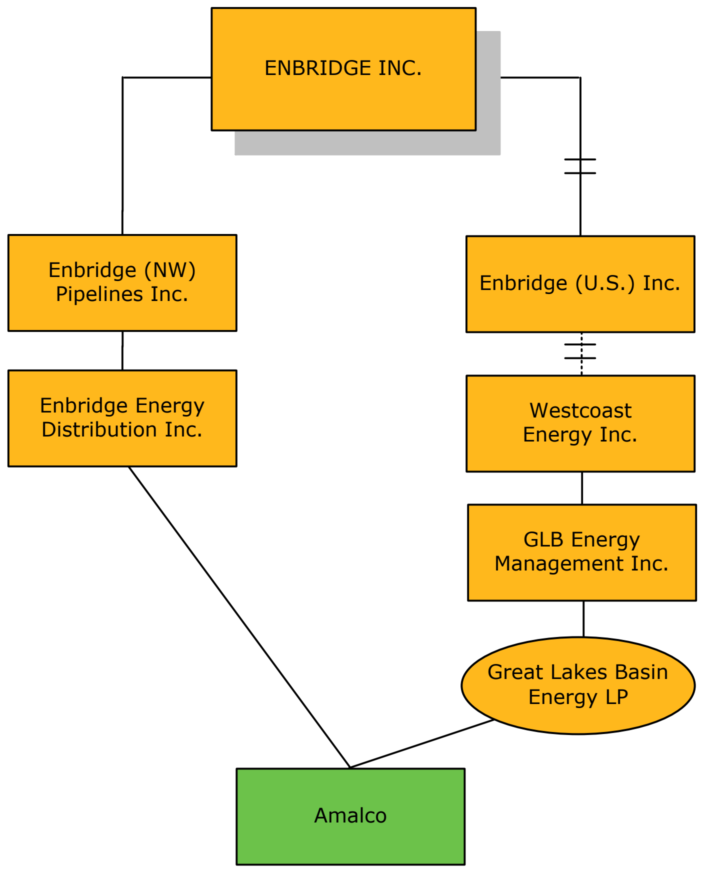
Current State



Post Amalgamation



Preliminary Utility Valuation
Summary of Enterprise Value and Equity Value as at November 2017

Description	A	B	C = A - B	Percentage of Total	Implied Multiples	
	Enterprise Value	Total Debt	Equity FMV		2017 EV / EBITDA	2017 EV / RB
	CAD$ BB	CAD$ BB	CAD$ BB			
Enbridge Gas Distribution	9.4	4.3	5.0	52%	12.8x	1.6x
Union Gas Limited	9.1	4.4	4.7	48%	12.9x	1.6x

Draft: November 2, 2017

AMALGAMATION AGREEMENT

THIS AMALGAMATION AGREEMENT is made this ■ day of ■, 201■,

B E T W E E N:

ENBRIDGE GAS DISTRIBUTION INC., a corporation existing under the laws of the Province of Ontario (hereinafter called "**EGD**")

- and -

UNION GAS LIMITED, a corporation existing under the laws of the Province of Ontario (hereinafter called "**Union Gas**")

RECITALS:

A. EGD and Union Gas have agreed to amalgamate pursuant to the Act;

B. EGD and Union Gas have each made disclosure to the other of their respective assets and liabilities; and

C. it is desirable that the Amalgamation should be effected.

NOW THEREFORE in consideration of the mutual covenants and agreements herein contained and other good and valuable consideration (the receipt and sufficiency of which are hereby acknowledged) the parties agree as follows:

1. Interpretation

In this Agreement (including the recitals hereto), the following terms shall have the following meanings:

1.1 "**Act**" means the *Business Corporations Act* (Ontario);

1.2 "**Agreement**" means this amalgamation agreement;

1.3 "**Amalgamated Corporation**" means the corporation continuing from the amalgamation of the Amalgamating Corporations;

1.4 "**Amalgamating Corporations**" means EGD and Union Gas and "**Amalgamating Corporation**" means either of them;

1.5 "**Amalgamation**" means the amalgamation of the Amalgamating Corporations as contemplated in this Agreement;

1.6 "**Effective Date**" means the date of the amalgamation as set forth in the certificate of amalgamation issued to the Amalgamated Corporation;

1.7 "**EGD Common Shares**" means the common shares in the capital of EGD;

1.8 "**Tax Act**" means the *Income Tax Act* (Canada) and all regulations promulgated thereunder from time to time; and

1.9 "**Union Gas Common Shares**" means the common shares in the capital of Union Gas.

Words and phrases used in this Agreement and defined in the Act shall have the same meaning in this Agreement as in the Act unless the context otherwise requires.

2. Agreement to Amalgamate

Each of the Amalgamating Corporations does hereby agree to amalgamate pursuant to the provisions of section 174 of the Act as of the Effective Date and to continue as one corporation on the terms and conditions set out in this Agreement.

3. Name

The name of the Amalgamated Corporation shall be ■.[1]

4. Registered Office

The registered office of the Amalgamated Corporation shall be located at ■.[2]

5. Authorized Capital

The Amalgamated Corporation is authorized to issue an unlimited number of Class A common shares and an unlimited number of Class B common shares. The rights, privileges, restrictions, conditions attaching to each class of shares in the capital of the Amalgamated Corporation are set forth in the attached Schedule A.

6. Number of Directors

The board of directors of the Amalgamated Corporation shall, until otherwise changed in accordance with the Act, consist of a minimum number of ■ and a maximum number of ■ directors.[3]

7. Business

There shall be no restriction on the business which the Amalgamated Corporation is authorized to carry on.

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[1] **[NTD: Name to be confirmed.]**

[2] **[NTD: Registered office to be confirmed.]**

[3] **[NTD: Board size to be confirmed.]**

8. Initial Directors and Auditors

The first directors of the Amalgamated Corporation shall be the persons whose names and addresses for service appear below:[4]

Name	Address	Resident Canadian
■	■	■
■	■	■
■	■	■

Such directors shall hold office until the first annual meeting of shareholders of the Amalgamated Corporation or until their successors are elected or appointed.

The current auditors of ■, ■, are hereby appointed auditors of the Amalgamated Corporation to hold office until the close of the next annual meeting of shareholders and the directors of the Amalgamated Corporation are authorized to fix their remuneration.[5]

9. Initial Officers

The following persons will be the first officers of the Amalgamated Corporation:[6]

Name	Title
■	■
■	■

10. Amalgamation

On the Effective Date:

10.1 each EGD Common Share that is issued and outstanding immediately prior to the Effective Date will, on and from the Effective Date, be converted into ■ Class A common shares in the capital of the Amalgamated Corporation;[7] and

---

[4] **[NTD: Initial board to be determined.]**

[5] **[NTD: Auditors to be confirmed.]**

[6] **[NTD: Initial officers to be confirmed.]**

[7] **[NTD: The number of common shares in the capital of the Amalgamated Corporation to be received for each EGD Common Share and each Union Gas Common Share will be determined based on the equity valuations of EGD and Union Gas prior to the Effective Date. In addition, the draft Amalgamation Agreement will be revised, if required, to reflect any additional shares of Union Gas (which may include shares of a new class of Union Gas common shares) issued as a result of equity capital contributed to Union Gas in 2018.]**

10.2 each Union Gas Common Share that is issued and outstanding immediately prior to the Effective Date will, on and from the Effective Date, be converted into ■ Class B common shares in the capital of the Amalgamated Corporation.

11. Stated Capital Accounts

The stated capital account in the records of the Amalgamated Corporation shall be:

11.1 for the Class A common shares of the Amalgamated Corporation, an amount equal to the aggregate of the paid up capital (as determined for purposes of the Tax Act) of the issued and outstanding EGD Common Shares; and

11.2 for the Class B common shares of the Amalgamated Corporation, an amount equal to the aggregate of the paid up capital (as determined for purposes of the Tax Act) of the issued and outstanding Union Gas Common Shares.

12. Constating Documents

The by-laws of the Amalgamated Corporation, until repealed, amended or altered, shall be the by-laws of EGD and a copy of these by-laws may be examined at 500 Consumers Road, North York, Ontario, M2J 1P8. In addition, the articles of amalgamation of the Amalgamated Corporation, until amended or altered, shall include or incorporate by reference the provisions of EGD's articles as they exist, as amended, immediately prior to the Effective Date, other than provisions of EGD's articles that are inconsistent with section 3, 4, 5, 6, 7, 8, 9 or 11 of this Agreement.

13. Termination

This Agreement may, prior to the issuance of a certificate of amalgamation in respect of the Amalgamation, be terminated by the boards of directors of EGD and Union Gas notwithstanding the approval by the shareholders of EGD and Union Gas of the terms and conditions hereof.

14. Filing of Documents

The Amalgamating Corporations shall jointly file with the Director under the Act articles of amalgamation and such other documents as may be required.

15. Governing Law

This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

16. Entire Agreement

This Agreement constitutes the entire agreement between the parties pertaining to the subject matter of this Agreement. There are no warranties, conditions, or representations (including any that may be implied by statute) and there are no agreements in connection with such subject matter except as specifically set forth or referred to in this Agreement. No reliance is placed on any warranty, representation, opinion, advice or assertion of fact made either prior to, contemporaneous with, or after entering into this Agreement, or any amendment or supplement thereto, by any party to this Agreement or its directors, officers, employees or agents, to any other party to this Agreement or its directors, officers, employees or agents, except to the extent that the same has been reduced to writing and included as a term of this Agreement, and none of the parties to this Agreement has been induced to enter into this Agreement or any amendment or supplement by reason of any such warranty, representation, opinion, advice or assertion of fact. Accordingly, there shall be no liability, either in tort or in contract, assessed in relation to any such warranty, representation, opinion, advice or assertion of fact, except to the extent contemplated above.

17. Further Assurances

Each party hereto shall do and take all such further acts and execute and deliver all such further documents and instruments as may be reasonably required or desirable in order to effect the purpose of this Agreement and carry out its provisions.

18. Execution in Counterparts

This Agreement may be executed in identical counterparts, each of which is, and is hereby conclusively deemed to be, an original and such counterparts collectively are to be conclusively deemed to be one and the same instrument. Delivery of counterparts may be effected by electronic transmission.

[Remainder of Page Intentionally Left Blank]

IN WITNESS WHEREOF the parties hereto have executed this Agreement.

ENBRIDGE GAS DISTRIBUTION INC.

By: ______________________________
Name:
Title:

UNION GAS LIMITED

By: ______________________________
Name:
Title:

SCHEDULE A

Rights, Privileges, Restrictions and Conditions Attaching to Each Class of Shares of the Amalgamated Corporation

A. Class A Common Shares

The Class A common shares, as a class, shall be designated as the Class A common shares and shall have attached thereto the following rights, privileges, restrictions and conditions:

1. Dividends

The holders of the Class A common shares shall be entitled to receive, and the Corporation shall pay thereon, any dividends declared by the Corporation on the Class A common shares, if, as and when declared by the directors of the Corporation out of moneys of the Corporation properly applicable to the payment of dividends, in such amounts as may be determined by the directors from time to time, each such dividend to be paid to such holders on such date as may be fixed by the directors at the time of declaration of such dividend. Unless the holders of the Class A common shares and the holders of the Class B common shares consent in writing otherwise, the Class A common shares and the Class B common shares shall rank equally as to dividends on a share for share basis, and all dividends declared by the Corporation shall be declared in equal amounts per share on all Class A common shares and all Class B common shares at the time outstanding, without preference or distinction.

2. Subdivision or Consolidation

No subdivision or consolidation of the Class B common shares or the Class A common shares shall occur unless, simultaneously, the Class A common shares or the Class B common shares, as the case may be, are subdivided or consolidated in the same manner, so as to maintain and preserve the relative rights of the holders of the shares of each of such classes.

3. Liquidation, Dissolution or Winding-up

Upon the liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or other distribution of the property and assets of the Corporation among its shareholders for the purpose of winding-up its affairs, the holders of the Class A common shares and the holders of the Class B common shares shall be entitled to receive the remaining property and assets of the Corporation and shall be entitled to share equally, on a share for share basis, in all distributions of such property and assets without preference or distinction unless the holders of the Class A common shares and the holders of the Class B common shares consent in writing otherwise.

4. Class A Common Shares to be Voting

The holders of the Class A common shares shall be entitled to receive notice of and to attend all meetings of shareholders of the Corporation, other than separate meetings of the holders of another class of shares, and to vote at any such meeting on the basis of one (1) vote for each Class A common share held.

B. Class B Common Shares

The Class B common shares, as a class, shall be designated as the Class B common shares and shall have attached thereto the following rights, privileges, restrictions and conditions:

1. Dividends

The holders of the Class B common shares shall be entitled to receive, and the Corporation shall pay thereon, any dividends declared by the Corporation on the Class B common shares, if, as and when declared by the directors of the Corporation out of moneys of the Corporation properly applicable to the payment of dividends, in such amounts as may be determined by the directors from time to time, each such dividend to be paid to such holders on such date as may be fixed by the directors at the time of declaration of such dividend. Unless the holders of the Class A common shares and the holders of the Class B common shares consent in writing otherwise, the Class A common shares and the Class B common shares shall rank equally as to dividends on a share for share basis, and all dividends declared by the Corporation shall be declared in equal amounts per share on all Class A shares and all Class B common shares at the time outstanding, without preference or distinction.

2. Subdivision or Consolidation

No subdivision or consolidation of the Class B common shares or the Class A common shares shall occur unless, simultaneously, the Class A common shares or the Class B common shares, as the case may be, are subdivided or consolidated in the same manner, so as to maintain and preserve the relative rights of the holders of the shares of each of such classes.

3. Liquidation, Dissolution or Winding-up

Upon the liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or other distribution of the property and assets of the Corporation among its shareholders for the purpose of winding-up its affairs, the holders of the Class A common shares and the holders of the Class B common shares shall be entitled to receive the remaining property and assets of the Corporation and shall be entitled to share equally, on a share for share basis, in all distributions of such property and assets without preference or distinction unless the holders of the Class A common shares and the holders of the Class B common shares consent in writing otherwise.

4. Class B Common Shares to be Voting

The holders of the Class B common shares shall be entitled to receive notice of and to attend all meetings of shareholders of the Corporation, other than separate meetings of the holders of another class of shares, and to vote at any such meeting on the basis of one (1) vote for each Class B common share held.

ENBRIDGE INC.

CERTIFICATE

I, Tyler W. Robinson, Vice President & Corporate Secretary of Enbridge Inc. (the "Corporation") hereby certify on behalf of the Corporation and not in my personal capacity that the following is an extract of resolutions passed by the Board of Directors of the Corporation at a meeting held on November 1, 2017, and that the said resolutions are in full force and effect as of the date hereof.

"WHEREAS it is desirable that Enbridge Gas Distribution Inc. ("EGD") and Union Gas Limited ("**Union**"), two indirect wholly-owned subsidiaries of the Corporation, amalgamate (the "Amalgamation");

AND WHEREAS prior approval of the Ontario Energy Board (the "OEB") is required pursuant to the OEB's Mergers, Acquisition, Amalgamation and Divestitures Policy and Guidelines (the "MAADs Application") for the Amalgamation;

AND WHEREAS Management of EGD and Union wish to submit to the OEB (i) a MAADs Application for the Amalgamation and (ii) an associated price cap rate setting mechanism application (together with the MAADs Application, the "OEB Applications"), the elements of which having been presented to and reviewed by the board of directors;

RESOLVED THAT:

1. the Amalgamation is hereby approved, subject to a determination by each of (i) the Corporation's board of directors, (ii) the holders of the common shares of EGD and Union and (iii) the board of directors of EGD and Union that it is prudent to proceed with the Amalgamation upon consideration of the OEB decisions on the OEB Applications;

2. Management of EGD and Union are hereby authorized to submit the OEB Applications, along with any necessary ancillary or supporting documents, to the OEB as soon as reasonably practicable; and

3. any officer or director of EGD or Union is hereby authorized and directed to execute and deliver for and in the name and on behalf of EGD or Union, as the case may be, and under corporate seal or otherwise all such certificates, instruments, agreements, notices, affidavits and other documents and to do all such other acts and things as in the opinion of such person may be necessary or desirable in connection with the OEB Applications."

DATED the 1st day of November, 2017.

Tyler W. Robinson
Vice President & Corporate Secretary

ENBRIDGE GAS DISTRIBUTION INC.

CERTIFICATE

I, David Taniguchi, Assistant Corporate Secretary of Enbridge Gas Distribution Inc. (the "Corporation"), hereby certify on behalf of the Corporation and not in my personal capacity that the following is an extract of resolutions passed by the Board of Directors of the Corporation on October 30, 2017 and the said resolutions are in full force and effect as of the date hereof.

"Utilities Integration

WHEREAS it is desirable that the Corporation amalgamate (the "Amalgamation") with Union Gas Limited ("Union"), an affiliate of the Corporation;

AND WHEREAS prior approval of the Ontario Energy Board (the "OEB") is required pursuant to the OEB's Mergers, Acquisition, Amalgamation and Divestitures Policy and Guidelines (the "MAADs Application") for the Amalgamation;

AND WHEREAS in connection with the Amalgamation, the Corporation, together with Union, wishes to submit to the OEB (i) a MAADs Application and (ii) an associated price cap rate setting mechanism application (together with the MAADs Application, the "OEB Applications"), the elements of which having been presented to and reviewed by the board of directors;

NOW THEREFORE BE IT RESOLVED THAT:

1. The Amalgamation is hereby approved, subject to a determination by each of (i) the Enbridge Inc. board of directors, (ii) the holders of the common shares of the Corporation and Union, and (iii) the board of directors of the Corporation and Union that it is prudent to proceed with the Amalgamation upon consideration of the OEB decisions on the OEB Applications.

2. Management of the Corporation, together with Union, is hereby authorized to submit the OEB Applications, along with any necessary ancillary or supporting documents, to the OEB as soon as reasonably practicable.
3. Any officer or director of the Corporation is hereby authorized and directed to execute and deliver for and in the name and on behalf of the Corporation and under its corporate seal or otherwise all such certificates, instruments, agreements, notices, affidavits and other documents and to do all such other acts and things as in the opinion of such person may be necessary or desirable in connection with the OEB Applications."

DATED the 1st day of November, 2017.

Taniguchi

David Taniguchi
Assistant Corporate Secretary

ENBRIDGE GAS DISTRIBUTION INC.

CERTIFICATE

I, David Taniguchi, Assistant Corporate Secretary of Enbridge Gas Distribution Inc. (the "Corporation"), hereby certify on behalf of the Corporation and not in my personal capacity that the following is an extract of special resolutions passed by the Sole Shareholder of the Corporation on November 1, 2017 and the said special resolutions are in full force and effect as of the date hereof.

"WHEREAS it is desirable that the Corporation, a wholly-owned subsidiary of Enbridge Energy Distribution Inc., and Union Gas Limited ("Union"), an affiliate of the Corporation, amalgamate (the "Amalgamation");

AND WHEREAS prior approval of the Ontario Energy Board (the "OEB") is required pursuant to the OEB's Mergers, Acquisition, Amalgamation and Divestitures Policy and Guidelines (the "MAADs Application") for the Amalgamation;

AND WHEREAS Management of EGD and Union wish to submit to the OEB (i) a MAADs Application for the Amalgamation and (ii) an associated price cap rate setting mechanism application (together with the MAADs Application, the "OEB Applications"), the elements of which having been presented to and reviewed by the boards of directors of EGD and Union;

NOW THEREFORE BE IT RESOLVED AS A SPECIAL RESOLUTION THAT:

1. the Amalgamation is hereby approved, subject to a determination by each of (i) the Enbridge Inc. board of directors, (ii) Enbridge Energy Distribution Inc., as sole shareholder of EGD, (iii) the holder of the common shares of Union, and (iv) the boards of directors of EGD and Union that it is prudent to proceed with the Amalgamation upon consideration of the OEB decisions on the OEB Applications; and

2. any officer or director of EGD is hereby authorized and directed to execute and deliver for and in the name and on behalf of EGD and under its corporate seal or otherwise all such certificates, instruments, agreements, notices, affidavits and other documents and to do all such other acts and things as in the opinion of such person may be necessary or desirable in connection with the OEB Applications."

DATED the 1st day of November, 2017.

David Taniguchi
Assistant Corporate Secretary

UNION GAS LIMITED

CERTIFICATE

I, David Taniguchi, Assistant Corporate Secretary of Union Gas Limited (the "Corporation"), hereby certify on behalf of the Corporation and not in my personal capacity that the following is an extract of resolutions passed by the Board of Directors of the Corporation on October 30, 2017 and the said resolutions are in full force and effect as of the date hereof.

"Utilities Integration

WHEREAS it is desirable that the Corporation amalgamate (the "Amalgamation") with Enbridge Gas Distribution Inc. ("EGD"), an affiliate of the Corporation;

AND WHEREAS prior approval of the Ontario Energy Board (the "OEB") is required pursuant to the OEB's Mergers, Acquisition, Amalgamation and Divestitures Policy and Guidelines (the "MAADs Application") for the Amalgamation;

AND WHEREAS in connection with the Amalgamation, the Corporation, together with EGD, wishes to submit to the OEB (i) a MAADs Application and (ii) an associated price cap rate setting mechanism application (together with the MAADs Application, the "OEB Applications"), the elements of which having been presented to and reviewed by the board of directors;

NOW THEREFORE BE IT RESOLVED THAT:

1. The Amalgamation is hereby approved, subject to a determination by each of (i) the Enbridge Inc. board of directors, (ii) the holders of the common shares of the Corporation and EGD, and (iii) the board of directors of the Corporation and EGD that it is prudent to proceed with the Amalgamation upon consideration of the OEB decisions on the OEB Applications.

2. Management of the Corporation, together with EGD, is hereby authorized to submit the OEB Applications, along with any necessary ancillary or supporting documents, to the OEB as soon as reasonably practicable.

3. Any officer or director of the Corporation is hereby authorized and directed to execute and deliver for and in the name and on behalf of the Corporation and under its corporate seal or otherwise all such certificates, instruments, agreements, notices, affidavits and other documents and to do all such other acts and things as in the opinion of such person may be necessary or desirable in connection with the OEB Applications."

DATED the 1st day of November, 2017.

David Taniguchi
Assistant Corporate Secretary

UNION GAS LIMITED

CERTIFICATE

I, David Taniguchi, Assistant Corporate Secretary of Union Gas Limited (the "Corporation"), hereby certify on behalf of the Corporation and not in my personal capacity that the following is an extract of special resolutions passed by the Sole Shareholder of the Corporation on November 1, 2017 and the said special resolutions are in full force and effect as of the date hereof.

"WHEREAS it is desirable that the Corporation, a wholly-owned subsidiary of Great Lakes Basin Energy LP and Enbridge Gas Distribution Inc. ("EGD"), an affiliate of the Corporation, amalgamate (the "Amalgamation");

AND WHEREAS prior approval of the Ontario Energy Board (the "OEB") is required pursuant to the OEB's Mergers, Acquisition, Amalgamation and Divestitures Policy and Guidelines (the "MAADs Application") for the Amalgamation;

AND WHEREAS Management of Union and EGD wish to submit to the OEB (i) a MAADs Application for the Amalgamation and (ii) an associated price cap rate setting mechanism application (together with the MAADs Application, the "OEB Applications"), the elements of which having been presented to and reviewed by the boards of directors of Union and EGD;

NOW THEREFORE BE IT RESOLVED AS A SPECIAL RESOLUTION THAT:

1. the Amalgamation is hereby approved, subject to a determination by each of (i) the Enbridge Inc. board of directors, (ii) Great Lakes Basin Energy LP, as sole shareholder of Union, (iii) the holder of the common shares of EGD, and (iv) the boards of directors of Union and EGD that it is prudent to proceed with the Amalgamation upon consideration of the OEB decisions on the OEB Applications; and

2. any officer or director of Union is hereby authorized and directed to execute and deliver for and in the name and on behalf of Union and under its corporate seal or otherwise all such certificates, instruments, agreements, notices, affidavits and other documents and to do all such other acts and things as in the opinion of such person may be necessary or desirable in connection with the OEB Applications."

DATED the 1st day of November, 2017.

David Taniguchi
Assistant Corporate Secretary

UNDERTAKINGS OF THE CONSUMERS' GAS COMPANY LTD., ENBRIDGE CONSUMERS ENERGY INC., 311594 ALBERTA LTD., ENBRIDGE PIPELINES (NW) INC. AND ENBRIDGE INC.

TO: Her Honour The Lieutenant Governor in Council for the Province of Ontario

WHEREAS Enbridge Consumers Energy Inc. holds all of the issued and outstanding common shares of The Consumers' Gas Company Ltd. ("Consumers");

AND WHEREAS 311594 Alberta Ltd. holds all of the issued and outstanding common shares of Enbridge Consumers Energy Inc.;

AND WHEREAS Enbridge Pipelines (NW) Inc. holds all of the issued and outstanding common shares of 311594 Alberta Ltd.;

AND WHEREAS Enbridge Inc. ("Enbridge") holds all of the issued and outstanding common shares of Enbridge Pipelines (NW) Inc.;

the above named corporations do hereby agree to the following undertakings:

1.0 Definitions

In these undertakings,

1.1 "Act" means the *Ontario Energy Board Act, 1998*;

1.2 "**affiliate**" has the same meaning as it does in the *Business Corporations Act*;

1.3 "**Board**" means the Ontario Energy Board;

1.4 "**business activity**" has the same meaning as it does under the Act or a regulation made under the Act; and

1.5 "**electronic hearing**", "**oral hearing**" and "**written hearing**" have the same meaning as they do under the *Statutory Powers Procedure Act*.

2.0 Restriction on Business Activities

2.1 Consumers shall not, except through an affiliate or affiliates, carry on any business activity other than the transmission, distribution or storage of gas, without the prior approval of the Board.

3.0 Maintenance of common equity

3.1 Where the level of equity in Consumers falls below the level which the Board has determined to be appropriate in a proceeding under the Act or a predecessor Act, Consumers shall raise or Enbridge and its affiliates shall provide within 90 days, or such longer period as the Board may specify, sufficient additional equity capital to restore the level of equity in Consumers to the appropriate level.

3.2 Any additional equity capital provided to Consumers by Enbridge or its affiliates shall be provided on terms no less favourable to Consumers than Consumers could obtain directly in the capital markets.

4.0 Head Office

4.1 The head office of Consumers shall remain within the franchise area of Consumers.

5.0 Prior Undertakings

5.1 Subject to Article 5.2, these undertakings supersede, replace and are in substitution for all prior undertakings of Consumers, Enbridge and their affiliates.

5.2 The undertakings of British Gas PLC and Consumers dated June 16th, 1994 and approved by the Lieutenant Governor in Council on June 23rd, 1994, remain in full force and effect.

6.0 Dispensation

6.1 The Board may dispense, in whole or in part, with future compliance by any of the signatories hereto with any obligation contained in an undertaking.

7.0 Hearing

7.1 In determining whether to grant an approval under these undertakings or a dispensation under Article 6.1, the Board may proceed without a hearing or by way of an oral, written or electronic hearing.

8.0 Monitoring

8.1 At the request of the Board, Consumers, Enbridge and their affiliates will provide to the Board any information the Board may require related to compliance with these undertakings.

9.0 Enforcement

9.1 The parties hereto acknowledge that there has been consideration exchanged for the receipt and giving of the undertakings and agree to be bound by these undertakings.

9.2 Any proceeding or proceedings to enforce these undertakings may be brought and enforced in the courts of the Province of Ontario and Enbridge, Consumers and their affiliates hereby submit to the jurisdiction of the courts of the Province of Ontario in respect of any such proceeding.

9.3 For the purpose of service of any document commencing a proceeding in accordance with Article 9.2, it is agreed that Consumers is the agent of Enbridge and its affiliates and that personal service of documents on Consumers will be sufficient to constitute personal service on Enbridge and its affiliates.

10.0 Release from undertakings

10.1 Enbridge, Consumers and their affiliates are released from these undertakings on the day that Enbridge no longer holds, either directly or through its affiliates, more than 50 per cent of the voting securities of Consumers or on the day that Consumers sells its gas transmission and gas distribution systems.

11.0 Effective Date

11.1 These undertakings become effective on March 31, 1999.

DATED this 7th day of December, 1998.

THE CONSUMERS' GAS COMPANY LIMITED

by ____________________

____

ENBRIDGE CONSUMERS ENERGY INC.

by ____________________

____

311594 ALBERTA LTD.

by ____________________

____

ENBRIDGE PIPELINES (NW) INC.

by ____________________

____

ENBRIDGE INC.

by ____________________

____

UNDERTAKINGS OF UNION GAS LIMITED, CENTRA GAS UTILITIES INC., CENTRA GAS HOLDINGS INC., WESTCOAST GAS INC., WESTCOAST GAS HOLDINGS INC., WESTCOAST ENERGY INC.

TO: Her Honour The Lieutenant Governor in Council for the Province of Ontario

WHEREAS Centra Gas Utilities Inc. holds all the issued and outstanding common shares of Union Gas Limited ("Union");

AND WHEREAS Centra Gas Holdings Inc. holds all the issued and outstanding common shares of Centra Gas Utilities Inc.;

AND WHEREAS Westcoast Gas Inc. holds all the issued and outstanding common shares of Centra Gas Holdings Inc.;

AND WHEREAS Westcoast Gas Holdings Inc. holds all the issued and outstanding common shares of Westcoast Gas Inc.;

AND WHEREAS Westcoast Energy Inc. holds all the issued and outstanding common shares of Westcoast Gas Holdings Inc. ("Westcoast");

the above named corporations do hereby agree to the following undertakings:

1.0 Definitions

In these undertakings,

1.1 **"Act"** means the *Ontario Energy Board Act, 1998*;

1.2 **"affiliate"** has the same meaning as it does in the *Business Corporations Act*;

1.3 **"Board"** means the Ontario Energy Board;

1.4 **"business activity"** has the same meaning as it does under the Act or a regulation made under the Act; and

1.5 **"electronic hearing"**, **"oral hearing"** and **"written hearing"** have the same meaning as they do under the *Statutory Powers Procedure Act.*

2.0 Restriction on Business Activities

2.1 Union shall not, except through an affiliate or affiliates, carry on any business activity other than the transmission, distribution or storage of gas, without the prior approval of the Board.

3.0 Maintenance of common equity

3.1 Where the level of equity in Union falls below the level which the Board has determined to be appropriate in a proceeding under the Act or a predecessor Act, Union shall raise or Westcoast and its affiliates shall provide within 90 days, or such longer period as the Board may specify, sufficient additional equity capital to restore the level of equity in Union to the appropriate level.

3.2 Any additional equity capital provided to Union by Westcoast or its affiliates shall be provided on terms no less favourable to Union than Union could obtain directly in the capital markets.

4.0 Head Office

4.1 The head office of Union shall remain in the Municipality of Chatham-Kent.

5.0 Prior Undertakings

5.1 These undertakings supersede, replace and are in substitution for all prior undertakings of Union, Westcoast and their affiliates.

6.0 Dispensation

6.1 The Board may dispense, in whole or in part, with future compliance by any of the signatories hereto with any obligation contained in an undertaking.

7.0 Hearing

7.1 In determining whether to grant an approval under these undertakings or a dispensation under Article 6.1, the Board may proceed without a hearing or by way of an oral, written or electronic hearing.

8.0 Monitoring

8.1 At the request of the Board, Union, Westcoast and their affiliates will provide to the Board any information the Board may require related to compliance with these undertakings.

9.0 Enforcement

9.1 The parties hereto acknowledge that there has been consideration exchanged for the receipt and giving of the undertakings and agree to be bound by these undertakings.

9.2 Any proceeding or proceedings to enforce these undertakings may be brought and enforced in the courts of the Province of Ontario and Westcoast, Union and their affiliates hereby submit to the jurisdiction of the courts of the Province of Ontario in respect of any such proceeding.

9.3 For the purpose of service of any document commencing a proceeding in accordance with Article 9.2, it is agreed that Union is the agent of Westcoast and its affiliates and that personal service of documents on Union will be sufficient to constitute personal service on Westcoast and its affiliates.

10.0 Release from undertakings

10.1 Westcoast, Union and their affiliates are released from these undertakings on the day that Westcoast no longer holds, either directly or through its affiliates, more than 50 per cent of the voting securities of Union or on the day that Union sells its gas transmission and gas distribution systems.

11.0 Effective Date

11.1 These undertakings become effective on March 31, 1999.

DATED this 7th day of December, 1998.

UNION GAS LIMITED

by ______________________

CENTRA GAS UTILITIES INC.

by ______________________

CENTRA GAS HOLDINGS INC.

by ______________________

WESTCOAST GAS INC.

by ______________________

WESTCOAST GAS HOLDINGS INC.

by ______________________

WESTCOAST ENERGY INC.

by ______________________

Ontario
Executive Council
Conseil des ministres

Order in Council
Décret

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and concurrence of the Executive Council, orders that:

Sur la recommandation du soussigné, le lieutenant-gouverneur, sur l'avis et avec le con- sentement du Conseil des ministres, décrète ce qui suit:

WHEREAS Enbridge Distribution Inc. and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999; and Union Gas Limited and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998, and that took effect on March 31, 1999;

AND WHEREAS opportunities exist for Enbridge Distribution Inc. and Union Gas Limited to carry on business activities that could assist the Government of Ontario in achieving its goals in energy conservation;

AND WHEREAS the Minister of Energy may issue, and the Ontario Energy Board shall implement, directives that have been approved by the Lieutenant Governor in Council that require the Board to take steps specified in the directives to promote energy conservation, energy efficiency, load management or the use of cleaner energy sources, including alternative and renewable energy sources;

NOW THEREFORE the attached Directive is approved.

Recommended: ______________________
Minister of Energy

Concurred: ______________________
Chair of Cabinet

Approved and Ordered: AUG 10 2006
Date

____
Administrator of the Government

O.C./Décret 1537/2006

Minister of Energy

Hearst Block, 4TH Floor
900 Bay Street
Toronto ON M7A 2E1
Tel: 416-327-6715
Fax: 416-327-6574

Ministre de l'Énergie

Édifice Hearst, 4e étage
900, rue Bay
Toronto ON M7A 2E1
Tél: 416-327-6715
Télé: 416-327-6574

Ontario

MINISTER'S DIRECTIVE

Re: Gas Utility Undertakings

Enbridge Gas Distribution Inc. and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Enbridge Undertakings"); and Union Gas Limited and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Union Undertakings").

Pursuant to section 27.1 of the *Ontario Energy Board Act, 1998*, I hereby direct the Ontario Energy Board to dispense,

- under section 6.1 of the Enbridge Undertakings, with future compliance by Enbridge Gas Distribution Inc. with section 2.1 ("Restriction on Business Activities") of the Enbridge Undertakings, and

- under section 6.1 of the Union Undertakings, with future compliance by Union Gas Limited with section 2.1 ("Restriction on Business Activities") of the Union Undertakings,

in respect of the provision of services by Enbridge Gas Distribution Inc. and Union Gas Limited that would assist the Government of Ontario in achieving its goals in energy conservation, including services related to:

(a) the promotion of electricity conservation, natural gas conservation and the efficient use of electricity;

(b) electricity load management; and

(c) the promotion of cleaner energy sources, including alternative energy sources and renewable energy sources.

.../cont'd

In addition, pursuant to section 27.1 of the *Ontario Energy Board Act, 1998*, I hereby direct the Board to dispense, under section 6.1 of the Enbridge Undertakings, with future compliance with section 2.1 of the Enbridge Undertakings in respect of research, review, preliminary investigation, project development and the provision of services related to the following business activities:

(a) the local distribution of steam, hot and cold water in a Markham District Energy initiative; and

(b) the generation of electricity by means of large stationary fuel cells integrated with energy recovery from natural gas transmission and distribution pipelines.

Further, pursuant to section 27.1 of the *Ontario Energy Board Act, 1998*, I hereby direct the Board to dispense, under section 6.1 of the Union Undertakings, with future compliance with section 2.1 of the Union Undertakings in respect of research, review, preliminary investigation, project development and the provision of services related to the following business activities:

(a) the generation of electricity by means of large stationary fuel cells integrated with energy recovery from natural gas transmission and distribution pipelines.

To the extent that any activities undertaken by Enbridge Gas Distribution Limited or Union Gas Limited in reliance on this Directive are forecast to impact upon their regulated rates, such activities are subject to the review of the Ontario Energy Board under the *Ontario Energy Board Act, 1998*.

In this directive, "alternative energy source" and "renewable energy source" have the same meanings as in the *Electricity Act, 1998*.

Dwight Duncan
Minister

Order in Council
Décret

Ontario
Executive Council
Conseil des ministres

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and concurrence of the Executive Council, orders that:

Sur la recommandation du soussigné, le lieutenant-gouverneur, sur l'avis et avec le consentement du Conseil des ministres, décrète ce qui suit:

WHEREAS Enbridge Gas Distribution Inc. and related parties ("Enbridge") gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Enbridge Undertakings"), and Union Gas Limited and related parties ("Union") gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Union Undertakings");

AND WHEREAS the Minister of Energy and Infrastructure has the authority under section 27.1 of the *Ontario Energy Board Act, 1998* to issue directives, approved by the Lieutenant Governor in Council, that require the Ontario Energy Board to take steps specified in the directives to promote energy conservation, energy efficiency, load management and the use of cleaner energy sources including alternative and renewable energy sources;

AND WHEREAS The Government of Ontario has, with the passage of the *Green Energy and Green Economy Act, 2009*, embarked upon a historic series of initiatives related to promoting the use of renewable energy sources and enhancing conservation throughout Ontario;

AND WHEREAS certain amendments to the *Ontario Energy Board Act, 1998* provided for by the above-noted statute authorize electricity distribution companies to directly own and operate renewable energy electricity generation facilities with a capacity of ten (10) megawatts or less, facilities that generate heat and electricity from a single source, or facilities that store energy, subject to criteria to be prescribed by regulation;

AND WHEREAS it is desirable that both Enbridge and Union are accorded authority similar to those of electricity distributors to own and operate the kinds of generation and storage facilities referenced above, while clarifying that the latter two activities, namely the ownership and operation of facilities that generate heat and electricity from a single source, or facilities that store energy, are to be interpreted to include stationary fuel-cell facilities each of which does not exceed 10 Megawatts in capacity, as well as to allow Enbridge and Union the authority to own and operate assets required in respect of the provision of services by Enbridge and Union that would assist the Government of Ontario in achieving its goals in energy conservation including where such assets relate to solar-thermal water and ground-source heat pumps;

AND WHEREAS the Minister of Energy has previously issued a directive pursuant to section 27.1 in respect of the Enbridge Undertakings and the Union Undertakings, under Order-in-Council No. 1537/2006, dated August 10, 2006.

NOW THEREFORE the directive attached hereto is approved and is effective as of the date hereof.

Recommended: [signature]
Minister of Energy and Infrastructure

Concurred: [signature]
Chair of Cabinet

Approved and Ordered: SEP 0 8 2009
Date

[signature]
Lieutenant Governor

O.C./Décret 1540/2009

MINISTER'S DIRECTIVE

Re: Gas Utility Undertakings Relating to the Ownership and Operation of Renewable Energy Electricity Generation Facilities, Facilities Which Generate Both Heat and Electricity From a Single Source and Energy Storage Facilities and the Ownership and Operation of Assets Required to Provide Conservation Services.

Enbridge Gas Distribution Inc. and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Enbridge Undertakings"); and Union Gas Limited and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Union Undertakings").

The Government of Ontario has, with the passage of the *Green Energy and Green Economy Act, 2009*, embarked upon a historic series of initiatives related to promoting the use of renewable energy sources and enhancing conservation throughout Ontario.

One of those initiatives is to allow electric distribution companies to directly own and operate renewable energy electricity generation facilities of a capacity of not more than 10 megawatts or such other capacity as is prescribed by regulation, facilities which generate both heat and electricity from a single source and facilities for the storage of energy, subject to such further criteria as may be prescribed by regulation.

The Government also wants to encourage initiatives that will reduce the use of natural gas and electricity.

Pursuant to section 27.1 of the *Ontario Energy Board Act, 1998*, and in addition to a previous directive issued thereunder on August 10, 2006 by Order in Council No. 1537/2006, in respect of the Enbridge Undertakings and the Union Undertakings, I hereby direct the Ontario Energy Board to dispense,

- under section 6.1 of the Enbridge Undertakings, with future compliance by Enbridge Gas Distribution Inc. with section 2.1 ("Restriction on Business Activities") of the Enbridge Undertakings, and
- under section 6.1 of the Union Undertakings, with future compliance by Union Gas Limited with section 2.1 ("Restriction on Business Activities") of the Union Undertakings,

in respect of the ownership and operation by Enbridge Gas Distribution, Inc. and Union Gas Limited, of:

(a) renewable energy electricity generation facilities each of which does not exceed 10 megawatts or such other capacity as may be prescribed, from time to time, by regulation made under clause 71(3)(a) of the *Ontario Energy Board Act, 1998* and which meet the criteria prescribed by such regulation;

(b) generation facilities that use technology that produces power and thermal energy from a single source which meet the criteria prescribed, from time to time, by regulation made under clause 71(3)(b) of the *Ontario Energy Board Act, 1998*;

(c) energy storage facilities which meet the criteria prescribed, from time to time, by regulation made under clause 71(3)(c) of the *Ontario Energy Board Act, 1998*; or

(d) assets required in respect of the provision of services by Enbridge Gas Distribution Inc. and Union Gas Limited that would assist the Government of Ontario in achieving its goals in energy conservation and includes assets related to solar-thermal water and ground-source heat pumps;

(e) for greater certainty, the use of the word "facilities" in paragraphs (b) and (c) above shall be interpreted to include stationary fuel-cell facilities each of which does not exceed 10 Megawatts in capacity.

This directive is not in any way intended to direct the manner in which the Ontario Energy Board determines, under the *Ontario Energy Board Act, 1998,* rates for the sale, transmission, distribution and storage of natural gas by Enbridge Gas Distribution Inc. and Union Gas Limited.

George Smitherman

George Smitherman
Deputy Premier, Minister of Energy and Infrastructure

UNDERTAKINGS OF BRITISH GAS PLC

TO: The Lieutenant Governor in Council for the Province of Ontario

WHEREAS British Gas plc ("British Gas") indirectly owned approximately 85 per cent of the outstanding common shares of the Consumers' Gas Company Ltd. ("Consumers Gas");

AND WHEREAS British Gas entered into a written agreement dated November 19, 1993 with Interprovincial Pipeline System Inc. (now IPL Energy Inc.) ("IPL") for the sale to IPL of British Gas' interest in Consumers Gas;

AND WHEREAS British Gas has applied to the Lieutenant Governor in Council for leave in respect of the sale to IPL pursuant in Article 1.5 of the Undertakings (the "1990 Undertakings") given to the Lieutenant Governor in Council by British Gas on December 13, 1990;

AND WHEREAS British Gas has also applied to be relieved from the 1990 Undertakings;

AND WHEREAS the Ontario Energy Board held a public hearing with respect to the application by British Gas and has submitted a report with respect thereto to the Lieutenant Governor in Council;

NOW THEREFORE in consideration of the Lieutenant Governor in Council granting leave to permit the sale to IPL of British Gas' indirect interest in Consumers Gas and relieving British Gas, British Gas Overseas Holdings Ltd., British Gas International Holdings B.V., British Gas Finance (Canada) Limited, British Gas Holdings (Canada) Limited, and The Consumers' Gas Company Ltd. of any and all obligations under the 1990 Undertakings British Gas agrees to be bound to the following Undertakings. In addition to the $9.9 million British Gas has already spent or committed on research and technology as a result of the 1990 Undertakings:

1.1 British Gas will spend or cause its affiliates to spend $10.0 million by December 31, 2000 in respect of research, development and demonstration activities in Ontario related to the efficient and environmentally friendly use of gas and in respect of the promotion of the commercial application and exploitation of such research and development. Consumers Gas shall co-ordinate, monitor and select such research, development, demonstration and promotion activities after reviewing those proposed activities with an advisory group comprised of a representative of each of the Ministry of Environment & Energy, Ministry of Economic Development and Trade, Gas Technology Canada and CANMET, provided further that British Gas shall make available to Consumers Gas such advice and assistance as Consumers Gas may reasonably request for the purpose of the research, development, demonstration and promotion activities contemplated in this Article.

1.2 The cumulative cost of any such advice and assistance provided from time to time by British Gas to Consumers Gas in accordance with Article 1.1, the administrative costs incurred by Consumers Gas in accordance with Article 1.1 and the administrative costs incurred by the Advisory Committee set out in Article 1.1 shall be deducted from the outstanding balance of British Gas' financial commitments under Article 1.1; provided that:

(i) the costs attributed to British Gas and the advisory committee shall be limited to British Gas' and the Advisory Committee members' out-of-pocket expenses and shall not include any charge in respect of over-head; and

(ii) the total of all costs under (i) above shall not exceed 10 per cent of the funds spent from time to time in accordance with Article 1.1. and British Gas and the Advisory Committee shall not be entitled to any credit or reimbursement for costs over that figure.

1.3 Consumers Gas, in consultation with the Advisory Committee shall submit annually to the Minister of Environment and Energy: a) a report prepared by its auditors detailing the degree to which the financial commitments in Article 1.1 have been fulfilled; and b) a report describing Consumers Gas' plans, and Undertakings regarding the financial commitment defined in Article 1.1.

At the request of the Minister of Environment & Energy, British Gas will provide to the Minister or Consumers Gas or its auditors any information in the power, possession or control of British Gas that the Minister may reasonably require related to compliance with these Undertakings.

1.4 Any and all commitments and obligations of British Gas and Consumers Gas pursuant to these Undertakings shall expire as of the earlier of:

(i) the date of which the sum of $10.0 million has been spent or committed in accordance with Article 1.1.; and

(ii) December 31, 2000, provided that British Gas shall remain obligated to pay all amounts committed for expenditure by such date.

1.5 The parties hereto agree to be bound by these Undertakings. These Undertakings are terms and conditions of the leave granted by the Lieutenant Governor in Council. Any proceeding or proceedings against British Gas to enforce these Undertakings may be brought and enforced in the courts of the Province of

Ontario and British Gas, its affiliates and associates hereby submit to the jurisdiction of the courts of the Province of Ontario in respect of any such proceeding or proceedings.

DATED this 16th day of June, 1994

BRITISH GAS PLC

Per:

THE CONSUMERS' GAS COMPANY LTD.

per:

ENBRIDGE GAS DISTRIBUTION INC.
(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2015

MANAGEMENT'S REPORT

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 related financial information, including Management's Discussion and Analysis. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors (the Board) and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (AF&RC) of the Board, includes directors who are unrelated and independent, and has a specific responsibility to oversee management's efforts to fulfill 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 U.S. GAAP 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.

(Signed)

Glenn W. Beaumont
President

(Signed)

William M. Ramos
Vice President, Finance & Regulatory

February 18, 2016

February 18, 2016

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, 2015 and December 31, 2014 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, 2015, 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 accounting principles generally accepted in the United States of America 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.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215, www.pwc.com/ca

pwc

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and their subsidiaries as at December 31, 2015 and December 31, 2014 and its results of operations and their cash flows for each of the three years in the period ended December 31, 2015 in accordance with accounting principles generally accepted in the United States of America.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Professional Accountants, Licensed Public Accountants

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	2015	2014	2013
(millions of Canadian dollars)			
Revenues			
Gas commodity and distribution revenue *(Note 21)*	**3,043**	2,803	2,221
Transportation of gas for customers	**344**	305	328
Other revenue *(Note 21)*	**97**	92	97
	3,484	3,200	2,646
Expenses			
Gas commodity and distribution costs *(Note 21)*	**2,322**	2,046	1,480
Operating and administrative *(Notes 19 and 21)*	**509**	493	496
Depreciation and amortization *(Notes 6 and 8)*	**290**	286	304
Earnings sharing *(Note 4)*	**7**	12	-
	3,128	2,837	2,280
	356	363	366
Other income *(Note 21)*	**70**	66	65
Interest expense, net *(Notes 10, 16 and 21)*	**(181)**	(177)	(171)
	245	252	260
Income taxes *(Note 17)*	**(11)**	(6)	(43)
Earnings	**234**	246	217
Preference share dividends *(Note 13)*	**(2)**	(2)	(2)
Earnings attributable to the common shareholder	**232**	244	215

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Earnings	**234**	246	217
Other comprehensive income/(loss), net of tax *(Notes 15 and 16)*			
Change in unrealized gain/(loss) on cash flow hedges	**(18)**	(62)	81
Reclassification to earnings of realized loss on cash flow hedges	**5**	-	1
Reclassification to earnings of unrealized gain on cash flow hedges	**-**	-	(2)
Actuarial gain/(loss) on other postretirement benefits (OPEB) *(Note 18)*	**-**	(7)	10
Change in foreign currency translation adjustment	**8**	3	1
Other comprehensive income/(loss)	**(5)**	(66)	91
Comprehensive income	**229**	180	308
Preference share dividends	**(2)**	(2)	(2)
Comprehensive income attributable to the common shareholder	**227**	178	306

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

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Preference shares *(Note 13)*	**100**	100	100
Common shares *(Note 13)*			
Balance at beginning of year	**1,437**	1,287	1,137
Common shares issued	**200**	150	150
Balance at end of year	**1,637**	1,437	1,287
Additional paid-in capital	**1,148**	1,148	1,148
Retained earnings			
Balance at beginning of year	**62**	22	7
Earnings attributable to the common shareholder	**232**	244	215
Common share dividends declared	**(223)**	(204)	(200)
Balance at end of year	**71**	62	22
Accumulated other comprehensive income/(loss) *(Note 15)*			
Balance at beginning of year	**(1)**	65	(26)
Other comprehensive income/(loss)	**(5)**	(66)	91
Balance at end of year	**(6)**	(1)	65
Total shareholders' equity	**2,950**	2,746	2,622

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Operating activities			
Earnings	**234**	246	217
Depreciation and amortization	**290**	286	304
Deferred income taxes	**16**	4	(9)
Refund of revenues *(Note 4)*	**(52)**	52	-
Non-cash net defined pension and OPEB obligations costs	**31**	(5)	2
Premium on issuance of term notes	**-**	-	12
Other	**(2)**	18	10
Changes in operating assets and liabilities *(Notes 3 and 20)*	**325**	(1,031)	(86)
	842	(430)	450
Investing activities			
Additions to property, plant and equipment	**(977)**	(601)	(519)
Additions to intangible assets	**(46)**	(36)	(34)
Change in construction payable	**151**	17	6
Proceeds from disposition	**8**	-	-
	(864)	(620)	(547)
Financing activities			
Change in bank indebtedness *(Note 3)*	**18**	9	(12)
Net change in short-term borrowings *(Note 10)*	**(340)**	564	(210)
Net change in short-term borrowing from affiliates *(Note 21)*	**(170)**	189	2
Term note issuance *(Note 10)*	**558**	729	400
Term note repayments	**(2)**	(400)	-
Common shares issued *(Note 13)*	**200**	150	150
Preference share dividends	**(2)**	(2)	(2)
Common share dividends	**(218)**	(203)	(200)
Other	**(3)**	(2)	(2)
	41	1,034	126
Increase/(decrease) in cash and cash equivalents	**19**	(16)	29
Cash and cash equivalents at beginning of year *(Note 3)*	**17**	33	4
Cash and cash equivalents at end of year	**36**	17	33
Supplementary cash flow information			
Income taxes paid	**17**	23	42
Interest paid *(Note 10)*	**193**	191	169

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

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2015**	2014
(millions of Canadian dollars, number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents *(Note 3)*	**36**	17
Accounts receivable and other *(Notes 4, 5, 16, and 17)*	**790**	1,178
Due from affiliates *(Note 21)*	**10**	11
Gas inventories	**547**	563
	1,383	1,769
Property, plant and equipment, net *(Notes 6 and 12)*	**7,081**	6,268
Investment in affiliate company *(Notes 16 and 21)*	**825**	825
Deferred amounts and other assets *(Notes 4, 7, and 17)*	**556**	738
Intangible assets, net *(Note 8)*	**157**	161
	10,002	9,761
Liabilities and shareholders' equity		
Current liabilities		
Bank indebtedness	**27**	9
Short-term borrowings *(Note 10)*	**599**	938
Short-term borrowings from affiliate *(Notes 10 and 21)*	**40**	204
Accounts payable and other *(Notes 3, 4, 9, 16, and 19)*	**870**	861
Due to affiliates *(Note 21)*	**87**	95
Current maturities of long-term debt *(Note 10)*	**2**	2
	1,625	2,109
Long-term debt *(Note 10)*	**3,681**	3,125
Other long-term liabilities *(Notes 4, 11, 12 and 16)*	**847**	943
Deferred income taxes *(Note 17)*	**524**	463
Loans from affiliate company *(Notes 10 and 21)*	**375**	375
	7,052	7,015
Commitments and contingencies *(Notes 21 and 22)*		
Shareholders' equity		
Share capital *(Note 13)*		
Preference shares *(convertible; 4 outstanding at December 31, 2015 and 2014)*	**100**	100
Common shares *(170 and 159 outstanding at December 31, 2015 and 2014, respectively)*	**1,637**	1,437
Additional paid-in capital	**1,148**	1,148
Retained earnings	**71**	62
Accumulated other comprehensive loss *(Note 15)*	**(6)**	(1)
	2,950	2,746
	10,002	9,761

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

Approved by the Board of Directors:

(Signed)

Glenn W. Beaumont
President

(Signed)

J. Herb England
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

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).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. The Company is permitted to prepare its consolidated financial statements in accordance with U.S. GAAP for purposes of meeting its Canadian continuous disclosure requirements under an exemption granted by securities regulators in Canada until 2018.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of consolidated financial statements in conformity with U.S. 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 4)*; unbilled revenues *(Note 5)*; allowance for doubtful accounts *(Note 5)*; carrying value of gas inventory; depreciation rates and carrying value of property, plant and equipment *(Note 6)*; amortization rates and carrying value of intangible assets *(Note 8)*; valuation of stock-based compensation *(Note 14)*; fair value of financial instruments *(Note 16)*; provisions for income taxes *(Note 17)*; assumptions used to measure retirement and OPEB *(Note 18);* commitments and contingencies *(Note 22)*; and fair value of asset retirement obligations (ARO) *(Note 12)*. Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its subsidiary. 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 ratemaking 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 U.S. GAAP for non rate-regulated entities *(Note 4)*.

REVENUE RECOGNITION

The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas commodity and 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. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's franchise areas.

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 approved by the Regulators. This may give rise to regulatory deferral accounts pending disposition by decisions of the Regulators.

PUSH-DOWN ACCOUNTING

The Company elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge, when it first adopted U.S. GAAP. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by the Company. Upon adopting push-down accounting, the historical cost of the Company's property, plant and equipment and related accounts was adjusted by the remaining unamortized fair value adjustment.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage its exposure to changes in 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 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 at December 31, 2015 or 2014.

Cash Flow Hedges

The Company uses cash flow hedges to manage its exposure to 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/loss (OCI) and is reclassified to earnings when the hedged item impacts earnings. 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 at that date is deferred in OCI and 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 derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives

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

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Consolidated Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments may be 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 Deferred amounts and other assets. 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. Deferred 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. Deferred 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 approved by the Regulators for rate-making purposes. As a result, rates do not include the recovery of deferred income taxes related to temporary differences. A corresponding deferred income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates (*Note 4*).

FOREIGN CURRENCY TRANSACTIONS AND 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, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the date of the Consolidated Statement of Financial Position. 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 functional currency of the Company's only foreign operation, St. Lawrence, is the United States dollar. The effects of translating the financial statements of St. Lawrence to Canadian dollars are included in the cumulative translation adjustment component of Accumulated other comprehensive income/loss (AOCI). Asset and liability accounts are translated at the exchange rates in effect on the date of the Consolidated Statement of Financial Position, while revenues and expenses are translated at monthly average rates.

CASH AND CASH EQUIVALENTS
Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased. Refer to Note 3 for changes in accounting policy.

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.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment is recorded at historical cost, including associated operating costs and an allowance for interest during construction at rates authorized by the Regulators. 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 a future benefit.

The pool method of accounting for property, plant and equipment is followed whereby similar assets with comparable useful lives are grouped and depreciated as a pool, as approved by the Regulators. 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 until the last asset in the pool is disposed of. Gains and losses from the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. 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.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily include: costs which the Regulators have permitted, or are expected to permit, to be recovered through future rates; deferred income taxes; derivative financial instruments; and deferred financing costs.

INTANGIBLE ASSETS

Intangible assets consist primarily of the Company's Customer Information System (CIS) and software costs. The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangible assets are amortized on a straight-line basis over their expected useful lives, commencing when the asset is available for use.

ASSET RETIREMENT OBLIGATIONS

ARO 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. ARO 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 ARO due to the indeterminate timing and scope of the asset retirements.

RETIREMENT AND POSTRETIREMENT 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 estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. In 2014, new mortality assumptions were issued and further revised in 2015. These assumptions were adopted by the Company for the measurement of the December 31, 2015 benefit obligations. The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans. Pension cost is charged to earnings and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of 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, changes in headcount 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 contributions occur.

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

The overfunded or underfunded status of defined benefit pension and OPEB plans is recognized as Deferred amounts and other assets or Other long-term liabilities, respectively, on the Consolidated Statements of Financial Position. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax.

The Company records regulatory adjustments to reflect the difference between pension expense and OPEB costs for accounting purposes and the pension expense and OPEB costs for rate-making purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension expense or OPEB costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation accounting, regulatory balances would not be recorded and pension and OPEB costs would be charged to earnings and OCI on an accrual basis.

STOCK-BASED COMPENSATION

Enbridge grants stock-based compensation to certain employees and senior officers of the Company through four long-term incentive compensation plans. Compensation expense associated with each of the plans, as determined under the methods outlined below is recognized in Operating and administrative expense. Amounts owing to Enbridge in respect of stock-based compensation are payable on a quarterly basis.

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 of the ISOs granted 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.

Performance Stock Units (PSU) and Restricted Stock Units (RSU) 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, compensation expense is recorded based on the number of units outstanding and the current market price of the Company's shares. The value of the PSUs is also dependent on the Company's performance relative to performance targets set out under the plan.

Performance Stock Options (PSO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the PSOs granted as calculated by the Bloomberg barrier option valuation model and is recognized over the vesting period. The options become exercisable when both performance targets and the time vesting requirements have been met.

COMMITMENTS AND CONTINGENCIES

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, the Company determines it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

FUTURE ACCOUNTING POLICY CHANGES

Measurement Date of Defined Benefit Obligation and Plan Assets

Accounting Standards Update (ASU) 2015-04 was issued in April 2015 with the intent to simplify the fair value measurement of defined benefit plan assets and obligations. Where there are significant events in an interim period that would trigger a re-measurement of the plan assets and obligations, an entity is permitted to re-measure such assets and obligations using the month end that is closest to the date of the significant event. The accounting update is effective for financial statements issued for fiscal years beginning after December 15, 2015 and is to be applied on a prospective basis. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

Simplifying the Presentation of Debt Issuance Costs
ASU 2015-03 was issued in April 2015 with the intent to simplify the presentation of debt issuance costs. The new standard requires a debt issuance cost related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, as consistent with the presentation of debt discounts or premiums. Further, ASU 2015-15 was issued in August 2015 to clarify the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements, whereby the Company may defer debt issuance costs as an asset and subsequently amortize them over the term of the line-of-credit. The accounting updates are effective for financial statements issued for fiscal years beginning after December 15, 2015 on a retrospective basis. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

Revenue from Contracts with Customers
ASU 2014-09 was issued in May 2014 with the intent of significantly enhancing comparability of revenue recognition practices across entities and industries. The new standard provides a single principles-based, five-step model to be applied to all contracts with customers and introduces new, increased disclosure requirements. In July 2015, the effective date of the new standard was delayed by one year and the new standard is now effective for annual and interim periods beginning on or after December 15, 2017 and may be applied on either a full or modified retrospective basis. The Company is currently assessing the impact of the new standard on its consolidated financial statements.

Classification of Deferred Taxes on the Statement of Financial Position
ASU 2015-17 was issued in November 2015 with the intent to simplify the presentation of deferred income taxes. The amendments eliminate the current requirement to present deferred tax assets and liabilities as current and noncurrent. The amendments require that all deferred tax assets and liabilities be classified as noncurrent in a classified statement of financial position. The accounting update is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years and is to be applied on a prospective basis. Early application is permitted for all entities as of the beginning of an interim or annual reporting period. Effective January 1, 2016, the Company will elect to early adopt ASU 2015-17. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

Recognition and Measurement of Financial Assets and Liabilities
ASU 2016-01 was issued in January 2016 with the intent to address certain aspects of recognition, measurement, presentation, and disclosure of financial assets and liabilities. The amendments revise accounting related to the classification and measurement of investments in equity securities, the presentation of certain fair value changes for financial liabilities measured at fair value, and the disclosure requirements associated with the fair value of financial instruments. The accounting update is effective for fiscal years beginning after December 15, 2017, and is to be applied by means of a cumulative-effect adjustment to the consolidated Statement of Financial Position as of the beginning of the fiscal year of adoption, with amendments related to equity securities without readily determinable fair values to be applied prospectively. The Company is currently assessing the impact of the new standard on its consolidated financial statements.

Simplifying the Measurement of Inventory
ASU 2015-11 was issued in July 2015 with the intent to simplify the measurement of inventory. The new standard requires inventory to be measured at the lower of cost and net realizable value and is applicable to all inventory, with the exception of inventory measured using last-in, first-out or the retail inventory method. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The new standard is effective for annual and interim reporting periods beginning after December 15, 2016 and is to be applied on a prospective basis.

CHANGES IN ACCOUNTING POLICY

Book Overdrafts
Prior to January 2015, the Company recorded all obligations for which cheques were issued but not presented to the financial institution in Accounts payable and other. Effective January 2015, the Company changed the accounting policy and began presenting only book overdrafts in Accounts payable and other. Comparative figures presented in the audited consolidated financial statements for the year ended December 31, 2015 have been retrospectively revised. The change in accounting policy did not have a material impact on the audited Consolidated Statements of Financial Position and audited Consolidated Statements of Cash Flows for previously issued financial statements. There was no impact to the audited Consolidated Statement of Earnings. The change in accounting policy allows for the Company to account for its book overdrafts in a preferable method.

4. 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.

RECENT RATE APPROVALS

Enbridge Gas Distribution
For the year ended December 31, 2015, Enbridge Gas Distribution’s rates were set according to the OEB approved settlement agreement (April 2015) and final rate order (May 2015). The rates approved as part of the 2015 rate application represented the second year of the Company’s customized incentive regulation (IR) plan, which set rates for the period of 2014 to 2018 and was approved by the OEB in July and August 2014.

For the year ended December 31, 2014, Enbridge Gas Distribution’s rates were set by the OEB’s July 2014 decision, and subsequent August 2014 decision and rate order in the Company’s customized IR application. The decisions and rate order established final 2014 allowed revenues and billing rates, as well as placeholder allowed revenues for 2015 through 2018. The customized IR plan requires Enbridge Gas Distribution to update select items in each of 2015 through 2018, in order to establish final allowed revenues and rates. The customized IR decision also approved the adoption of a new approach for determining net negative salvage percentages as a component of the Enbridge Gas Distribution’s depreciation rates in addition to Enbridge Gas Distribution shares earnings above the approved base return, equally with customers.

Under the customized IR plan, the Company has continued to apply the accounting guidance found in Accounting Standards Codification (ASC) 980 – Regulated Operations.

For the year ended December 31, 2013, Enbridge Gas Distribution’s rates were set on a cost of service (COS) basis pursuant to an OEB approved settlement agreement.

St. Lawrence Gas
For the years ended December 31, 2015, 2014 and 2013, St. Lawrence’s rates were set using a COS methodology. Under COS, revenues are set to recover costs and to earn a rate of return on the deemed common equity component of rate base. Costs include natural gas commodity and transportation, operating and administrative, depreciation and amortization, interest and income taxes. 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. Gas costs are not recovered through revenue rates, but are set separately in gas cost rates.

Under COS, it is the responsibility of Enbridge Gas Distribution and St. Lawrence to demonstrate to the Regulators the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken.

During the years ended December 31, 2015, 2014 and 2013, the cost of natural gas was passed on to customers as a flow-through.

APPROVED RETURNS ON EQUITY

Enbridge Gas Distribution

Enbridge Gas Distribution's rates for 2015 included an after-tax rate of return on common equity of 9.30% (2014 - 9.36% and 2013 - 8.93%) based on a 36% (2014 and 2013 - 36%) deemed common equity component of rate base.

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, 2015 (2014 and 2013 - 10.5%) based on a 50% (2014 and 2013 - 50%) deemed common equity component of rate base. Any earnings above a return on equity of 11% (2014 and 2013 - 11%) were shared equally with customers. The calculation of such earnings was cumulative from January 1, 2010 to December 31, 2015 and resulted in no sharing impact as at December 31, 2015 (2014 and 2013 - nil).

IMPACTS OF RATE REGULATION

Regulatory Assets and Liabilities

As a result of rate regulation accounting, 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 accounting, 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. The Regulators' future actions may differ from current expectations or future legislative changes may impact the regulatory environment in which the Company operates. To the extent that the Regulators' future actions are different from current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

FINANCIAL STATEMENT EFFECTS

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

December 31,	**2015**	2014	Consolidated Statement of Financial Position Location**	Estimated Recovery/ Settlement Period *(years)*
(millions of Canadian dollars)				
Regulatory assets/(liabilities)				
Enbridge Gas Distribution				
Deferred income taxes[1]	**324**	270	AP/DA	*
Purchased gas variance[2]	**129**	673	AR	1
OPEB[3]	**75**	84	AR/DA	17
Unabsorbed demand cost[4]	**66**	14	AR	*
Constant dollar net salvage adjustment[5]	**42**	37	DA	*
Pension plans, net[6]	**30**	90	DA/OLTL	*
Customer care CIS rate smoothing deferral[7]	**9**	8	AR/DA	3
Demand side management incentive[8]	**8**	13	AR	*
Storage and transportation deferral[9]	**5**	(3)	AR	1
Unaccounted for gas variance[10]	**3**	13	AR	1
Design day criteria transportation[11]	**-**	13	-	*
Revenue adjustment[12]	**-**	(52)	-	*
Future removal and site restoration reserves[13]	**(553)**	(536)	OLTL	*
Site restoration clearance adjustment[14]	**(193)**	(283)	AP/OLTL	3
Transactional services deferral[15]	**(9)**	(26)	AP	1
Earnings sharing deferral[16]	**(6)**	(12)	AP	*
Average use true-up variance[17]	**(2)**	1	AP	1
Post-retirement true-up variance[18]	**(1)**	(3)	AP	*
Other regulatory assets and liabilities, net	**3**	(1)	***	***
	(70)	300		
St. Lawrence				
Other regulatory assets and liabilities, net	**6**	5	***	***
	(64)	305		

* 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 deferred income taxes balance represents the regulatory offset to deferred 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 the temporary differences. In the absence of rate regulation accounting, this regulatory balance and the related earnings impact would not be recorded.*

2 *Purchased gas variance (PGVA) 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 on a rolling 12 month basis via the Quarterly Rate Adjustment Mechanism process. In May 2014, the OEB issued a decision allowing a portion of the PGVA balance as at June 30, 2014 to be recovered over a 24-month period from July 1, 2014 to June 30, 2016. In the absence of rate regulation accounting, 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.*

3 *The OPEB balance represents the Company's right to recover OPEB costs pursuant to an OEB rate order, which allows the amount as at December 31, 2013 to be collected in rates over a 20-year period commencing in 2013. In the absence of rate regulation accounting, this regulatory balance and related earnings impact would not be recorded.*

4 *The Unabsorbed demand cost deferral account (UDCDA) represents the actual cost consequences of unutilized transportation capacity contracted by Enbridge Gas Distribution to meet requirements resulting from its Peak Gas Design Day Criteria (PGDDC). Enbridge Gas Distribution updated its PGDDC in 2013 and 2014. The impact of this update was phased in equally over the two years.*

The balance for 2014 captures the cost consequences of unutilized transportation capacity above the amount associated with the 2014 Design day criteria transportation deferral account (DDCTDA). In the absence of rate regulation accounting, these costs would be expensed as incurred.

5 *The Constant dollar net salvage adjustment represents the cumulative variance between the amount proposed for clearance and the actual amount cleared, relating specifically to the site restoration clearance adjustment. At the end of 2018 any residual balance will be cleared in a post 2018 true up, ensuring that the actual amount cleared is equivalent to the required $380 million.*

6 *The pension plan balance represents the regulatory offset to the pension liability/asset to the extent the amounts are to be collected/refunded in future rates. The settlement period for this balance is not determinable. In the absence of rate regulation accounting, this regulatory balance would not be recorded and pension expense would have been charged to earnings and OCI based on the accrual basis of accounting.*

7 *Customer care CIS rate smoothing deferral represents the difference between the forecast costs and the approved costs for customer care and CIS reflected in rates. The balance accumulated during 2013 to 2015 when the cost per customer exceeds the cost approved for recovery in rates. The balance will be drawn down during 2016 to 2018 when the cost per customer will be lowered than the cost approved for recovery in rates. Enbridge Gas Distribution has received OEB approval to collect from or refund to customers any remaining balance after 2018. In the absence of rate regulation accounting, the variance would be included in earnings in the year incurred.*

8 *Demand side management incentive deferral account (DSMIDA) 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 DSMIDA 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 accounting.*

9 *Storage and transportation deferral represents the difference between the actual cost and the approved cost of natural gas storage and transportation reflected in rates. Enbridge Gas Distribution has historically been granted OEB approval to collect this balance from or to refund this balance to customers, generally in the subsequent year. In the absence of rate regulation accounting, the actual cost of natural gas storage and transportation 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.*

10 *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 accounting, this variance would be included in earnings in the year incurred.*

11 *DDCTDA balance represents the actual cost consequences of unutilized transportation capacity contracted by Enbridge Gas Distribution to meet increased requirements resulting from the PGDDC. Enbridge Gas Distribution updated its PGDDC in 2013 and 2014. The impact of this update was phased in equally over the two years. The heating degree days used within its design day criteria for 2013 and 2014's design day criteria were updated. The balance for 2014 captures the cost consequences of unutilized transportation capacity associated with the 2014 DDCTDA. In the absence of rate regulation accounting, these costs would be expensed as incurred.*

12 *The revenue adjustment represents the revenue variance between interim rates, which were in place from January 2014 to September 2014, and the final OEB approved 2014 rates, which were implemented in October 2014, but effective in January 2014. The revenue adjustment balance is the 2014 OEB approved revenue adjustment amount that was refunded to customers in January 2015. There would be no change in the treatment of this item in the absence of rate regulation accounting.*

13 *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 that is recorded in rates. 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 accounting, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

14 *The Site restoration clearance adjustment represents the amount, that was determined by the OEB, of previously collected costs for future removal and site restoration that is now considered to be in excess of future requirements and will be refunded to customers over the customized IR term. This was a result of the OEB's approval of the adoption of a new approach for determining net negative salvage percentages. The new approach resulted in lower depreciation rates and lower future removal and site restoration reserves. There would be no change in the treatment of this item in the absence of rate regulation accounting.*

15 *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 accounting.*

16 *Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the customized IR plan. The Earnings sharing is payable to customers and represents 50% of normalized U.S. GAAP utility earnings represented by an ROE in*

excess of the allowed utility ROE applicable to Enbridge Gas Distribution, as determined for each year of the customized IR plan. There would be no change in the treatment of this item in the absence of rate regulation accounting.

17 *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 weather 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 accounting, this regulatory balance and the related earnings impact would not be recorded.*

18 *Post-retirement true-up variance is the difference between the actual cost and the approved cost of pension and OPEB 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 subsequent year, up to a maximum of $5 million per year. Any amounts in excess of $5 million per year will be deferred for refund or collection in the next subsequent year. In the absence of rate regulation accounting, the variance would be included in earnings in the year incurred.*

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 accounting, a portion of such operating costs would be charged to earnings in the year incurred.

The Company entered into a services 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, 2015, cumulative costs relating to this services contract of $174 million (2014 - $166 million) were included in gas mains and are being depreciated over the average service life of 25 years. In the absence of rate regulation accounting, some of these costs would be charged to earnings in the year incurred.

Property, Plant and Equipment

In the absence of rate regulation accounting, 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/disposal 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, 2015, the net book value of these costs was $48 million (2014 - $60 million). In the absence of rate regulation accounting, 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. Included in gas inventories at December 31, 2015 is $40 million (2014 - $42 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 accounting, these costs would be expensed as incurred and inventory would be recorded at the lower of cost or market value.

Depreciation

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

5. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2015**	2014
(millions of Canadian dollars)		
Trade receivables	**309**	372
Regulatory assets *(Note 4)*	**216**	567
Unbilled revenues	**151**	161
Agent billing and collection receivable	**39**	-
Sundry receivables	**28**	22
Taxes receivable	**19**	28
Current deferred income taxes *(Note 17)*	**18**	23
Prepaid expenses	**11**	8
Other	**33**	30
Allowance for doubtful accounts *(Note 16)*	**(34)**	(33)
	790	1,178

During the first half of 2014, increases in natural gas prices and colder than normal weather resulted in the Company accumulating a significant balance in its PGVA. Included in Regulatory assets as at December 31, 2015 is $129 million (December 31, 2014 - $491 million) which represents the PGVA balance that is expected to be recovered from customers within the next 12 months.

6. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2015**	2014
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas mains	**2.2%**	**3,740**	3,593
Gas services	**2.3%**	**2,929**	2,798
Regulating and metering equipment	**5.7%**	**848**	825
Gas storage	**2.1%**	**327**	323
Right-of-way	**1.0%**	**52**	52
Computer technology	**37.5%**	**31**	40
Under construction	**-**	**893**	307
Construction materials inventory	**-**	**40**	39
Land	**-**	**24**	24
Other	**6.9%**	**303**	289
		9,187	8,290
Accumulated depreciation		**(2,197)**	(2,115)
		6,990	6,175
Unregulated property, plant and equipment			
Gas storage	**2.1%**	**88**	88
Other	**8.6%**	**27**	27
		115	115
Accumulated depreciation		**(24)**	(22)
		91	93
Property, plant and equipment, net		**7,081**	6,268

Depreciation expense, including amounts collected for future removal and site restoration costs, was $239 million for the year ended December 31, 2015 (2014 - $237 million, 2013 - $267 million).

7. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2015**	2014
(millions of Canadian dollars)		
Regulatory assets *(Note 4)*	**526**	711
Deferred financing costs	**13**	12
Pension and OPEB asset *(Note 18)*	**8**	4
Deferred income taxes *(Note 17)*	**8**	8
Other	**1**	3
	556	738

At December 31, 2015, deferred financing costs of $29 million (2014 - $34 million) were subject to amortization and are presented net of accumulated amortization of $16 million (2014 - $22 million). Amortization expense for the year ended December 31, 2015 was $2 million (2014 and 2013 - $2 million).

In May 2014, the OEB issued a decision allowing a portion of the PGVA balance as at June 30, 2014 to be recovered over a 24-month period from July 1, 2014 to June 30, 2016. Included in Regulatory assets at December 31, 2015 is nil (2014 - $182 million) which represents the portion of the PGVA balance that is expected to be recovered beyond the next 12 months.

8. INTANGIBLE ASSETS

December 31, 2015	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	**23.2%**	**238**	**(129)**	**109**
CIS	**10.0%**	**127**	**(79)**	**48**
		365	**(208)**	**157**

December 31, 2014	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	24.1%	198	(97)	101
CIS	10.0%	127	(67)	60
		325	(164)	161

Intangible assets include $61 million of work-in-progress as at December 31, 2015 (2014 - $23 million). Total amortization expense for intangible assets was $51 million for the year ended December 31, 2015 (2014 - $49 million, 2013 - $37 million). The Company expects aggregate amortization expense for the years ending December 31, 2016 through 2020 of $58 million, $47 million, $45 million, $41 million and $32 million, respectively.

9. ACCOUNTS PAYABLE AND OTHER

December 31,	**2015**	2014
(millions of Canadian dollars)		
Accrued liabilities	**396**	351
Regulatory liabilities *(Note 4)*	**136**	233
Budget billing plan payable	**105**	137
Trade payables	**62**	17
Security deposits	**61**	61
Contractual holdbacks	**38**	7
Interest payable	**33**	27
Short-term portion of derivative liabilities *(Note 16)*	**14**	6
Taxes payable	**9**	11
Current portion of OPEB liability *(Note 18)*	**4**	4
Agent billing and collection payable	**-**	2
Dividends payable	**1**	1
Other	**11**	4
	870	861

Included in Regulatory liabilities at December 31, 2015 is $84 million (2014 - $90 million) relating to the portion of site restoration clearance adjustment that is expected to be refunded to customers within the next 12 months. Also included in Regulatory liabilities at December 31, 2015 is nil (2014 - $52 million) relating to the refund of revenues to customers.

10. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2015**	2014
(millions of Canadian dollars)				
Debenture	9.85%	2024	**85**	85
Medium-term notes	4.56%	2017-2050	**3,595**	3,025
Commercial paper and credit facility draws, net[1]			**607**	1,122
Other[2]			**35**	37
Total debt			**4,322**	4,269
Current maturities			**(2)**	(2)
Short-term borrowings	0.81%		**(599)**	(938)
Short-term borrowings from affiliates *(Note 21)*	0.80%		**(40)**	(204)
Long-term debt			**3,681**	3,125
Loans from affiliate company *(Note 21)*			**375**	375

1 *Includes amounts drawn on uncommitted demand credit facilities.*
2 *Consists of note payable to affiliate company and debt premium.*

In September 2015, the Company issued $400 million of 10-year medium-term notes at an interest rate of 3.31% and an additional $170 million of medium-term notes under the same terms as the August 2044 30-year medium-term note pricing supplement issued in August 2014 at an interest rate of 4.00%.

In December 2015, a new $1.5 billion shelf prospectus was filed as a continuation of the Company's medium-term note program, which was previously renewed in June 2014. The prospectus is effective for a 25-month period.

For the years ending December 31, 2016 through 2020, medium-term note maturities are $2 million, $502 million, $2 million, $2 million and $400 million, respectively. The Company's debentures and medium-term notes bear interest at fixed rates, and interest obligations for the years ending December 31, 2016 through 2020 are $171 million, $169 million, $156 million, $156 million and $155 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Debentures and medium-term notes	**158**	149	138
Loans from affiliate company *(Note 21)*	**27**	29	27
Commercial paper and credit facility draws	**8**	9	4
Other interest and finance costs	**9**	(4)	9
Capitalized	**(21)**	(6)	(7)
	181	177	171

In 2015, total interest paid to third parties was $166 million (2014 - $163 million, 2013 - $142 million) and total interest paid to affiliate company and related party was $27 million (2014 - $29 million, 2013 - $27 million).

The Company's borrowings, whether debentures or medium-term notes, are unsecured. As at December 31, 2015, the Company was in compliance with all covenants.

CREDIT FACILITIES

The Company currently has a $1 billion commercial paper program limit that is backstopped by committed lines of credit of $1 billion. The term of any commercial paper issued under this program may not exceed one year. The maturity date of the credit facility may be extended annually for an additional year from the end of the applicable revolving term, at the lender's option. In July 2015, the Company extended the term out date of this external credit facility to July 2016, with a maturity date in July 2017.

The Company also has a $300 million revolving credit facility from Enbridge. In June 2015, the Company extended the term out date to May 2016 on this revolving credit facility, with a maturity date in May 2017. As at December 31, 2015, no amounts were drawn on this credit facility.

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

				December 31, 2015	December 31, 2014
	Maturity Dates	Total Facilities[1]	Draws[2]	Available	Total Facilities[1]
(millions of Canadian dollars)					
Enbridge Gas Distribution Inc.	2017	**1,300**	**595**	**705**	1,300
St. Lawrence Gas Company, Inc.	2019	**10**	**8**	**2**	8
Total credit facilities		**1,310**	**603**	**707**	1,308

1 *Includes a $300 million revolving credit facility from the Company's ultimate parent, Enbridge and matures in May 2017.*
2 *Includes facility draws and commercial paper issuances, net of discount, that are backstopped by the external credit facility.*

In addition to the committed credit facilities noted above, St. Lawrence also has $7 million (2014 - $6 million) of uncommitted demand credit facilities, of which $3 million (2014 - $2 million) was unutilized as at December 31, 2015.

Credit facilities carried a weighted average standby fee of 0.2% on the unused portion and draws bear interest at market rates.

11. OTHER LONG-TERM LIABILITIES

December 31,	**2015**	2014
(millions of Canadian dollars)		
Regulatory liabilities *(Note 4)*	**670**	740
Pension and OPEB liabilities *(Note 18)*	**163**	190
Long-term portion of derivative liabilities *(Note 16)*	**-**	5
Other *(Note 12)*	**14**	8
	847	943

Included in Regulatory liabilities at December 31, 2015 is $109 million (2014 - $193 million) relating to the portion of site restoration clearance adjustment that is expected to be refunded to customers beyond the next 12 months.

12. ASSET RETIREMENT OBLIGATIONS

The liability for the expected cash flows as recognized in the consolidated financial statements reflected discount rates ranging from 1.65% to 3.77% (2014 - 1.65% to 3.77%). A reconciliation of movements in the Company's ARO is as follows:

December 31,	**2015**	2014
(millions of Canadian dollars)		
Obligations at beginning of year	**9**	6
Liabilities settled	**(2)**	-
Change in estimate	**2**	3
Accretion expense	**-**	-
Obligations at end of year	**9**	9
Presented as follows:		
Other long-term liabilities *(Note 11)*	**9**	9
	9	9

13. 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 preference shares.

COMMON SHARES

	2015		2014		2013	
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	**158.9**	**1,437**	150.6	1,287	142.3	1,137
Common shares issued	**11.1**	**200**	8.3	150	8.3	150
Balance at end of year	**170.0**	**1,637**	158.9	1,437	150.6	1,287

PREFERENCE SHARES

December 31, 2015, 2014, and 2013	Authorized	Issued and Outstanding	Amount
(millions of Canadian dollars, number of preference shares in millions)			
Group 1	0.2	-	-
Group 2, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 2, Series D, Cumulative Redeemable Convertible	4	-	-
Group 3, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible	4	4	100
Group 4	10	-	-
Group 5	10	-	-
			100

Floating adjustable cumulative cash dividends on the Group 3, Series D preference 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 preference shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case. As at December 31, 2015, no preference shares have been redeemed.

On July 1, 2019, and every five years thereafter, the Group 3, Series D preference shares can be converted, at the holder's option, into Group 2, Series D preference 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 3, Series D preference shareholders opted not to convert their shares into Group 2, Series D preference shares effective July 1, 2014.

The Group 2, Series D preference shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preference shares can also be converted into Group 3, Series D preference shares on a one-for-one basis at the holder's option on July 1, 2019 and every five years thereafter.

14. STOCK OPTION AND STOCK UNIT PLANS

Enbridge's four long-term incentive compensation plans include the ISO Plan, the PSO Plan, the PSU Plan and the RSU Plan. The Company reimburses Enbridge for stock-based compensation costs associated with its employees on a quarterly basis. As of December 31, 2015, the Company did not have any employees that had options in the PSO Plan.

INCENTIVE STOCK OPTIONS

Key employees of the Company 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.

December 31, 2015	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(options in thousands; exercise price and intrinsic value in Canadian dollars)				
Options outstanding at beginning of year	**2,665**	**33.53**		
Options granted	**458**	**59.08**		
Options exercised[1]	**(422)**	**23.20**		
Options cancelled	**(16)**	**44.94**		
Employee movements from other Enbridge companies	**3**	**18.24**		
Options outstanding at end of year	**2,688**	**39.43**	**6.3**	**45**
Options vested at end of year[2]	**1,560**	**30.85**	**4.9**	**40**

1 *The total intrinsic value of ISOs exercised during the year ended December 31, 2015 was $14 million (2014 - $11 million; 2013 - $7 million) and cash received by Enbridge on exercise was $10 million (2014 - $5 million; 2013 - $2 million).*
2 *The total fair value of options vested under the ISO Plan during the year ended December 31, 2015 was $2 million (2014 and 2013 - $2 million).*

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

Year ended December 31,	**2015**	2014	2013
Fair value per option *(Canadian dollars)*[1]	**6.48**	5.53	5.27
Valuation assumptions			
Expected option term *(years)*[2]	**5**	5	5
Expected volatility[3]	**19.9%**	16.9%	17.4%
Expected dividend yield[4]	**3.2%**	2.9%	2.8%
Risk-free interest rate[5]	**0.9%**	1.6%	1.2%

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 and the Canadian options. The fair values per option were $6.22 (2014 - $5.45; 2013 - $5.15) for Canadian employees and US$6.22 (2014 - US$5.35, 2013 - US$5.63) 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 and consideration of the implied volatility observable in call option values near the grant date.*
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 the United States Treasury Bond Yields.*

Compensation expense recorded for the year ended December 31, 2015 for ISOs was $4 million (2014 - $4 million; 2013 - $3 million). At December 31, 2015, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO Plan was $4 million. The cost is expected to be fully recognized over a weighted average period of approximately three years.

PERFORMANCE STOCK UNITS

Enbridge has a PSU Plan for senior officers of the Company 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 share price for 20 days prior to the maturity of the grant 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 2013, 2014 and 2015 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 earnings per share, adjusted for unusual non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2015 expense, multipliers of two, based upon multiplier estimates at December 31, 2015, were used for each of the 2013, 2014 and 2015 PSU grants.

December 31, 2015	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**26**		
Units granted	**14**		
Units matured[1]	**(11)**		
Dividend reinvestment	**1**		
Units outstanding at end of year	**30**	**1.5**	**3**

1 The total amount paid by Enbridge during the year ended December 31, 2015 for PSUs was $2 million (2014 - $1 million; 2013 - $2 million).

Compensation expense recorded for the year ended December 31, 2015 for PSUs was $2 million (2014 - $5 million; 2013 - $4 million). As of December 31, 2015, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $2 million and is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Enbridge has a 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 for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2015	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**196**		
Units granted	**81**		
Units cancelled	**(9)**		
Units matured[1]	**(96)**		
Dividend reinvestment	**10**		
Employee movements from other Enbridge companies	**2**		
Units outstanding at end of year	**184**	**1.4**	**11**

1 The total amount paid by Enbridge during the year ended December 31, 2015 for RSUs was $5 million (2014 and 2013 - $5 million).

Compensation expense recorded for the year ended December 31, 2015 for RSUs was $6 million (2014 and 2013 - $5 million). As of December 31, 2015, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $6 million and is expected to be fully recognized over a weighted average period of approximately two years.

15. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in AOCI for the years ended December 31, 2015, 2014 and 2013, are as follows:

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of Canadian dollars)				
Balance at January 1, 2015	**8**	**(2)**	**(7)**	**(1)**
Other comprehensive income retained in AOCI	**(24)**	**8**	**-**	**(16)**
Other comprehensive loss reclassified to earnings	**6**	**-**	**-**	**6**
Income tax on amounts retained in AOCI	**6**	**-**	**-**	**6**
Income tax on amounts reclassified to earnings	**(1)**	**-**	**-**	**(1)**
	(13)	**8**	**-**	**(5)**
Balance at December 31, 2015	**(5)**	**6**	**(7)**	**(6)**

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(*millions of Canadian dollars*)				
Balance at January 1, 2014	70	(5)	-	65
Other comprehensive income/(loss) retained in AOCI	(84)	3	(9)	(90)
Other comprehensive income reclassified to earnings	-	-	-	-
Income tax on amounts retained in AOCI	22	-	2	24
	(62)	3	(7)	(66)
Balance at December 31, 2014	8	(2)	(7)	(1)

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of Canadian dollars)				
Balance at January 1, 2013	(10)	(6)	(10)	(26)
Other comprehensive income retained in AOCI	109	1	14	124
Other comprehensive loss reclassified to earnings	(1)	-	-	(1)
Income tax on amounts retained in AOCI	(28)	-	(4)	(32)
	80	1	10	91
Balance at December 31, 2013	70	(5)	-	65

16. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

MARKET RISK

The Company's earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates and natural gas prices (collectively, market 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 risks to which the Company is exposed and the risk management instruments used to mitigate them.

Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates.

The Company generates certain revenues, and holds a subsidiary that is denominated in a currency other than Canadian dollars. As a result, the Company's earnings, cash flows, and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

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 in the exchange rate 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 Company has no net exposure to movements in the foreign exchange rate on natural gas purchases.

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 mitigate the volatility of short-term interest rates on interest expense related to variable rate debt.

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 mitigate the Company's exposure to long-term interest rate variability on select forecast term debt issuances. The Company uses qualifying derivative instruments to manage interest rate risk.

The Company's portfolio mix of fixed and variable rate debt instruments is monitored by its ultimate parent company, Enbridge. The Company does not typically manage the fair value of its debt instruments.

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. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by the customer, therefore, the net exposure to the Company is nil (2014 - nil).

TOTAL DERIVATIVE INSTRUMENTS
The following table summarizes the Consolidated Statements of Financial Position location and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value or net investment hedges at December 31, 2015 or 2014.

The Company generally has a common practice of entering into individual International Swaps and Derivatives Association, Inc. (ISDA) agreements, or other similar derivative agreements, with the majority of its 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 those particular circumstances. The following table also summarizes the maximum potential settlement amount in the event of those specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2015	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts payable and other					
Interest rate contracts	**(14)**	**-**	**(14)**	**-**	**(14)**
Other long-term liabilities					
Interest rate contracts	**-**	**-**	**-**	**-**	**-**
Total net derivative liability					
Interest rate contracts	**(14)**	**-**	**(14)**	**-**	**(14)**

December 31, 2014	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts payable and other					
Interest rate contracts	(6)	-	(6)	-	(6)
Other long-term liabilities					
Interest rate contracts	(5)	-	(5)	-	(5)
Total net derivative liability					
Interest rate contracts	(11)	-	(11)	-	(11)

The Company's derivatives instruments mature through 2017 and have a notional principal of $154 million for interest rate contracts for short-term borrowings (2014 - $346 million), and $162 million for interest rate contracts on long-term debt (2014 - $422 million).

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on the Company's consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Amount of unrealized (loss)/gain recognized in OCI			
Cash flow hedges			
Interest rate contracts	**(24)**	(84)	109
	(24)	(84)	109
Amount of loss reclassified from AOCI to earnings *(effective portion)*			
Interest rate contracts[1]	**(2)**	-	(2)
	(2)	-	(2)
Amount of (loss)/gain reclassified from AOCI to earnings *(ineffective portion)*			
Interest rate contracts[1]	**(4)**	-	2
	(4)	-	2

1 Reported within Interest expense, net in the Consolidated Statements of Earnings.

The Company estimates that $3 million in AOCI 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. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 13 months at December 31, 2015.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments *(Notes 21 and 22)* 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, draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes, and, if necessary, additional liquidity is available through intercompany transactions with its ultimate parent, Enbridge, and other related entities. These sources are expected to be sufficient to enable the Company to fund all anticipated requirements. The Company maintains a current MTN shelf prospectus with securities regulators, which enables ready access to the Canadian public capital markets, subject to market conditions. In addition to the Company's access to the Canadian public capital markets, the Company maintains committed credit facilities *(Note 10)* with a diversified group of banks and institutions. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2015. 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.

CREDIT RISK

The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is 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 receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts *(Note 5),* which totaled $34 million at December 31, 2015 (December 31, 2014 - $33 million).

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.

Entering into derivative financial instruments may also result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Company enters into risk management transactions primarily 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.

Derivative assets are adjusted for non-performance risk of the Company's counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

The Company did not have group credit concentration and maximum credit exposure, with respect to derivative instruments, in the Canadian financial institutions or European financial institutions counterparty segments at December 31, 2015 and 2014.

FAIR VALUE MEASUREMENTS

The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. 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.

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 does not have any derivative instruments classified as Level 1.

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 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. The Company does not have any derivative instruments classified as Level 3.

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, the Company uses observable market prices (interest and natural gas) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

At December 31, 2015, the Company had Level 2 derivative assets with fair value of nil (2014 - nil), and Level 2 derivative liabilities with fair value of $14 million (2014 - $11 million).

The Company's policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers as at December 31, 2015 or 2014.

Fair Value of Other Financial Instruments

The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted market prices are not available for fair value measurement in which case these investments are recorded at cost. The Company's investment in IPL System Inc., an affiliate company, is recorded at fair value. At December 31, 2015, the fair value of the investment was $825 million (2014 - $825 million). The fair value of the Company's investment is classified as a Level 2 measurement and as of December 31, 2015 and 2014 the fair value approximated its cost and redemption value and therefore no amount was recognized in OCI.

The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor, and is classified as a Level 2 measurement. At December 31, 2015, the Company's long-term debt had a carrying value of $3,683 million (2014 - $3,127 million) and a fair value of $4,159 million (2014 - $3,709 million).

The fair value of other financial assets and liabilities other than derivative instruments approximates their cost due to the short period to maturity.

17. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	2015	2014	2013
(millions of Canadian dollars)			
Earnings before income taxes	**245**	252	260
Federal statutory income tax rate	**15.0%**	15.0%	15.0%
Federal income taxes at statutory rate	**37**	38	39
Increase/(decrease) resulting from:			
Provincial and state income taxes	**5**	3	19
Effects of rate regulated accounting[1]	**(22)**	(25)	(5)
Non-taxable intercompany distributions	**(9)**	(9)	(9)
Other[2]	**-**	(1)	(1)
Income taxes	**11**	6	43
Effective income tax rate	**4.5%**	2.4%	16.5%

1 *During 2015 and 2014, previously collected costs for future removal and site restoration were refunded to customers that resulted in a decrease in income taxes of $24 million at December 31, 2015 (2014 - $26 million).*

2 *Included in "Other" are miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals & entertainment, and change in prior year estimates arising from the filing of tax returns in respect of the prior year.*

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	2015	2014	2013
(millions of Canadian dollars)			
Earnings before income taxes			
Canada	**243**	249	258
United States	**2**	3	2
	245	252	260
Current income taxes			
Canada	**(4)**	2	51
United States	**(1)**	1	1
	(5)	3	52
Deferred income taxes			
Canada	**14**	3	(9)
United States	**2**	-	-
	16	3	(9)
Income taxes	**11**	6	43

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are:

December 31,	**2015**	2014
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(600)**	(577)
Financial derivatives	**-**	(3)
Regulatory assets	**(86)**	(72)
Other	**(1)**	(1)
Total deferred income tax liabilities	**(687)**	(653)
Deferred income tax assets		
Future removal and site restoration reserves	**146**	143
Deferrals	**-**	53
Retirement and postretirement benefits	**30**	21
Minimum tax credits	**9**	-
Financial derivatives	**2**	-
Other	**2**	4
Total deferred income tax assets	**189**	221
Net deferred income tax liabilities	**(498)**	(432)
Presented as follows:		
Assets		
Accounts receivable and other *(Note 5)*	**18**	23
Deferred amounts and other assets *(Note 7)*	**8**	8
Total deferred income tax assets	**26**	31
Liabilities		
Deferred income taxes	**(524)**	(463)
Total deferred income tax liabilities	**(524)**	(463)
Net deferred income tax liabilities	**(498)**	(432)

The Company has assessed all tax positions. As a result, no significant adjustments were required to be made to the income tax provisions for the year ended December 31, 2015.

The Company has not provided for deferred income taxes on the difference between the carrying value of its foreign subsidiaries and their corresponding tax bases as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying value of the investment and its tax basis is largely a result of unremitted earnings and currency translation adjustments. The unremitted earnings and currency translation adjustment for which no deferred taxes have been recognized in respect of foreign subsidiaries is $30 million (2014 - $21 million). If such earnings were remitted, in the form of dividends or otherwise, the Company may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is not practicable.

The Company and its subsidiaries are subject to taxation in Canada and the Unites States. The material jurisdictions in which the Company is subject to potential examinations include Canada (Federal and Ontario). The Company's 2011 to 2014 taxation years are still open for audit in Canada.

18. RETIREMENT AND POSTRETIREMENT BENEFITS

PENSION PLANS

The Company maintains a non-contributory basic pension plan that provides either defined benefit or defined contribution pension benefits to the majority of its employees. The Company has two supplemental non-contributory defined benefit pension plans that provide pension benefits in excess of the basic plan for certain employees.

A measurement date of December 31, 2015 was used to determine the plan assets and accrued benefit obligation for the pension 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 date of the most recent actuarial valuation was December 31, 2013. The effective date of the next required actuarial valuation is December 31, 2016.

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.

OTHER POSTRETIREMENT BENEFITS
The Company also provides OPEB, which primarily includes supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

BENEFIT OBLIGATIONS AND FUNDED STATUS
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		OPEB	
December 31,	**2015**	2014	**2015**	2014
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**1,046**	875	**117**	100
Service cost	**35**	25	**1**	2
Interest cost	**41**	43	**5**	6
Actuarial loss/(gain)	**(54)**	142	**(1)**	12
Benefits paid	**(43)**	(41)	**(4)**	(3)
Other	**-**	2	**2**	-
Benefit obligation at end of year	**1,025**	1,046	**120**	117
Change in plan assets				
Fair value of plan assets at beginning of year	**960**	866	**13**	9
Actual return on plan assets	**49**	96	**-**	2
Employer's contributions	**3**	41	**5**	5
Benefits paid	**(43)**	(41)	**(4)**	(3)
Other	**-**	(2)	**3**	-
Fair value of plan assets at end of year	**969**	960	**17**	13
Underfunded status at end of year	**(56)**	(86)	**(103)**	(104)
Presented as follows:				
Deferred amounts and other assets *(Note 7)*	**6**	4	**2**	-
Accounts payable and other *(Note 9)*	**-**	-	**(4)**	(4)
Other long-term liabilities *(Note 11)*	**(62)**	(90)	**(101)**	(100)

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

	Pension			OPEB		
Year ended December 31,	**2015**	2014	2013	**2015**	2014	2013
Discount rate	**4.2%**	4.0%	5.0%	**4.2%**	4.0%	5.0%
Average rate of salary increases	**3.4%**	3.7%	3.5%	**3.4%**	3.7%	3.5%

NET BENEFIT COSTS RECOGNIZED

	Pension			OPEB		
Year ended December 31,	**2015**	2014	2013	**2015**	2014	2013
(millions of Canadian dollars)						
Benefits earned during the year	**35**	25	25	**1**	1	1
Interest cost on projected benefit obligations	**41**	43	38	**5**	6	4
Expected return on plan assets	**(62)**	(59)	(52)	**(1)**	(1)	(1)
Amortization of prior service costs	**-**	-	1	**-**	-	-
Amortization of actuarial loss	**19**	16	28	**1**	-	2
Net defined benefit costs on an accrual basis	**33**	25	40	**6**	6	6
Defined contribution benefit costs	**1**	1	1	**-**	-	-
Net benefit cost recognized on an accrual basis	**34**	26	41	**6**	6	6
Net amount recognized in OCI						
Net actuarial (gain)/loss[1]	**-**	-	-	**-**	9	(14)
Total amount recognized in OCI	**-**	-	-	**-**	9	(14)
Total net benefit cost on an accrual basis and amount recognized in OCI	**34**	26	41	**6**	15	(8)

1 *Unamortized actuarial losses included in AOCI, before tax, were $9 million relating to OPEB at December 31, 2015 (2014 - $9 million, 2013 - nil).*

The Company estimates that approximately $13 million related to pension plans and OPEB at December 31, 2015 will be reclassified into earnings in the next 12 months, as follows:

	Pension Benefits	OPEB	Total
(millions of Canadian dollars)			
Actuarial loss	**13**	**-**	**13**
	13	**-**	**13**

Pension and OPEB costs related to the period on an accrual basis are presented above and were initially expensed. However, there was a partially offsetting adjustment for pension and OPEB costs due to the regulatory mechanism in place. As a result, the net pension and OPEB expense primarily consists of OEB approved pension and OPEB costs.

Regulatory adjustments were recorded in the Consolidated Statements of Earnings, the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension or OPEB costs or gains are expected to be collected from or refunded to customers, respectively, in future rates *(Note 4)*. For the year ended December 31, 2015, an offsetting regulatory asset of nil (2014 - regulatory liability of $6 million) has been recorded to the extent pension and OPEB costs are expected to be collected from customers in future rates.

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

	Pension			OPEB		
Year ended December 31,	**2015**	2014	2013	**2015**	2014	2013
Discount rate	**4.0%**	5.0%	4.3%	**4.0%**	5.0%	4.3%
Average rate of return on pension plan assets	**6.8%**	6.8%	6.8%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.7%**	3.5%	3.5%	**3.7%**	3.5%	3.5%

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	7.7%	4.3%	2029
Other medical and dental	4.5%	4.5%	-

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $12 million in the benefit obligation 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 $10 million in the benefit obligation and a decrease of $1 million in benefit and interest costs.

PLAN ASSETS

The Company manages the investment risk of its 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.

Expected Rate of Return on Plan Assets

	Pension		OPEB	
Year ended December 31,	**2015**	2014	**2015**	2014
Expected rate of return	**6.8%**	6.8%	**-**	-

Target Mix for Plan Assets

Equity securities	44.5%
Fixed income securities	40.0%
Other	15.5%

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, 2015, the pension assets were invested in 47% (2014 - 55%) in equity securities, 36% (2014 - 36%) in fixed income securities and 17% (2014 - 9%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $29 million (2014 - $18 million) have been excluded from the table below.

	2015				2014			
December 31,	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	**10**	**-**	**-**	**10**	14	-	-	14
Fixed income securities								
Canadian government real return bonds	**73**	**-**	**-**	**73**	71	-	-	71
Canadian corporate bond index fund	**133**	**-**	**-**	**133**	137	-	-	137
Canadian government bond index fund	**128**	**-**	**-**	**128**	131	-	-	131
Corporate bonds and debentures	**4**	**-**	**-**	**4**	4	-	-	4
United States debt index fund	**2**	**-**	**-**	**2**	2	-	-	2
Equity								
Canadian equity securities	**71**	**-**	**-**	**71**	71	-	-	71
Canadian equity funds	**128**	**-**	**-**	**128**	137	-	-	137
United States equity securities	**1**	**-**	**-**	**1**	1	-	-	1
United States equity funds	**100**	**-**	**-**	**100**	77	19	-	96
Global equity funds	**71**	**79**	**-**	**150**	149	63	-	212
Infrastructure[4]	**-**	**-**	**96**	**96**	-	-	30	30
Real estate[5]	**-**	**-**	**51**	**51**	-	-	39	39
Forward currency contracts	**-**	**(7)**	**-**	**(7)**	-	(3)	-	(3)
	721	**72**	**147**	**940**	794	79	69	942
OPEB								
Cash and cash equivalents	**1**	**-**	**-**	**1**	1	-	-	1
Fixed income securities								
United States government and government agency bonds	**6**	**-**	**-**	**6**	5	-	-	5
Equity								
United States equity fund	**5**	**-**	**-**	**5**	4	-	-	4
Global equity fund	**5**	**-**	**-**	**5**	3	-	-	3
	17	**-**	**-**	**17**	13	-	-	13

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 and IFM Global Infrastructure (Canada) L.P. are established through the use of valuation models.
5 The fair value of the investment in Bentall Kennedy Prime Canadian Property Fund Ltd and MetLife Core Property Fund L.P. are 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:

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Balance at beginning of year	**69**	67
Unrealized and realized gains	**26**	15
Purchases and settlements, net	**52**	(13)
Balance at end of year	**147**	69

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension		OPEB	
Year ended December 31,	**2015**	2014	**2015**	2014
(millions of Canadian dollars)				
Total contributions	**4**	41	**5**	5

The contributions expected to be paid in 2016 for pension is $4 million and for OPEB is $4 million.

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2016	2017	2018	2019	2020	2021-2025
(millions of Canadian dollars)						
Expected future benefit payments	48	50	52	54	56	310

19. SEVERANCE COSTS

Included in Operating and administrative expense is $12 million in severance costs related to one-time termination benefits to employees. This resulted from an Enbridge-wide reduction of workforce that occurred in November 2015 that affected approximately 5% of Enbridge's workforce.

In 2015, $4 million was paid with the remaining $8 million to be paid in 2016 and is included in Accounts payable and other as at December 31, 2015.

20. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Regulatory assets	**532**	(732)	(31)
Regulatory liabilities[1]	**(178)**	(102)	2
Accounts receivable and other[2,3]	**34**	24	(13)
Gas inventories	**17**	(181)	(41)
Deferred amounts and other assets[2]	**-**	(3)	(2)
Accounts payable and other[2,3]	**(84)**	(92)	80
Other long-term liabilities[2]	**4**	55	(81)
	325	(1,031)	(86)

1 *Excludes the refund of revenues paid to customers in January 2015.*
2 *The cash flow impacts of regulatory assets and liabilities have been separately disclosed and are not included.*
3 *Includes amounts related to affiliated companies.*

21. RELATED PARTY TRANSACTIONS

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

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Enbridge Energy Distribution Inc.			
Common share dividends declared	**223**	204	200
IPL System Inc. *(Note 16)*			
Dividend income	**63**	63	63
Interest expense *(Note 10)*	**27**	27	27
Enbridge			
Purchase of treasury and other management services	**50**	41	38
Interest expense *(Note 10)*	**-**	2	-
Tidal Energy Marketing Inc.			
Purchase of natural gas	**23**	41	30
Revenue from optimization services	**7**	7	4
Tidal Energy Marketing (U.S.) LLC			
Purchase of natural gas	**24**	57	21
Aux Sable Canada LP			
Purchase of natural gas	**62**	16	-
Gazifère Inc.			
Revenue from wholesale service, including gas sales	**40**	31	30
Vector Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**28**	27	24
Vector Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**2**	2	2
Alliance Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**28**	26	26
Alliance Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**22**	20	19
Niagara Gas Transmission Limited			
Purchase of gas transportation services	**2**	2	2

The Company had related party balances as follows:

December 31,	**2015**	2014
(millions of Canadian dollars)		
Common share ownership from parent company		
Enbridge Energy Distribution Inc.	**1,637**	1,437
Dividend payable	**56**	51
Investment in affiliate company		
IPL System Inc.	**825**	825
Dividend receivable	**5**	5
Loans from affiliate company		
IPL System Inc.	**375**	375
Interest payable	**2**	2
Note payable to affiliate company		
Enbridge (U.S.)	**40**	29
Credit facility to affiliate company		
Enbridge	**-**	175
Other accounts receivable/(payable)		
Gazifère Inc.	**3**	6
Enbridge Employee Services Inc.	**(13)**	-
Enbridge	**(4)**	(7)
Tidal Energy Marketing (U.S.) LLC	**(4)**	(3)
Alliance Pipeline Limited Partnership (Canadian)	**(2)**	(2)
Aux Sable Canada LP	**(2)**	(8)
Alliance Pipeline Limited Partnership (U.S.)	**(2)**	(2)
Vector Pipeline Limited Partnership (U.S.)	**(1)**	(2)
Enbridge Pipelines Inc.	**-**	(15)
Tidal Energy Marketing Inc.	**-**	(3)
Other accounts receivable	**2**	-
Other accounts payable	**(1)**	-

Financing Transactions
The Company has invested in Class D, non-voting, redeemable, retractable preference shares of IPL System Inc., an affiliate under common control. At December 31, 2015, the investment of $825 million (2014 - $825 million) in these shares resulted in a weighted average dividend yield of 7.60%.

At December 31, 2015, 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 preference shares of the Company. For the year ended December 31, 2015, interest paid amounted to $27 million (2014 - $27 million).

The Company has a $300 million revolving credit facility with Enbridge with a maturity date in May 2017. At December 31, 2015, the total drawings on the revolving credit facility were nil (2014 - $175 million). For the year ended December 31, 2015, interest paid amounted to nil (2014 - $2 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 on a cost recovery basis.

Natural Gas Purchases
The Company has contracted for the purchase of natural gas from Aux Sable Canada LP, Tidal Energy Marketing Inc. and Tidal Energy Marketing (U.S.) LLC, related entities under common control, at prevailing market prices and under normal trade terms. Contractual obligations under these contracts are nil.

Wholesale Service
These gas procurement and transportation 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, and Niagara Gas Transmission Limited. Contractual obligations under these contracts are 2016 to 2017 - $71 million, 2018 to 2019 - $20 million and thereafter - nil.

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 shared corporate services to affiliates on a fully-allocated cost basis. Market prices, if they are reasonably determinable, are charged for affiliate services that are not shared corporate services. 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
The Company and affiliates invoice on a monthly basis and amounts are due and paid on a monthly basis.

22. COMMITMENTS AND CONTINGENCIES

COMMITMENTS
The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $5,722 million. The amounts which are expected to be paid in the next five years are $1,354 million, $942 million, $595 million, $566 million, and $487 million, respectively, and $1,778 million thereafter.

Minimum future payments under operating leases are estimated at $4 million in aggregate. Estimated annual lease payments for the years ended December 31, 2016 through 2020 are $4 million, nil, nil, nil and nil, respectively. Total rental expense for operating leases, classified in Operating and administrative expense, was $3 million for each of the years ended December 31, 2015, 2014 and 2013.

The Company, Enbridge, and Enbridge Pipeline Inc., in aggregate, have access to $95 million of letters of credit that they can issue, of which $37 million was unutilized as of December 31, 2015. The total outstanding letters of credit that related to the Company as of December 31, 2015 was $5 million. The Company had access to $75 million of letters of credit that it could issue, of which $51 million was unutilized as of December 31, 2014. The total outstanding letters of credit that related to the Company as of December 31, 2014 was $24 million.

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, a former owner of part of the Historic Distillery District (Wyndham Court Canada Inc.) commenced an action in the Ontario Court of Justice (General Division) against the Company alleging that coal tar originating from the Company's Station A MGP in Toronto had migrated to its lands. The Company entered into a Tolling Agreement with Wyndham Court Canada Inc. pursuant to which this action was discontinued, without prejudice to the right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham Court Canada Inc. 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 the required steps in the discovery process were not completed by the plaintiff. The Company has brought a motion to dismiss the plaintiff's action for delay. At present, it is unknown when or if 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 2015 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs 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.

OTHER LITIGATON

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 significant impact on the Company's consolidated financial position or results of operations.

A Spectra Energy Company

uniongas
A Spectra Energy Company

Stephen W. Baker
President

March 3, 2016

Dear Shareholder:

I am pleased to forward you a copy of the Union Gas Limited (Union Gas) 2015 Annual Report. It contains Union Gas' Management's Discussion and Analysis, Management Responsibility for Financial Reporting, Financial Statements, and Corporate Directory. I invite you to visit www.sedar.com for electronic versions of Union Gas' Financial Statements, Management's Discussion and Analysis, and other filings throughout the year.

Stephen W. Baker

President

INTRODUCTION

The terms "we," "our," "us" and "Union Gas" as used in this report refer to Union Gas Limited unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Union Gas. On June 1, 2015, Union Gas dissolved its subsidiary, Huron Tipperary Limited Partnership I (HTLP), transferring HTLP's assets and liabilities to Union Gas with no material financial impact to Union Gas. Comparative figures for 2014 are shown consolidated with HTLP.

This Management's Discussion and Analysis (MD&A) for the twelve months ended December 31, 2015, should be read in conjunction with the audited Financial Statements and accompanying notes. The results reported herein have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP) and are presented in millions of Canadian dollars, except where noted. Additional information relating to us, including our most recent Annual Information Form, can be found at www.sedar.com.

In 2014, Canadian securities regulators approved the extension of our exemptive relief to continue reporting under U.S. GAAP instead of International Financial Reporting Standards (IFRS) until the earlier of January 1, 2019, and the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this document to provide readers with information about Union Gas, including management's assessment of Union Gas' future plans and operations. This information may not be appropriate for other purposes. This document includes forward-looking statements. Forward-looking statements are based on management's intentions, plans, expectations, beliefs and assumptions about future events. These forward-looking statements are typically identified by terms and phrases such as: anticipate, believe, intend, estimate, expect, continue, should, could, may, likely, plan, project, predict, will, potential, forecast, target and similar words suggesting future outcomes or statements regarding an outlook. Although Union Gas believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and the 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. Material assumptions used to develop these forward-looking statements include assumptions about: the supply and demand for natural gas; prices of natural gas; inflation; interest rates; the results and costs of financing efforts; expected future cash flows; expected earnings/(loss); expected costs related to projects under construction; expected capital expenditures; estimated future dividends; expected costs related to leak remediation and potential insurance recoveries; the availability and price of labour and construction materials; operational reliability; the ability to successfully complete merger, acquisition or divestiture plans; anticipated in-service dates and weather.

Forward-looking statements are subject to risks, uncertainties and other factors, many of which are outside our control and could cause actual results to differ materially from the results expressed or implied by those forward-looking statements. 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 Union Gas' future course of action depends on management's assessment of all information available at the relevant time. Factors used to develop these forward-looking statements and that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- local, provincial and federal legislative and regulatory initiatives that affect cost and investment recovery, have an effect on rate structure, and affect the speed at and degree to which competition enters the natural gas industries;
- outcomes of litigation and regulatory investigations, proceedings or inquiries;

- weather and other natural phenomena, including the economic, operational and other effects of storms;
- the timing and extent of changes in commodity prices and interest rates;
- general economic conditions, including the risk of a prolonged economic slowdown or decline, or the risk of delay in a recovery, which can affect the long-term demand for natural gas and related services;
- potential effects arising from terrorist attacks and any consequential or other hostilities;
- changes in environmental, safety and other laws and regulations;
- the development of alternative energy resources;
- results of financing efforts, including the ability to obtain financing on favourable terms, which can be affected by various factors, including credit ratings and general market and economic conditions;
- increases in the cost of goods and services required to complete capital projects;
- declines in the market prices of equity and debt securities and resulting funding requirements for defined benefit pension plans;
- growth in opportunities, including the timing and success of efforts to develop pipeline, storage, and other related infrastructure projects and the effects of competition;
- the performance of natural gas storage, transmission and distribution facilities;
- sensitivity to variances in the commodity measurement process;
- the extent of success in connecting new natural gas supplies to Ontario transmission systems and in connecting to expanding gas markets;
- the effects of accounting pronouncements issued periodically by accounting standard-setting bodies;
- conditions of the capital markets during the periods covered by these forward-looking statements; and
- the ability to successfully complete merger, acquisition or divestiture plans; regulatory or other limitations imposed as a result of a merger, acquisition or divestiture; and the success of the business following a merger, acquisition or divestiture.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. We undertake no obligation to publicly update or revise any forward-looking statements made in this document or otherwise, whether as a result of new information, future events or otherwise, except as required by applicable securities law. All subsequent forward-looking statements, whether written or oral, attributable to Union Gas or persons acting on Union Gas' behalf, are expressly qualified in their entirety by these cautionary statements.

GENERAL

Union Gas is a major Canadian natural gas storage, transmission and distribution company based in Ontario with over 100 years of experience and service to customers. The distribution business serves about 1.4 million residential, commercial and industrial customers in more than 400 communities across northern, southwestern and eastern Ontario. Union Gas' storage and transmission business offers a variety of storage and transportation services to customers at the Dawn Hub (Dawn), the largest integrated underground storage facility in Canada and one of the largest in North America. Effective November 1, 2015, Union Gas' transmission system has an effective peak daily demand capacity of 6.7 billion cubic feet per day (Bcf/d).

Dawn offers customers an important link in the movement of natural gas from western Canadian and United States (U.S.) supply basins to markets in central Canada and the northeast U.S. Key pipeline interconnects in Canada and the U.S. have enabled us to deliver approximately 735 billion cubic feet (Bcf) of gas through our transmission system in 2015. A substantial amount of Union Gas' annual transportation and storage revenue is generated by fixed demand charges. The average length of these long-term contracts is approximately seven years, with the longest remaining contract term being 14 years.

As the supply of affordable natural gas in areas close to Ontario continues to grow, there is an increased demand to access these diverse supplies at Dawn and transport them along the Dawn-Parkway pipeline system to markets in Ontario, eastern Canada and the U.S. northeast. To secure the continued reliable delivery of natural gas and to serve a growing demand for clean, affordable natural gas, Union Gas plans to invest approximately $1.5 billion between 2015 and 2017 to expand the Dawn-Parkway natural gas transmission system. This will increase the takeaway capacity from Dawn by approximately 20 percent or from 6.3 Bcf/d in 2014 to more than 7.5 Bcf/d by 2017.

Our distribution system consists of approximately 65,000 kilometres (km) of main and service pipelines. Our distribution pipelines carry natural gas from the point of local supply to customers. Our underground natural gas storage facilities have a working capacity of approximately 160 Bcf in 23 underground facilities located in depleted gas fields. The transmission system consists of approximately 4,800 km of high-pressure pipeline and five mainline compressor stations.

Union Gas' common stock is held by Great Lakes Basin Energy L.P. (GLBE), a wholly-owned limited partnership of Westcoast Energy Inc. (Westcoast). Westcoast is an indirect wholly-owned subsidiary of Spectra Energy Corp (Spectra Energy).

Spectra Energy is a Delaware corporation that is a public company in the U.S. and whose common stock is listed on the New York Stock Exchange.

Our board of directors (the Board) is comprised of at least one-third independent directors with the remainder consisting of officers of Union Gas, Westcoast or Spectra Energy. There is no audit committee of the Board. The function of the audit committee is carried out at the level of Spectra Energy during the review of its Consolidated Financial Statements.

HIGHLIGHTS

($millions except where noted)	For the Years Ended December 31, **2015**	2014	2013
Income			
Total operating revenues	**1,939**	2,042	1,899
Net income applicable to common stock	**185**	192	204
Dividends			
Dividends on preferred stock	**3**	3	3
Dividends on common stock	**50**	100	149
Assets and long-term liabilities[(a)]			
Total assets	**7,190**	7,034	6,375
Total long-term liabilities	**4,321**	3,958	3,607
Volumes of gas (10^6m^3)[(b)]			
Distribution volumes	**13,881**	14,748	14,546
Transportation volumes	**20,824**	19,696	25,181
Total throughput	**34,705**	34,444	39,727
Customers *(thousands)*	**1,437**	1,419	1,399
Heating degree days[(c)] *(degree Celsius)*			
Actual	**4,104**	4,506	4,189
Normal[(d)]	**3,969**	3,929	3,981

(a) 2014 amounts restated due to debt issuance costs reclassification. See New Accounting Pronouncements section for additional details.

(b) 10^6m^3 equals millions of cubic metres. One cubic metre is equivalent to 35.30096 cubic feet.

(c) A heating degree day is a measure of temperature that identifies the need for heating. A heating degree day occurs when the average daily temperature falls below 18 degrees Celsius. A temperature of zero degrees Celsius on a particular day equals 18 heating degree days.

(d) As per Ontario Energy Board approved methodology used in setting rates.

DIVIDENDS

	For the Years Ended December 31, **2015**	2014	2013
Per Common Stock	**$0.86**	$1.73	$2.58
Per Class A Preferred Stock			
5.5% Series A	**$2.75**	$2.75	$2.75
6% Series B	**$3.00**	$3.00	$3.00
5% Series C	**$2.50**	$2.50	$2.50
Per Class B Preferred Stock			
4.88% Series 10	**$0.56**	$0.60	$0.60

RESULTS OF OPERATIONS

	Three Months Ended December 31,			Twelve Months Ended December 31,		
($millions)	2015	2014	**Increase (Decrease)**	2015	2014	**Increase (Decrease)**
Gas sales and distribution revenue	421	505	**(84)**	1,675	1,755	**(80)**
Cost of gas	205	297	**(92)**	875	977	**(102)**
Gas distribution margin	216	208	**8**	800	778	**22**
Storage and transportation revenue	60	57	**3**	239	266	**(27)**
Other revenue, net	11	13	**(2)**	26	21	**5**
	287	278	**9**	1,065	1,065	—
Expenses	193	182	**11**	692	678	**14**
Interest expense	39	39	—	157	156	**1**
Income tax expense	7	7	—	28	36	**(8)**
Net income	48	50	**(2)**	188	195	**(7)**
Net income applicable to common stock	47	49	**(2)**	185	192	**(7)**

Three months ended December 31, 2015 compared to three months ended December 31, 2014

Gas sales and distribution revenue. The $84 million decrease was mainly driven by:

- an $87 million decrease in residential customer usage of natural gas primarily due to weather that was warmer than in 2014,
- a $19 million decrease from lower natural gas prices passed through to customers without a mark-up. Prices charged to customers are adjusted quarterly based on the 12 month New York Mercantile Exchange (NYMEX) forecast and
- a $6 million decrease in industrial market usage, partially offset by
- a $14 million increase from lower earnings to be shared with customers in accordance with the incentive regulation framework and
- a $14 million increase from growth in the number of customers.

Cost of gas. The $92 million decrease was mainly driven by:

- a $67 million decrease due to lower volumes of natural gas sold to residential customers primarily due to warmer weather,
- a $19 million decrease from lower natural gas prices passed through to customers,
- an $8 million decrease in operating fuel costs primarily due to gas measurement variances and
- a $6 million decrease in industrial market usage, partially offset by
- a $10 million increase from growth in the number of customers.

Expenses. The $11 million increase was mainly driven by higher operating and maintenance expense and higher depreciation expense due to new projects placed into service.

Twelve months ended December 31, 2015 compared to twelve months ended December 31, 2014

Gas sales and distribution revenue. The $80 million decrease was mainly driven by:

- a $128 million decrease in residential customer usage of natural gas primarily due to weather that was warmer than in 2014 and
- a $14 million decrease from lower natural gas prices passed through to customers without a mark-up, partially offset by

- a $35 million increase from growth in the number of customers,
- a $15 million increase related to the 2014 increase in earnings to be shared with customers as a result of the March 2014 Ontario Energy Board (OEB) decision regarding the treatment of certain 2012 revenues realized from the optimization of upstream transportation contracts as utility earnings, as described below under the heading Storage and transportation revenue and
- a $9 million increase from lower earnings to be shared with customers in accordance with the incentive regulation framework.

Cost of gas. The $102 million decrease was mainly driven by:

- a $105 million decrease due to lower volumes of natural gas sold to residential customers primarily due to warmer weather,
- a $14 million decrease from lower natural gas prices passed through to customers and
- a $9 million decrease in operating fuel costs primarily due to gas measurement variances, partially offset by
- a $22 million increase from growth in the number of customers.

Storage and transportation revenue. The $27 million decrease was mainly driven by a $32 million increase in 2014 transportation revenues as a result of the March 2014 OEB decision regarding the treatment of certain 2012 revenues realized from the optimization of upstream transportation contracts as utility earnings that were included in the prior year.

Other revenue, net. The $5 million increase was mainly the result of a decision by the OEB in March 2014 disallowing a proposal to establish a new deferral clearing variance account to capture differences between deferral balances approved for disposition and amounts prospectively refunded to or recovered from customers.

Expenses. The $14 million increase was mainly driven by higher depreciation expense due to new projects placed into service.

Income taxes. The $8 million decrease was mainly driven by:

- a $6 million decrease due to a lower effective tax rate and
- a $2 million decrease due to lower pre-tax income.

QUARTERLY RESULTS

($millions)	Q1 2014	Q2 2014	Q3 2014	Q4 2014	Q1 2015	Q2 2015	Q3 2015	Q4 2015
Gas sales and distribution revenue	690	337	223	505	752	292	210	421
Storage and transportation revenue	104	50	55	57	63	59	57	60
Other revenue, net	(2)	5	5	13	5	5	5	11
Total operating revenues	792	392	283	575	820	356	272	492
Net income (loss)	132	15	(2)	50	126	18	(4)	48
Net income (loss) applicable to common stock	131	15	(3)	49	125	18	(5)	47

Seasonal Trends

The natural gas distribution business is highly seasonal due to volume-based rates and the significant effect of the winter heating season on volumes. This is typically reflected in strong first quarter results, second and third quarters that show either small profits or losses and strong fourth quarter results, subject to the impact of weather variations relative to demand during the winter heating season. Changes in natural gas rates that are charged to customers result in corresponding changes in gas sales and distribution revenue. These increases or decreases in gas sales revenue are completely offset in the cost of gas as a result of the associated regulatory recovery and refund mechanisms.

REGULATORY MATTERS

Union Gas is regulated by the OEB pursuant to the provisions of the *Ontario Energy Board Act, (1998)*, which is part of a package of legislation known as the *Energy Competition Act, (1998)*. This legislation provides for different forms of regulation and competition in the energy (electricity and natural gas) industry in Ontario. We are subject to regulation with respect to the rates that we may charge our customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting practices.

Rate Regulation

Our distribution rates, beginning January 1, 2014, are set under a five-year incentive regulation framework. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The framework allows for:

- annual inflationary rate increases, offset by a productivity factor of 60% of inflation, such that the annual net rate escalator in each year is 40% of inflation,
- rate increases or decreases in the small volume customer classes where average use declines or increases,
- certain adjustments to base rates,
- the continued pass-through of gas commodity, upstream transportation and demand side management costs,
- the additional pass-through of costs associated with major capital investments and certain fuel variances,
- an allowance for unexpected cost changes that are outside of management’s control,
- equal sharing of tax changes between Union Gas and our customers, and
- an earnings sharing mechanism that permits Union Gas to fully retain the return on equity from utility operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.

In September 2015, we filed an application with the OEB for new rates effective January 1, 2016, pursuant to our incentive regulation framework. In December 2015, the OEB approved the application with an implementation date of January 1, 2016. The impact on a typical residential customer ranges from a decrease of $3 to $10 annually, depending on the customer's location within our service territory.

Annual Deferral Account Disposition

In April 2015, we filed an application with the OEB for the annual disposition of the 2014 deferral account balances and earnings sharing amount. The combined impact was a net receivable from customers of approximately $2 million. In August 2015, a decision from the OEB was received approving recovery from ratepayers effective October 1, 2015.

Demand Side Management (DSM)

In January 2016, the OEB issued its decision on Union Gas' 2015-2020 DSM plan. The decision approved Union Gas' 2015 budget as filed and found that Union Gas had appropriately applied the OEB's DSM framework's $2 per month bill impact guidance as part of its 2016-2020 DSM budgets. The approved DSM budget is $57 million for 2016 and will increase up to $64 million by 2020. Under the OEB guidelines, Union Gas’ maximum shareholder incentive is approximately $10 million annually for 2016-2020. A mid-term review is to be completed by June 1, 2018 to assess the natural gas utilities’ performance and the appropriateness of the long-term DSM targets.

In December 2015, we filed an application with the OEB for the disposition of the 2014 DSM deferral and variance account balances. As a result of this application, Union Gas has a receivable from customers of approximately $11 million which is reflected as Accounts receivable, net on the Balance Sheets at December 31, 2015 and December 31, 2014. A hearing and decision from the OEB is expected in 2016.

Commodity Rates

Union Gas and the OEB have a mechanism in place to change gas commodity rates on a quarterly basis (Quarterly Rate Adjustment Mechanism), to ensure that customers' rates reflect future expected prices to the extent reasonably possible. The difference between the approved and the actual cost of gas incurred is deferred for future recovery from or repayment to customers. These differences are included in quarterly gas commodity rates and recovered from or refunded to customers over the subsequent twelve months. This allows us to adjust customers' rates closer to the time costs are incurred.

Parkway Projects

In April 2015, the OEB approved the construction and related rate recovery of the Dawn to Parkway 2016 Expansion Project. This project involves the installation of a new compressor at the existing Lobo Compressor Station (Lobo), modifications to existing facilities at Lobo and construction of a pipeline from the Hamilton Valve Site to the Milton Valve Site along our Dawn to Parkway system. These facilities will provide incremental capacity on our Dawn to Parkway transmission system and are supported by signed contracts with our customers. The total capital cost of the facilities is projected to be approximately $400 million with service to customers expected in the fall of 2016. The Lobo Compressor Station construction commenced in May 2015 and the construction of the pipeline is expected to begin in May 2016 with service to customers expected in the fall of 2016.

In December 2015, the OEB approved the rate recovery of the Dawn to Parkway 2017 Expansion Project. This project involves the installation of a new compressor and associated facilities at each of our Dawn, Lobo and Bright Compressor Stations to provide incremental capacity on our Dawn to Parkway transmission system and is supported by signed contracts with our customers. The total capital cost of the facilities is expected to be approximately $623 million with service to customers expected in the fourth quarter of 2017. The construction of the three new compressors commenced in January 2016.

Burlington-Oakville Pipeline

In December 2015, the OEB approved the construction and rate recovery of a new transmission pipeline to serve the growing demands in the Burlington-Oakville area. The total capital cost of the pipeline is expected to be approximately $120 million with service to customers expected in the fall of 2016. The construction of the new transmission pipeline is expected to commence in the second quarter of 2016.

OEB Consultation on Pensions and Other Post-employment Benefits (OPEBs)

In May 2015, the OEB invited interested rate-regulated utilities, in both the gas and electricity sectors, to participate in a consultation on pensions and OPEBs. The objectives of the consultation are to develop standard principles to guide the OEB's review of pension and OPEB costs in the future, to establish specific information requirements for applications and to establish appropriate regulatory mechanisms for cost recovery which can be applied consistently across the gas and electricity sectors for rate-regulated utilities. In May 2015, Union Gas filed its intent to participate with the OEB. Initial written submissions were filed in July 2015. At this time, it is too early to assess any potential impacts as a result of this review.

Community Expansion

In response to a request from the Ontario Minister of Energy, the OEB invited all parties with the financial and technical expertise interested in distributing natural gas to unserved rural and remote communities in Ontario to submit an application for consideration pertaining to expansion portfolios and specific projects. In July 2015, Union Gas submitted its community expansion application which outlines a proposal for regulatory flexibility regarding project economics, a temporary expansion surcharge for new customers, an incremental tax equivalent contribution from municipalities and a capital pass-through mechanism that would allow Union Gas to expand its systems to serve over 30 communities that would otherwise not have access to natural gas.

In January 2016, the OEB issued a notice that Union Gas' application would be put on hold pending a generic proceeding on the distribution of natural gas to unserved rural and remote communities in Ontario. The generic proceeding will consider possible alternative ratemaking frameworks to provide natural gas service to these communities. The OEB has announced an oral hearing to be held in April 2016. At this time, it is too early to assess any potential impacts as a result of the generic proceeding.

GAS SUPPLY

The gas supply portfolio of Union Gas primarily includes gas supply purchase contracts that are typically based on an index, depending on where Union Gas sources natural gas from across North America. This includes, but is not limited to, indices such as NYMEX, Alberta, and Chicago.

Natural gas markets in North America have been substantially transformed in recent years by the declining supplies from Alberta, and the emergence of unconventional supplies, such as Marcellus and Utica Shale gas and U.S. Rocky Mountain gas. The amount of gas economically available for export from Alberta on TransCanada PipeLines Limited's (TransCanada) Mainline to eastern Canada and the U.S. has steadily declined in recent years. Supplies from the emerging shale gas plays in the east are displacing western supplies and, as a result, are changing the way gas has been traditionally transported.

Security and reliability of gas supply are very important to Union Gas. One mechanism to help achieve security and reliability is through having a diverse gas supply portfolio. We continue to monitor and evaluate the new and changing natural gas supply dynamics to determine what opportunities exist for our customers. We have taken steps to allow for the emerging Marcellus and Utica Shale gas supplies to be delivered to Dawn to serve our Ontario sales service customers. In December 2015, the OEB approved our application for pre-approval of the cost consequences of entering into a long-term transportation capacity contract with the Nexus Gas Transmission pipeline (NEXUS) commencing November 1, 2017. The NEXUS project is being jointly developed by DTE Energy Company and Spectra Energy. This contract will transport gas from the Marcellus and Utica Shale areas through Michigan and into Ontario.

The overall increase in domestic natural gas supply in North America resulting from shale gas development has led to the current and projected low and more stable natural gas prices.

OUTLOOK

Gas Sales and Distribution

We expect that the long-term demand for natural gas in Ontario will remain relatively stable with continued growth in peak day demands, subject to the impacts of governmental actions to reduce greenhouse gas (GHG) emissions. Some modest growth driven by low natural gas prices is expected to continue, with specific interest coming from communities that are not currently serviced by natural gas, given the significant price advantage relative to their alternate energy options.

We continue to focus on promoting conservation and energy efficiency by undertaking activities focused on reducing natural gas consumption through our various DSM programs offered across all markets. For 2015, we rolled forward our 2014 DSM plan and spent $32 million. For 2016, we plan to spend approximately $57 million and the approved DSM budget will increase up to $64 million by 2020. We are also pursuing other opportunities to assist in lowering GHG emissions. Union Gas and Enbridge Gas Distribution Inc. (Enbridge) recently announced plans to work with the government of Ontario to deliver a home renovation program valued in total at $100 million over 3 years.

Storage and Transportation

The storage and transportation marketplace continues to respond to changing natural gas supply dynamics including a robust supply environment. In recent years, the robust North American gas supply balance has resulted in lower commodity prices and narrow seasonal price spreads. Unregulated storage values are determined based on the difference in value between winter and summer natural gas prices, and the narrow seasonal price spreads result in low unregulated storage values. We saw low storage values in both 2013 and 2014. Improvements were seen in 2015 and continuing into 2016 as North American natural gas supplies and reserves continued to increase due to the development of shale gas volumes including the British Columbia, Marcellus and Utica shale areas.

We expect that demand for natural gas in North America will continue to see low annual growth over the long-term with continued growth in peak day demands. However, the development of the Marcellus and Utica Shale areas is leading to significant new pipeline infrastructure to connect these supplies to the North American pipeline grid and the associated natural gas consuming market areas. The proximity of our storage and transportation facilities and our interconnections with major U.S. markets in the Great Lakes region and in the northeast U.S. support long-term growth opportunities. These opportunities focus on connecting new supply sources to Dawn and ensuring that there is sufficient transportation capacity on Union Gas's transmission system and pipelines downstream of Parkway to serve eastern Canadian and U.S. markets.

In response to customer demand to access new supply at Dawn, Union Gas is currently moving forward with the 2016 and 2017 Dawn to Parkway Growth projects. For additional information regarding these projects, see the Regulatory Matters section.

Environmental, Health and Safety

In 2014, we obtained an Environmental Compliance Approval (ECA) from the Ontario Ministry of the Environment and Climate Change (MOECC) for the permitting of our air and noise emission sources effective until February 2020. The ECA treats Union Gas as a single integrated natural gas storage, transmission and distribution system incorporating all storage pools, metering and regulating stations, compressor stations and buildings into a single environmental permit.

The terms and conditions of the ECA include financial obligations for capital, operating and maintenance expenditures until 2017, and the total estimated obligation has been included in the Contractual Obligations section of this document. Under the terms of the ECA, we will be allowed to add and modify facilities without prior approval from the MOECC (with the exception of new greenfield compressor stations), thereby reducing the risk of delays associated with obtaining environmental permits.

The MOECC requires third party audits to confirm that our facilities are operating in accordance with the conditions specified in the ECA. There have been no major findings to date from these audits.

In November 2015, the MOECC issued and posted a proposed draft Director's Order (the Order) naming Union Gas, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of Union Gas in Hamilton. If issued in its current form, the Order would require all parties to act jointly to develop a Conceptual Site Model to fully delineate the extent of the soil and groundwater contamination and to assess remedial measures, if necessary. In December 2015, Union Gas requested that the Ministry revise the proposed draft Order to more properly focus only on the party responsible for the contamination, as opposed to those parties impacted by the contamination. Union Gas is of the view that the cost of any potential remedial measures, if any, cannot be estimated at this time.

RISK FACTORS

Our earnings are affected by the risks inherent in the natural gas industry and energy marketplace. In general, our business and earnings level may be adversely affected by a number of risks, including but not limited to the risks described below.

Market Risk

Sales to industrial customers are affected by general economic conditions, the absolute and relative price of energy, foreign exchange rates, local and global competition and government legislation and regulations. The modest growth seen in 2015 in the North American economy is expected to further improve in 2016. Ontario's natural gas energy market will benefit from this improvement while also being impacted by negative market forces arising from globalization and more energy efficient technology.

Electricity demand in Ontario remains low due to permanent industrial demand destruction and energy conservation that has occurred, resulting in an oversupply of electricity. This has resulted in the non-renewal of several power purchase agreements with some non-utility generators and the extension of previously declared end of life nuclear units at Pickering. As a result, power revenues have declined and could remain weak until the nuclear refurbishment program begins in earnest.

Sales to Union Gas' residential, small commercial and small industrial customers are affected by the number of new customer additions to the system, the price of natural gas, the warming trend in weather that is not fully reflected in rates and the continued shift to higher efficiency. New customer additions in 2016 are expected to remain consistent with 2015 trends as a result of residential conversions offsetting the declining activity in new housing starts. High electricity prices are furthering the conversion market.

A large quantity of our transportation capacity is subject to renewal on an annual basis. Our standard contract terms provide automatic renewal of contracts, after the initial term, for one year at a time unless the customer provides two years' prior notice of termination. Future termination notices and reselling terminated capacity are dependent on the demand for the capacity which is affected by the changing flows of gas in the Great Lakes region. It is also dependent on the availability of transportation downstream of Parkway including Enbridge's Greater Toronto Area Project as well as TransCanada's King's North, Maple Compressor and Vaughn Loop Projects. These projects will provide access to Dawn supplies for customers located in the downstream Ontario, Quebec and northeast U.S. markets. We have received notice of termination for capacity of approximately 0.02 Bcf/d in 2016 and 0.08 Bcf/d in 2017. The 2016 turnback capacity was included as a part of the capacity offering of the 2017 expansion open season.

Commodity Price Risk

Fluctuations in natural gas prices affect our gas purchase costs for our own operating requirements as well as for the gas supply costs we incur for and collect from our system customers. Our gas procurement policy primarily includes contracts with pricing mechanisms that reflect monthly and daily variations in the price of gas. Commodity price volatility and absolute price levels also impact the amount of natural gas used by customers.

Credit Risk

Credit risk represents the loss that we could incur if a counterparty fails to perform under its contractual obligations. We analyze the customer's financial condition prior to entering into an agreement, obtain collateral when appropriate, establish credit limits and monitor the appropriateness of those limits on an ongoing basis.

Our credit exposure consists of both the risk of collecting receivables for services provided, as well as the risk related to gas imbalances that occur as a regular part of the services provided in both the direct purchase market and ex-franchise market.

In the normal course of operations, we provide gas loans to other parties from our holdings of gas in storage. The replacement cost of the gas on loan at December 31, 2015 was $51 million (2014 – $102 million). We manage our credit exposure related to gas loans by subjecting these parties to the same credit policies used for all customers.

Weather Risk

As the primary component of our rates is volume based, our revenue levels approved by the OEB are impacted by weather. The volume forecasts used to determine the rates approved by the OEB assume normal weather conditions. Normal weather, as mandated by the OEB, is based on a 50:50 weighting of the 30-year average forecast and 20-year trend forecast respectively, for 2013 forward. Since a large portion of the gas distributed to the residential and commercial markets is used for space heating and is charged using volume-based rates, differences from normal weather have a significant effect on the consumption of gas and on our financial results.

Regulatory Risk

Our natural gas assets and operations are subject to regulation by federal, provincial and local authorities including the OEB and by various federal and provincial authorities under environmental laws. Regulation affects almost every aspect of our business, including the ability to determine terms and rates for services, acquisitions, construction, expansion and operation of facilities, issuance of equity or debt securities and dividend payments.

In addition, regulators in Canada have taken actions to strengthen market forces in the gas pipeline industry, which have led to increased competition. In a number of key markets, natural gas pipeline and storage operators are facing competitive pressure from a number of new industry participants, such as alternative suppliers as well as traditional pipeline competitors. Increased competition driven by regulatory changes could have a material effect on our business, earnings, financial condition and cash flows.

Our pipelines and related facilities are also regulated by the Ontario Technical Standards and Safety Authority (TSSA) while a few are regulated by the National Energy Board of Canada (NEB). Through our participation on the TSSA Natural Gas Advisory Council and associated Risk Reduction Groups we have the opportunity to provide input on the direction of regulatory changes. Union Gas also has extensive engagement on the Canadian Standards Association Technical Code and Standards Committees. Amendments to the Ontario regulations made by the TSSA could have an impact on our Integrity Management Program and the direction the U.S. industry is taking may prompt some further regulatory requirements. Given the mature status of our integrity management programs, potential changes are not expected to have a material impact on the organization. We have very limited NEB regulated assets, so the amendments to the NEB Management Systems and Performance Measures are not expected to have a significant impact on our business. Union Gas utilizes a comprehensive and integrated Operations Management System (OMS) to manage the operations of the organization. We have taken the NEB requirements into account and have enhanced our OMS to be able to meet the requirements. The OMS provides the necessary structure and discipline to ensure we operate in a way that provides for demonstrated legal and regulatory safety and compliance.

Competition Risk

As our distribution business is regulated by the OEB, it is generally not subject to third-party competition within our distribution franchise area. However, as a result of a 2006 decision by the OEB, physical bypass of Union Gas' system may be permitted, even within our franchise area. In addition, other companies could enter our markets or regulations could change.

Union Gas competes with other forms of energy available to its customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

Storage Market Risk

We use market based prices for some of our storage operations and sell our storage services based on seasonal natural gas market spreads and volatility. If seasonal natural gas market spreads or volatility deviate from historical norms or there is significant growth in the amount of storage capacity available to natural gas markets relative to demand, our approach to managing our market-based storage capacity through a portfolio of varying contract terms may not protect us from significant variations in storage revenues, including possible declines as contracts renew.

For storage contracts, our standard contract terms do not allow for renewals but will typically have contract terms of one to five years. Storage prices are subject to market conditions at the time the contracts are renewed.

Gas Measurement Risk

In determining the quantities of gas delivered and received, differences arise from the measurement process. The cost of these differences is referred to as unaccounted for gas (UFG). Rates for storage, transmission and distribution of gas, approved by the OEB effective January 2013, were reset to recover an estimate of UFG based on actual experience in the previous three years, which was lower than amounts previously included in rates. Variances between the estimate included in rates and the actual cost of UFG result from measurement and estimation errors. Under the current incentive regulation framework, the impact on our financial results arising from these variances is limited to $5 million.

Financing Risk

Our business is financed to a large degree through debt. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from assets. Accordingly, we rely on access to both short-term and long-term capital markets as a source of liquidity for capital requirements not satisfied by the cash flow from operations and to fund investments originally financed through debt. Our long-term debt is currently rated investment-grade by various rating agencies. If the rating agencies were to rate us below investment-grade, our borrowing costs would increase, perhaps significantly. In addition, we would likely be required to pay a higher interest rate in future financings and our potential pool of investors and funding sources could decrease.

We are subject to long-term debt covenants that include a limitation on the payment of dividends and requirements to satisfy specific interest coverage ratios prior to the issuance of additional long-term debt. Although we do not anticipate any impact to our current financing plans, reduced earnings may limit the payment of future dividends and the level of new long-term debt available to us. We maintain a revolving credit facility to backstop our commercial paper programs for short-term borrowings. This facility includes a financial covenant which limits the amount of debt that can be outstanding as a percentage of total capital. Failure to maintain this covenant could preclude us from issuing commercial paper or borrowing under the revolving credit facility and could require immediate pay down of any outstanding drawn amounts under other revolving credit agreements, which could adversely affect our cash flow.

If we are not able to access capital at competitive rates, our ability to finance operations and implement our strategy may be adversely affected. Restrictions on our ability to access financial markets may also affect our ability to execute our business plan as scheduled. An inability to access capital may limit our ability to pursue improvements or acquisitions that we may otherwise rely on for future growth. Any downgrade or other event negatively affecting the credit ratings could make our costs of borrowing higher or access to funding sources more limited.

Human Resources Risk

Union Gas' workforce consists of both unionized and non-unionized employees. Labour disruptions associated with the collective bargaining process can affect our ongoing operations. Projected changes in workforce demographics and a future shortage of skilled trades represent issues that are being addressed by Union Gas. All of Union Gas' collective agreements have been ratified with new expiry dates between December 2017 and May 2018.

Performance Risk

We have extensive contractual relationships with natural gas producers, customers, marketers, commercial enterprises, industrial companies and others. The risk of non-performance by us or a contracting party may be analyzed and mitigated but it cannot be entirely eliminated and could affect our earnings, financial position and cash flows. Ongoing consolidation of customers and partners may increase the severity of a default.

Litigation Risk

Union Gas, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Although it is possible that liabilities may be incurred in instances for which no accruals have been made, we have no reason to believe that the ultimate outcome of such matters currently known to us could have a material effect on our Financial Statements.

Facility Risk

We carry on business through a large and complex array of natural gas transmission, storage and distribution assets. These facilities, like any other industrial operations, are subject to outages from time to time. Depending on circumstances, such outages may result in loss of revenues and/or increased maintenance costs.

Political Risk

The province of Ontario is operating with a large financial deficit and significant spending commitments. As such, it is expected that the current provincial Government may look for new sources of revenues, including non-tax revenue streams such as fees and levies. At this time, we do not anticipate any material financial impact to Union Gas.

Jurisdictions across North America are increasingly implementing policies and regulations to limit or reduce GHG emissions from various industry sectors, including the emissions associated with the combustion of natural gas for residential, commercial and industrial purposes. For example, in 2015, the State of California and the Province of Quebec expanded their cap-and-trade systems for GHG emissions to cover natural gas distributors in an effort, over time, to significantly limit the combustion of natural gas in those jurisdictions. The Province of Ontario is developing its own cap-and-trade system. Union Gas is currently reviewing the draft Ontario regulations that were published for comment in February 2016. It is expected that, following the April 2016 deadline for comments, the Province of Ontario will develop final regulations later in 2016 that are proposed to take effect January 1, 2017. Given the uncertainty around these new initiatives, we cannot estimate the potential effect of proposed GHG policies on our future results of operations, financial position or cash flows. However, such legislation and regulation could materially reduce our revenues, materially increase our operating costs or require material capital expenditures. The extent to which the Ontario cap-and-trade system will impact Union Gas or its customers will depend upon the final version of the implementing legislation and regulations. Union Gas will continue to monitor any potential impacts and opportunities, including through ongoing consultation with regulatory agencies.

Environmental, Health and Safety Risk

There are a variety of hazards and operating risks inherent in natural gas storage, transmission, and distribution activities, such as leaks, explosions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in significant injury, loss of human life, significant damage to property, environmental pollution and impairment of operations, any of which could result in substantial losses. For pipeline and storage assets located near populated areas, including residential areas, commercial business centres, industrial sites and other public gathering areas, the level of damage resulting from these risks could be greater. We do not maintain insurance coverage against all of these risks and losses, and any insurance coverage we might maintain may not fully cover the damages caused by these risks and losses. Therefore, should any of these risks materialize, it could have a material adverse effect on our business, earnings, financial condition and cash flows.

Protecting Against Potential Terrorist Activities

The potential for terrorism because of the high profile of the natural gas industry has subjected our operations to increased risks that could have a material adverse effect on our business. This risk is particularly great for companies, like ours, operating in any energy infrastructure industry that handles volatile gaseous and liquid hydrocarbons. The potential for terrorism, including cyber-terrorism, has subjected our operations to increased risks that could have a material effect on our business. In particular, we may experience increased capital and operating costs to implement increased security for our facilities and pipelines, such as additional physical facility and pipeline security and additional security personnel. Moreover, any physical damage to high profile facilities resulting from acts of terrorism may not be covered, or covered fully, by insurance. We may be required to expend material amounts of capital to repair any facilities, the expenditure of which could adversely affect our cash flows and business. A cyber attack could also lead to a significant interruption in our operations or unauthorized release of confidential information or otherwise protected information, which could damage our reputation or lead to financial losses.

Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

Pension Risk

Our costs of providing defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates used to measure pension liabilities, actuarial gains and losses, future government regulation and our contributions made to the plans. Without sustained growth in the pension plan investments over time to increase the value of our plan assets, and depending upon the other factors impacting our costs as listed above, we could experience net asset, expense and funding volatility. This volatility could have a material effect on our earnings and cash flows.

Land Rights

Various aboriginal groups in Ontario have claimed aboriginal and treaty rights in areas where Union Gas' facilities, and the gas supply areas served by those facilities, are located. In addition to aboriginal groups, other landowners have also claimed their rights in Union Gas' franchise area. The existence of these claims could give rise to future uncertainty regarding land tenure and expansion depending upon their negotiated outcome. We continue to proactively plan and manage the risks associated with these issues and work with provincial government regulators in that regard.

Capital Project Execution Risk

A portion of our growth is accomplished through the construction of new pipelines and storage facilities as well as the expansion of existing facilities.

Construction of these facilities is subject to various regulatory, development, operational and market risks, including: the ability to obtain necessary approvals and permits from regulatory agencies and municipalities on a timely basis and on acceptable terms, and to maintain those approvals and permits issued and satisfy the terms and conditions imposed therein; the availability of skilled labour, equipment, and materials to complete expansion projects; potential changes in federal, provincial and local statutes and regulations, including environmental requirements, that may prevent a project from proceeding or increase the anticipated cost of the project; impediments on our ability to acquire right-of-ways or land rights on a timely basis and on acceptable terms; the ability to construct projects within anticipated costs, including the risk of cost overruns resulting from inflation, foreign exchange or increased costs of equipment, materials or labour, weather, geologic conditions, or other factors beyond our control, that may be material; and general economic factors that affect the demand for natural gas infrastructure.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated costs. As a result, new facilities may not achieve their expected investment return, which could affect our earnings, financial position and cash flows.

Shale Gas Development

Recent community and political pressures have arisen around the production and transmission of natural gas originating from shale basins. Although we continue to believe that natural gas will remain a viable energy solution for Canada and the U.S., these pressures could increase costs and/or cause a slowdown in pipeline project development and/or the production of natural gas from these shale basins. This could negatively affect our growth plans and our access to this natural gas supply.

RELATED PARTY TRANSACTIONS

We occasionally perform services for and incur costs on behalf of our affiliates, which are subsequently reimbursed. Likewise, certain affiliates may perform services for or incur costs on behalf of us, which are then reimbursed by us. These transactions are in the normal course of operations and are recorded at exchange amounts agreed to between the related parties.

In addition, Spectra Energy and its affiliates perform centralized corporate functions for us, pursuant to an agreement with Spectra Energy and its affiliates, including legal, accounting, compliance, treasury, information technology and other areas, as well as certain engineering and other services. We reimburse Spectra Energy and its affiliates for the expenses to provide these services as well as other expenses they incur on our behalf. Spectra Energy and its affiliates charge such expenses based on the cost of actual services provided or using various allocation methodologies based on our percentage of assets, employees, earnings or other measures, as compared to Spectra Energy's other affiliates.

Our transactions with affiliated companies are as follows:

($millions), net	**Transport and Storage Expenses**	**Corporate Charges (Receipts)[a]**	**Gas Purchases**
2015			
St Clair Pipelines 1996, a division of Westcoast	—	(2)	—
Pipeline and Field Services, a division of Westcoast	—	(3)	—
Spectra Energy Empress L.P.	—	—	55
Spectra Energy Gas Transmission LLC	—	14	—
Sarnia Airport Storage Pool Limited Partnership	4	—	—
2014			
Pipeline and Field Services, a division of Westcoast	—	(4)	—
Spectra Energy Empress L.P.	—	—	133
Spectra Energy Gas Transmission LLC	—	10	—
Sarnia Airport Storage Pool Limited Partnership	4	—	—

[a]Excludes compensation arrangements.

Net amounts due (to) from related affiliates are as follows:

($millions), net	**2015**	**2014**
Spectra Energy Empress L.P.	(6)	(10)
Spectra Energy Gas Transmission LLC	(7)	6
Total[a]	(13)	(4)

[a]At December 31, 2015, $14 million (2014 – $10 million) is recognized in Accounts payable and accrued charges and $1 million (2014 – $6 million) is recognized in Accounts receivable, net on the Balance Sheets.

In the normal course of operations, we provide or obtain funds from Westcoast on an unsecured basis. The balance outstanding at December 31, 2015 was a payable of $56 million (December 31, 2014 – payable of $48 million). During 2015, interest paid on these loans totalled less than $1 million (2014 – less than $1 million) and interest received on these loans totalled less than $1 million (2014 – less than $1 million). Interest on these loans is calculated based on the monthly average of 30-day banker's acceptance rates.

We also have a promissory note to borrow up to $150 million from GLBE on an unsecured basis. Funds from this promissory note are used for general corporate purposes. There was no balance outstanding at December 31, 2015 or December 31, 2014.

In addition, beginning in 2014, we declared and paid common stock dividends on an annual rather than quarterly basis, and as a result, we made a dividend payment to GLBE of $50 million during 2015 (2014 – $100 million).

LIQUIDITY AND CAPITAL RESOURCES

We manage cash to ensure appropriate amounts are available as required. We invest our available cash in high-quality money market securities. Such money market securities are designed for the safety of principal and for liquidity, and accordingly do not include equity-based securities.

We will rely upon cash flows from operations and various financing transactions, which may include issuances of short-term and long-term debt and utilization of loans from Westcoast and GLBE, to fund our liquidity and capital requirements. We have access to a revolving credit facility that is used principally as a back-stop for our commercial paper program, which supports our short-term working capital fluctuations.

Changes in Cash Flow	For the years ended December 31,	
($millions)	**2015**	2014
Operating activities	**501**	305
Investing activities	**(701)**	(474)
Financing activities	**185**	179

Operating Activities

Union Gas' heating season extends from approximately November through March. We begin the heating season with near-capacity natural gas inventory levels which are drawn throughout the heating season. December year-end inventory levels decrease and thus contribute to a positive cash flow from operations during the first quarter. After the heating season ends, inventory is replenished for the next heating season. During the third quarter, gas inventory injections typically exceed withdrawals, negatively affecting cash flows. During the fourth quarter inventory decreases as withdrawals exceed injections.

Some of our customers purchase gas directly from marketers. Marketers typically deliver gas to us evenly throughout the year, whereas most of their customers use gas based on seasonality. As part of our normal billing process, we bill the marketers' customers as gas is used and remit this cash to the marketer when gas is delivered to us. Therefore, during the first and fourth quarters of the year, customers typically use more gas than is delivered to us and we collect cash from the marketers' customers creating a positive cash flow. During the second and third quarters, marketers deliver more gas than their customers use, thus creating a significant cash outflow. These are normal seasonal trends.

Cash provided from operating activities was $501 million for 2015 compared with $305 million for 2014. The increase was primarily due to an over collection of commodity costs in 2015 compared to an under collection in 2014 and higher collections of accounts receivable, partially offset by higher repayment of accounts payable mainly due to higher refunds to customers in 2015 and an increase in tax installments in 2015.

Investing Activities

The table below is a summary of capital expenditures:

	For The Years Ended December 31,		
	2016	2015	2014
	(estimated)		
Storage and transmission projects	70%	61%	46%
Distribution	27%	34%	44%
General equipment	3%	5%	10%
	100%	100%	100%

The table below is a summary of capital project type:

	For The Years Ended December 31,		
($millions)	2016	2015	2014
	(estimated)		
Maintenance projects	203	219	231
Expansion projects	1,006	482	243
Total capital expenditures	1,209	701	474

Capital expenditures for 2015 were higher compared to 2014 primarily due to the 2015, 2016 and 2017 Dawn to Parkway Growth projects.

In 2015, the following key expansion project was placed into service:

- 2015 Dawn-Parkway - A 0.3965 Bcf/d expansion of the Dawn to Parkway transmission system that consisted of the Parkway West project which included the development of a new Greenfield compressor site west of Toronto and the installation of two new compressors and associated infrastructure, the Parkway C and D compressor units and the Brantford-Kirkwall 48 inch pipeline loop.

The 2016 expansion capital expenditures reflect our continued assessment of the timing of projected long-term market requirements and general economic conditions. Significant 2016 expansion project expenditures are expected to include:

- Burlington-Oakville - 0.2903 Bcf/d of new capacity for the Burlington/Oakville market. The project consists of 12 km of 20 inch pipe. The project is expected to be in service during the fourth quarter of 2016.
- 2016 Dawn Parkway - A 0.4057 Bcf/d expansion of the Dawn to Parkway transmission system consisting of 20 km of 48 inch Hamilton to Milton pipeline and the installation of a new compressor and associated infrastructure at Lobo. The project is expected to be in service during the fourth quarter of 2016.
- 2017 Dawn Parkway - A 0.4185 Bcf/d expansion of the Dawn to Parkway transmission system consisting of the addition of a new 44,500 horsepower compressor at each of our Dawn, Lobo and Bright Compressor Stations. Service to customers is expected in the fourth quarter of 2017.

Consistent with 2015, the 2016 maintenance expenditures are for maintaining the integrity of existing pipelines and related infrastructure.

As outlined in the financing activities discussion that follows, we have sufficient financing available to meet our investing requirements. Management expects that financing of 2016 projects will be done through a combination of cash generated from operations, available debt facilities, and issuance of long-term debt.

Financing Activities

The primary factors increasing cash flow from financing activities for 2015 compared to 2014 include the lower payment of dividends partially offset by lower funds from short-term borrowings.

In order to maintain the common equity component of the capital structure at the level approved by the OEB, we typically pay dividends to our parent company. Beginning in 2014, we declared and paid a common stock dividend on an annual rather than quarterly basis. For 2015, we paid dividends to GLBE of $50 million (2014 – $100 million).

Available Credit Facility and Restrictive Debt Covenants

			Commercial Paper Debt Outstanding at	
($millions)	**Expiration Date**	**Credit Facility Capacity**	**December 31, 2015**	December 31, 2014
Multi-year syndicated [(a)]	2019	500	**207**	270

[(a)] The credit facility contains a covenant requiring the debt-to-total capitalization ratio, as defined in the agreement, to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 67.8% at December 31, 2015 (December 31, 2014 – 68.3%).

The issuance of commercial paper, letters of credit and revolving borrowings reduce the amount available under the credit facility. As of December 31, 2015 and December 31, 2014 there were no letters of credit issued or revolving borrowings outstanding under the credit facility. The majority of our short-term cash requirements are funded through the issuance of commercial paper. The weighted average rate on outstanding commercial paper as of December 31, 2015 was 0.86% (2014 – 1.22%). The weighted average days to maturity on outstanding commercial paper as of December 31, 2015 was 9 days (2014 – 12 days).

Our credit agreement contains various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreement. As of December 31, 2015 and December 31, 2014, we were in compliance with those covenants. In addition, the credit agreement allows for the acceleration of payments or termination of the agreement due to non-payment, or in some cases, due to the acceleration of other significant indebtedness of the borrower.

This facility is intended to be used primarily to manage the significant changes in working capital experienced by Union Gas as a result of volumes and prices associated with natural gas purchases and sales. Most of the short-term cash requirements are funded through issuing commercial paper at rates generally below the lender's prime rate. Our 2015 commercial paper peaked in August at $328 million (2014 – peaked in February at $386 million).

Other Financing Matters

We maintain a current base shelf prospectus with the Canadian securities regulators, which enables ready access to Canadian public debt capital markets. As of the date of this filing, we have $1.05 billion available for the issuance of medium-term note debentures under the base shelf prospectus, which expires on January 4, 2017.

In September 2015, we issued $200 million of Series 13 medium-term note debentures at 3.19% per annum, due September 2025 and issued an additional $250 million of Series 12 4.20% medium-term note debentures, due June 2044. Proceeds from the offerings were used for repayment of short-term debt, to fund capital expenditures, and for general corporate purposes.

OUTSTANDING STOCK

	December 31, 2015	December 31, 2014
Preferred stock		
5.5% Cumulative Redeemable Class A Preferred Stock, Series A	**47,672**	47,672
6% Cumulative Redeemable Class A Preferred Stock, Series B	**90,000**	90,000
5% Cumulative Redeemable Class A Preferred Stock, Series C	**49,500**	49,500
4.88% Cumulative Redeemable Convertible Class B Preferred Stock, Series 10	**4,000,000**	4,000,000
Common stock	**57,822,650**	57,822,650

CONTRACTUAL OBLIGATIONS

The table below is a summary of our contractual payment obligations, due by period.

($millions)	Total	2016	2017-2018	2019-2020	Thereafter
Long-term debt [(a)]	5,468	359	816	227	4,066
Operating leases	33	7	12	12	2
Purchase obligations[(b)]	1,554	648	490	219	197
Environmental obligations[(c)]	7	3	4	—	—
Retirement plan contributions[(d)]	4	4	—	—	—
Total contractual obligations[(e)]	7,066	1,021	1,322	458	4,265

(a) Includes estimated scheduled interest payments over the life of the associated debt.

(b) Includes: firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage; contractual obligations to purchase physical quantities of natural gas; contracts for software and consulting or advisory services; and contractual obligations for engineering, procurement and construction costs for pipeline projects. Due to a timing uncertainty, all procurement obligations have been included in 2016 as we are unable to reasonably estimate the payments due by period.

(c) Includes capital, operating and maintenance expenditures related to the ECA.

(d) We are unable to reasonably estimate retirement plan contributions beyond 2016 due primarily to uncertainties about market performance of plan assets.

(e) Excludes cash obligations for asset retirement activities. The amount of cash flows to be paid to settle the asset retirement obligations is not known with certainty as Union Gas may use internal resources or external resources to perform retirement activities. Amounts also exclude reserves for litigation, environmental remediation, annual insurance premiums that are necessary to operate the business and regulatory liabilities because Union Gas is uncertain as to the amount and/or timing of when cash payments will be required. Also, amounts exclude deferred income taxes and investment tax credits on the Balance Sheets since cash payments for income taxes are determined based primarily on taxable income for each discrete fiscal year. Our analysis also indicated that there are no expected payments and interest related to uncertain tax positions for 2016. We are unable to reasonably estimate the timing of uncertain tax positions and interest payments in years beyond 2016 due to uncertainties in the timing of cash settlements with taxing authorities.

NEW ACCOUNTING PRONOUNCEMENTS

In April 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2015-03, "*Interest-Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*", which requires that debt issuance costs be presented on the balance sheet as a direct deduction from the carrying amount of the related debt liability, rather than as a deferred charge asset. We adopted this standard on December 31, 2015. The adoption of this ASU resulted in the retrospective adjustment of the December 31, 2014 Balance Sheet, which resulted in the presentation of $11 million of debt issuance costs previously reported in Regulatory and other assets as a reduction to Long-term debt. In addition, $12 million of debt issuance costs are presented as a reduction of Long-term debt on our December 31, 2015 Balance Sheet.

In July 2015, the FASB issued ASU No. 2015-11, "*Inventory (Topic 330): Simplifying the Measurement of Inventory*", which simplifies the subsequent measurement of inventory by requiring inventory to be measured at the lower of cost and net realizable value. This ASU is effective for us January 1, 2016 and is not expected to have a material impact on our Financial Statements.

In July 2015, the FASB decided to defer the effective date of the revenue standard ASU No. 2014-09, "*Revenue from Contracts with Customers (Topic 606),*" for one year and to permit entities to early adopt the standard as of the original effective date. ASU No. 2014-09 supersedes the revenue recognition requirements of "*Revenue Recognition (Topic 605)*" and clarifies the principles of recognizing revenue. This ASU is effective for us January 1, 2018. We are currently evaluating this ASU and its potential impact on us.

In November 2015, the FASB issued ASU No. 2015-17, "*Accounting for Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes."* This ASU simplifies the balance sheet presentation of deferred income taxes by requiring deferred tax liabilities and assets be classified as noncurrent in a classified balance sheet. We adopted this standard on December 31, 2015 and applied it prospectively. The adoption of this ASU did not have a material impact on our Financial Statements.

In January 2016, the FASB issued ASU 2016-01, "*Financial Instruments--Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities,*" which amends the classification and measurement of financial instruments. Changes primarily affect the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. This ASU is effective for us beginning after December 15, 2017. Early adoption is not permitted. We are currently evaluating this ASU and its potential impact on us.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure Controls and Procedures

We have established and maintained disclosure controls and procedures designed to provide reasonable assurance that: (a) material information required to be disclosed by us is accumulated and communicated to management to allow timely decisions regarding required disclosure; and (b) information required to be disclosed by us is recorded, processed, summarized, and reported within the time periods specified in applicable securities legislation.

Our management, with the participation of the President and the Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2015, and, based upon this evaluation, the President and the Chief Financial Officer have concluded that these disclosure controls and procedures, as defined by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings (NI 52-109), are effective for the purposes set out above.

Internal Control over Financial Reporting

Our management is responsible for designing, establishing and maintaining an adequate system of internal control over financial reporting. Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with U.S. GAAP. Because of 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 policies and procedures may deteriorate.

Our management, with the participation of our President and the Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2015 based on the framework in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting, as defined by NI 52-109, is effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with U.S. GAAP.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the President and Chief Financial Officer, we have evaluated changes in internal control over financial reporting that occurred during the fiscal quarter and year ended December 31, 2015 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

Our Board has reviewed and approved this MD&A and the attached Audited Financial Statements prior to their release.

CRITICAL ACCOUNTING POLICIES & ESTIMATES

The application of accounting policies and estimates is an important process that continues to evolve as Union Gas' operations change and accounting guidance is issued. Union Gas has identified a number of critical accounting policies and estimates that require the use of significant estimates and judgments.

Management bases its estimates and judgments on historical experience and on other various assumptions that they believe are reasonable at the time of application. The estimates and judgments may change as time passes and more information becomes available. If estimates and judgments are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information. Union Gas discusses its critical accounting policies and estimates and other significant accounting policies with senior members of management and the Board.

Regulatory Accounting

The economic effects of regulation can result in a regulated company recording assets for costs that have been or are expected to be approved for recovery from customers or recording liabilities for amounts that are expected to be returned to customers or for instances where the regulator provides current rates that are intended to recover costs that are expected to be incurred in the future. Accordingly, we record assets and liabilities that result from the regulated ratemaking process that may not be recorded under U.S. GAAP for non-regulated entities. We continually assess whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders to other regulated entities and the effect of competition. Based on this assessment, we believe our existing regulatory assets are probable of recovery. Total regulatory assets were $499 million as of December 31, 2015 and $480 million as of December 31, 2014. Total regulatory liabilities were $432 million as of December 31, 2015 and $410 million as of December 31, 2014.

Unbilled Revenue

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month. Gas sales and distribution revenue and Cost of gas are recorded on the basis of regular meter readings and estimates of the unbilled customer usage. The unbilled estimate covers the period of the last meter reading date to the end of each month and is calculated using the number of days unbilled, heating degree-days and historical consumption per heating degree-day. Unbilled revenue recorded at December 31, 2015 was $106 million (2014 – $141 million) which was included in Accounts receivable, net on the Balance Sheets. Included in unbilled revenue are natural gas costs passed through to customers without a mark-up. At December 31, 2015 $62 million (2014 – $97 million) was included in unbilled revenue for the cost of natural gas.

Pension and Other Post-Retirement Benefits

The calculations of pension and other post-retirement expense and liabilities require the use of numerous assumptions. Changes in these assumptions can result in different reported expense and liability amounts, and future actual experience can differ from the assumptions. We believe that the most critical assumptions used in the accounting for pension and other post-retirement benefits are the expected long-term rate of return on plan assets, the assumed discount rate, and medical and prescription drug cost trend rate assumptions.

Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in our pension and post-retirement plans will impact future pension expense and funding.

The expected return on plan assets is important since certain of our pension plans are funded. Expected long-term rates of return on plan assets are developed by using a weighted average of expected returns for each asset class to which the plan assets are allocated. For 2015, the assumed average return for the pension plan assets was 7.40%. A change in the rate of return of 25 basis points for these assets would impact annual benefit expense by approximately $2 million before tax. The other post-retirement benefit plans are not funded.

Since pension and other post-retirement benefit costs and obligations are measured on a discounted basis, the discount rates used to determine the net periodic benefit cost and the benefit obligation are significant assumptions.

The discount rate used for our defined benefit and other post-retirement benefit plans is based on the yields constructed from a portfolio of high-quality bonds for which the timing and amount of cash outflows approximate the estimated payouts of the plans. A discount rate of 4.00% was used to calculate the 2015 net periodic benefit cost and represents a weighted average of the applicable rates as at December 31, 2014. A 25 basis-point change in the discount rate would impact annual before-tax net periodic benefit cost by $3 million. A discount rate of 4.03% was used to calculate the 2015 year-end benefit obligations and represents a weighted average of the applicable rates as at December 31, 2015. The weighted average discount rate increased approximately 0.03% during 2015. The increase in the discount rate and actuarial experience resulted in a decrease in benefit liabilities at December 31, 2015 compared to December 31, 2014.

Asset Retirement Obligations

In determining the value of the asset retirement obligations, Union Gas must estimate such factors as timing of settlements and abandonment or remediation costs. These estimates require extensive judgment about the nature, cost and timing of the settlement. Any changes in the estimates can impact the Asset retirement obligations, Regulatory and other liabilities and Property, plant and equipment, net. To arrive at the timing of settlements of abandoning pipelines, Union Gas uses retirement dispersion parameters as estimated in its most recent depreciation rate study.

The Financial Statements and all information in this report have been prepared by and are the responsibility of management. The Financial Statements have been prepared in conformity with generally accepted accounting principles in the United States of America and include certain estimated amounts, which are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon Union Gas Limited's system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization. Management is also supported and assisted by a program of internal audit services.

The Board of Directors (the Board) is responsible for ensuring that management fulfils its responsibility for financial reporting and for final approval of the Financial Statements.

The Board meets regularly with management, the internal auditors and the shareholders' auditors to review the Financial Statements, the Independent Auditor's Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities.

The shareholders' auditors have full and free access to the Board, as does the Director of Internal Audit Services.

Deloitte LLP performed an independent audit of the 2015 and 2014 Financial Statements in this report. Their independent professional opinion on the fairness of these Financial Statements is included in the Independent Auditor's Report.

March 3, 2016

Stephen W. Baker	J. Patrick Reddy
President	Chief Financial Officer

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Independent Auditor's Report

To the Shareholders of
Union Gas Limited

We have audited the accompanying financial statements of Union Gas Limited, which comprise the balance sheets as at December 31, 2015 and December 31, 2014, and the statements of operations and comprehensive income, statements of equity, and statements of cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of 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 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 audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the 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 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 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 financial statements present fairly, in all material respects, the financial position of Union Gas Limited as at December 31, 2015 and December 31, 2014, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Deloitte LLP

Chartered Professional Accountants
Licensed Public Accountants
March 1, 2016

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

For the Years Ended December 31 ($millions)	**2015**	2014
Gas sales and distribution revenue	**1,675**	1,755
Cost of gas (note 9)	**875**	977
Gas distribution margin	**800**	778
Storage and transportation revenue (note 9)	**239**	266
Other revenue, net	**26**	21
Net operating revenue	**1,065**	1,065
Expenses		
Operating and maintenance (note 9)	**399**	397
Depreciation and amortization	**224**	212
Property taxes and other	**69**	69
Total expenses	**692**	678
Income before interest and income taxes	**373**	387
Interest expense (notes 9 and 10)	**157**	156
Income before income taxes	**216**	231
Income tax expense (note 6)	**28**	36
Net income	**188**	195
Preferred stock dividends	**3**	3
Net income applicable to common stock	**185**	192
Other comprehensive income, net of tax		
Pension and benefits impact (net of tax of 6 and (12) respectively) (note 12)	**16**	(33)
Comprehensive income applicable to common stock	**201**	159

(See accompanying notes)

BALANCE SHEETS

As at December 31 ($millions)	**2015**	2014
Assets		
Current assets		
Cash and cash equivalents	**5**	20
Accounts receivable, net (notes 4 and 9)	**650**	1,135
Income taxes receivable (note 6)	**24**	17
Inventories (note 5)	**297**	239
Total current assets	**976**	1,411
Property, plant and equipment (note 7)		
Cost	**8,300**	7,627
Accumulated depreciation and amortization	**(2,622)**	(2,473)
Property, plant and equipment, net	**5,678**	5,154
Regulatory and other assets (notes 3 and 8)	**536**	469
Total Assets	**7,190**	7,034
Liabilities and Equity		
Current liabilities		
Short-term borrowings (note 9)	**56**	48
Commercial paper (note 10)	**207**	270
Accounts payable and accrued charges (notes 4 and 9)	**793**	1,117
Current maturities of long-term debt (note 10)	**200**	150
Deferred income taxes (note 6)	**—**	25
Total current liabilities	**1,256**	1,610
Long-term liabilities		
Long-term debt (note 10)	**2,921**	2,676
Deferred income taxes (note 6)	**451**	417
Asset retirement obligations (note 13)	**440**	368
Regulatory and other liabilities (notes 3 and 8)	**509**	497
Total long-term liabilities	**4,321**	3,958
Total Liabilities	**5,577**	5,568
Preferred Stock (note 11)	**110**	110
Equity		
Common stock, unlimited shares authorized, 57,822,650 outstanding	**627**	627
Retained earnings	**1,051**	916
Accumulated other comprehensive loss	**(179)**	(195)
Paid-in capital (note 2)	**4**	—
Non-controlling interest (note 2)	**—**	8
Total Equity	**1,503**	1,356
Total Liabilities and Equity	**7,190**	7,034

(See accompanying notes)

Approved by the Board

Director

Director

STATEMENTS OF CASH FLOWS

For the Years Ended December 31 ($millions)	**2015**	2014
Operating Activities		
Net income	**188**	195
Items not affecting cash		
Depreciation and amortization	**224**	212
Loss on disposal of assets	**—**	1
Deferred income taxes	**(40)**	13
Changes in working capital		
Accounts receivable	**89**	(89)
Inventories	**(60)**	(112)
Accounts payable, accrued charges and other	**100**	85
Net cash provided by operating activities	**501**	305
Investing Activities		
Capital expenditures	**(701)**	(474)
Financing Activities		
Net increase in short-term borrowings	**8**	48
Net decrease in commercial paper	**(63)**	(66)
Long-term debt issued	**445**	450
Long-term debt repayments	**(150)**	(150)
Purchase of subsidiary shares from non-controlling interest	**(2)**	—
Dividends paid	**(53)**	(103)
Net cash provided by financing activities	**185**	179
Change in cash and cash equivalents, during the year	**(15)**	10
Cash and cash equivalents, beginning of year	**20**	10
Cash and cash equivalents, end of year	**5**	20
Supplementary Disclosure of Cash Flow Information:		
Cash payments of interest, net of amounts capitalized	**160**	160
Cash payments of income taxes, net of refunds received	**66**	26

(See accompanying notes)

STATEMENTS OF EQUITY

($millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Paid-in Capital	Non-controlling Interest	Total
December 31, 2014	627	916	(195)	—	8	1,356
Net income	—	188	—	—	—	188
Other comprehensive income	—	—	16	—	—	16
Dividends						
Preferred stock	—	(3)	—	—	—	(3)
Common stock	—	(50)	—	—	—	(50)
Purchase of subsidiary shares from non-controlling interest	—	—	—	4	(8)	(4)
December 31, 2015	627	1,051	(179)	4	—	1,503
December 31, 2013	627	824	(162)	—	9	1,298
Net income	—	195	—	—	—	195
Other comprehensive income	—	—	(33)	—	—	(33)
Dividends						
Preferred stock	—	(3)	—	—	—	(3)
Common stock	—	(100)	—	—	—	(100)
Other	—	—	—	—	(1)	(1)
December 31, 2014	627	916	(195)	—	8	1,356

(See accompanying notes)

UNION GAS LIMITED
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2015 AND 2014

1. Summary of Operations and Significant Accounting Policies

The terms "Union Gas" or "the Company" as used in these Financial Statements refer to Union Gas Limited unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Union Gas. Union Gas' common stock is held by Great Lakes Basin Energy L.P. (GLBE), a wholly-owned limited partnership of Westcoast Energy Inc. (Westcoast). Westcoast is an indirect wholly-owned subsidiary of Spectra Energy Corp (Spectra Energy).

Nature of Operations

Union Gas owns and operates natural gas distribution, storage and transmission facilities in Ontario. The Company distributes natural gas to customers in northern, southwestern and eastern Ontario and provides natural gas storage and transportation services for other utilities and energy market participants. The property, plant and equipment of the Company consist primarily of pipeline, storage and compression facilities used in the distribution, storage and transportation of natural gas.

Basis of Presentation

The Financial Statements of the Company include the standalone accounts of the Company. On June 1, 2015 the Company dissolved its subsidiary, Huron Tipperary Limited Partnership I (HTLP), transferring HTLP's assets and liabilities to the Company with no material financial impact to the Company. Comparative figures for 2014 are shown consolidated with HTLP.

The Financial Statements of the Company have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). All amounts are presented in millions of Canadian dollars except where noted.

In 2014, Canadian securities regulators approved the extension of the Company's exemptive relief to continue reporting under U.S. GAAP instead of International Financial Reporting Standards (IFRS) until the earlier of January 1, 2019, and the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation.

Use of Estimates

The preparation of the Financial Statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual amounts could differ from these estimates.

Regulation

The Company is regulated by the Ontario Energy Board (OEB) pursuant to the provisions of the *Ontario Energy Board Act, (1998)*, which is part of a package of legislation known as the *Energy Competition Act, (1998)*. This legislation provides an opportunity for different forms of regulation and increased competition in the energy (electricity and natural gas) industry in Ontario. The Company is subject to regulation with respect to the rates that it may charge its customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting principles. The OEB has determined that it will forbear from regulating the prices for long-term storage services. The Storage Forbearance Decision created an unregulated storage operation within the Company and provides the framework required to support new storage investments.

The OEB is mandated to approve rates that are just and reasonable. Utility earnings are regulated by the OEB under cost of service regulation, on the basis of a return on rate base for a future period. Under cost of service regulation, a rate application process leads to the implementation of new rates intended to provide a utility with the opportunity to earn an allowed rate of return. The actual rate of return achieved by the Company may vary from the rate allowed by the OEB as a result of unexpected changes in weather, average use per customer, inflation, the price of competing fuels, interest rates, general economic conditions and its ability to achieve forecasted revenues and manage costs.

Effective January 1, 2014, the Company began a five year incentive regulation term. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts.

As part of the Company's OEB-approved incentive regulation framework, an earnings sharing mechanism exists whereby earnings in excess of 100 basis points above the allowable return on equity are shared with ratepayers as a reduction in earnings during the year, if applicable.

The Company follows U.S. GAAP, which may differ for regulated operations from those otherwise expected in non rate-regulated businesses. As a result, the Company records assets and liabilities that result from the regulated ratemaking process that may not be recorded under U.S. GAAP for non rate-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate at the provincial and national levels, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs could be recognized in current period earnings.

Revenue Recognition

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered and collection is reasonably assured. Revenues related to these services provided or products delivered but not yet billed are estimated each month.

Gas Sales and Cost of Gas

Gas sales revenue is recorded on the basis of regular meter readings and estimates of customer volume usage since the last meter reading date to the end of the reporting period applied using OEB approved rates. Cost of gas is recorded using amounts approved by the OEB in the determination of customer sales rates. Differences between the OEB approved reference amounts and those costs actually incurred are deferred on the Balance Sheets for future disposition subject to approval by the OEB.

In determining the quantities of gas delivered and received, differences arise from the measurement process. The Company includes in the cost of gas an estimated amount of these differences based upon the methodology used by the OEB in the determination of rates for storage, transmission and distribution of gas. Annual fluctuations from the estimated level are recognized in earnings during the year.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term investments, with an original maturity of three months or less.

Income Taxes

Deferred income taxes are recognized for differences between the financial reporting and tax bases of assets and liabilities at enacted statutory tax rates in effect for the years in which the differences are expected to reverse. The effect on deferred taxes of a change in tax rates is recognized in income in the period that includes the enactment date. Actual income taxes could vary from these estimates due to the future changes in income tax law or results from the final review of tax returns by federal and provincial tax authorities.

Financial statement effects on tax positions are recognized in the period in which it is more likely than not that the position will be sustained upon examination, the position is effectively settled or when the statute of limitations to challenge the position has expired. Interest related to the unrecognized tax benefits is recorded as Interest expense on the Statements of Operations and Comprehensive Income.

Inventories

Gas in storage for resale to customers is carried at weighted average cost approved by the OEB in the determination of customer sales rates. The difference between the approved cost and the actual cost of the gas purchased is deferred on the Balance Sheets for future disposition subject to approval by the OEB. Inventories of materials and supplies are valued at the lower of average cost or net realizable value.

Property, Plant and Equipment and Depreciation

Property, plant and equipment is stated at historical cost less accumulated depreciation and amortization. The Company capitalizes all construction-related direct labour and material costs, as well as indirect construction costs. Indirect costs include general engineering and the cost of funds used during construction. The costs of renewals and betterments that extend the useful life or increase the expected output of property, plant and equipment are also capitalized. The cost of repairs, replacements and major maintenance projects that do not extend the useful life or increase the expected output of property, plant and equipment are expensed as incurred.

Regulated depreciation is computed based on the asset's average service life using the straight-line method. Unregulated depreciation is computed based on management's assumption of useful life using the straight-line method.

When regulated property, plant and equipment is retired, the original cost plus the cost of retirement, less salvage value, is charged to accumulated depreciation and amortization. When entire regulated operating units are sold or non-regulated property, plant and equipment is retired, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body.

Asset Retirement Obligations (AROs)

The Company recognizes AROs for legal commitments associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset and conditional AROs in which the timing or method of settlement are conditional on a future event that may or may not be within the Company's control. The fair value of a liability for an ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made and is added to the carrying amount of the associated asset. This additional carrying amount is depreciated over the estimated useful life of the asset.

Stock-Based Compensation

Union Gas employees participate in a stock-based compensation plan sponsored by Spectra Energy. For employee awards, equity-classified and liability-classified stock-based compensation cost is measured at the grant date based on the fair value of the award. Liability classified stock-based compensation cost is re-measured at each reporting period until settlement. Related compensation expense is recognized over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests, the date the employee becomes retirement-eligible, or the date the award market condition is met. Awards, including stock options, granted to employees that are already retirement-eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted.

Pension and Other Post-Retirement Benefits

The Company fully recognizes the overfunded or underfunded status of pension and other post-retirement benefit plans as Regulatory and other assets, Accounts payable and accrued charges, or Regulatory and other liabilities on the Balance Sheets. A plan's funded status is the difference between the fair value of plan assets and the plan's benefit obligation. The Company records deferred plan costs and income (unrecognized losses and gains, and unrecognized prior service costs and credits) in Accumulated other comprehensive loss, until they are amortized to be recognized as a component of benefit expense within Operating and maintenance expenses in the Statements of Operations and Comprehensive Income. See note 12 for further discussion.

New Accounting Pronouncements

In April 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2015-03, "*Interest-Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*", which requires that debt issuance costs be presented on the balance sheet as a direct deduction from the carrying amount of the related debt liability, rather than as a deferred charge asset. The Company adopted this standard on December 31, 2015. The adoption of this ASU resulted in the retrospective adjustment of the December 31, 2014 Balance Sheet, which resulted in the presentation of $11 million of debt issuance costs previously reported in Regulatory and other assets as a reduction to Long-term debt. In addition, $12 million of debt issuance costs are presented as a reduction of Long-term debt on the Company's December 31, 2015 Balance Sheet.

In July 2015, the FASB issued ASU No. 2015-11, "*Inventory (Topic 330): Simplifying the Measurement of Inventory*", which simplifies the subsequent measurement of inventory by requiring inventory to be measured at the lower of cost and net realizable value. This ASU is effective for the Company January 1, 2016 and is not expected to have a material impact on the Company's Financial Statements.

In July 2015, the FASB decided to defer the effective date of the revenue standard ASU No. 2014-09, "*Revenue from Contracts with Customers (Topic 606),*" for one year and to permit entities to early adopt the standard as of the original effective date. ASU No. 2014-09 supersedes the revenue recognition requirements of "*Revenue Recognition (Topic 605)*" and clarifies the principles of recognizing revenue. This ASU is effective for the Company January 1, 2018. The Company is currently evaluating this ASU and its potential impact.

In November 2015, the FASB issued ASU No. 2015-17, "*Accounting for Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes."* This ASU simplifies the balance sheet presentation of deferred income taxes by requiring deferred tax liabilities and assets be classified as noncurrent in a classified balance sheet. The Company adopted this standard on December 31, 2015 and applied it prospectively. The adoption of this ASU did not have a material impact on the Company's Financial Statements.

In January 2016, the FASB issued ASU 2016-01, "*Financial Instruments--Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities,*" which amends the classification and measurement of financial instruments. Changes primarily affect the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. This ASU is effective for the Company beginning after December 15, 2017. Early adoption is not permitted. The Company is currently evaluating this ASU and its potential impact.

2. Acquisitions

On January 30, 2015, Union Gas purchased the remaining 25% of HTLP. Total consideration for the transaction consisted of $2.25 million in cash. This purchase resulted in an increase to Paid-in capital of approximately $6 million ($4 million net of tax) and a decrease to Non-controlling interest of approximately $8 million. The Company dissolved HTLP on June 1, 2015 which did not have a significant impact to the Company's Financial Statements.

3. Regulatory Matters

Regulatory Assets and Liabilities

The Company recorded the following assets and liabilities that result from the regulated ratemaking process that would not be recorded under U.S. GAAP for non-regulated entities. See note 1 for further discussion.

($millions)	Financial Statement Location	**December 31, 2015**	December 31, 2014	Recovery/Settlement Period
Regulatory assets[a]				
Customer deferrals	Accounts receivable, net	**43**	42	Less than 1 year
Gas cost deferrals	Accounts receivable, net	**—**	67	Less than 1 year
Gas in storage inventory	Inventories	**53**	8	Less than 1 year
Other deferrals – long-term	Regulatory and other assets	**—**	1	2 – 3 years
Deferred income taxes – long-term[b]	Regulatory and other assets	**403**	362	2 years – remaining life of asset
Total regulatory assets		**499**	480	
Regulatory liabilities[a]				
Other deferrals – current[b]	Accounts payable and accrued charges	**7**	7	Less than 1 year
Customer deferrals	Accounts payable and accrued charges	**1**	28	Less than 1 year
Gas cost deferrals	Accounts payable and accrued charges	**67**	—	Less than 1 year
Asset removal costs[b]	Regulatory and other liabilities	**357**	375	Exceeds remaining life of asset
Total regulatory liabilities		**432**	410	

[a] All regulatory assets and liabilities are excluded from rate base unless otherwise noted.

[b] All or a portion of the balance is included in rate base.

The Company has regulatory assets of $403 million as of December 31, 2015 and $362 million as of December 31, 2014 related to deferred income tax liabilities. Under the current OEB-authorized rate structure, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since substantially all of these timing differences are related to property, plant and equipment costs, recovery of these regulatory assets is expected to occur over the life of those assets.

The Company has regulatory liabilities associated with plant removal costs of $357 million as of December 31, 2015 and $375 million as of December 31, 2014. These regulatory liabilities represent collections from customers under approved rates for future asset removal activities that are expected to occur associated with its regulated facilities.

In addition, the Company has regulatory liabilities of $67 million as of December 31, 2015 and regulatory assets of $67 million as of December 31, 2014 representing gas cost collections from customers under approved rates that vary from the actual cost of gas for the associated periods. The Company files an application quarterly with the OEB to ensure that customers' rates are updated to reflect published forward-market prices. The difference between the approved and actual cost of gas is deferred for future repayment to or refund from customers.

Rate Related Information

The Company's distribution rates, beginning January 1, 2014 are set under a five-year incentive regulation framework. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The framework allows for:

- annual inflationary rate increases, offset by a productivity factor of 60% of inflation, such that the annual net rate escalator in each year is 40% of inflation,
- rate increases or decreases in the small volume customer classes where average use declines or increases,
- certain adjustments to base rates,
- the continued pass-through of gas commodity, upstream transportation and demand side management costs,
- the additional pass-through of costs associated with major capital investments and certain fuel variances,
- an allowance for unexpected cost changes that are outside of management's control,
- equal sharing of tax changes between the Company and its customers, and
- an earnings sharing mechanism that permits the Company to fully retain the return on equity from utility operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.

Demand Side Management (DSM)

In December 2015, the Company filed an application with the OEB for the disposition of the 2014 DSM deferral and variance account balances. As a result of this application, the Company has a receivable from customers of approximately $11 million which is reflected as Accounts receivable, net on the Balance Sheets at December 31, 2015 and December 31, 2014. A hearing and decision from the OEB is expected in 2016.

4. Gas Imbalances

The Company, in the normal course of its operations, experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the Balance Sheet dates. As the settlement of imbalances is done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

At December 31, 2015 Accounts receivable, net and Accounts payable and accrued charges include $350 million (2014 - $660 million) related to gas imbalances and gas balancing services.

5. Inventories

Gas in storage includes gas for delivery to customers and for use in the Company's operations. Inventories of materials and supplies are for use in the Company's operations.

($millions)	**December 31, 2015**	December 31, 2014
Gas in storage	**279**	221
Materials and supplies	**18**	18
	297	239

6. Income Taxes

Income Tax Expense Components

($millions)	2015	2014
Current		
Federal	**43**	16
Provincial	**25**	7
Total current tax expense	**68**	23
Deferred		
Federal	**(24)**	7
Provincial	**(16)**	6
Total deferred tax expense	**(40)**	13
Total Income taxes	**28**	36

Reconciliation of Income Tax Expense at the Combined Federal and Ontario Statutory Tax Rate to Actual Income Tax Expense

($millions)	2015	2014
Income before income taxes	**216**	231
Statutory income tax rate	**26.5%**	26.5%
Statutory income tax rate applied to accounting income	**57**	61
Increase/(decrease) resulting from:		
Deferred income tax adjustments related to rate regulated operations	**(33)**	(27)
Other - net	**4**	2
Total income tax expense	**28**	36
Effective rate of income tax	**13.0%**	15.6%

Net Deferred Income Tax Liability Components

($millions)	December 31, 2015	December 31, 2014
Deferred income tax liabilities		
Accelerated depreciation rates	**370**	344
Regulatory asset	**105**	94
Reserves	**(1)**	27
Other	**(23)**	(23)
Total deferred income tax liabilities	**451**	442

The above deferred tax amounts have been classified in the Balance Sheets as follows:

($millions)	December 31, 2015	December 31, 2014
Current liabilities	—	(25)
Long-term liabilities	**(451)**	(417)
	(451)	(442)

Reconciliation of Gross Unrecognized Income Tax Benefits

($millions)	**December 31, 2015**	December 31, 2014
Balance, beginning of year	**19**	11
Increases related to prior year tax positions	**11**	9
Increases related to current year tax positions	**2**	2
Reductions due to lapse of statute of limitations	**(4)**	(3)
Balance, end of year	**28**	19

Unrecognized tax benefits totalled $28 million at December 31, 2015. Of this, $26 million would reduce the effective tax rate if recognized on or after January 1, 2016. The Company recorded a net increase of $9 million in gross unrecognized tax benefits in 2015. This was a result of $4 million attributable to deferred tax liability and $13 million increase in income tax expense.

The Company recognized potential accrued interest related to unrecognized tax benefits as interest expense. A $1 million benefit was recorded to interest expense in 2015 compared to a $1 million benefit in 2014. Accrued interest totalled $1 million at December 31, 2015 and $2 million at December 31, 2014.

Although uncertain, the Company believes it is reasonably possible that the total amount of unrecognized tax benefits could decrease by $20 million prior to December 31, 2016. The anticipated changes in unrecognized tax benefits relate to the expiration of statutes of limitations and expected audit settlements.

The Company remains subject to examination for income tax returns for years 2009 through 2014.

7. Property, Plant and Equipment, net

($millions)	Useful Life	**December 31, 2015**	December 31, 2014
	(years)		
Plant			
Natural gas transmission	32 - 58	**2,210**	1,819
Natural gas distribution	25 - 60	**4,494**	4,278
Storage	10 - 50	**887**	881
Land rights and rights of way	48 - 61	**120**	110
Other buildings and improvements	2 - 42	**62**	51
Equipment	4 - 15	**86**	89
Vehicles	6	**56**	55
Land	—	**78**	77
Construction in progress	—	**193**	167
Software	4 - 10	**89**	77
Other	15 - 18	**25**	23
Total Property, plant and equipment		**8,300**	7,627
Total accumulated depreciation		**2,545**	2,399
Total accumulated amortization		**77**	74
Total Property, plant and equipment, net		**5,678**	5,154

The Company had no capital leases at December 31, 2015 or 2014.

95% of the Company's property, plant and equipment is regulated with estimated useful lives based on rates approved by the OEB. Composite weighted-average depreciation rates were 2.97% for 2015 and 3.00% for 2014.

The Company capitalized interest of $7 million in 2015 and $4 million in 2014.

Amortization expense of intangible assets totaled $18 million in 2015 and $17 million in 2014. Estimated amortization expense for the next five years is as follows:

($millions)	**2016**	**2017**	**2018**	**2019**	**2020**
Estimated amortization expense	16	13	10	7	6

8. Regulatory and Other Assets and Liabilities

($millions)	**December 31, 2015**	December 31, 2014
Regulatory assets	**403**	363
Goodwill	**12**	12
Pension assets	**28**	5
Gas balancing	**67**	69
Material and supplies	**10**	9
Deposits on projects	**14**	10
Other	**2**	1
Total Regulatory and other assets	**536**	469
Regulatory liabilities	**357**	375
Pension liabilities	**122**	101
Unrecognized tax benefits	**28**	19
Other	**2**	2
Total Regulatory and other liabilities	**509**	497

9. Related Party Transactions

The Company occasionally perform services for and incur costs on behalf of the Company's affiliates, which are subsequently reimbursed. Likewise, certain affiliates may perform services for or incur costs on behalf of the Company, which are then reimbursed by the Company. These transactions are in the normal course of operations and are recorded at exchange amounts agreed to between the related parties.

In addition, Spectra Energy and its affiliates perform centralized corporate functions for the Company, pursuant to an agreement with Spectra Energy and its affiliates, including legal, accounting, compliance, treasury, information technology and other areas, as well as certain engineering and other services. The Company reimburses Spectra Energy and its affiliates for the expenses to provide these services as well as other expenses they incur on the Company's behalf. Spectra Energy and its affiliates charge such expenses based on the cost of actual services provided or using various allocation methodologies based on the Company's percentage of assets, employees, earnings or other measures, as compared to Spectra Energy's other affiliates.

The Company's transactions with affiliated companies are as follows:

($millions), net	**Transport and Storage Expenses**	**Corporate Charges (Receipts)[a]**	**Gas Purchases**
2015			
St Clair Pipelines 1996, a division of Westcoast	—	(2)	—
Pipeline and Field Services, a division of Westcoast	—	(3)	—
Spectra Energy Empress L.P.	—	—	55
Spectra Energy Gas Transmission LLC	—	14	—
Sarnia Airport Storage Pool Limited Partnership	4	—	—
2014			
Pipeline and Field Services, a division of Westcoast	—	(4)	—
Spectra Energy Empress L.P.	—	—	133
Spectra Energy Gas Transmission LLC	—	10	—
Sarnia Airport Storage Pool Limited Partnership	4	—	—

[a]Excludes compensation arrangements.

Net amounts due (to) from related affiliates are as follows:

($millions), net	**2015**	**2014**
Spectra Energy Empress L.P.	(6)	(10)
Spectra Energy Gas Transmission LLC	(7)	6
Total[a]	(13)	(4)

[a]At December 31, 2015, $14 million (2014 – $10 million) is recognized in Accounts payable and accrued charges and $1 million (2014 – $6 million) is recognized in Accounts receivable, net on the Balance Sheets.

In the normal course of operations, the Company provides or obtains funds from Westcoast on an unsecured basis. The balance outstanding at December 31, 2015 was a payable of $56 million (December 31, 2014 – payable of $48 million). During 2015, interest paid on these loans totalled less than $1 million (2014 – less than $1 million) and interest received on these loans totalled less than $1 million (2014 – less than $1 million). Interest on these loans is calculated based on the monthly average of 30-day banker's acceptance rates.

The Company also has a promissory note to borrow up to $150 million from GLBE on an unsecured basis. Funds from this promissory note are used for general corporate purposes. There was no balance outstanding at December 31, 2015 or December 31, 2014.

In addition, beginning in 2014, the Company declared and paid common stock dividends on an annual rather than quarterly basis, and as a result, the Company made a dividend payment to GLBE of $50 million during 2015 (2014 – $100 million).

10. Debt and Credit Facilities

Summary of Debt and Related Terms

($millions)		**December 31, 2015**	December 31, 2014
11.50%	1990 Series debentures, due August 28, 2015	**—**	150
4.64%	Series 5, due June 30, 2016	**200**	200
9.70%	1992 Series II debentures, due November 6, 2017	**125**	125
5.35%	Series 6, due April 27, 2018	**200**	200
8.75%	1993 Series debentures, due August 3, 2018	**125**	125
8.65%	Senior debentures, due October 19, 2018	**75**	75
2.76%	Series 11, due June 2, 2021	**200**	200
4.85%	Series 6, due April 25, 2022	**125**	125
3.79%	Series 10, due July 10, 2023	**250**	250
3.19%	Series 13, due September 17, 2025	**200**	—
8.65%	1995 Series debentures, due November 10, 2025	**125**	125
5.46%	Series 6, due September 11, 2036	**165**	165
6.05%	Series 7, due September 2, 2038	**300**	300
5.20%	Series 8, due July 23, 2040	**250**	250
4.88%	Series 9, due June 21, 2041	**300**	300
4.20%	Series 12, due June 2, 2044	**500**	250
Long-term debt principal (including current maturities)		**3,140**	2,840
Less: Unamortized debt discount		**7**	3
Less: Debt issue costs		**12**	11
Add: Commercial paper		**207**	270
Total debt		**3,328**	3,096
Less: Current maturities of long-term debt		**200**	150
Less: Commercial paper		**207**	270
Total Long-term debt		**2,921**	2,676

The Company's long-term debt is unsecured. Principal repayment requirements on long-term debt are as follows:

($millions)	**Total**	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**
Long-term debt[(a)]	3,140	200	125	400	—	—	2,415

(a) Excludes commercial paper of $207 million.

Under the terms of the trust indentures relating to certain debentures, the Company has agreed to several covenants including a limitation on the payment of dividends. As of December 31, 2015 and 2014, the Company is in compliance with all such covenants.

Total interest expense on long-term debt in 2015 was $163 million (2014 – $159 million).

Available Credit Facility and Restrictive Debt Covenants

($millions)	**Expiration Date**	**Credit Facility Capacity**	**Commercial Paper Debt Outstanding at December 31, 2015**	December 31, 2014
Multi-year syndicated [(a)]	2019	500	**207**	270

[(a)] The credit facility contains a covenant requiring the debt-to-total capitalization ratio, as defined in the agreement, to not exceed 75% and a provision which requires the Company to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 67.8% at December 31 2015 (December 31, 2014 – 68.3%).

The issuance of commercial paper, letters of credit and revolving borrowings reduce the amount available under the credit facility. As of December 31, 2015 and December 31, 2014 there were no letters of credit issued or revolving borrowings outstanding under the credit facility. The majority of the Company's short-term cash requirements are funded through the issuance of commercial paper. The weighted average rate on outstanding commercial paper as of December 31, 2015 was 0.86% (2014 – 1.22%). The weighted average days to maturity on outstanding commercial paper as of December 31, 2015 was 9 days (2014 – 12 days).

The Company's credit agreement contains various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreement. As of December 31, 2015 and December 31, 2014, the Company was in compliance with those covenants. In addition, the credit agreement allows for the acceleration of payments or termination of the agreement due to non-payment, or in some cases, due to the acceleration of other significant indebtedness of the borrower.

Total Interest paid on short term debt in 2015 was $1 million (2014 - $1 million).

11. Preferred Stock

		Outstanding			
	Authorized	**December 31, 2015**	December 31, 2014	**December 31, 2015**	December 31, 2014
	(shares)	*(shares)*		*($millions)*	
Class A	202,072				
5.5% Series A		**47,672**	47,672	**3**	3
6% Series B		**90,000**	90,000	**5**	5
5% Series C		**49,500**	49,500	**2**	2
4.88% Class B, Series 10	Unlimited	**4,000,000**	4,000,000	**100**	100
				110	110

The Class A, Series A and C Preferred stock are cumulative and redeemable at $50.50 per share. The Company is obligated to offer to purchase $170,000 of Series A and $140,000 of Series C shares annually at the lowest price obtainable, but not exceeding $50 per share.

The Class A, Series B Preferred stock are cumulative and redeemable at $55 per share at the option of the Company.

The Class B, Series 10 Preferred stock are cumulative and redeemable at $25 per share at the option of the Company and, at the option of the holders, convertible back into Series 11 shares once every five years commencing January 1, 2014. The holders of the Class B, Series 10 Preferred stock did not exercise their option on January 1, 2014 and their next optional conversion date is January 1, 2019. Union Gas may redeem at any time all, but not less than all, of the outstanding Series 10 Shares. The dividend rate of the Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2018.

The Company has an unlimited number of authorized 4.79% Class B, Series 11 Preferred stock. These shares are cumulative and redeemable at $25 per share at the option of the Company, and at the option of the holders, convertible back into Series 10 shares every five years. At December 31, 2015 and December 31, 2014 none of these shares were issued or outstanding.

The shares are not subject to any sinking fund or mandatory redemption and are not convertible into any other type of securities other than preferred stock. As these shares are not solely in the control of the Company, they have been classified as temporary equity on the Balance Sheets.

12. Employee Benefit Plans

Retirement Plans

The Company maintains registered and non-registered, contributory and non-contributory defined benefit (DB Plans) and defined contribution (DC Plan) retirement plans covering substantially all employees. The DB Plans provide retirement benefits based on each plan participant's years of service and final average earnings. Under the DC Plan, company contributions are determined according to the terms of the plan and based on each plan participant's age, years of service and current eligible earnings. The Company also provides non-registered DB Plans to all employees who retire under a registered DB Plan and whose pension is limited by the maximum pension limits under the Income Tax Act.

The Company's policy is to fund the retirement plans, where applicable, on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants or as required by legislation or plan terms. Total contributions to the DB Plans were $6 million during the twelve months ended December 31, 2015 and $18 million during the twelve months ended December 31, 2014. Contributions of $6 million in both 2015 and 2014 were made to the Company's DC Plan. The Company anticipates that in 2016 it will make total contributions of approximately $4 million to its DB Plans and $6 million to its DC Plan.

Actuarial gains and losses are amortized over the average remaining service period of active employees. The average remaining service periods of active employees covered by the registered and non-registered DB Plans is 11 years. The Company determines the market-related value of plan assets using a calculated value that recognizes changes in fair value of the plan assets over three years.

Registered and Non-Registered Pension Plans

Change in Projected Benefit Obligation and Change in Fair Value of Plan Assets

($millions)	**2015**	2014
Change in Projected Benefit Obligation		
Projected benefit obligation, beginning of year	**863**	748
Service cost	**20**	15
Interest cost	**34**	35
Actuarial (gain) loss	**(5)**	98
Participant contributions	**4**	3
Benefits paid	**(39)**	(36)
Projected benefit obligation, end of year	**877**	863
Change in Fair Value of Plan Assets		
Plan assets, beginning of year	**829**	761
Actual return on plan assets	**45**	86
Benefits paid	**(39)**	(36)
Employer contributions	**6**	18
Plan participants' contributions	**4**	3
Expected non-investment expenses	**(3)**	(3)
Plan assets, end of year	**842**	829
Net amount recognized	**(35)**	(34)

Accumulated Benefit Obligation	**824**	812

($millions)	**2015**	2014
Net amount recognized		
Current Liabilities - Other	**(2)**	(2)
Deferred Credits and Other Liabilities - Regulatory and Other	**(61)**	(37)
Other Assets - Other	**28**	5
Total net amount recognized	**(35)**	(34)

The table above includes non-registered pension plans that are not funded and had projected benefit obligations of $42 million at December 31, 2015 and $39 million at December 31, 2014. At December 31, 2015 there were no registered DB plans with accumulated benefit obligations in excess of plan assets. Non-registered DB plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations of $42 million and accumulated benefit obligations of $38 million.

Amounts Recognized in Accumulated Other Comprehensive Income (AOCI)

($millions)	**2015**	2014
Net actuarial loss	**241**	256
Prior service costs	**4**	5
Total amounts recognized in AOCI, pre-tax	**245**	261

Components of Net Periodic Pension Costs

($millions)	**2015**	2014
Net Periodic Pension Cost		
Service cost benefit earned	**22**	18
Interest cost on projected benefit obligation	**34**	35
Expected return on plan assets	**(56)**	(52)
Amortization of prior service cost	**1**	1
Amortization of loss	**22**	18
Net periodic pension cost	**23**	20
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Current year actuarial (gain) loss	**7**	64
Amortization of actuarial loss	**(22)**	(18)
Amortization of prior service cost	**(1)**	(1)
Total recognized in other comprehensive income	**(16)**	45
Total Recognized in Net Periodic Pension Cost and Other Comprehensive Income	**7**	65

At December 31, 2015, approximately $16 million of actuarial losses will be amortized from AOCI on the Balance Sheets into net periodic pension cost in 2016.

At December 31, 2015, approximately $1 million of prior service costs will be amortized from AOCI on the Balance Sheets into net periodic pension costs in 2016.

Assumptions Used for Pension Benefits Accounting

	2015	2014
Benefit Obligations		
Discount rate	**4.03%**	4.00%
Salary increase	**3.00%**	3.25%
Net Periodic Benefit Cost		
Discount rate	**4.00%**	4.81%
Salary increase	**3.25%**	3.25%
Expected long-term rate of return on plan assets	**7.40%**	7.40%

The discount rates used to determine the benefit obligations are the rates at which the benefit obligations could be effectively settled. The discount rates are developed from yields on available high-quality bonds and reflect each plan's expected cash flows.

The long-term rates of return for the plan assets in 2015 were developed using weighted-average calculations of expected returns based primarily on future expected returns across classes considering the use of active asset managers applied against the plans' respective targeted asset mix.

Registered Pension Plan Assets

Asset Category	Target Allocation	**December 31, 2015**	December 31, 2014
U.S. equity securities	17%	**18%**	17%
Canadian equity securities	25%	**24%**	25%
Other equity securities	13%	**13%**	13%
Fixed income securities	45%	**45%**	45%
Total	100%	**100%**	100%

Pension plan assets are maintained in a master trust. The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trust. Equities are held for their high expected return. Other equity and fixed income securities are held for diversification. Investments within asset classes are diversified to achieve broad market participation and reduce the effects of individual managers or investments. The Company regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate.

The following table summarizes the fair values of pension plan assets recorded at each fair value hierarchy level, as determined in accordance with the valuation techniques described in note 14:

($millions)	**Total**	**Level 1**	**Level 2**	**Level 3**
December 31, 2015				
Cash and cash equivalents	3	3	—	—
Fixed income securities	375	375	—	—
Equity securities	464	205	259	—
Total	842	583	259	—
December 31, 2014				
Cash and cash equivalents	2	2	—	—
Fixed income securities	372	372	—	—
Equity securities	455	270	185	—
Total	829	644	185	—

Expected Benefit Payments

($millions)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021-2025**
Expected benefit payments	40	42	44	46	48	257

Other Post-Retirement Benefit Plans

The Company provides health care and life insurance benefits for retired employees on a non-contributory basis predominantly under defined contribution plans. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. The other post-retirement benefits are not funded.

Other Post-Retirement Benefit Plans - Change in Projected Benefit Obligation and Fair Value of Plan Assets

($millions)	**2015**	2014
Change in Benefit Obligation		
Accumulated post-retirement benefit obligation, beginning of year	**67**	64
Service cost	**2**	1
Interest cost	**2**	3
Actuarial (gains) losses	**(6)**	1
Benefits paid	**(2)**	(2)
Accumulated post-retirement benefit obligation, end of year	**63**	67
Change in Fair Value of Plan Assets		
Plan assets, beginning of year	**—**	—
Benefits paid	**(2)**	(2)
Employer contributions	**2**	2
Plan assets, end of year	**—**	—
Net amount recognized[(a)]	**(63)**	(67)

[(a)] $61 million is recognized in Regulatory and other liabilities and $2 million is recognized in Accounts payable and accrued charges on the Balance Sheets.

Other Post-Retirement Benefit Plans - Amounts Recognized in AOCI

($millions)	**December 31, 2015**	December 31, 2014
Net actuarial (gain) loss recognized in AOCI	**(2)**	4

($millions)	**2015**	2014
Other Post-Retirement Benefit Plans - Components of Net Periodic Benefit Cost		
Service cost benefit earned	**2**	1
Interest cost on accumulated post-retirement benefit obligation	**2**	3
Net periodic other post-retirement benefit cost	**4**	4
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Current year actuarial (losses) gains	**(6)**	1
Total recognized in other comprehensive income	**(6)**	1
Total recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**(2)**	5

Other Post-Retirement Benefits Plans - Assumptions Used for Benefits Accounting

	2015	2014
Benefit Obligations		
Discount rate for post-retirement plans	**4.03%**	4.00%
Salary increase	**3.00%**	3.25%
Net Periodic Benefit Cost		
Discount rate for post-retirement plans	**4.00%**	4.83%
Salary increase	**3.25%**	3.25%

The discount rates used to determine the post-retirement obligations are the rates at which the benefit obligations could be effectively settled. The discount rates for the plans are developed from yields on available high-quality bonds in Canada and reflect each plan's expected cash flows.

Assumed Health Care Cost Trend Rates

	2015	2014
Health care cost trend rate assumed for next year	**5.50%**	6.00%
Rate to which the cost trend rate is assumed to decline	**5.00%**	5.00%
Year that the rate reaches the ultimate trend rate	**2017**	2017

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

($millions)	**1% Point Increase**	1% Point Decrease
Effect on total service and interest costs	**1**	—
Effect on post-retirement benefit obligations	**4**	(3)

Other Post-Retirement Benefit Plans - Payments and Receipts

The Company expects to make future benefit payments, which reflect expected future service, as appropriate. The following benefit payments are expected to be paid over each of the next five years and thereafter.

($millions)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021-2025**
Expected benefit payments	2	3	3	3	3	17

Retirement/Savings Plan

The Company has employee savings plans available to eligible employees. Employees may participate in a matching contribution where the Company matches a certain percentage of before tax employee contributions of up to 5% of eligible pay per pay period. The Company expensed pre-tax employer matching contributions of $8 million in both the twelve months ended December 31, 2015 and 2014.

13. Asset Retirement Obligations

The Company's AROs relate to the legal obligation to disconnect, purge and cap abandoned pipelines, capping abandoned storage wells, and in some buildings, special handling and disposition of asbestos if it is disturbed.

The Company has non-asbestos AROs which include easements and some railway license agreements relating to pipeline assets located on land which the Company does not own. The Company has not recognized a liability in regard to the non-asbestos ARO because the fair value of the ARO cannot be reasonably estimated. The Company's pipeline system is considered a critical component of its business and is expected to be maintained and remain in place indefinitely. Natural gas supplies are also considered sufficient for the Company to operate in the long-term. The Company has determined that sufficient information to estimate the fair value of an ARO is not available because the assets are considered permanent with indeterminate useful lives and that sufficient information is not available to estimate a range of potential settlement dates in order to employ a present value technique to estimate fair value.

AROs are adjusted each period for liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Reconciliation of Changes in Asset Retirement Obligation Liabilities

($millions)	**December 31, 2015**	December 31, 2014
Balance, beginning of year	**368**	328
Accretion expense	**17**	16
Liabilities settled	**(7)**	(6)
Revisions in estimated cash flows	**62**	30
Balance, end of year	**440**	368

14. Fair Value Measurements

Financial instruments recorded at fair value on the Balance Sheets are valued using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1

Level 1 valuations represent quoted unadjusted prices for identical instruments in active markets.

Level 2 Valuation Techniques

Fair values of the Company's financial instruments that are actively traded in the secondary market are determined based on market-based prices. These valuations may include inputs such as quoted market prices of the exact or similar instruments, broker or dealer quotations, or alternative pricing sources that may include models or matrix pricing tools, with reasonable levels of price transparency. The fair value of the Company's pension plan assets designated as Level 2 financial instruments is determined through the market approach valuation technique using observable inputs including matrix pricing and market corroborated pricing.

Level 3 Valuation Techniques

Level 3 valuation techniques include the use of pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation. The fair value of the Company's pension plan assets designated as Level 3 financial instruments is determined through the market approach valuation technique using unobservable inputs including investment manager pricing for private placements and private equities.

There were no transfers between levels during the year ended December 31, 2015.

Financial Instruments

The fair values of financial instruments that are recorded and carried at book value are summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. These estimates are not necessarily indicative of the amounts that could have been realized in current markets.

	December 31, 2015		December 31, 2014	
($millions)	**Book Value**	**Fair Value**	Book Value	Fair Value
Long-term debt, including current maturities[a]	**3,140**	**3,538**	2,840	3,323

[a] Excludes unamortized items.

The fair value of the Company's Long-term debt is determined based on market-based prices as described in the Level 2 valuation technique described above.

The fair values of Cash and cash equivalents, Accounts receivable, net, Accounts payable and accrued charges, Short-term borrowings and Commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates.

Credit risk

Credit risk is the risk of financial loss to the Company if a counterparty to a financial instrument fails to meet its contractual obligations. The maximum exposure to credit risk for the Company at period end is the carrying value of its financial assets. The Company's principal customers for natural gas transportation and storage services are industrial end-users, marketers, local distribution companies and utilities. The Company's distribution customers are primarily industrial and residential end-users. These concentrations of customers may affect the Company's overall credit risk.

The Company, in the normal course of its operations, provides gas loans to other parties from its holdings of gas in storage. The replacement cost of gas loans at December 31, 2015 is $51 million receivable (2014 - $102 million receivable). The Company manages its credit exposure related to gas loans by subjecting these parties to the same credit policies it uses for all customers, and obtaining collateral when appropriate.

The Company manages its credit risk on Cash and cash equivalents by dealing solely with reputable banks and financial institutions. To manage its credit risk on Accounts receivable, net the Company performs ongoing credit reviews of all its customers. In cases where the credit quality of a customer does not meet the Company's requirements, a cash deposit, letter of credit or parental guarantee is required. Deposits held by the Company at December 31, 2015 amounted to $40 million (2014 - $37 million). Significant financial difficulties of the debtor, the probability that the debtor will enter bankruptcy or financial reorganization, and default or delinquency in payments are considered indicators that the account receivable may be uncollectible and therefore should be included in the allowance for doubtful accounts.

The Company continues to utilize its established risk management policies and procedures to ensure the appropriate monitoring of customer credit positions and, based on current evaluations, does not expect any significant negative impacts associated with these positions.

The following table sets forth details of the age of trade receivables that are not impaired as well as the allowance for the doubtful accounts:

($millions)	**December 31, 2015**	December 31, 2014
Current	**218**	316
30 Days over due	**10**	13
60 Days over due	**4**	5
90+ Days over due	**11**	12
Total trade accounts receivable	**243**	346
Allowance for doubtful accounts	**(6)**	(6)
Total trade accounts receivable, net[a]	**237**	340

[a] The carrying amount of accounts receivable is impacted by changes in gas prices, which may fluctuate significantly from year to year.

For the years ended December 31, 2015 and 2014, no one customer accounted for more than 10% of sales or 10% of receivables.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its obligations as they become due. The Company manages its liquidity risk by forecasting cash flows from operations and anticipated investing and financing activities. The Company has credit facilities available to help meet short-term financing needs (note 10).

The following are the contractual maturities of the undiscounted cash flows of financial liabilities as at December 31, 2015:

($millions)	**Total**	**2016**	**2017-2018**	**2019-2020**	**Thereafter**
Commercial paper	207	207	—	—	—
Accounts payable and accrued charges	793	793	—	—	—
Long-term debt (including principal and interest)	5,468	359	816	227	4,066
Total	6,468	1,359	816	227	4,066

15. Stock Based Compensation

The Spectra Energy 2007 Long-Term Incentive Plan (the 2007 LTIP), as amended and restated, provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for Spectra Energy. A maximum of 40 million shares of common stock may be awarded under the 2007 LTIP. Union Gas employees participate in the 2007 LTIP.

Stock based performance awards generally vest over three years at the earliest, if performance metrics are met. Spectra Energy granted 36,100 performance awards in 2015 and 38,200 in 2014, with fair values of U.S. $2 million for both 2015 and 2014 to Union Gas employees. There were no performance awards vested in 2015 and the total fair value of the performance awards vested in 2014 was U.S. $1 million. As of December 31, 2015, the Company expects to recognize U.S. $2 million of future compensation cost related to performance awards over a weighted-average period of less than one year.

Stock based phantom awards generally vest over three years. Spectra Energy awarded 22,650 phantom awards in 2015 and 24,200 in 2014, with fair values of U.S. $1 million for both 2015 and 2014 to Union Gas employees. The total fair value of the phantom awards vested was U.S. $1 million in both 2015 and 2014. As of December 31, 2015, the Company expects to recognize U.S. $1 million of future compensation cost related to phantom awards over a weighted-average period of less than two years.

	Performance Awards		**Phantom Awards**	
	Units	**Weighted-Average Grant Date Fair Value U.S. $**	**Units**	**Weighted-Average Grant Date Fair Value U.S. $**
Outstanding, beginning of year	126,519	35	78,872	32
Granted	36,100	48	22,650	37
Vested	—	—	(25,902)	31
Forfeited	(42,516)	21	(523)	19
Outstanding, end of year	120,103	39	75,097	26
Awards expected to vest	116,070	39	74,186	26

16. Guarantees

The Company has various financial guarantees which are issued in the normal course of business. The Company enters into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these agreements involve elements of performance and credit risk, which are not included on the Balance Sheets. The possibility of having to perform under these guarantees is largely dependent upon future operations of other third parties or the occurrence of certain future events. The Company's potential exposure under these agreements can range from a specific dollar amount to an unlimited dollar amount depending on the nature of the claim and the particular transaction. The Company is unable to estimate the total potential amount of future payments under these agreements due to several factors, such as unlimited exposure under certain guarantees.

17. Contingencies

The Company, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Accruals are made in instances where it is probable that liabilities will be incurred and where such liabilities can be reasonably estimated.

In November 2015, the Ontario Ministry of the Environment and Climate Change issued and posted a proposed draft Director's Order (the Order) naming the Company, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of the Company in Hamilton. If issued in its current form, the Order would require all parties to act jointly to develop a Conceptual Site Model to fully delineate the extent of the soil and groundwater contamination and to assess remedial measures, if necessary. In December 2015, the Company requested that the Ministry revise the proposed draft Order to more properly focus only on the party responsible for the contamination, as opposed to those parties impacted by the contamination. The Company is of the view that the cost of any potential remedial measures, if any, cannot be estimated at this time.

Other than the potential contingency noted above, of which the impact is unknown, the Company has no reason to believe that the ultimate outcome of these matters could have a significant impact on its Financial Statements.

18. Subsequent Events

Management has evaluated significant events and transactions that occurred from January 1, 2016 through March 3, 2016, the date the financial statements were filed, and no subsequent events requiring disclosure were noted.

DIRECTORS

David G. Unruh
Stephen W. Baker
Bruce E. Pydee

OFFICERS

Stephen W. Baker
Chair and President

J. Patrick Reddy
Chief Financial Officer

M. Richard Birmingham
Vice President, Regulatory, Lands and Public Affairs

Bruce E. Pydee
Vice President and General Counsel

Janice L. Ferguson
Vice President, Human Resources

Mark J. Isherwood
Vice President, Business Development - Storage and Transmission

Paul Rietdyk
Vice President, Engineering, Construction and Storage and Transmission Operations

Michael G.P. Shannon
Vice President, Distribution Operations

Wendy H. Zelond
Vice President, Finance

Laura J. Sayavedra
Vice President and Treasurer

Timothy J. Kennedy
Vice President, Government and Aboriginal Affairs

David G. Simpson
Vice President, In-Franchise Sales, Marketing and Customer Care

Paul K. Haralson
Assistant Treasurer

Annachiara Jones
Corporate Secretary

Patricia M. Rice
Assistant Corporate Secretary

Tanya Mushynski
Assistant Secretary

CORPORATE INFORMATION

Transfer Agent and Registrar **CST Trust Company**

Union Gas Limited preferred stock are listed on the Toronto Stock Exchange
Class A Preferred, Series A - 5½% (UNG.PR.C)

Class A Preferred, Series B - 6% (UNG.PR.D)

REGISTERED OFFICE

50 Keil Drive North
Chatham, Ontario N7M 5M1

ENBRIDGE

ENBRIDGE GAS DISTRIBUTION INC.
(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2016

MANAGEMENT'S REPORT

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 related financial information, including Management's Discussion and Analysis. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors (the Board) and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (AF&RC) of the Board, includes directors who are unrelated and independent, and has a specific responsibility to oversee management's efforts to fulfill 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 U.S. GAAP 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.

(Signed)

Cynthia L. Hansen
President

(Signed)

William M. Ramos
Vice President, Finance

February 16, 2017

February 16, 2017

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, 2016 and December 31, 2015 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, 2016, 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 accounting principles generally accepted in the United States of America 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.

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Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and their subsidiaries as at December 31, 2016 and December 31, 2015 and its results of operations and their cash flows for each of the three years in the period ended December 31, 2016 in accordance with accounting principles generally accepted in the United States of America.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Professional Accountants, Licensed Public Accountants

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	2016	2015	2014
(millions of Canadian dollars)			
Revenues			
Gas commodity and distribution revenue *(Note 22)*	**2,437**	3,043	2,803
Transportation of gas for customers	**330**	344	305
Other revenue *(Note 22)*	**100**	97	92
	2,867	3,484	3,200
Expenses			
Gas commodity and distribution costs *(Note 22)*	**1,636**	2,322	2,046
Operating and administrative *(Notes 15, 20 and 22)*	**534**	509	493
Depreciation and amortization *(Notes 7 and 9)*	**322**	290	286
Earnings sharing *(Note 4)*	**3**	7	12
	2,495	3,128	2,837
	372	356	363
Other income *(Note 22)*	**73**	70	66
Interest expense, net *(Notes 11, 17 and 22)*	**(206)**	(181)	(177)
	239	245	252
Income taxes expense *(Note 18)*	**(9)**	(11)	(6)
Earnings	**230**	234	246
Preference share dividends *(Note 14)*	**(2)**	(2)	(2)
Earnings attributable to the common shareholder	**228**	232	244

The accompanying notes are an integral part of these Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Earnings	**230**	234	246
Other comprehensive loss, net of tax *(Notes 16 and 17)*			
Change in unrealized loss on cash flow hedges	**(11)**	(18)	(62)
Reclassification to earnings of realized loss on cash flow hedges	**5**	5	-
Actuarial gain/(loss) on other postretirement benefits (OPEB) *(Note 19)*	**(1)**	-	(7)
Change in foreign currency translation adjustment	**(2)**	8	3
Other comprehensive loss	**(9)**	(5)	(66)
Comprehensive income	**221**	229	180
Preference share dividends	**(2)**	(2)	(2)
Comprehensive income attributable to the common shareholder	**219**	227	178

The accompanying notes are an integral part of these Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Preference shares *(Note 14)*	**100**	100	100
Common shares *(Note 14)*			
Balance at beginning of year	**1,637**	1,437	1,287
Common shares issued	**280**	200	150
Balance at end of year	**1,917**	1,637	1,437
Additional paid-in capital	**1,148**	1,148	1,148
Retained earnings			
Balance at beginning of year	**71**	62	22
Earnings attributable to the common shareholder	**228**	232	244
Common share dividends declared *(Note 22)*	**(237)**	(223)	(204)
Balance at end of year	**62**	71	62
Accumulated other comprehensive loss *(Note 16)*			
Balance at beginning of year	**(6)**	(1)	65
Other comprehensive loss	**(9)**	(5)	(66)
Balance at end of year	**(15)**	(6)	(1)
Total shareholders' equity	**3,212**	2,950	2,746

The accompanying notes are an integral part of these Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Operating activities			
Earnings	**230**	234	246
Depreciation and amortization *(Notes 7 and 9)*	**322**	290	286
Deferred income taxes *(Note 18)*	**(22)**	16	4
Refund of revenues	**-**	(52)	52
Non-cash net defined pension and OPEB obligation costs	**30**	31	(5)
Other	**4**	(2)	18
Changes in operating assets and liabilities *(Notes 5 and 21)*	**78**	325	(1,031)
	642	842	(430)
Investing activities			
Additions to property, plant and equipment	**(545)**	(977)	(601)
Additions to intangible assets	**(57)**	(46)	(36)
Change in construction payable	**(138)**	151	17
Proceeds from disposition	**-**	8	-
	(740)	(864)	(620)
Financing activities			
Change in bank indebtedness	**45**	18	9
Net change in short-term borrowings *(Note 11)*	**(248)**	(340)	564
Net change in short-term borrowings from affiliates *(Note 22)*	**(6)**	(170)	189
Term note and credit facility issuances *(Note 11)*	**309**	558	729
Term credit facility repayments	**(7)**	(2)	(400)
Common shares issued *(Notes 14 and 22)*	**280**	200	150
Preference share dividends	**(2)**	(2)	(2)
Common share dividends	**(233)**	(218)	(203)
Other	**-**	(3)	(2)
	138	41	1,034
Increase/(decrease) in cash and cash equivalents	**40**	19	(16)
Cash and cash equivalents at beginning of year	**36**	17	33
Cash and cash equivalents at end of year	**76**	36	17
Supplementary cash flow information			
Income taxes paid/(received)	**5**	(17)	23
Interest paid *(Note 11)*	**208**	193	191

The accompanying notes are an integral part of these Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2016**	2015
(millions of Canadian dollars, number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**76**	36
Restricted cash *(Note 5)*	**58**	-
Accounts receivable and other *(Notes 3, 4, 6, 17 and 18)*	**655**	790
Due from affiliates *(Note 22)*	**16**	10
Gas inventories	**512**	547
	1,317	1,383
Property, plant and equipment, net *(Note 7)*	**7,418**	7,081
Investment in affiliate *(Notes 17 and 22)*	**825**	825
Deferred amounts and other assets *(Notes 3, 4, 8, 18 and 19)*	**576**	543
Intangible assets, net *(Note 9)*	**158**	157
	10,294	9,989
Liabilities and shareholders' equity		
Current liabilities		
Bank indebtedness	**72**	27
Short-term borrowings *(Note 11)*	**351**	599
Short-term borrowings from affiliate *(Notes 11 and 22)*	**34**	40
Accounts payable and other *(Notes 4, 5, 10, 17, 19 and 20)*	**807**	870
Due to affiliates *(Note 22)*	**95**	87
Current maturities of long-term debt *(Note 11)*	**500**	2
	1,859	1,625
Long-term debt *(Notes 3 and 11)*	**3,470**	3,668
Other long-term liabilities *(Notes 4, 12, 13, 17 and 19)*	**846**	847
Deferred income taxes *(Notes 3 and 18)*	**532**	524
Loans from affiliate *(Notes 11 and 22)*	**375**	375
	7,082	7,039
Shareholders' equity		
Share capital *(Note 14)*		
Preference shares *(convertible; 4 outstanding at December 31, 2016 and December 31, 2015)*	**100**	100
Common shares *(186 and 170 outstanding at December 31, 2016 and 2015, respectively)*	**1,917**	1,637
Additional paid-in capital	**1,148**	1,148
Retained earnings	**62**	71
Accumulated other comprehensive loss *(Note 16)*	**(15)**	(6)
	3,212	2,950
	10,294	9,989

The accompanying notes are an integral part of these Consolidated Financial Statements.

Approved by the Board of Directors:

(Signed)

Cynthia L. Hansen
President

(Signed)

J. Herb England
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

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).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These Consolidated Financial Statements are prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

The Company is permitted to prepare its Consolidated Financial Statements in accordance with U.S. GAAP for purposes of meeting its Canadian continuous disclosure requirements under an exemption granted by securities regulators in Canada until 2018.

BASIS OF PRESENTATION AND USE OF ESTIMATES
The preparation of Consolidated Financial Statements in conformity with U.S. 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 4)*; unbilled revenues *(Note 6)* and unbilled amounts pertaining to the Budget Billing Program *(Note 10)*; allowance for doubtful accounts *(Note 6)*; carrying value of gas inventory; depreciation rates and carrying value of property, plant and equipment *(Note 7)*; amortization rates and carrying value of intangible assets *(Note 9)*; valuation of stock-based compensation *(Note 15)*; fair value of financial instruments *(Note 17)*; provisions for income taxes *(Note 18)*; assumptions used to measure retirement and OPEB *(Note 19);* commitments and contingencies *(Note 23)*; and fair value of asset retirement obligations (ARO) *(Note 13)*. Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION
The Consolidated Financial Statements include the accounts of the Company and its subsidiary. 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 ratemaking 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 U.S. GAAP for non rate-regulated entities *(Note 4)*.

REVENUE RECOGNITION
The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas commodity and 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. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company’s franchise areas.

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 approved by the Regulators. This may give rise to regulatory deferral accounts pending disposition by decisions of the Regulators.

PUSH-DOWN ACCOUNTING
The Company elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge, when it first adopted U.S. GAAP. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by the Company. Upon adopting push-down accounting, the historical cost of the Company's property, plant and equipment and related accounts was adjusted by the remaining unamortized fair value adjustment.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships
The Company uses derivative financial instruments to manage its exposure to changes in interest rates and foreign exchange. 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 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 at December 31, 2016 or 2015.

Cash Flow Hedges
The Company uses cash flow hedges to manage its exposure to changes in currency exchange rates related to unregulated storage revenue and 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/loss (OCI) and is reclassified to earnings when the hedged item impacts earnings. 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 at that date is deferred in OCI and 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 derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

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

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Consolidated Statements of Cash Flows.

Balance Sheet Offset
Assets and liabilities arising from derivative instruments may be 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 as a direct deduction from the carrying amount of the related debt liability. These costs are amortized using the effective interest rate method over the life of the related debt instrument and are recorded in Interest expense.

INCOME TAXES
The liability method of accounting for income taxes is followed. Deferred 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. Deferred 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. Deferred tax liabilities and assets are classified as noncurrent in the Consolidated Statements of Financial Position.

The regulated utility operations of the Company recover income tax expense based on the taxes payable method as approved by the Regulators for rate-making purposes. As a result, rates do not include the recovery of deferred income taxes related to temporary differences. A corresponding deferred income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates (*Note 4*).

FOREIGN CURRENCY TRANSACTIONS AND 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, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the date of the Consolidated Statement of Financial Position. 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 functional currency of the Company's only foreign operation, St. Lawrence, is the United States dollar (USD). The effects of translating the financial statements of St. Lawrence to Canadian dollars are included in the cumulative translation adjustment component of Accumulated other comprehensive income/loss (AOCI). Asset and liability accounts are translated at the exchange rates in effect on the date of the Consolidated Statement of Financial Position, while revenues and expenses are translated at monthly average rates.

CASH AND CASH EQUIVALENTS
Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

RESTRICTED CASH
Cash and cash equivalents that are restricted as to withdrawal or usage, in accordance with specific agreements, are presented as Restricted cash on the Consolidated Statements of Financial Position *(Note 5)*.

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.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment is recorded at historical cost, including associated operating costs and an allowance for interest during construction as authorized by the Regulators. 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 a future benefit.

The pool method of accounting for property, plant and equipment is followed whereby similar assets with comparable useful lives are grouped and depreciated as a pool, as approved by the Regulators. 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 until the last asset in the pool is disposed of. Gains and losses from the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. 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.

DEFERRED AMOUNTS AND OTHER ASSETS
Deferred amounts and other assets primarily include: costs which the Regulators have permitted, or are expected to permit, to be recovered through future rates; deferred income taxes; and derivative financial instruments.

INTANGIBLE ASSETS
Intangible assets consist primarily of the Company's Customer Information System (CIS) and software costs, including the Work and Asset Management Solution (WAMS). The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangible assets are amortized on a straight-line basis over their expected useful lives, commencing when the asset is available for use.

ASSET RETIREMENT OBLIGATIONS
ARO 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. ARO 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 ARO due to the indeterminate timing and scope of the asset retirements.

RETIREMENT AND POSTRETIREMENT 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 estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality.

Effective January 1, 2016, the Company refined the method to estimate current service cost and interest cost for pension and other postretirement benefits. Previously, these were estimated utilizing a single weighted-average discount rate derived from the yield curve used to measure the defined benefit obligation at the beginning of the year. Under the refined method, different discount rates are derived from the same yield curve, reflecting the different timing of benefit payments for past service (the defined benefit obligation) and future service (the current service cost). Differentiating in this way represents a refinement in the basis of estimation applied in prior periods. This change does not affect the measurement of the total defined benefit obligation recorded on the Consolidated Statements of Financial Position as at December 31, 2016 or any other period. The refinement compared to the previous method resulted in a decrease in the current service cost and interest components with an equal offset to actuarial gains (losses) with no net impact on the total benefit obligation. The refinement did not have a material impact on the Consolidated Statements of Earnings for the year ended December 31, 2016. This change was accounted for prospectively as a change in accounting estimate.

In 2014, new mortality assumptions were issued and further revised in 2015. These assumptions were adopted by the Company for the measurement of the December 31, 2015 benefit obligations. The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans. Pension cost is charged to earnings and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of 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, changes in headcount 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 contributions occur.

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

The overfunded or underfunded status of defined benefit pension and OPEB plans is recognized as Deferred amounts and other assets or Other long-term liabilities, respectively, on the Consolidated Statements of Financial Position. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax.

The Company records regulatory adjustments to reflect the difference between pension expense and OPEB costs for accounting purposes and the pension expense and OPEB costs for rate-making purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension expense or OPEB costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation accounting, regulatory balances would not be recorded and pension and OPEB costs would be charged to earnings and OCI on an accrual basis.

STOCK-BASED COMPENSATION

Enbridge grants stock-based compensation to certain employees and senior officers of the Company through four long-term incentive compensation plans. Compensation expense associated with each of the plans, as determined under the methods outlined below is recognized in Operating and administrative expense. Amounts owing to Enbridge in respect of stock-based compensation are payable on a quarterly basis.

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 of the ISOs granted 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.

Performance Stock Units (PSU) and Restricted Stock Units (RSU) 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, compensation expense is recorded based on the number of units outstanding and the current market price of the Company's shares. The value of the PSUs is also dependent on the Company's performance relative to performance targets set out under the plan.

Performance Stock Options (PSO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the PSOs granted as calculated by the Bloomberg barrier option valuation model and is recognized over the vesting period. The options become exercisable when both performance targets and the time vesting requirements have been met.

COMMITMENTS AND CONTINGENCIES

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, the Company determines it is either probable that an asset has been impaired, or a liability has been incurred, and the amount of the impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Classification of Deferred Taxes on the Statement of Financial Position

Effective January 1, 2016, the Company elected to early adopt Accounting Standards Update (ASU) 2015-17 and applied the standard on a prospective basis. The amendments require that deferred tax liabilities and assets be classified as noncurrent in the Consolidated Statements of Financial Position. The adoption of the standard resulted in a decrease to Deferred income taxes of $18 million and a decrease to Accounts receivable and other of $18 million.

Measurement Date of Defined Benefit Obligation and Plan Assets

Effective January 1, 2016, the Company adopted ASU 2015-04 on a prospective basis. The revised criteria simplifies the fair value measurement of defined benefit plan assets and obligations. The adoption of the pronouncement did not have a material impact on the Company's Consolidated Financial Statements.

Simplifying the Presentation of Debt Issuance Costs

Effective January 1, 2016, the Company adopted ASU 2015-03 on a retrospective basis which, as at December 31, 2015, resulted in a decrease in Deferred amounts and other assets of $13 million and a corresponding decrease in Long-term debt of $13 million. The new standard requires debt issuance costs related to a recognized debt liability to be presented in the Consolidated Statements of Financial Position as a direct deduction from the carrying amount of that debt liability, consistent with the presentation of debt discounts or premiums. Further, effective January 1, 2016, the Company adopted ASU 2015-15 which clarifies that debt issuance costs associated with line-of-credit arrangements may be deferred as an asset and subsequently amortized over the term of the arrangement. The adoption of ASU 2015-15 did not have a material impact on the Company's Consolidated Financial Statements.

FUTURE ACCOUNTING POLICY CHANGES

Clarifying the Presentation of Restricted Cash in the Statement of Cash Flows

ASU 2016-18 was issued in November 2016 with the intent to add or clarify the guidance on the classification and presentation of changes in restricted cash and restricted cash equivalents within the cash flow statement. The amendments require that changes in restricted cash and restricted cash equivalents should be included within cash and cash equivalents when reconciling the opening and closing period amounts shown on the Statements of Cash Flows. The Company is currently assessing the impact of the new standard on its Consolidated Financial Statements. The accounting update is effective for fiscal years beginning after December 15, 2017 and is to be applied on a retrospective basis.

Simplifying Cash Flow Classification
ASU 2016-15 was issued in August 2016 with the intent of reducing diversity in practice of how certain cash receipts and cash payments are classified in the Consolidated Statements of Cash Flows. The new guidance addresses eight specific presentation issues. The Company is currently assessing the impact of the new standard on its Consolidated Financial Statements. The accounting update is effective for annual and interim periods beginning on or after December 15, 2017 and is to be applied on a retrospective basis.

Accounting for Credit Losses
ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred loss methodology for recognizing credit losses, which delays the recognition until it is probable a loss has been incurred. The amendment adds a new impairment model, known as the current expected credit loss model that is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes will result in more timely recognition of such losses. The Company is currently assessing the impact of the new standard on its Consolidated Financial Statements. The accounting update is effective for annual and interim periods beginning on or after December 15, 2019.

Improvements to Employee Share-Based Payment Accounting
ASU 2016-09 was issued in March 2016 with the intent of simplifying and improving several aspects of accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities, and classification on the Consolidated Statements of Cash Flows. The accounting update is effective for annual and interim periods beginning on or after December 15, 2016 and is to be applied on a prospective or retrospective basis. The adoption of the pronouncement is not anticipated to have a material impact on the Company's Consolidated Financial Statements.

Recognition of Leases
ASU 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the Statement of Financial Position and disclosing additional key information about leasing arrangements. The Company is currently assessing the impact of the new standard on its Consolidated Financial Statements. The accounting update is effective for interim and annual periods beginning on or after December 15, 2018, and is to be applied using a modified retrospective approach.

Recognition and Measurement of Financial Assets and Liabilities
ASU 2016-01 was issued in January 2016 with the intent to address certain aspects of recognition, measurement, presentation, and disclosure of financial assets and liabilities. The amendments revise accounting related to the classification and measurement of investments in equity securities, the presentation of certain fair value changes for financial liabilities measured at fair value, and the disclosure requirements associated with the fair value of financial instruments. The Company is currently assessing the impact of the new standard on its Consolidated Financial Statements. The accounting update is effective for fiscal years beginning after December 15, 2017, and is to be applied by means of a cumulative-effect adjustment to the Statements of Financial Position as of the beginning of the fiscal year of adoption, with amendments related to equity securities without readily determinable fair values to be applied prospectively.

Revenue from Contracts with Customers
ASU 2014-09 was issued in 2014 with the intent of significantly enhancing consistency and comparability of revenue recognition practices across entities and industries. The new standard establishes a single, principles-based five-step model to be applied to all contracts with customers and introduces new and enhanced disclosure requirements. The standard is effective January 1, 2018. The new revenue standard permits either a full retrospective method of adoption with restatement of all prior periods presented, or a

modified retrospective method with the cumulative effect of applying the new standard recognized as an adjustment to opening retained earnings in the period of adoption. The Company is currently assessing which transition method to use.

The Company has reviewed a sample of its revenue contracts in order to evaluate the effect of the new standard on its revenue recognition practices. Based on our initial assessment, the application of the standard may result in a change in presentation related to payments to customers under the earnings sharing mechanism which are currently shown as an expense in the Consolidated Statements of Earnings. Under the new standard, these payments would be reflected as a reduction of revenue. While we have not yet completed our assessment, our preliminary view is that we do not expect these changes to have a material impact on our revenue or earnings. The Company is also developing processes to generate the disclosures required under the new standard.

4. 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.

RECENT RATE APPROVALS

Enbridge Gas Distribution
For the year ended December 31, 2016, Enbridge Gas Distribution’s rates were set according to the OEB approved settlement agreement (December 2015) in the Company’s 2016 rate application, updated to reflect the OEB’s decision and final rate order (May 2016) in the Company’s multi-year demand side management (DSM) application. The rates approved as part of the 2016 rate application represented the third year of the Company’s customized incentive regulation (IR) plan, which set rates for the period of 2014 to 2018, and was approved by the OEB in July and August 2014. As specified within the customized IR plan, DSM costs are one of the select items to be updated annually.

For the year ended December 31, 2015, Enbridge Gas Distribution’s rates were set according to the OEB approved settlement agreement (April 2015) and final rate order (May 2015), in the Company’s 2015 rate application.

For the year ended December 31, 2014, Enbridge Gas Distribution’s rates were set by the OEB’s July 2014 decision, and subsequent August 2014 decision and rate order in the Company’s customized IR application. The decisions and rate order established final 2014 allowed revenues and billing rates, as well as placeholder allowed revenues for 2015 through 2018. The customized IR plan requires Enbridge Gas Distribution to update select items in each of 2015 through 2018, in order to establish final allowed revenues and rates. The customized IR decision also approved the adoption of a new approach for determining net negative salvage percentages as a component of Enbridge Gas Distribution’s depreciation rates, as well as an earnings sharing mechanism in which Enbridge Gas Distribution shares earnings above the approved base return equally with customers.

Under the customized IR plan, the Company has continued to apply the accounting guidance found in Accounting Standards Codification (ASC) 980 – Regulated Operations.

St. Lawrence
St. Lawrence is currently in a rate year ending May 31, 2017, according to the recent NYSPSC order establishing a three year rate plan covering the period of June 1, 2016 through May 31, 2019. For the years ended December 31, 2016, 2015 and 2014, St. Lawrence’s rates were set using a Cost of Service (COS) methodology. Under COS, revenues are set to recover costs and to earn a rate of return on the deemed common equity component of rate base. Costs include natural gas commodity and transportation, operating and administrative, depreciation and amortization, interest and income taxes. 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. Gas costs are not recovered through revenue rates, but are set separately in gas cost rates.

For the rate year ending May 31, 2017, any earnings above the approved return on equity and between 9.5% to 10.0% will be shared 50/50 between customers and the Company; from 10.0% to 10.5%, 80/20; and over 10.5%, 90/10; respectively. The calculation of earnings is on an annual basis for each rate year period commencing June 1, 2016. There was no earnings sharing for the period of January 1, 2016 to May 31, 2016. In fiscal 2015 and fiscal 2014, any earnings above a return on equity of 11% were shared equally with the customers. The calculation from January 1, 2015 to December 31, 2015 resulted in no sharing impact as at December 31, 2015 (2014 – nil).

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.

During the years ended December 31, 2016, 2015 and 2014, the cost of natural gas was passed on to customers as a flow-through.

APPROVED RETURNS ON EQUITY

Enbridge Gas Distribution

Enbridge Gas Distribution's rates for 2016 included an after-tax rate of return on common equity of 9.19% (2015 - 9.30% and 2014 - 9.36%) based on a 36% (2015 and 2014 - 36%) deemed common equity component of rate base.

St. Lawrence

St. Lawrence's approved after-tax rate of return on common equity embedded in rates was 9.0% for the rate year ended May 31, 2017 (fiscal 2015 and fiscal 2014 - 10.5%) based on a 48% (fiscal 2015 and fiscal 2014 - 50%) deemed common equity component of rate base.

IMPACTS OF RATE REGULATION

Regulatory Assets and Liabilities

As a result of rate regulation accounting, 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 accounting, 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. The Regulators' future actions may differ from current expectations or future legislative changes may impact the regulatory environment in which the Company operates. To the extent that the Regulators' future actions are different from current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

FINANCIAL STATEMENT EFFECTS

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

December 31,	**2016**	2015	Consolidated Statement of Financial Position Location**	Estimated Recovery/ Settlement Period *(years)*
(millions of Canadian dollars)				
Regulatory assets/(liabilities)				
Enbridge Gas Distribution				
Deferred income taxes[1]	**381**	324	DA	*
OPEB[2]	**71**	75	AR/DA	16
Pension plans, net[3]	**55**	30	DA/OLTL	*
Constant dollar net salvage adjustment[4]	**38**	42	DA	*
Unaccounted for gas variance[5]	**13**	3	AR	1
Average use true-up variance[6]	**10**	(2)	AR/OLTL	*
Storage and transportation deferral[7]	**10**	5	AR	1
Customer care CIS rate smoothing deferral[8]	**8**	9	DA/OLTL	2
Deferred rebate deferral[9]	**8**	-	AR	1
Demand side management incentive[10]	**6**	8	AR	*
Purchased gas variance[11]	**5**	129	AR	1
GTA incremental transmission capital revenue requirement deferral[12]	**4**	-	AR	1
Unabsorbed demand cost[13]	**-**	66	AR	*
Future removal and site restoration reserves[14]	**(577)**	(553)	OLTL	*
Site restoration clearance adjustment[15]	**(109)**	(193)	AP/OLTL	2
Post-retirement true-up variance[16]	**(10)**	(1)	AP/OLTL	*
Transactional services deferral[17]	**(4)**	(9)	AP	1
Earnings sharing deferral[18]	**(3)**	(6)	AP	*
Other regulatory assets and liabilities, net	**1**	3	***	***
	(93)	(70)		
St. Lawrence				
Other regulatory assets and liabilities, net	**7**	6	***	***
	(86)	(64)		

* 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 deferred income taxes balance represents the regulatory offset to deferred 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 the temporary differences. In the absence of rate regulation accounting, this regulatory balance and the related earnings impact would not be recorded.*

2 *The OPEB balance represents Enbridge Gas Distribution's right to recover OPEB costs resulting from the adoption of the accrual basis of accounting for OPEB costs upon transition to US GAAP in 2012. Pursuant to the OEB rate order, the amount as at December 31, 2012 is to be collected in rates over a 20-year period that commenced in 2013. In the absence of rate regulation accounting, this regulatory balance and related earnings impact would not be recorded.*

3 *The pension plan balance represents the regulatory offset to the pension liability/asset to the extent the amounts are to be collected/refunded in future rates. The settlement period for this balance is not determinable. In the absence of rate regulation accounting, this regulatory balance would not be recorded and pension expense would have been charged to earnings and OCI based on the accrual basis of accounting.*

4 The Constant dollar net salvage adjustment represents the cumulative variance between the amount proposed for clearance and the actual amount cleared, relating specifically to the site restoration clearance adjustment. At the end of 2018 any residual balance will be cleared in a post 2018 true up, ensuring that the actual amount cleared is equivalent to the required $380 million.

5 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 historically been granted OEB approval for recovery or required refund of this amount in the subsequent year. In the absence of rate regulation accounting, this variance would be included in earnings in the year incurred.

6 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 weather 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 accounting, this regulatory balance and the related earnings impact would not be recorded.

7 Storage and transportation deferral represents the difference between the actual cost and the approved cost of natural gas storage and transportation reflected in rates. Enbridge Gas Distribution has historically been granted OEB approval to collect this balance from or to refund this balance to customers, generally in the subsequent year. In the absence of rate regulation accounting, the actual cost of natural gas storage and transportation 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.

8 Customer care CIS rate smoothing deferral represents the difference between the forecast costs and the approved costs for customer care and CIS reflected in rates. The balance accumulated during 2013 to 2015 when the cost per customer exceeded the cost approved for recovery in rates will be drawn down during 2016 to 2018 when the cost per customer will be lower than the cost approved for recovery in rates. Enbridge Gas Distribution has received OEB approval to collect from or refund to customers any remaining balance after 2018. In the absence of rate regulation accounting, the variance would be included in earnings in the year incurred.

9 The Deferred rebate account reflects amounts payable to, or receivable from, customers as a result of the clearing of deferral and variance accounts authorized by the OEB which remain outstanding due to the Company's inability to locate such customers. Enbridge Gas Distribution has historically been granted OEB approval to collect this balance from or to refund this balance to customers, generally in the subsequent year. There would be no change in the treatment of this item in the absence of rate regulation accounting.

10 Demand side management incentive deferral account (DSMIDA) represents the benefit earned by Enbridge Gas Distribution as a result of its energy efficiency programs. Enbridge Gas Distribution has historically been granted OEB approval to recover the DSMIDA 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 accounting.

11 Purchased gas variance (PGVA) 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 on a rolling 12 month basis via the Quarterly Rate Adjustment Mechanism process. In May 2014, the OEB issued a decision allowing a portion of the PGVA balance as at June 30, 2014 to be recovered over a 24-month period from July 1, 2014 to June 30, 2016. In the absence of rate regulation accounting, 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.

12 The GTA incremental transmission capital revenue requirement deferral account reflects the revenue requirement related to incremental capital costs which resulted from the upsizing of Segment A of the GTA project to a Nominal Pipe Size (NPS) 42 pipeline, from an NPS 36 pipeline. The account was required in the event that at the time Segment A was put into service, there are no transportation customers, or there is no ability for transportation customers to utilize Segment A. The revenue requirement reflects revenue to be collected from transportation customers once they are able to take service under Rate 332. In the absence of rate regulation accounting, the amount would be recognized when included in rates billed to transportation customers.

13 The Unabsorbed demand cost deferral account represents the actual cost consequences of unutilized transportation capacity contracted by Enbridge Gas Distribution to meet requirements resulting from its Peak Gas Design Day Criteria. In the absence of rate regulation accounting, these costs would be expensed as incurred.

14 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 that is recorded in rates. 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 accounting, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.

15 *The Site restoration clearance adjustment represents the amount, that was determined by the OEB, of previously collected costs for future removal and site restoration that is now considered to be in excess of future requirements and will be refunded to customers over the customized IR term. This was a result of the OEB's approval of the adoption of a new approach for determining net negative salvage percentages. The new approach resulted in lower depreciation rates and lower future removal and site restoration reserves. There would be no change in the treatment of this item in the absence of rate regulation accounting.*

16 *Post-retirement true-up variance is the difference between the actual cost and the approved cost of pension and OPEB 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 subsequent year, up to a maximum of $5 million per year. Any amounts in excess of $5 million per year will be deferred for refund or collection in the next subsequent year. In the absence of rate regulation accounting, the variance would be included in earnings in the year incurred.*

17 *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 accounting.*

18 *Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the customized IR plan. The Earnings sharing is payable to customers and represents 50% of normalized U.S. GAAP utility earnings represented by a return on equity in excess of the allowed utility return on equity applicable to Enbridge Gas Distribution, as determined for each year of the customized IR plan. There would be no change in the treatment of this item in the absence of rate regulation accounting.*

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
In the absence of rate regulation accounting, property, plant and equipment would not include some operating costs since these costs would have been charged to earnings in the period incurred.

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 accounting, a portion of such operating costs would be charged to earnings in the year incurred.

The Company entered into a services 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, 2016, cumulative costs relating to this services contract of $181 million (2015 - $174 million) were included in gas mains and are being depreciated over the average service life of 25 years. In the absence of rate regulation accounting, some of these costs would be charged to earnings in the year incurred.

The Company entered into contracts relating to CIS integration services, software maintenance and support. At December 31, 2016, the net book value of these costs included in intangible assets was $35 million (2015 - $48 million). In the absence of rate regulation accounting, a portion of the original cost of these assets would have been expensed in the period incurred.

WAMS is the Company's new integrated work and asset management solution. At December 31, 2016, the net book value of the asset included in intangible assets was $84 million (2015 - $52 million was included in work-in-progress). In the absence of rate regulation accounting, a portion of the original cost of the asset 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. Included in gas inventories at December 31, 2016 is $49 million (2015 - $40 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 accounting, these costs would be expensed as incurred and inventory would be recorded at the lower of cost or market value.

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

5. GREEN INVESTMENT FUND

In July 2016, the Company received $58 million from the Government of Ontario for the purpose of carrying out the Green Investment Fund (GIF) program. The purpose of the GIF program is to reduce greenhouse gas emissions in the residential sector. The Company's use of the funds is limited to eligible expenditures for the purpose of executing the program. The Company will manage the GIF program separately from its core regulated activities. There is no earnings impact relating to the GIF program. Any unspent funds must be returned to the Government of Ontario at the expiry of the agreement on May 31, 2019, or should the Government of Ontario elect to terminate the agreement at any time prior to its expiration date.

As at December 31, 2016, the Company had Restricted cash of $58 million and Accounts payable and other *(Note 10)* of $57 million on the Consolidated Statements of Financial Position related to the funds received for the GIF program. The cash flow impacts of these items are included in Changes in operating assets and liabilities on the Consolidated Statements of Cash Flows (*Note 21*).

6. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2016**	2015
(millions of Canadian dollars)		
Trade receivables	**327**	309
Unbilled revenues	**135**	151
Regulatory assets *(Note 4)*	**66**	216
Rebillables receivable	**50**	40
Taxes receivable	**48**	19
Agent billing and collection receivable	**35**	39
Prepaid expenses	**11**	11
Current deferred income taxes *(Notes 3 and 18)*	**-**	18
Other	**16**	21
Allowance for doubtful accounts *(Note 17)*	**(33)**	(34)
	655	790

During the first half of 2014, increases in natural gas prices and colder than normal weather resulted in the Company accumulating a significant balance in its PGVA. In May 2014, the OEB issued a decision allowing a portion of the PGVA balance as at June 30, 2014 to be recovered over a 24-month period from July 1, 2014 to June 30, 2016. Included in Regulatory assets as at December 31, 2016 is $5 million (December 31, 2015 - $129 million) which represents the PGVA balance that is expected to be recovered from customers within the next 12 months.

7. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2016**	2015
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas mains	**2.2%**	**4,637**	3,740
Gas services	**2.3%**	**3,065**	2,929
Regulating and metering equipment	**5.5%**	**963**	848
Gas storage	**1.9%**	**366**	327
Right-of-way	**1.2%**	**106**	52
Computer technology	**36.6%**	**33**	31
Under construction	**-**	**130**	893
Construction materials inventory	**-**	**34**	40
Land	**-**	**28**	24
Other	**6.7%**	**300**	303
		9,662	9,187
Accumulated depreciation		**(2,334)**	(2,197)
		7,328	6,990
Unregulated property, plant and equipment			
Gas storage	**2.0%**	**90**	88
Other	**0.5%**	**23**	27
		113	115
Accumulated depreciation		**(23)**	(24)
		90	91
Property, plant and equipment, net		**7,418**	7,081

Depreciation expense, including amounts collected for future removal and site restoration costs, was $266 million for the year ended December 31, 2016 (2015 - $239 million, 2014 - $237 million).

8. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2016**	2015
(millions of Canadian dollars)		
Regulatory assets *(Note 4)*	**568**	526
Pension and OPEB asset *(Note 19)*	**6**	8
Deferred income taxes *(Note 18)*	**-**	8
Other	**2**	1
	576	543

9. INTANGIBLE ASSETS

December 31, 2016	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	**22.2%**	**279**	**(156)**	**123**
CIS	**10.0%**	**127**	**(92)**	**35**
		406	**(248)**	**158**

December 31, 2015	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	23.2%	238	(129)	109
CIS	10.0%	127	(79)	48
		365	(208)	157

Intangible assets include $12 million of work-in-progress as at December 31, 2016 (2015 - $61 million). Total amortization expense for intangible assets was $56 million for the year ended December 31, 2016 (2015 - $51 million, 2014 - $49 million). The Company expects aggregate amortization expense for the years ending December 31, 2017 through 2021 of $65 million, $70 million, $71 million, $64 million and $66 million, respectively.

10. ACCOUNTS PAYABLE AND OTHER

December 31,	**2016**	2015
(millions of Canadian dollars)		
Accrued liabilities *(Note 20)*	**371**	396
Regulatory liabilities *(Note 4)*	**96**	136
Trade payables	**82**	62
Budget billing plan payable	**75**	105
GIF liability *(Note 5)*	**57**	-
Security deposits	**51**	61
Interest payable	**36**	33
Taxes payable	**17**	9
Current portion of OPEB liability *(Note 19)*	**4**	4
Agent billing and collection payable	**3**	-
Contractual holdbacks	**3**	38
Dividends payable	**1**	1
Short-term portion of derivative liabilities *(Note 17)*	**1**	14
Other	**10**	11
	807	870

Included in Regulatory liabilities at December 31, 2016 is $78 million (2015 - $84 million) relating to the portion of site restoration clearance adjustment that is expected to be refunded to customers within the next 12 months.

11. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2016**	2015
(millions of Canadian dollars)				
Debenture	9.85%	2024	**85**	85
Medium-term notes	4.38%	2017-2050	**3,895**	3,595
Commercial paper and credit facility draws, net[1]			**360**	607
Other *(Note 3)*[2]			**15**	22
Total debt			**4,355**	4,309
Current maturities			**(500)**	(2)
Short-term borrowings	0.85%		**(351)**	(599)
Short-term borrowings from affiliates *(Note 22)*	1.66%		**(34)**	(40)
Long-term debt *(Note 3)*			**3,470**	3,668
Loans from affiliate company *(Note 22)*			**375**	375

1 Includes amounts drawn on uncommitted demand credit facilities.
2 Consists of note payable to affiliate company, debt premium and debt issuance costs.

In August 2016, the Company issued $300 million of ten-year medium-term notes (MTNs) at an interest rate of 2.50%.

For the years ending December 31, 2017 through 2021, medium-term note maturities are $500 million, nil, $9 million, $400 million and $175 million, respectively. The Company's debentures and medium-term notes bear interest at fixed rates, and interest obligations for the years ending December 31, 2017 through 2021 are $176 million, $163 million, $163 million, $163 million and $147 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Debentures and medium-term notes	**176**	158	149
Loans from affiliate company *(Note 22)*	**27**	27	29
Commercial paper and credit facility draws	**7**	8	9
Other interest and finance costs	**10**	9	(4)
Capitalized	**(14)**	(21)	(6)
	206	181	177

In 2016, total interest paid to third parties was $181 million (2015 - $166 million, 2014 - $163 million) and total interest paid to affiliates was $27 million (2015 - $27 million, 2014 - $29 million).

The Company's borrowings, whether debentures or medium-term notes, are unsecured. As at December 31, 2016, the Company was in compliance with all covenants.

CREDIT FACILITIES

The Company currently has a $1 billion commercial paper program limit that is backstopped by committed lines of credit of $1 billion. The term of any commercial paper issued under this program may not exceed one year. The maturity date of the credit facility may be extended annually for an additional year from the end of the applicable revolving term, at the lender's option. In July 2016, the Company extended the term out date of this external credit facility to July 2017, with a maturity date in July 2018.

During the first quarter of 2016, St. Lawrence terminated its credit facility and entered into new banking agreements with a new financial institution in which $9 million (US$7 million) of promissory notes were issued under the loan agreement at an interest rate of 2.98%, maturing in July 2019.

During the second quarter of 2016, St. Lawrence terminated its uncommitted demand credit facilities, and entered into new banking agreements with a new financial institution in which $8 million (US$6 million) of committed credit facilities were issued under the agreement. The credit facilities bear interest at market rates and mature in June 2019.

In May 2016, the Company did not renew its $300 million revolving credit facility that it had with Enbridge.

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, 2016.

		December 31, 2016			December 31, 2015
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities[2]
(millions of Canadian dollars)					
Enbridge Gas Distribution Inc.	2018	**1,000**	**345**	**655**	1,300
St. Lawrence Gas Company, Inc.	2019	**17**	**15**	**2**	10
Total credit facilities		**1,017**	**360**	**657**	1,310

1 Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the external credit facility.
2 Includes a $300 million revolving credit facility from the Company's ultimate parent, Enbridge.

As at December 31, 2016, the Company did not have any uncommitted demand credit facilities. As at December 31, 2015, the Company had $7 million of uncommitted demand credit facilities, of which $3 million was unutilized.

Credit facilities carried a weighted average standby fee of 0.2% on the unused portion and the draws bear interest at market rates.

12. OTHER LONG-TERM LIABILITIES

December 31,	**2016**	2015
(millions of Canadian dollars)		
Regulatory liabilities *(Note 4)*	**624**	670
Pension and OPEB liabilities *(Note 19)*	**208**	163
Long-term portion of derivative liabilities *(Note 17)*	**1**	-
Other *(Note 13)*	**13**	14
	846	847

Included in Regulatory liabilities at December 31, 2016 is $31 million (2015 - $109 million) relating to the portion of site restoration clearance adjustment that is expected to be refunded to customers beyond the next 12 months.

13. ASSET RETIREMENT OBLIGATIONS

The liability for the expected cash flows as recognized in the Consolidated Financial Statements reflected discount rates ranging from 1.65% to 3.77% (2015 - 1.65% to 3.77%). A reconciliation of movements in the Company's ARO is as follows:

December 31,	**2016**	2015
(millions of Canadian dollars)		
Obligations at beginning of year	**9**	9
Liabilities settled	**(1)**	(2)
Change in estimate	**(1)**	2
Accretion expense	**-**	-
Obligations at end of year	**7**	9
Presented as follows:		
Other long-term liabilities *(Note 12)*	**7**	9
	7	9

14. 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 preference shares.

COMMON SHARES

	2016		2015		2014	
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	**170.0**	**1,637**	158.9	1,437	150.6	1,287
Common shares issued	**15.6**	**280**	11.1	200	8.3	150
Balance at end of year *(Note 22)*	**185.6**	**1,917**	170.0	1,637	158.9	1,437

PREFERENCE SHARES

December 31, 2016, 2015, and 2014	Authorized	Issued and Outstanding	Amount
(millions of Canadian dollars, number of preference shares in millions)			
Group 2, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 2, Series D, Cumulative Redeemable Convertible	4	-	-
Group 3, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible	4	4	100
Group 4	10	-	-
Group 5	10	-	-
			100

Floating adjustable cumulative cash dividends on the Group 3, Series D preference 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 preference shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case. As at December 31, 2016, no preference shares have been redeemed.

On July 1, 2019, and every five years thereafter, the Group 3, Series D preference shares can be converted, at the holder's option, into Group 2, Series D preference 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 3, Series D preference shareholders opted not to convert their shares into Group 2, Series D preference shares effective July 1, 2014.

The Group 2, Series D preference shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preference shares can also be converted into Group 3, Series D preference shares on a one-for-one basis at the holder's option on July 1, 2019 and every five years thereafter.

15. STOCK OPTION AND STOCK UNIT PLANS

Enbridge's four long-term incentive compensation plans include the ISO Plan, the PSO Plan, the PSU Plan and the RSU Plan. The Company reimburses Enbridge for stock-based compensation costs associated with its employees on a quarterly basis. As at December 31, 2016, the Company did not have any employees that had options in the PSO Plan.

INCENTIVE STOCK OPTIONS

Key employees of the Company 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.

December 31, 2016	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(options in thousands; exercise price and intrinsic value in Canadian dollars)				
Options outstanding at beginning of year	**2,688**	**39.43**		
Options granted	**703**	**44.06**		
Options exercised[1]	**(419)**	**28.78**		
Options cancelled	**(7)**	**44.83**		
Employee movements from other Enbridge companies	**511**	**38.56**		
Options outstanding at end of year	**3,476**	**41.54**	**6.3**	**39**
Options vested at end of year[2]	**1,957**	**35.74**	**4.8**	**33**

1 The total intrinsic value of ISOs exercised during the year ended December 31, 2016 was $10 million (2015 - $14 million; 2014 - $11 million) and cash received by Enbridge on exercise was $12 million (2015 - $10 million; 2014 - $5 million).

2 The total fair value of options vested under the ISO Plan during the year ended December 31, 2016 was $3 million (2015 and 2014 - $2 million).

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

Year ended December 31,	**2016**	2015	2014
Fair value per option *(Canadian dollars)*[1]	**7.37**	6.48	5.53
Valuation assumptions			
Expected option term *(years)*[2]	**5**	5	5
Expected volatility[3]	**25.1%**	19.9%	16.9%
Expected dividend yield[4]	**4.4%**	3.2%	2.9%
Risk-free interest rate[5]	**0.8%**	0.9%	1.6%

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 and the Canadian options. The fair values per option were $7.01 (2015 - $6.22; 2014 - $5.45) for Canadian employees and US$6.60 (2015 - US$6.16, 2014 - US$5.35) for United States employees.

2 The expected option term is based on historical exercise practice and three years for retirement eligible employees.

3 Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.

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 the United States Treasury Bond Yields.

Compensation expense recorded for the year ended December 31, 2016 for ISOs was $6 million (2015 and 2014 - $4 million). At December 31, 2016 , unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO Plan was $4 million. The cost is expected to be fully recognized over a weighted average period of approximately three years.

PERFORMANCE STOCK UNITS

Enbridge has a PSU Plan for senior officers of the Company 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 share price for 20 days prior to the maturity of the grant 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 performance multiplier is derived through a calculation of Enbridge's price/earnings ratio relative to a specified peer group of companies and Enbridge's earnings per share, adjusted for unusual non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2016 expense, multipliers of two, based upon multiplier estimates at December 31, 2016, were used for each of the 2014, 2015 and 2016 grants.

December 31, 2016	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**30**		
Units granted	**23**		
Units cancelled	**(8)**		
Units matured[1]	**(22)**		
Dividend reinvestment	**3**		
Employee movements from other Enbridge companies	**9**		
Units outstanding at end of year	**35**	**1.5**	**5**

1 The total amount paid by Enbridge during the year ended December 31, 2016 for PSUs was $1 million (2015 - $2 million; 2014 - $1 million).

Compensation expense recorded for the year ended December 31, 2016 for PSUs was $4 million (2015 - $2 million; 2014 - $5 million). As at December 31, 2016, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $2 million and is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Enbridge has a 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 for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2016	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**184**		
Units granted	**97**		
Units cancelled	**(9)**		
Units matured[1]	**(96)**		
Dividend reinvestment	**12**		
Employee movements from other Enbridge companies	**(1)**		
Units outstanding at end of year	**187**	**1.5**	**17**

1 The total amount paid by Enbridge during the year ended December 31, 2016 for RSUs was $5 million (2015 and 2014 - $5 million).

Compensation expense recorded for the year ended December 31, 2016 for RSUs was $6 million (2015 - $6 million; 2014 - $5 million). As at December 31, 2016 , unrecognized compensation expense related to non-vested units granted under the RSU Plan was $6 million and is expected to be fully recognized over a weighted average period of approximately two years.

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

Changes in AOCI for the years ended December 31, 2016, 2015, and 2014, are as follows:

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of Canadian dollars)				
Balance at January 1, 2016	**(5)**	**6**	**(7)**	**(6)**
Other comprehensive loss retained in AOCI	**(14)**	**(2)**	**(2)**	**(18)**
Other comprehensive loss reclassified to earnings	**6**	**-**	**-**	**6**
Income tax on amounts retained in AOCI	**3**	**-**	**-**	**3**
Income tax on amounts reclassified to earnings	**(1)**	**-**	**1**	**-**
	(6)	**(2)**	**(1)**	**(9)**
Balance at December 31, 2016	**(11)**	**4**	**(8)**	**(15)**

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of Canadian dollars)				
Balance at January 1, 2015	8	(2)	(7)	(1)
Other comprehensive income/(loss) retained in AOCI	(24)	8	-	(16)
Other comprehensive loss reclassified to earnings	6	-	-	6
Income tax on amounts retained in AOCI	6	-	-	6
Income tax on amounts reclassified to earnings	(1)	-	-	(1)
	(13)	8	-	(5)
Balance at December 31, 2015	(5)	6	(7)	(6)

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of Canadian dollars)				
Balance at January 1, 2014	70	(5)	-	65
Other comprehensive income/(loss) retained in AOCI	(84)	3	(9)	(90)
Other comprehensive loss reclassified to earnings	-	-	-	-
Income tax on amounts retained in AOCI	22	-	2	24
	(62)	3	(7)	(66)
Balance at December 31, 2014	8	(2)	(7)	(1)

17. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

The Company's earnings, cash flows and OCI are subject to movements in natural gas prices, foreign exchange rates and interest rates (collectively, market 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 risks to which the Company is exposed and the risk management instruments used to mitigate them.

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. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by the customer; therefore, the net exposure to the Company is nil.

Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. The

Company generates certain revenues, and holds a subsidiary that is denominated in USD. As a result, the Company's earnings, cash flows, and OCI are exposed to fluctuations resulting from USD exchange rate variability.

The Company implemented a policy in 2016 to hedge a portion of USD denominated unregulated storage revenue exposures. Qualifying derivative instruments are used to hedge anticipated USD denominated revenues and to manage variability in cash flows.

A portion of the Company's purchases of natural gas are denominated in USD and as a result there is exposure to fluctuations in the exchange rate of the USD against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the Company has no net exposure to movements in the foreign exchange rate on natural gas purchases.

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 are used to mitigate the volatility of short-term interest rates on interest expense related to variable rate debt.

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 mitigate the Company's exposure to long-term interest rate variability on select forecast term debt issuances. The Company uses qualifying derivative instruments to manage interest rate risk.

The Company's portfolio mix of fixed and variable rate debt instruments is monitored by its ultimate parent company, Enbridge. The Company does not typically manage the fair value of its debt instruments.

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the financial statement line item in the Consolidated Statements of Financial Position and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges or net investment hedges at December 31, 2016 or 2015.

The Company generally has a common practice of entering into individual International Swaps and Derivatives Association, Inc. (ISDA) agreements, or other similar derivative agreements, with the majority of its 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 those particular circumstances. The following table also summarizes the maximum potential settlement amount in the event of those specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2016	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts payable and other					
Interest rate contracts	**-**	**-**	**-**	**-**	**-**
Other long-term liabilities					
Foreign exchange contracts	**(1)**	**-**	**(1)**	**-**	**(1)**
Total net derivative liabilities					
Interest rate contracts	**-**	**-**	**-**	**-**	**-**
Foreign exchange contracts	**(1)**	**-**	**(1)**	**-**	**(1)**

December 31, 2015	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts payable and other					
Interest rate contracts	(14)	-	(14)	-	(14)
Total net derivative liabilities					
Interest rate contracts	(14)	-	(14)	-	(14)

The Company's derivative instruments relating to interest rate contracts mature through 2017 and have a notional principal of $8 million for interest rate contracts for short-term borrowings (2015 - $154 million) and nil for interest rate contracts on the anticipated issuance of long-term debt (2015 - $162 million).

The Company's derivative instruments relating to foreign exchange forward contracts mature through 2022 and have a notional principal of $13 million for the sale of foreign exchange (2015 – nil).

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on the Company's consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Amount of unrealized loss recognized in OCI Cash flow hedges			
Interest rate contracts	**(13)**	(24)	(84)
Foreign exchange contracts	**(1)**	-	-
	(14)	(24)	(84)
Amount of loss reclassified from AOCI to earnings *(effective portion)*			
Interest rate contracts[1]	**(3)**	(2)	
	(3)	(2)	-
Amount of loss reclassified from AOCI to earnings *(ineffective portion)*			
Interest rate contracts[1]	**(3)**	(4)	
	(3)	(4)	-

1 Reported within Interest expense in the Consolidated Statements of Earnings.

The Company estimates that nil in AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on interest and foreign exchange rates in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is one month at December 31, 2016.

LIQUIDITY RISK

Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments *(Notes 22 and 23)* 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, draws under committed credit facilities and long-term debt, which includes debentures and MTNs and, if necessary, additional liquidity is available through intercompany transactions with its ultimate parent, Enbridge, and other related entities. These sources are expected to be sufficient to enable the Company to fund all anticipated requirements. The Company maintains a current MTN shelf prospectus with securities regulators, which enables ready access to the Canadian public capital markets, subject to market conditions. The Company also maintains committed credit facilities *(Note 11)* with a diversified group of banks and institutions. The Company is in compliance with all the terms and conditions of its committed credit facilities as at December 31, 2016. As a result, all credit facilities are available to the Company and the banks are obligated to fund the Company under the terms of the facilities.

CREDIT RISK

Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is 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 obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts *(Note 6),* which totaled $33 million at December 31, 2016 (December 31, 2015 - $34 million).

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.

Entering into derivative financial instruments may also result in exposure to credit risk. The Company enters into risk management transactions primarily 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.

Derivative assets are adjusted for non-performance risk of the Company's counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

The Company did not have group credit concentrations and maximum credit exposure, with respect to derivative instruments, in the Canadian financial institutions or European financial institutions counterparty segments at December 31, 2016 or 2015.

FAIR VALUE MEASUREMENTS

The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects the Company's best estimates of fair value based on generally accepted valuation techniques or models and are 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.

FAIR VALUE OF FINANCIAL INSTRUMENTS
The Company categorizes its derivative instruments 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 does not have any derivative instruments classified as Level 1.

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 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 a 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. The Company does not have any derivative instruments classified as Level 3.

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, the Company uses observable market prices (interest, foreign exchange, and natural gas) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

At December 31, 2016, the Company had Level 2 derivative assets with fair value of nil (2015 - nil) and Level 2 derivative liabilities with fair value of $1 million (2015 - $14 million).

The Company's policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers between levels as at December 31, 2016 or 2015.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS
The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted market prices are not available for fair value measurement in which case these investments are recorded at cost. The Company's investment in IPL System Inc., an affiliate company, is recorded at fair value. At December 31, 2016, the fair value of the investment was $825 million (2015 - $825 million). The fair value of the Company's investment is classified as a Level 2 measurement and as at December 31, 2016 and 2015 the fair value

approximated its cost and redemption value and therefore no amount was recognized in OCI.

The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor, and is classified as a Level 2 measurement. At December 31, 2016, the Company's long-term debt, including the current portion had a carrying value of $3,983 million (2015 - $3,683 million) and a fair value of $4,585 million (2015 - $4,159 million).

The fair value of other financial assets and liabilities other than derivative instruments and long-term debt approximate their cost due to the short period to maturity.

18. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Earnings before income taxes	**239**	245	252
Federal statutory income tax rate	**15.0%**	15.0%	15.0%
Federal income taxes at statutory rate	**36**	37	38
Increase/(decrease) resulting from:			
Provincial and state income taxes	**(27)**	5	3
Effects of rate regulated accounting[1,2]	**(25)**	(22)	(25)
Non-taxable intercompany distributions[2]	**(9)**	(9)	(9)
Part VI.1 tax, net of federal Part I tax deduction[2]	**35**	-	-
Other[3]	**(1)**	-	(1)
Income taxes	**9**	11	6
Effective income tax rate	**3.8%**	4.5%	2.4%

1 During 2016, 2015 and 2014, previously collected costs for future removal and site restoration were refunded to customers that resulted in a decrease in income taxes of $22 million at December 31, 2016 (2015 - $24 million, 2014 - $26 million).
2 The provincial tax component of these items is included in "Provincial and state income taxes" above.
3 Included in "Other" are miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals & entertainment, and change in prior year estimates arising from the filing of tax returns in respect of the prior year.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Earnings before income taxes			
Canada	**236**	243	249
United States	**3**	2	3
	239	245	252
Current income taxes			
Canada	**32**	(4)	2
United States	**(1)**	(1)	1
	31	(5)	3
Deferred income taxes			
Canada	**(24)**	14	3
United States	**2**	2	-
	(22)	16	3
Income taxes	**9**	11	6

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are:

December 31,	**2016**	2015
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(637)**	(600)
Regulatory assets	**(101)**	(86)
Deferrals	**(8)**	-
Other	**-**	(1)
Total deferred income tax liabilities	**(746)**	(687)
Deferred income tax assets		
Future removal and site restoration reserves	**153**	146
Retirement and postretirement benefits	**37**	30
Minimum tax credits	**13**	9
Loss carryforwards	**4**	-
Financial derivatives	**4**	2
Other	**3**	2
Total deferred income tax assets	**214**	189
Net deferred income tax liabilities	**(532)**	(498)
Presented as follows:		
Assets		
Accounts receivable and other *(Note 6)*	**-**	18
Deferred amounts and other assets *(Note 8)*	**-**	8
Total deferred income tax assets	**-**	26
Liabilities		
Deferred income taxes	**(532)**	(524)
Total deferred income tax liabilities	**(532)**	(524)
Net deferred income tax liabilities	**(532)**	(498)

The Company has assessed all tax positions. As a result, no significant adjustments were required to be made to the income tax provisions for the year ended December 31, 2016.

The Company has not provided for deferred income taxes on the difference between the carrying value of its foreign subsidiaries and their corresponding tax bases as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying value of the investment and its tax basis is largely a result of unremitted earnings and currency translation adjustments. The unremitted earnings and currency translation adjustment for which no deferred taxes have been recognized in respect of foreign subsidiaries is $30 million (2015 - $30 million). If such earnings were remitted, in the form of dividends or otherwise, the Company may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is not practicable.

The Company and its subsidiaries are subject to taxation in Canada and the Unites States. The material jurisdictions in which the Company is subject to potential examinations include Canada (Federal and Ontario). The Company's 2012 to 2015 taxation years are still open for audit in Canada.

19. RETIREMENT AND POSTRETIREMENT BENEFITS

PENSION PLANS

The Company provides a non-contributory basic pension plan that provides defined benefit or defined contribution pension benefits to the majority of its employees. The Company has two supplemental non-contributory defined benefit pension plans that provide pension benefits in excess of the basic plan for certain employees.

A measurement date of December 31, 2016 was used to determine the plan assets and accrued benefit obligation for the pension 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 date of the most recent actuarial valuation was December 31, 2013. The effective date of the next required actuarial valuation is December 31, 2016.

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.

OTHER POSTRETIREMENT BENEFITS
The Company also provides OPEB, which primarily includes supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

BENEFIT OBLIGATIONS AND FUNDED STATUS
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		OPEB	
December 31,	**2016**	2015	**2016**	2015
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**1,025**	1,046	**120**	117
Service cost	**32**	35	**1**	1
Interest cost	**35**	41	**5**	5
Actuarial loss/(gain)	**51**	(54)	**2**	(1)
Benefits paid	**(46)**	(43)	**(4)**	(4)
Other	**1**	-	**(1)**	2
Benefit obligation at end of year	**1,098**	1,025	**123**	120
Change in plan assets				
Fair value of plan assets at beginning of year	**969**	960	**17**	13
Actual return on plan assets	**73**	49	**1**	-
Employer's contributions	**1**	3	**5**	5
Benefits paid	**(46)**	(43)	**(4)**	(4)
Other	**1**	-	**(2)**	3
Fair value of plan assets at end of year	**998**	969	**17**	17
Underfunded status at end of year	**(100)**	(56)	**(106)**	(103)
Presented as follows:				
Deferred amounts and other assets *(Note 8)*	**3**	6	**3**	2
Accounts payable and other *(Note 10)*	**-**	-	**(4)**	(4)
Other long-term liabilities *(Note 12)*	**(103)**	(62)	**(105)**	(101)

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

	Pension			OPEB		
Year ended December 31,	**2016**	2015	2014	**2016**	2015	2014
Discount rate	**3.9%**	4.2%	4.0%	**3.9%**	4.2%	4.0%
Average rate of salary increases	**3.5%**	3.4%	3.7%	**3.5%**	3.4%	3.7%

NET BENEFIT COSTS RECOGNIZED

	Pension			OPEB		
Year ended December 31,	**2016**	2015	2014	**2016**	2015	2014
(millions of Canadian dollars)						
Benefits earned during the year	**32**	35	25	**1**	1	1
Interest cost on projected benefit obligations	**35**	41	43	**5**	5	6
Expected return on plan assets	**(60)**	(62)	(59)	**(1)**	(1)	(1)
Amortization of actuarial loss	**14**	19	16	**-**	1	-
Net defined benefit costs on an accrual basis	**21**	33	25	**5**	6	6
Defined contribution benefit costs	**1**	1	1	**-**	-	-
Net benefit cost recognized on an accrual basis	**22**	34	26	**5**	6	6
Net amount recognized in OCI						
Net actuarial (gain)/loss[1]	**-**	-	-	**2**	-	9
Total amount recognized in OCI	**-**	-	-	**2**	-	9
Total net benefit cost on an accrual basis and amount recognized in OCI	**22**	34	26	**7**	6	15

1 Unamortized actuarial losses included in AOCI, before tax, were $11 million relating to OPEB at December 31, 2016 (2015 - $9 million, 2014 - $9 million).

The Company estimates that approximately $16 million related to pension plans and OPEB at December 31, 2016 will be reclassified into earnings in the next 12 months, as follows:

	Pension Benefits	OPEB	Total
(millions of Canadian dollars)			
Actuarial loss	**16**	**-**	**16**
	16	**-**	**16**

Pension and OPEB costs related to the period on an accrual basis are presented above and were initially expensed. However, there was a partially offsetting adjustment for pension and OPEB costs due to the regulatory mechanism in place. As a result, the net pension and OPEB expense primarily consists of OEB approved pension and OPEB costs.

Regulatory adjustments were recorded in the Consolidated Statements of Earnings, the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension or OPEB costs or gains are expected to be collected from or refunded to customers, respectively, in future rates *(Note 4)*. For the year ended December 31, 2016, an offsetting regulatory liability increased by $10 million (2015 - nil) and has been recorded to the extent pension and OPEB costs are expected to be refunded to customers in future rates.

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

	Pension			OPEB		
Year ended December 31,	**2016**	2015	2014	**2016**	2015	2014
Discount rate - service cost	**4.3%**	4.0%	5.0%	**4.3%**	4.0%	5.0%
Discount rate - interest cost	**3.5%**	4.0%	5.0%	**3.5%**	4.0%	5.0%
Average rate of return on pension plan assets	**6.5%**	6.8%	6.8%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.4%**	3.7%	3.5%	**3.4%**	3.7%	3.5%

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	6.6%	4.3%	2034
Other medical and dental	4.5%	4.5%	-

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $13 million in the benefit obligation and an increase of nil in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $11 million in the benefit obligation and a decrease of nil in benefit and interest costs.

PLAN ASSETS

The Company manages the investment risk of its 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.

Expected Rate of Return on Plan Assets

	Pension		OPEB	
Year ended December 31,	**2016**	2015	**2016**	2015
Expected rate of return	**6.5%**	6.8%	**-**	-

Target Mix for Plan Assets

Equity securities	44.5%
Fixed income securities	40.0%
Other	15.5%

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, 2016, the pension assets were invested in 47% (2015 - 47%) in equity securities, 36% (2015 - 36%) in fixed income securities and 17% (2015 - 17%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $24 million (2015 - $29 million) have been excluded from the table below.

December 31,	2016 Level 1[1]	2016 Level 2[2]	2016 Level 3[3]	2016 Total	2015 Level 1[1]	2015 Level 2[2]	2015 Level 3[3]	2015 Total
(millions of Canadian dollars)								
Pension Benefits								
Cash and cash equivalents	**7**	**-**	**-**	**7**	10	-	-	10
Fixed income securities								
Canadian government real return bonds	**74**	**-**	**-**	**74**	73	-	-	73
Canadian corporate bond index fund	**140**	**-**	**-**	**140**	133	-	-	133
Canadian government bond index fund	**128**	**-**	**-**	**128**	128	-	-	128
Corporate bonds and debentures	**5**	**-**	**-**	**5**	4	-	-	4
United States debt index fund	**2**	**-**	**-**	**2**	2	-	-	2
Equity								
Canadian equity securities	**67**	**-**	**-**	**67**	71	-	-	71
Canadian equity funds	**142**	**-**	**-**	**142**	128	-	-	128
United States equity securities	**2**	**-**	**-**	**2**	1	-	-	1
United States equity funds	**108**	**-**	**-**	**108**	100	-	-	100
Global equity funds	**74**	**72**	**-**	**146**	71	79	-	150
Infrastructure[4]	**-**	**-**	**90**	**90**	-	-	96	96
Real estate[4]	**-**	**-**	**63**	**63**	-	-	51	51
Forward currency contracts	**-**	**-**	**-**	**-**	-	(7)	-	(7)
	749	**72**	**153**	**974**	721	72	147	940
OPEB								
Cash and cash equivalents	**-**	**-**	**-**	**-**	1	-	-	1
Fixed income securities								
United States government and government agency bonds	**7**	**-**	**-**	**7**	6	-	-	6
Equity								
United States equity fund	**5**	**-**	**-**	**5**	5	-	-	5
Global equity fund	**5**	**-**	**-**	**5**	5	-	-	5
	17	**-**	**-**	**17**	17	-	-	17

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 values of the infrastructure and real estate investments are 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:

Year ended December 31,	2016	2015
(millions of Canadian dollars)		
Balance at beginning of year	**147**	69
Unrealized and realized gains	**13**	26
Purchases and settlements, net	**(7)**	52
Balance at end of year	**153**	147

PLAN CONTRIBUTIONS BY THE COMPANY

Year ended December 31,	Pension 2016	Pension 2015	OPEB 2016	OPEB 2015
(millions of Canadian dollars)				
Total contributions	**1**	4	**5**	5

The contributions expected to be paid in 2017 for pension is $34 million and for OPEB is $4 million.

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2017	2018	2019	2020	2021	2022-2026
(millions of Canadian dollars)						
Expected future benefit payments	53	55	56	58	60	326

20. SEVERANCE COSTS

Included in Operating and administrative expense for the year ended December 31, 2016 is $20 million (2015 - $12 million) in severance costs related to termination benefits to employees. This resulted from Enbridge-wide reductions of workforce that occurred in October 2016 and November 2015 that affected approximately 5% of Enbridge's workforce in each respective year.

In 2016, $9 million was paid with the remaining $11 million to be paid in 2017, and is included in Accounts payable and other as at December 31, 2016.

In 2015, $4 million was paid with the remaining $8 million paid in 2016, and was included in Accounts payable and other as at December 31, 2015.

21. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Regulatory assets *(Note 4)*	**158**	532	(732)
Regulatory liabilities *(Note 4)*	**(127)**	(178)	(102)
Restricted cash *(Note 5)*	**(58)**	-	-
Accounts receivable and other[1,2]	**(39)**	34	24
Gas inventories	**35**	17	(181)
Deferred amounts and other assets[1]	**-**	-	(3)
Accounts payable and other[1,2]	**109**	(84)	(92)
Other long-term liabilities[1]	**-**	4	55
	78	325	(1,031)

1 The cash flow impacts of regulatory assets and liabilities have been separately disclosed and are not included.
2 Includes amounts related to affiliated companies.

22. RELATED PARTY TRANSACTIONS

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

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Enbridge Energy Distribution Inc.			
Common share dividends declared	**237**	223	204
IPL System Inc. *(Note 17)*			
Dividend income	**63**	63	63
Interest expense *(Note 11)*	**27**	27	27
Enbridge			
Purchase of treasury and other management services	**49**	50	41
Interest expense *(Note 11)*	**-**	-	2
Part IV.1 tax reimbursement *(Note 18)*	**5**	-	-
Tidal Energy Marketing Inc.			
Purchase of natural gas	**17**	23	41
Revenue from optimization services	**8**	8	8
Tidal Energy Marketing (U.S.) LLC			
Purchase of natural gas	**26**	24	57
Aux Sable Canada LP			
Purchase of natural gas	**16**	62	16
Gazifère Inc.			
Revenue from wholesale service, including gas sales	**30**	40	31
Vector Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**20**	28	27
Vector Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**1**	2	2
Alliance Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**2**	28	26
Alliance Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**4**	22	20
Niagara Gas Transmission Limited			
Purchase of gas transportation services	**2**	2	2
2193914 Canada Limited			
Purchase of gas transportation services	**2**	1	2

The Company had related party balances as follows:

December 31,	2016	2015
(millions of Canadian dollars)		
Common share ownership from parent company		
Enbridge Energy Distribution Inc. *(Note 14)*	**1,917**	1,637
Dividend payable	**59**	56
Investment in affiliate company *(Note 17)*		
IPL System Inc.	**825**	825
Dividend receivable	**5**	5
Loans from affiliate company *(Note 11)*		
IPL System Inc.	**375**	375
Interest payable	**2**	2
Note payable to affiliate company *(Note 11)*		
Enbridge (U.S.) Inc.	**34**	40
Other accounts receivable/(payable)		
Gazifère Inc.	**5**	3
Enbridge	**5**	(4)
Enbridge Employee Services Inc.	**(13)**	(13)
Tidal Energy Marketing (U.S.) LLC	**(8)**	(4)
Enbridge Pipelines Inc.	**(6)**	-
Tidal Energy Marketing Inc.	**(4)**	-
Vector Pipeline Limited Partnership (U.S.)	**(2)**	(1)
Aux Sable Canada LP	**-**	(2)
Alliance Pipeline Limited Partnership (Canadian)	**-**	(2)
Alliance Pipeline Limited Partnership (U.S.)	**-**	(2)
Other accounts receivable	**1**	2
Other accounts payable	**(1)**	(1)

Financing Transactions
The Company has invested in Class D, non-voting, redeemable, retractable preference shares of IPL System Inc., an affiliate under common control. At December 31, 2016, the investment of $825 million (2015 - $825 million) in these shares resulted in a weighted average dividend yield of 7.60%.

At December 31, 2016, 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 preference shares of the Company. For the year ended December 31, 2016, interest paid amounted to $27 million (2015 - $27 million).

The note payable to Enbridge (U.S.) Inc. bears interest at the LIBOR rate plus 1.1% and is payable on demand.

Treasury and Other Management Services
Enbridge provides treasury and other management services and charges the Company on a cost recovery basis.

Part IV.1 Tax Reimbursement
The Company entered into an agreement with Enbridge for the transfer of Part VI.1 tax and the related Part 1 tax deduction. The Company received a non-taxable reimbursement relating to the transfer.

Natural Gas Purchases
The Company contracted for the purchase of natural gas from Aux Sable Canada LP, Tidal Energy

Marketing Inc. and Tidal Energy Marketing (U.S.) LLC, related entities under common control, at prevailing market prices and under normal trade terms. Contractual obligations under the Tidal Energy Marketing (U.S.) LLC contract are 2017 to 2018 - $3 million, 2019 to 2020 – nil and thereafter - nil.

Optimization Services
The Company provides pipeline and storage optimization services to Tidal Energy Marketing Inc., an affiliated entity under common control.

Wholesale Service
These gas procurement and transportation 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 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, and Niagara Gas Transmission Limited and 2193914 Canada Limited. Contractual obligations under the Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian) and Niagara Gas Transmission Limited contracts are 2017 to 2018 - $46 million, 2019 to 2020 - $43 million and thereafter – $101 million.

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 shared corporate services to affiliates on a fully-allocated cost basis. Market prices, if they are reasonably determinable, are charged for affiliate services that are not shared corporate services. 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
The Company and affiliates invoice on a monthly basis and amounts are due and paid on a monthly basis.

23. COMMITMENTS AND CONTINGENCIES

COMMITMENTS
The Company has signed contracts for the purchase of services, pipe and other materials, as well as natural gas and transportation, totaling $4,729 million. The amounts which are expected to be paid in the next five years are $1,216 million, $630 million, $599 million, $513 million, and $465 million, respectively, and $1,306 million thereafter. Included in these amounts are right-of-way payments, estimated to be approximately $2 million per year, related to cancellable gas storage lease payments that are reasonably likely to occur for the remaining life of all storage reservoirs, which has been assumed to be 65 years.

Minimum future payments under operating leases are estimated at $2 million in aggregate. Estimated annual lease payments for the years ended December 31, 2016 through 2021 are $2 million, nil, nil, nil and nil, respectively. Total rental expense for operating leases, classified in Operating and administrative expense, was $2 million for the year ended December 31, 2016, and $3 million for each of the years ended December 31, 2015 and 2014.

The Company, Enbridge, and Enbridge Pipeline Inc., in aggregate, have access to $95 million of letters of credit that they can issue, of which $33 million was unutilized as at December 31, 2016. The total outstanding letters of credit that related to the Company as at December 31, 2016 was $8 million. The Company had access to $95 million of letters of credit that it could issue, of which $37 million was unutilized as at December 31, 2015. The total outstanding letters of credit that related to the Company as at December 31, 2015 was $5 million.

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, a former owner of part of the Historic Distillery District (Wyndham Court Canada Inc.) commenced an action in the Ontario Court of Justice (General Division) against the Company alleging that coal tar originating from the Company's Station A MGP in Toronto had migrated to its lands. The Company entered into a Tolling Agreement with Wyndham Court Canada Inc. pursuant to which this action was discontinued, without prejudice to the right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham Court Canada Inc. 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 the required steps in the discovery process were not completed by the plaintiff. The Company has brought a motion to dismiss the plaintiff's action for delay. At present, it is unknown when or if 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 2016 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs 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.

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 significant impact on the Company's consolidated financial position or results of operations.

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Stephen W. Baker
President

February 26, 2017

Dear Shareholder:

I am pleased to forward you a copy of the Union Gas Limited (Union Gas) 2016 Annual Report. It contains Union Gas' Management's Discussion and Analysis, Management Responsibility for Financial Reporting, Financial Statements, and Corporate Directory. I invite you to visit www.sedar.com for electronic versions of Union Gas' Financial Statements, Management's Discussion and Analysis, and other filings throughout the year.

Stephen W. Baker

President

INTRODUCTION

The terms "we," "our," "us" and "Union Gas" as used in this report refer to Union Gas Limited unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Union Gas.

This Management's Discussion and Analysis (MD&A) for the twelve months ended December 31, 2016, should be read in conjunction with the audited Financial Statements and accompanying notes. The results reported herein have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP) and are presented in millions of Canadian dollars, except where noted. Additional information relating to us, including our most recent Annual Information Form, can be found at www.sedar.com.

In 2014, Canadian securities regulators approved the extension of our exemptive relief to continue reporting under U.S. GAAP instead of International Financial Reporting Standards (IFRS) until the earlier of January 1, 2019, and the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this document to provide readers with information about Union Gas, including management's assessment of Union Gas' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are based on management's intentions, plans, expectations, beliefs and assumptions about future events. These forward-looking statements are typically identified by terms and phrases such as: anticipate, believe, intend, estimate, expect, continue, should, could, may, likely, plan, project, predict, will, potential, forecast, target and similar words suggesting future outcomes or statements regarding an outlook. Although Union Gas believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and the 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. Material assumptions used to develop these forward-looking statements include assumptions about: the supply and demand for natural gas; prices of natural gas; inflation; interest rates; the results and costs of financing efforts; expected future cash flows; expected earnings (losses); expected costs related to projects under construction; expected capital expenditures; estimated future dividends; expected costs related to remediation and potential insurance recoveries; the availability and price of labour and construction materials; operational reliability; the ability to successfully complete merger, acquisition or divestiture plans; anticipated in-service dates and weather.

Forward-looking statements are subject to risks, uncertainties and other factors, many of which are outside our control and could cause actual results to differ materially from the results expressed or implied by those forward-looking statements. 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 Union Gas' future course of action depends on management's assessment of all information available at the relevant time. Factors used to develop these forward-looking statements and that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- local, provincial and federal legislative and regulatory initiatives that affect cost and investment recovery, have an effect on rate structure, and affect the speed at and degree to which competition enters the natural gas industries;
- outcomes of litigation and regulatory investigations, proceedings or inquiries;
- weather and other natural phenomena, including the economic, operational and other effects of storms;
- the timing and extent of changes in commodity prices, interest rates and exchange rates;

- general economic conditions, including the risk of a prolonged economic slowdown or decline, or the risk of delay in a recovery, which can affect the long-term demand for natural gas and related services;
- potential effects arising from terrorist attacks and any consequential or other hostilities;
- changes in environmental, safety and other laws and regulations;
- changes in tax law and tax rate increases;
- the development of alternative energy resources;
- results of financing efforts, including the ability to obtain financing on favourable terms, which can be affected by various factors, including credit ratings and general market and economic conditions;
- increases in the cost of goods and services required to complete capital projects;
- declines in the market prices of equity and debt securities and resulting funding requirements for defined benefit pension plans;
- growth in opportunities, including the timing and success of efforts to develop pipeline, storage, and other related infrastructure projects and the effects of competition;
- the performance of natural gas storage, transmission and distribution facilities;
- sensitivity to variances in the commodity measurement process;
- the extent of success in connecting new natural gas supplies to Ontario transmission systems and in connecting to expanding gas markets;
- the effects of accounting pronouncements issued periodically by accounting standard-setting bodies;
- conditions of the capital markets during the periods covered by these forward-looking statements; and
- the ability to successfully complete merger, acquisition or divestiture plans; regulatory or other limitations imposed as a result of a merger, acquisition or divestiture; and the success of the business following a merger, acquisition or divestiture.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. We undertake no obligation to publicly update or revise any forward-looking statements made in this document or otherwise, whether as a result of new information, future events or otherwise, except as required by applicable securities law. All subsequent forward-looking statements, whether written or oral, attributable to Union Gas or persons acting on Union Gas' behalf, are expressly qualified in their entirety by these cautionary statements.

GENERAL

Union Gas is a major Canadian natural gas storage, transmission and distribution company based in Ontario with over 100 years of experience and service to customers. The distribution business serves about 1.5 million residential, commercial and industrial customers in more than 400 communities across northern, southwestern and eastern Ontario. Union Gas' storage and transmission business offers a variety of storage and transportation services to customers at the Dawn Hub (Dawn), the largest integrated underground storage facility in Canada and one of the largest in North America. Effective November 1, 2016, Union Gas' transmission system has an effective peak daily demand capacity of 7.2 billion cubic feet per day (Bcf/d), which increased from 6.7 Bcf/d.

Dawn offers customers an important link in the movement of natural gas from western Canadian and United States (U.S.) supply basins to markets in central Canada and the northeast U.S. Key pipeline interconnects in Canada and the U.S. have enabled us to deliver approximately 733 billion cubic feet (Bcf) of gas through our transmission system in 2016. A substantial amount of Union Gas' annual transportation and storage revenue is generated by fixed demand charges. The average length of these long-term contracts is approximately seven years, with the longest remaining contract term being 15 years.

As the supply of affordable natural gas in areas close to Ontario continues to grow, there is an increased demand to access these diverse supplies at Dawn and transport them along the Dawn-Parkway pipeline system to markets in Ontario, eastern Canada and the U.S. northeast. To secure the continued reliable delivery of natural gas and to serve a growing demand for clean, affordable natural gas, Union Gas has invested $800 million between 2015 and 2016, and will invest another $600 million in 2017 to expand the Dawn-Parkway natural gas transmission system. This will increase the takeaway capacity from Dawn by approximately 20 percent or from 6.3 Bcf/d in 2014 to more than 7.5 Bcf/d in 2017.

Our distribution system consists of approximately 65,000 kilometres (km) of main and service pipelines. Our distribution pipelines carry natural gas from the point of local supply to customers. Our underground natural gas storage facilities have a working capacity of approximately 162 Bcf in 23 underground facilities located in depleted gas fields. The transmission system consists of approximately 4,900 km of high-pressure pipeline and five mainline compressor stations.

Union Gas' common stock is held by Great Lakes Basin Energy L.P. (GLBE), a wholly-owned limited partnership of Westcoast Energy Inc. (Westcoast). Westcoast is an indirect wholly-owned subsidiary of Spectra Energy Corp (Spectra Energy).

Spectra Energy is a Delaware corporation that is a public company in the U.S. and whose common stock is listed on the New York Stock Exchange.

Our Board of Directors (the Board) is comprised of at least one-third independent directors with the remainder consisting of officers of Union Gas, Westcoast or Spectra Energy. There is no audit committee of the Board. The function of the audit committee is carried out at the level of Spectra Energy during the review of its Consolidated Financial Statements.

On September 6, 2016, Spectra Energy announced that it entered into a definitive merger agreement with Enbridge Inc. (Enbridge). Under this agreement, Enbridge and Spectra Energy will combine in a stock-for-stock merger transaction, which values Spectra Energy's stock at approximately $37 billion, based on the closing price of Enbridge common shares as of September 2, 2016. This transaction was approved by the boards of directors and shareholders of both Spectra Energy and Enbridge and has received all necessary regulatory approvals. The transaction is expected to close on February 27, 2017.

Upon completion of the proposed merger, Spectra Energy shareholders will receive 0.984 Enbridge common shares for each share of Spectra Energy stock they own. The consideration to be received is valued at U.S. $40.33 per Spectra Energy share, based on the closing price of Enbridge common shares as of September 2, 2016, representing an approximate 11.5% premium to the closing price of Spectra Energy stock as of September 2, 2016. Upon completion of the merger, Enbridge shareholders are expected to own approximately 57% of the combined company and Spectra Energy shareholders are expected to own approximately 43%.

As a result of this transaction, Enbridge and its subsidiaries will own Union Gas through their ownership of Spectra Energy.

HIGHLIGHTS

($millions except where noted)	**2016**	2015	2014
	For the Years Ended December 31,		
Income			
Total operating revenues	**1,828**	1,940	2,042
Net income applicable to common stock	**202**	185	192
Dividends			
Dividends on preferred shares	**3**	3	3
Dividends on common stock	—	50	100
Assets and long-term liabilities[a]			
Total assets	**8,227**	7,190	7,034
Total long-term liabilities	**4,830**	4,321	3,958
Volumes of gas (10^6m^3)[b]			
Distribution volumes	**13,376**	13,881	14,748
Transportation volumes	**20,759**	20,824	19,696
Total throughput	**34,135**	34,705	34,444
Customers *(thousands)*	**1,459**	1,437	1,419
Heating degree days[c] *(degree Celsius)*			
Actual	**3,789**	4,104	4,506
Normal[d]	**4,068**	3,969	3,929

[a] 2015 and 2014 amounts restated due to debt issue costs reclassification. See New Accounting Pronouncements section in our 2015 Annual Report for additional details.

[b] 10^6m^3 equals millions of cubic metres. One cubic metre is equivalent to 35.30096 cubic feet.

[c] A heating degree day is a measure of temperature that identifies the need for heating. A heating degree day occurs when the average daily temperature falls below 18 degrees Celsius. A temperature of zero degrees Celsius on a particular day equals 18 heating degree days.

[d] As per Ontario Energy Board approved methodology used in setting rates.

DIVIDENDS

	For the Years Ended December 31,		
	2016	2015	2014
Per Common Stock	**$—**	$0.86	$1.73
Per Class A Preferred Shares			
5.5% Series A	**$2.75**	$2.75	$2.75
6% Series B	**$3.00**	$3.00	$3.00
5% Series C	**$2.50**	$2.50	$2.50
Per Class B Preferred Shares			
4.88% Series 10	**$0.54**	$0.56	$0.60

RESULTS OF OPERATIONS

	Three Months Ended December 31,			Twelve Months Ended December 31,		
($millions)	2016	2015	**Increase (Decrease)**	2016	2015	**Increase (Decrease)**
Gas sales and distribution revenue	470	421	**49**	1,529	1,675	**(146)**
Cost of gas	243	205	**38**	717	875	**(158)**
Gas distribution margin	227	216	**11**	812	800	**12**
Storage and transportation revenue	72	60	**12**	278	239	**39**
Other revenue, net	9	11	**(2)**	21	26	**(5)**
	308	287	**21**	1,111	1,065	**46**
Expenses	204	193	**11**	724	692	**32**
Interest expense	42	39	**3**	161	157	**4**
Income tax expense	9	7	**2**	21	28	**(7)**
Net income	53	48	**5**	205	188	**17**
Net income applicable to common stock	52	47	**5**	202	185	**17**

Three months ended December 31, 2016 compared to three months ended December 31, 2015

Gas sales and distribution revenue. The $49 million increase was mainly driven by:

- a $34 million increase in residential customer usage of natural gas primarily due to weather that was colder than in 2015,
- a $12 million increase in industrial market usage,
- an $8 million increase from growth in the number of customers, and
- a $7 million increase in rates primarily due to increase demand side management (DSM) program charges, partially offset by
- an $8 million decrease related to utility earnings to be shared with customers in accordance with the incentive regulation framework, and
- a $5 million decrease from lower natural gas prices passed through to customers without a mark-up. Prices charged to customers are adjusted quarterly based on the 12 month New York Mercantile Exchange (NYMEX) forecast.

Cost of gas. The $38 million increase was mainly driven by:

- a $24 million increase due to higher volumes of natural gas sold primarily due to colder weather,
- a $9 million increase in industrial market usage, and
- a $5 million increase from growth in the number of customers, partially offset by
- a $5 million decrease from lower natural gas prices passed through to customers.

Storage and transportation revenue. The $12 million increase was mainly driven by:

- an $8 million increase due to incremental transportation revenue from the 2015 Dawn-Parkway expansion project, and
- a $2 million increase in storage revenue due to higher storage pricing.

Expenses. The $11 million increase was mainly driven by:

- a $9 million increase in operating and maintenance expenses primarily due to increased DSM charges, partially offset by lower employee related expenses.

Twelve months ended December 31, 2016 compared to twelve months ended December 31, 2015

Gas sales and distribution revenue. The $146 million decrease was mainly driven by:

- a $108 million decrease from lower natural gas prices passed through to customers without a mark-up, and
- a $92 million decrease in residential customer usage of natural gas primarily due to weather that was warmer than in 2015, partially offset by
- a $37 million increase from growth in the number of customers,
- a $21 million increase in rates primarily due to increased DSM programs charges, and
- a $4 million increase in industrial market usage.

Cost of gas. The $158 million decrease was mainly driven by:

- a $109 million decrease from lower natural gas prices passed through to customers, and
- an $81 million decrease due to lower volumes of natural gas sold primarily due to warmer weather, partially offset by
- a $28 million increase from growth in the number of customers.

Storage and transportation revenue. The $39 million increase was mainly driven by:

- a $29 million increase in transportation revenue primarily due to incremental revenue from the 2015 Dawn-Parkway expansion project, and
- a $12 million increase in storage revenue primarily due to higher storage pricing and higher storage optimization, partially offset by
- a $2 million decrease in transportation revenue primarily due to fewer short term opportunities.

Expenses. The $32 million increase was mainly driven by:

- a $15 million increase in depreciation expense primarily due to new projects placed into service during the fourth quarter of 2016, and
- a $12 million increase in operating and maintenance expenses primarily due to increased DSM charges, partially offset by lower employee related expenses.

QUARTERLY RESULTS

($millions)	Q1 2015	Q2 2015	Q3 2015	Q4 2015	Q1 2016	Q2 2016	Q3 2016	Q4 2016
Gas sales and distribution revenue	752	292	210	421	565	295	199	470
Storage and transportation revenue	63	59	57	60	70	67	69	72
Other revenue, net	5	5	5	11	4	4	4	9
Total operating revenues	820	356	272	492	639	366	272	551
Net income (loss)	126	18	(4)	48	125	29	(2)	53
Net income (loss) applicable to common stock	125	18	(5)	47	124	29	(3)	52

Seasonal Trends

The natural gas distribution business is highly seasonal due to volume-based rates and the significant effect of the winter heating season on volumes. This is typically reflected in strong first quarter results, second and third quarters that show either small profits or losses and strong fourth quarter results, subject to the impact of weather variations relative to demand during the winter heating season. Changes in natural gas rates that are charged to customers result in corresponding changes in gas sales and distribution revenue. These increases or decreases in gas sales revenue are completely offset in the cost of gas as a result of the associated regulatory recovery and refund mechanisms.

REGULATORY MATTERS

Union Gas is regulated by the Ontario Energy Board (OEB) pursuant to the provisions of the *Ontario Energy Board Act, (1998)*, which is part of a package of legislation known as the *Energy Competition Act, (1998)*. This legislation provides for different forms of regulation and competition in the energy (electricity and natural gas) industry in Ontario. We are subject to regulation with respect to the rates that we may charge our customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting practices.

Rate Regulation

Our distribution rates, beginning January 1, 2014, are set under a five-year incentive regulation framework. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The framework allows for:

- annual inflationary rate increases, offset by a productivity factor of 60% of inflation, such that the annual net rate escalator in each year is 40% of inflation,
- rate increases or decreases in the small volume customer classes where average use declines or increases,
- certain adjustments to base rates,
- the continued pass-through of gas commodity, upstream transportation and demand side management costs,
- the additional pass-through of costs associated with major capital investments and certain fuel variances,
- an allowance for unexpected cost changes that are outside of management's control,
- equal sharing of tax changes between Union Gas and our customers, and
- an earnings sharing mechanism that permits Union Gas to fully retain the return on equity from utility operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.

In October 2016, we filed an application with the OEB for new rates effective January 1, 2017 pursuant to our incentive regulation framework. In December 2016, the OEB approved the application on an interim basis with an implementation date of January 1, 2017 to be included in our Quarterly Rate Adjustment Mechanism (QRAM). The impact on a typical residential customer, including bill impacts related to the implementation of Cap and Trade, ranges from an increase of $56 to $163 annually depending on the customer's location within our service territory. A final rate order is expected after the OEB completes its review of our Cap and Trade Compliance Plan.

Annual Deferral Account Disposition

In April 2016, we filed an application with the OEB for the annual disposition of the 2015 deferral account balances. The impact was a net receivable from customers of approximately $23 million. In August 2016, a decision from the OEB was received approving recovery from ratepayers which began October 1, 2016.

Demand Side Management

In June 2016, a decision from the OEB was received approving recovery of the 2014 DSM deferral and variance account balances from ratepayers. We began recovery of approximately $11 million from customers on October 1, 2016.

In March 2016, we filed a Draft Rate Order with the OEB for rates effective January 1, 2016 based on the OEB's February 24, 2016 updated Decision and Order on the 2015-2020 DSM Plan. In May 2016, a decision from the OEB was received approving recovery in rates of the incremental 2016 DSM related charges from ratepayers of approximately $24 million effective January 1, 2016. The impact on a typical residential customer ranged from an increase of $7 to $9 annually, depending on the customer's location within our service territory. These charges are being recovered over a six month period which began July 1, 2016 for general service rate classes and as a one-time adjustment for contract rate classes that was made in July 2016.

As part of our 2017 rates application, we have included an approved DSM budget of approximately $58 million in 2017 rates. The 2017 budget was approved as part of the OEB Revised Decision in the 2015-2020 DSM Plan proceeding.

Commodity Rates

Union Gas and the OEB have a mechanism in place to change gas commodity rates on a quarterly basis (QRAM), to ensure that customers' rates reflect future expected prices to the extent reasonably possible. The difference between the approved and the actual cost of gas incurred is deferred for future recovery from or repayment to customers. These differences are included in quarterly gas commodity rates and recovered from or refunded to customers over the subsequent twelve months. This allows us to adjust customers' rates closer to the time costs are incurred.

Dawn to Parkway Projects

In April 2015, the OEB approved the construction and related rate recovery of the Dawn to Parkway 2016 Expansion Project. The project involved the installation of a new compressor at the existing Lobo Compressor Station (Lobo), modifications to existing facilities at Lobo and construction of a pipeline from the Hamilton Valve Site to the Milton Valve Site along our Dawn to Parkway system. These facilities provided incremental capacity on our Dawn to Parkway transmission system and were supported by signed contracts with our customers. The project went into service in November 2016 with a total capital cost of approximately $363 million.

In December 2015, the OEB approved the rate recovery of the Dawn to Parkway 2017 Expansion Project. This project involves the installation of a new compressor and associated facilities at each of our Dawn, Lobo and Bright Compressor Stations to provide incremental capacity on our Dawn to Parkway transmission system and is supported by signed contracts with our customers. The total capital cost of the facilities is expected to be approximately $623 million with service to customers expected in the fourth quarter of 2017. The construction of the three new compressors commenced in January 2016.

Burlington-Oakville Pipeline

In December 2015, the OEB approved the construction and rate recovery of a new transmission pipeline to serve the growing demands in the Burlington-Oakville area. The project went into service in October 2016 with a total capital cost of approximately $85 million.

Panhandle Reinforcement Pipeline Project

In February 2017, the OEB approved the construction and rate recovery of a new pipeline from the Dawn Compressor Station to the Dover Transmission Station to serve firm demand growth in southwestern Ontario. The total capital cost of the pipeline is expected to be approximately $265 million with service to customers expected in the fall of 2017.

OEB Consultation on Pensions and Other Post-employment Benefits (OPEBs)

In May 2015, the OEB invited interested rate-regulated utilities, in both the gas and electricity sectors, to participate in a consultation on pensions and OPEBs. The objectives of the consultation are to develop standard principles to guide the OEB's review of pension and OPEB costs in the future, to establish specific information requirements for applications and to establish appropriate regulatory mechanisms for cost recovery which can be applied consistently across the gas and electricity sectors for rate-regulated utilities. Union Gas' initial written submissions were filed in July 2015. In July 2016, Union Gas participated in an OEB stakeholder forum. In September 2016, Union Gas filed its written submission as a follow-up to the stakeholder forum advocating that continuing with Union Gas' current practices remain in the best interests of its ratepayers. At this time, it is too early to assess any potential impacts as a result of this review.

OEB Consultation on Cap and Trade

In September 2016, the OEB released its final "Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities" report. The framework is used to guide the OEB's assessment of natural gas distributors' Cap and Trade Compliance Plans, including the cost consequences of these plans, monitoring and reporting, customer outreach, confidentiality of the Cap and Trade information and the mechanism for the recovery of costs in rates. The OEB determined that charges related to the recovery of customer-related obligation costs, Union Gas' facility-related obligation costs and administrative costs relating to the implementation and ongoing operation of the Cap and Trade Program will be included in the delivery charge on customer bills. In November 2016, we filed our 2017 Compliance Plan and the OEB issued an interim rate order approving the associated Cap and Trade costs for recovery from customers effective January 1, 2017. The OEB will complete its review of our 2017 Compliance Plan and approve the final rates in 2017. A decision is expected in the second quarter of 2017.

Cap and Trade Deferral Account

In April 2016, the OEB approved the establishment of a Greenhouse Gas (GHG) Emissions Impact Deferral Account. The deferral account is intended to capture the administrative costs that are incurred to implement the Province of Ontario's (the Province's) Cap and Trade framework. Balances at year end will be disposed of as part of Union Gas' annual Deferral Account Disposition application.

As part of the Cap and Trade Compliance Plan, we requested the approval of the Greenhouse Gas Emissions Compliance Obligation - Customer Related Deferral Account and the Greenhouse Gas Emissions Compliance Obligation - Facility Related Deferral Account. These deferral accounts will separately track the variance between the actual costs incurred related to the customer-related GHG obligation cost and the facility-related GHG obligation cost and the amount collected through rates. A decision from the OEB is expected as part of its review of our Compliance Plan in the second quarter of 2017.

Community Expansion

In response to a request from the Ontario Minister of Energy, the OEB invited all parties with the financial and technical expertise interested in distributing natural gas to unserved rural and remote communities in Ontario to submit an application for consideration pertaining to expansion portfolios and specific projects. In July 2015, Union Gas submitted its community expansion application which outlines a proposal for regulatory flexibility regarding project economics, a temporary expansion surcharge for new customers, an incremental tax equivalent contribution from municipalities and a capital pass-through mechanism that would allow Union Gas to expand its systems to serve over 30 communities that would otherwise not have access to natural gas.

In January 2016, the OEB issued a notice that our application would be put on hold pending a generic proceeding on the distribution of natural gas to unserved rural and remote communities in Ontario. The generic proceeding would consider possible alternative rate making frameworks to provide natural gas service to these communities. In May 2016, the OEB held an oral hearing in the generic proceeding and in July 2016, we filed our final submissions in the proceeding.

In November 2016, the OEB released its Decision with Reasons (Decision) in the generic community expansion proceeding. Although the Board continues to support the expansion of natural gas service to remote and rural areas, the Decision deviates from our proposal as the OEB denied the ability for existing customers to cross-subsidize the expansion projects. Instead, the OEB granted the ability for the distributor to charge "stand alone" rates for each new community to ensure that the projects are self-funding over the life of the project. Union Gas expects to file its updated community expansion application and evidence proposals for four projects by the end of March 2017. This filing with the OEB will reflect the findings in the generic community expansion proceeding.

In January 2017, the Ontario Ministry of Infrastructure announced a change to the Natural Gas Grant program providing $100 million in grants instead of the original program which consisted of $30 million in grants and $200 million in loans. The purpose of these grants is to facilitate expanding access to rural, Northern Ontario and First Nation communities that do not currently have natural gas service.

GAS SUPPLY

Union Gas ensures that customers receive a secure and diverse gas supply portfolio that is cost-effective. We continuously monitor and evaluate the new and changing natural gas supply dynamics to determine what opportunities exist for our customers.

Union Gas currently holds a diverse portfolio of transportation contracts that allow for the purchase of natural gas from various supply basins and suppliers across North America. The price that Union Gas pays for natural gas is a market sensitive price, typically based on the NYMEX Physical Basis or an index depending on where Union Gas sources natural gas from across North America. This includes, but is not limited to, indices such as Alberta, Michigan and Chicago.

The North American natural gas market has experienced and is expected to continue to experience change. While production from some conventional North American natural gas basins is in decline, production from shale gas formations continues to exceed expectations, and the supply economics generally favour shale gas formations which are closer to the consuming markets. As a result, the flow of natural gas on the Canadian and U.S. pipeline grid is changing as shippers shift from long-haul to short-haul transportation.

In support of this change in natural gas flows, in December 2015, the OEB approved our application for the pre-approval of the cost consequences of entering into a long-term transportation capacity contract with the Nexus Gas Transmission pipeline (NEXUS) commencing November 1, 2017. NEXUS will transport natural gas from the Appalachian region of the U.S. Northeast, which is the single largest and fastest growing producing region of natural gas in North America, into Dawn. The NEXUS project is being jointly developed by DTE Energy Company and Spectra Energy.

The overall increase in natural gas supply in North America resulting from shale gas development has led to current and projected, low and stable natural gas prices.

OUTLOOK

Gas Sales and Distribution

We expect that the long-term demand for natural gas in Ontario will remain relatively stable with continued growth in peak day demands, subject to the impacts of governmental actions to reduce GHG emissions. Some modest growth driven by low natural gas prices is expected to continue, with specific interest coming from communities that are not currently serviced by natural gas, given the significant price advantage relative to their alternate energy options.

We continue to focus on promoting conservation and energy efficiency by undertaking activities focused on reducing natural gas consumption through our various DSM programs offered across all markets. For 2016, we spent approximately $48 million and for 2017 we plan to spend approximately $58 million. The OEB approved DSM budget will increase to $64 million by 2020. We are also pursuing other opportunities to assist in lowering GHG emissions. Union Gas and Enbridge Gas Distribution Inc. have partnered with the Government of Ontario to deliver a home renovation program using $100 million in funding over 3 years through the Green Investment Fund.

Storage and Transportation

The storage and transportation marketplace continues to respond to changing natural gas supply dynamics including a robust supply environment. In recent years, the robust North American gas supply balance, due mainly to the development of shale gas volumes including the British Columbia, Marcellus and Utica shale areas, has resulted in lower commodity prices and narrower seasonal price spreads. Unregulated storage values are primarily determined based on the difference in value between winter and summer natural gas prices. We saw low storage values in both 2013 and 2014. Improvements were seen in 2015 and continued throughout 2016 as the North American natural gas supply and demand slowly returned to a more balanced position.

We expect that demand for natural gas in North America will continue to see low annual growth over the long-term with continued growth in peak day demands. The development of the Marcellus and Utica Shale areas is leading to significant new pipeline infrastructure to connect these supplies to the North American pipeline grid and the associated natural gas consuming market areas. The proximity of our storage and transportation facilities and our interconnections with major U.S. markets in the Great Lakes region and in the northeast U.S. support long-term growth opportunities. These opportunities focus on connecting new supply sources to Dawn and ensuring that there is sufficient transportation capacity on Union Gas' transmission system and pipelines downstream of Parkway to serve eastern Canadian and U.S. markets.

In response to customer demand to access new supply at Dawn, Union Gas is currently moving forward with the 2017 Dawn to Parkway Growth project. For additional information regarding this and other projects, see the Regulatory Matters section.

Environmental, Health and Safety

In 2014, we obtained an Environmental Compliance Approval (ECA) from the Ontario Ministry of the Environment and Climate Change (MOECC) for the permitting of our air and noise emission sources effective until February 2020. The ECA treats Union Gas as a single integrated natural gas storage, transmission and distribution system incorporating all storage pools, metering and regulating stations, compressor stations and buildings into a single environmental permit.

The terms and conditions of the ECA include financial obligations for capital, operating and maintenance expenditures until 2017, and the total estimated obligation has been included in the Contractual Obligations section of this document. Under the terms of the ECA, we will be allowed to add and modify facilities without prior approval from the MOECC (with the exception of new greenfield compressor stations), thereby reducing the risk of delays associated with obtaining environmental permits.

The MOECC requires third party audits to confirm that our facilities are operating in accordance with the conditions specified in the ECA. There have been no major findings to date from these audits.

In April 2016, the MOECC issued a Director's Order (Order) naming Union Gas, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of Union Gas in Hamilton. The Order requires all parties to act jointly to develop a Conceptual Site Model (CSM) to fully delineate the extent of the soil and groundwater contamination and to assess remedial measures, if necessary. In May 2016, Union Gas appealed the Order, which should have been issued to the party responsible for the contamination and the owner of the source of the contamination, as opposed to those parties impacted by the contamination. In June 2016, the Environmental Review Tribunal (Tribunal), on consent of the MOECC's Director, stayed the application of parts of the Order on the condition that a Preliminary CSM (PCSM) be provided to the MOECC's Director, which in fact was delivered (with cooperation from the owners of the immediately adjacent owners, including Union Gas) in December 2016. The MOECC has provided its preliminary responses to the PSCM. In February 2017, the Tribunal extended the stay of the Order until May 9, 2017, pending a technical conference to be attended by the MOECC and the owners of the immediately adjacent properties in order to determine next steps. The risk of material environmental liability is unknown at this time.

RISK FACTORS

Our earnings are affected by the risks inherent in the natural gas industry and energy marketplace. In general, our business and earnings level may be adversely affected by a number of risks, including but not limited to the risks described below.

Climate Change

The Province brought regulations into effect on July 1, 2016 that established the Province's Cap and Trade system which began on January 1, 2017. It covers natural gas distributors (and others) and puts a price on certain carbon emissions. Union Gas is required to purchase emission allowances/credits on behalf of most of its end use customers, and for its own emissions.

In June 2016, the Province also issued its Climate Change Action Plan (the CCAP), a high-level policy that describes how proceeds from the Cap and Trade system may be used over the next five years to reduce GHG emissions in Ontario. Longer term impacts of the Cap and Trade system and the CCAP and associated programs and their future effects on Union Gas' results of operations, financial position or cash flows remain uncertain.

Union Gas will continue to monitor any potential impacts and opportunities, and will participate in ongoing consultation with regulatory agencies and government ministries, as the Cap and Trade system begins to operate and the CCAP and associated programs are finalized.

Union Gas expects to incorporate any impacts on its revenues, operating costs or capital expenditures of the Cap and Trade system and the CCAP into future regulatory applications, including by seeking cost recovery through rates, and will continue to actively monitor and respond to actions and initiatives resulting from the CCAP.

In late 2016, the Government of Canada announced the Pan-Canadian Framework on Clean Growth and Climate Change (Framework). The Framework, which was signed on to by eight provinces and three territories, is intended to support Canada's international commitments to reducing GHG emissions and addressing climate change. The Framework includes elements such as national carbon pricing benchmarks (which are intended to create a uniform carbon price across Canada), complementary actions and innovation. Specific details regarding each of these elements are still to be defined. The incremental impact of the Framework on Ontario's Cap and Trade system and CCAP is unknown at this time, but continues to be closely monitored.

Market Risk

Sales to industrial customers are affected by general economic conditions, the absolute and relative price of energy, foreign exchange rates, local and global competition and government legislation and regulations. The modest growth seen in 2016 in the North American economy is expected to further improve in 2017. Ontario's natural gas energy market will benefit from this improvement while also being impacted by negative market forces arising from globalization and more energy efficient technology.

Electricity demand in Ontario remains low due to permanent industrial demand destruction and energy conservation that has occurred, resulting in an oversupply of electricity. That, coupled with the extension of previously declared end of life nuclear units at Pickering, has resulted in the non-renewal of several power purchase agreements with some non-utility natural gas fueled power generators (specifically, Northland Cochrane, Atlantic North Bay and Kapuskasing). Other factors affecting the power market include the province of Quebec's recent announcement to sell hydro-electric power to Ontario displacing gas-fired power generation, and the Independent Electricity System Operator's (IESO's) announced intent to replace expiring long term power purchase agreements with capacity auctions. As the IESO continues to advance its market renewal initiative, the commercial framework for gas-fired power generators could continue to change. These policy and market dynamics could impact our ability to re-contract with existing power generators moving forward. Revenues from power generators have declined due to the changes in the Province's power procurement process and the power purchase agreements noted above.

Sales to Union Gas' residential, small commercial and small industrial customers are affected by the number of new customer additions to the system, the price of natural gas, the warming trend in weather that is not fully reflected in rates and the continued shift to higher efficiency. New customer additions in 2017 are expected to remain consistent with 2016 trends as a result of residential conversions offsetting the declining activity in new housing starts. High electricity prices are furthering the conversion market.

A large quantity of our transportation capacity is subject to renewal on an annual basis. Our standard contract terms provide automatic renewal of contracts, after the initial term, for one year at a time unless the customer provides two years' prior notice of termination. Future termination notices and reselling terminated capacity are dependent on the demand for the capacity which is affected by the changing flows of gas in the Great Lakes region. It is also dependent on the availability of transportation downstream of Parkway. Any new projects that create downstream capacity will provide access to Dawn supplies for customers located in the downstream Ontario, Quebec and northeast U.S. markets. We have received notice of termination for capacity of approximately 0.16 Bcf/d in 2017 and 0.16 Bcf/d in 2018. This terminated capacity will be available to serve new transportation demand as well as growth in in-franchise loads.

Commodity Price Risk

Fluctuations in natural gas prices affect our gas purchase costs for our own operating requirements as well as for the gas supply costs we incur for and collect from our system customers. Our gas procurement policy primarily includes contracts with pricing mechanisms that reflect monthly and daily variations in the price of gas. Commodity price volatility and absolute price levels also impact the amount of natural gas used by customers.

Credit Risk

Credit risk represents the loss that we could incur if a counterparty fails to perform under its contractual obligations. We analyze the customer's financial condition prior to entering into an agreement, obtain collateral when appropriate, establish credit limits and monitor the appropriateness of those limits on an ongoing basis.

Our credit exposure consists of both the risk of collecting receivables for services provided, as well as the risk related to gas imbalances that occur as a regular part of the services provided in both the direct purchase market and ex-franchise market.

In the normal course of operations, we provide gas loans to other parties from our holdings of gas in storage. The replacement cost of the gas on loan at December 31, 2016 was $84 million (2015 – $51 million). We manage our credit exposure related to gas loans by subjecting these parties to the same credit policies used for all customers.

Weather Risk

As the primary component of our rates is volume based, our revenue levels approved by the OEB are impacted by weather. The volume forecasts used to determine the rates approved by the OEB assume normal weather conditions. Normal weather, as mandated by the OEB, is based on a 50:50 weighting of the 30-year average forecast and 20-year trend forecast respectively, for 2013 forward. Since a large portion of the gas distributed to the residential and commercial markets is used for space heating and is charged using volume-based rates, differences from normal weather have a significant effect on the consumption of gas and on our financial results.

Regulatory Risk

Our natural gas assets and operations are subject to regulation by federal, provincial and local authorities including the OEB and by various federal and provincial authorities under environmental laws. Regulation affects almost every aspect of our business, including the ability to determine terms and rates for services, acquisitions, construction, expansion and operation of facilities, issuance of equity or debt securities and dividend payments.

In addition, regulators in Canada have taken actions to strengthen market forces in the gas pipeline industry, which have led to increased competition. In a number of key markets, natural gas pipeline and storage operators are facing competitive pressure from a number of new industry participants, such as alternative suppliers as well as traditional pipeline competitors. Increased competition driven by regulatory changes could have a material effect on our business, earnings, financial condition and cash flows.

Our pipelines and related facilities are also regulated by the Ontario Technical Standards and Safety Authority (TSSA) while a few are regulated by the National Energy Board of Canada (NEB). Through our participation on the TSSA Natural Gas Advisory Council and associated Risk Reduction Groups we have the opportunity to provide input on the direction of regulatory changes. Union Gas also has extensive engagement on the Canadian Standards Association Technical Code and Standards Committees. Amendments to the Ontario regulations made by the TSSA could have an impact on our Integrity Management Program and the direction the U.S. industry is taking may prompt some further regulatory requirements. Given the mature status of our integrity management programs, potential changes are not expected to have a material impact on the organization. We have very limited NEB regulated assets, so the amendments to the NEB Management Systems and Performance Measures are not expected to have a significant impact on our business. Union Gas utilizes a comprehensive and integrated Operations Management System (OMS) to manage the operations of the organization. We have taken the NEB requirements into account and have enhanced our OMS to be able to meet the requirements. The OMS provides the necessary structure and discipline to ensure we operate in a way that provides for demonstrated legal and regulatory safety and compliance.

Competition Risk

As our distribution business is regulated by the OEB, it is generally not subject to third-party competition within our distribution franchise area. However, as a result of a 2006 decision by the OEB, physical bypass of Union Gas' system may be permitted, even within our franchise area. In addition, the OEB decision in the Generic Proceeding on Community Expansion provides a framework that facilitates the entry of new participants and allows for competition as it pertains to serving rural and First Nations communities that do not currently have access to natural gas.

Union Gas competes with other forms of energy available to its customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

Storage Market Risk

We sell our storage services based on seasonal natural gas market price spreads and volatility. If seasonal natural gas market spreads or volatility deviate from historical norms or there is significant growth in the amount of storage capacity available to natural gas markets relative to demand, our approach to managing our market-based storage capacity through a portfolio of varying contract terms may not protect us from significant variations in storage revenues, including possible declines as contracts renew.

Our standard storage contract terms do not allow for automatic renewals but typically have contract terms of one to five years. Storage prices are subject to market conditions at the time the contracts are renegotiated. Given the changes occurring to the Province's power generation markets, there is risk associated with the renegotiation of expiring storage contracts with the Province's power generators, including volume and price risk.

Gas Measurement Risk

In determining the quantities of gas delivered and received, differences arise from the measurement process. The cost of these differences is referred to as unaccounted for gas (UFG). Rates for storage, transmission and distribution of gas, approved by the OEB effective January 2013, were reset to recover an estimate of UFG based on actual experience in the previous three years, which was lower than amounts previously included in rates. Variances between the estimate included in rates and the actual cost of UFG result from measurement and estimation errors. Under the current incentive regulation framework, the impact on our financial results arising from these variances is limited to $5 million.

Financing Risk

Our business is financed to a large degree through debt. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from assets. Accordingly, we rely on access to both short-term and long-term capital markets as a source of liquidity for capital requirements not satisfied by the cash flow from operations and to fund investments originally financed through debt. Our long-term debt is currently rated investment-grade by various rating agencies. If the rating agencies were to rate us below investment-grade, our borrowing costs would increase, perhaps significantly. In addition, we would likely be required to pay a higher interest rate in future financings and our potential pool of investors and funding sources could decrease.

We are subject to long-term debt covenants that include a limitation on the payment of dividends and requirements to satisfy specific interest coverage ratios prior to the issuance of additional long-term debt. Although we do not anticipate any impact to our current financing plans, reduced earnings may limit the payment of future dividends and the level of new long-term debt available to us. We maintain a revolving credit facility to backstop our commercial paper programs for short-term borrowings. This facility includes a financial covenant which limits the amount of debt that can be outstanding as a percentage of total capital. Failure to maintain this covenant could preclude us from issuing commercial paper or borrowing under the revolving credit facility and could require immediate pay down of any outstanding drawn amounts under other revolving credit agreements, which could adversely affect our cash flow.

If we are not able to access capital at competitive rates, our ability to finance operations and implement our strategy may be adversely affected. Restrictions on our ability to access financial markets may also affect our ability to execute our business plan as scheduled. An inability to access capital may limit our ability to pursue improvements or acquisitions that we may otherwise rely on for future growth. Any downgrade or other event negatively affecting the credit ratings could make our costs of borrowing higher or access to funding sources more limited.

Human Resources Risk

Union Gas' workforce consists of both unionized and non-unionized employees. Labour disruptions associated with the collective bargaining process can affect our ongoing operations. Projected changes in workforce demographics and a future shortage of skilled trades represent issues that are being addressed by Union Gas. All of Union Gas' collective agreements have been ratified with new expiry dates between December 2017 and May 2018.

Performance Risk

We have extensive contractual relationships with natural gas producers, customers, marketers, commercial enterprises, industrial companies and others. The risk of non-performance by us or a contracting party may be analyzed and mitigated but it cannot be entirely eliminated and could affect our earnings, financial position and cash flows. Ongoing consolidation of customers and partners may increase the severity of a default.

Litigation Risk

Union Gas, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Although it is possible that liabilities may be incurred in instances for which no accruals have been made, we have no reason to believe that the ultimate outcome of such matters currently known to us could have a material effect on our Financial Statements.

Facility Risk

We carry on business through a large and complex array of natural gas transmission, storage and distribution assets. These facilities, like any other industrial operations, are subject to outages from time to time. Depending on circumstances, such outages may result in loss of revenues and/or increased maintenance costs.

Political Risk

The Province is operating with a large financial deficit and significant spending commitments. As such, it is expected that the current provincial Government may look for new sources of revenues, including non-tax revenue streams such as fees and levies. At this time, we do not anticipate any material financial impact to Union Gas.

Environmental, Health and Safety Risk

There are a variety of hazards and operating risks inherent in natural gas storage, transmission and distribution activities, such as leaks, explosions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in significant injury, loss of human life, significant damage to property, environmental pollution and impairment of operations, any of which could result in substantial losses. For pipeline and storage assets located near populated areas, including residential areas, commercial business centres, industrial sites and other public gathering areas, the level of damage resulting from these risks could be greater. We do not maintain insurance coverage against all of these risks and losses, and any insurance coverage we might maintain may not fully cover the damages caused by these risks and losses. Therefore, should any of these risks materialize, it could have a material adverse effect on our business, earnings, financial condition and cash flows.

Protecting Against Potential Terrorist Activities

The potential for terrorism because of the high profile of the natural gas industry has subjected our operations to increased risks that could have a material adverse effect on our business. This risk is particularly great for companies, like ours, operating in any energy infrastructure industry that handles volatile gaseous and liquid hydrocarbons. The potential for terrorism, including cyber-terrorism, has subjected our operations to increased risks that could have a material effect on our business. In particular, we may experience increased capital and operating costs to implement increased security for our facilities and pipelines, such as additional physical facility and pipeline security and additional security personnel. Moreover, any physical damage to high profile facilities resulting from acts of terrorism may not be covered, or covered fully, by insurance. We may be required to expend material amounts of capital to repair any facilities, the expenditure of which could adversely affect our cash flows and business. A cyber attack could also lead to a significant interruption in our operations or unauthorized release of confidential information or otherwise protected information, which could damage our reputation or lead to financial losses.

Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

Pension Risk

Our costs of providing defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates used to measure pension liabilities, actuarial gains and losses, future government regulation and our contributions made to the plans. Without sustained growth in the pension plan investments over time to increase the value of our plan assets, and depending upon the other factors impacting our costs as listed above, we could experience net asset, expense and funding volatility. This volatility could have a material effect on our earnings and cash flows.

Land Rights

Various aboriginal groups in Ontario have claimed aboriginal and treaty rights in areas where Union Gas' facilities, and the gas supply areas served by those facilities, are located. In addition to aboriginal groups, other landowners have also claimed their rights in Union Gas' franchise area. The existence of these claims could give rise to future uncertainty regarding land tenure and expansion depending upon their negotiated outcome. We continue to proactively plan and manage the risks associated with these issues and work with provincial government regulators in that regard.

Capital Project Execution Risk

A portion of our growth is accomplished through the construction of new pipelines and storage facilities as well as the expansion of existing facilities.

Construction of these facilities is subject to various regulatory, development, operational and market risks, including: the ability to obtain necessary approvals and permits from regulatory agencies and municipalities on a timely basis and on acceptable terms, and to maintain those approvals and permits issued and satisfy the terms and conditions imposed therein; the availability of skilled labour, equipment, and materials to complete expansion projects; potential changes in federal, provincial and local statutes and regulations, including environmental requirements, that may prevent a project from proceeding or increase the anticipated cost of the project; impediments on our ability to acquire rights-of-way or land rights on a timely basis and on acceptable terms; the ability to construct projects within anticipated costs, including the risk of cost overruns resulting from inflation, foreign exchange or increased costs of equipment, materials or labour, weather, geologic conditions, or other factors beyond our control, that may be material; and general economic factors that affect the demand for natural gas infrastructure.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated costs. As a result, new facilities may not achieve their expected investment return, which could affect our earnings, financial position and cash flows.

Shale Gas Development

Recent community and political pressures have arisen around the production and transmission of natural gas originating from shale basins. Although we continue to believe that natural gas will remain a viable energy solution for Canada and the U.S., these pressures could increase costs and/or cause a slowdown in pipeline project development and/or the production of natural gas from these shale basins. This could negatively affect our growth plans and our access to this natural gas supply.

RELATED PARTY TRANSACTIONS

We occasionally perform services for and incur costs on behalf of our affiliates, which are subsequently reimbursed. Likewise, certain affiliates may perform services for or incur costs on behalf of us, which are then reimbursed by us. These transactions are in the normal course of operations and are recorded at exchange amounts agreed to between the related parties.

In addition, Spectra Energy and its affiliates perform centralized corporate functions for us, pursuant to an agreement with Spectra Energy and its affiliates, including legal, accounting, compliance, treasury, information technology and other areas, as well as certain engineering and other services. We reimburse Spectra Energy and its affiliates for the expenses to provide these services as well as other expenses they incur on our behalf. Spectra Energy and its affiliates charge such expenses based on the cost of actual services provided or using various allocation methodologies based on our percentage of assets, employees, earnings or other measures, as compared to Spectra Energy's other affiliates.

Our transactions with affiliated companies are as follows:

($millions), net	Transport and Storage Expenses	Corporate Charges (Receipts)[(a)]	Gas Purchases
2016			
St Clair Pipelines 1996, a division of Westcoast	—	(2)	—
Pipeline and Field Services, a division of Westcoast	—	(4)	—
Spectra Energy Empress L.P.	—	—	21
Spectra Energy Gas Transmission LLC	—	21	—
Sarnia Airport Storage Pool Limited Partnership	4	—	—
2015			
St Clair Pipelines 1996, a division of Westcoast	—	(2)	—
Pipeline and Field Services, a division of Westcoast	—	(3)	—
Spectra Energy Empress L.P.	—	—	55
Spectra Energy Gas Transmission LLC	—	14	—
Sarnia Airport Storage Pool Limited Partnership	4	—	—

[(a)]Excludes compensation arrangements.

Net amounts due (to) from related affiliates are as follows:

($millions), net	**2016**	2015
Spectra Energy Empress L.P.	**—**	(6)
Spectra Energy Gas Transmission LLC	**(1)**	(7)
Total[(a)]	**(1)**	(13)

[(a)]At December 31, 2016, $5 million (2015 – $14 million) is recognized in Accounts payable and accrued charges and $4 million (2015 – $1 million) is recognized in Accounts receivable, net on the Balance Sheets.

In the normal course of operations, we provide or obtain funds from Westcoast on an unsecured basis. The balance outstanding at December 31, 2016 was a payable of $253 million (December 31, 2015 – payable of $56 million). During 2016, interest paid on these loans totalled less than $1 million (2015 – less than $1 million) and interest received on these loans totalled less than $1 million (2015 – less than $1 million). Interest on these loans is calculated based on the monthly average of 30-day banker’s acceptance rates.

We also have a promissory note to borrow up to $150 million from GLBE on an unsecured basis. Funds from this promissory note are used for general corporate purposes. There was no balance outstanding at December 31, 2016 or December 31, 2015.

In 2016, no common stock dividend payments were made to GLBE (2015 – $50 million).

LIQUIDITY AND CAPITAL RESOURCES

We manage cash to ensure appropriate amounts are available as required. We invest our available cash in high-quality money market securities. Such money market securities are designed for the safety of principal and for liquidity, and accordingly do not include equity-based securities.

We will rely upon cash flows from operations and various financing transactions, which may include issuances of short-term and long-term debt and utilization of loans from Westcoast and GLBE, to fund our liquidity and capital requirements. We have access to a revolving credit facility that is used principally as a back-stop for our commercial paper program, which supports our short-term working capital fluctuations.

Changes in Cash Flow	For the years ended December 31,	
($millions)	**2016**	2015
Operating activities	**402**	501
Investing activities	**(999)**	(701)
Financing activities	**619**	185

Operating Activities

Union Gas' heating season extends from approximately November through March. We begin the heating season with near-capacity natural gas inventory levels which are drawn throughout the heating season. December year-end inventory levels decrease and thus contribute to a positive cash flow from operations during the first quarter. After the heating season ends, inventory is replenished for the next heating season. During the third quarter, gas inventory injections typically exceed withdrawals, negatively affecting cash flows. During the fourth quarter inventory decreases as withdrawals exceed injections.

Some of our customers purchase gas directly from marketers. Marketers typically deliver gas to us evenly throughout the year, whereas most of their customers use gas based on seasonality. As part of our normal billing process, we bill the marketers' customers as gas is used and remit this cash to the marketer when gas is delivered to us. Therefore, during the first and fourth quarters of the year, customers typically use more gas than is delivered to us and we collect cash from the marketers' customers creating a positive cash flow. During the second and third quarters, marketers deliver more gas than their customers use, thus creating a significant cash outflow. These are normal seasonal trends.

Cash provided from operating activities was $402 million for 2016 compared with $501 million for 2015. The decrease was primarily due to changes in working capital.

Investing Activities

The table below is a summary of capital expenditures:

	For The Years Ended December 31,		
	2017	2016	2015
	(estimated)		
Storage and transmission projects	60%	73%	61%
Distribution	35%	24%	34%
General equipment	5%	3%	5%
	100%	100%	100%

The table below is a summary of capital project type:

	For The Years Ended December 31,		
($millions)	2017	2016	2015
	(estimated)		
Maintenance projects	231	202	219
Expansion projects	698	834	482
Total capital expenditures	929	1,036	701

Capital expenditures for 2016 were higher compared to 2015 primarily due to the Dawn to Parkway Growth and Burlington-Oakville projects.

In 2016, the following key expansion projects were placed into service:

- 2016 Dawn to Parkway - A 0.41 Bcf/d expansion of the Dawn to Parkway transmission system consisting of 20 km of 48 inch Hamilton to Milton pipeline and the installation of a new 44,500 horsepower compressor and associated infrastructure at Lobo. The project went in to service November 2016.
- Burlington-Oakville - 0.29 Bcf/d of new capacity for the Burlington/Oakville market. The project consists of 12 km of 20 inch pipe. The project went in to service October 2016.

The 2017 expansion capital expenditures reflect our continued assessment of the timing of projected long-term market requirements and general economic conditions. Significant 2017 expansion project expenditures are expected to include:

- 2017 Dawn to Parkway - A 0.42 Bcf/d expansion of the Dawn to Parkway transmission system consisting of the addition of a new 44,500 horsepower compressor at each of our Dawn, Lobo and Bright Compressor Stations. Service to customers is expected in the fourth quarter of 2017.
- Panhandle Reinforcement - will create 0.10 Bcf/d of transmission capacity along Union's Panhandle System, meeting future residential, commercial and industrial demands along the Chatham to Windsor corridor for the next five years (2017-2021). The project consists of replacing 40 km of 16 inch pipe with 36 inch pipe and station modifications at Dawn and other Panhandle stations.

Consistent with 2016, the 2017 maintenance expenditures are for maintaining the integrity of existing pipelines and related infrastructure.

As outlined in the financing activities discussion that follows, we have sufficient financing available to meet our investing requirements. Management expects that financing of 2017 projects will be done through a combination of cash generated from operations, available debt facilities, and issuance of long-term debt.

Financing Activities

The primary factors increasing cash flow from financing activities for 2016 compared to 2015 include the increase in short-term borrowings and commercial paper and the higher issuance of long-term debt.

The declaration of dividends on the common shares is at the discretion of the Board. In order to maintain the common equity component of the capital structure at the level approved by the OEB, we typically pay dividends to our parent company based on net income, less earnings reinvested in expansion capital projects. For 2016, no dividends were paid to GLBE, due to our significant investment in expansion capital projects (2015 – $50 million).

Available Credit Facility and Restrictive Debt Covenants

			Commercial Paper Debt Outstanding at	
($millions)	**Expiration Date**	**Credit Facility Capacity**	**December 31, 2016**	December 31, 2015
Multi-year syndicated [(a), (b)]	2021	700	**333**	207

[(a)] The credit facility contains a covenant requiring the debt-to-total capitalization ratio, as defined in the agreement, to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 69.0% at December 31, 2016 (December 31, 2015 – 67.8%).

[(b)] In April 2016, the Company amended the revolving credit agreement. The facility was increased from $500 million to $700 million and its expiration date was extended from 2019 to 2021.

The issuance of commercial paper, letters of credit and revolving borrowings reduce the amount available under the credit facility. As of December 31, 2016 and December 31, 2015 there were no letters of credit issued or revolving borrowings outstanding under the credit facility. The majority of our short-term cash requirements are funded through the issuance of commercial paper. The weighted average rate on outstanding commercial paper as of December 31, 2016 was 0.87% (2015 – 0.86%). The weighted average days to maturity on outstanding commercial paper as of December 31, 2016 was 8 days (2015 – 9 days).

Our credit agreement contains various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreement. As of December 31, 2016 and December 31, 2015, we were in compliance with those covenants. In addition, the credit agreement allows for the acceleration of payments or termination of the agreement due to non-payment, or in some cases, due to the acceleration of other significant indebtedness of the borrower.

This facility is intended to be used primarily to manage the significant changes in working capital experienced by Union Gas as a result of volumes and prices associated with natural gas purchases and sales. Most of the short-term cash requirements are funded through issuing commercial paper at rates generally below the lender's prime rate. Our 2016 commercial paper peaked in December at $333 million (2015 – peaked in August at $328 million).

Other Financing Matters

We maintain a current base shelf prospectus with the Canadian securities regulators, which enables ready access to Canadian public debt capital markets. As of December 31, 2016, we had $550 million available for the issuance of medium-term note debentures under the base shelf prospectus, which expired on January 4, 2017.

In May 2016, we issued $250 million of unsecured 2.81% medium-term note debentures, due June 2026 and $250 million of unsecured 3.80% medium-term note debentures, due June 2046. Net proceeds from the offerings were used for repayment of short-term debt and debt maturities, capital expenditures and general corporate purposes.

OUTSTANDING STOCK

	December 31, 2016	December 31, 2015
Preferred shares		
5.5% Cumulative Redeemable Class A Preferred Shares, Series A	**47,672**	47,672
6% Cumulative Redeemable Class A Preferred Shares, Series B	**90,000**	90,000
5% Cumulative Redeemable Class A Preferred Shares, Series C	**49,500**	49,500
4.88% Cumulative Redeemable Convertible Class B Preferred Shares, Series 10	**4,000,000**	4,000,000
Common stock	**57,822,650**	57,822,650

CONTRACTUAL OBLIGATIONS

The table below is a summary of our contractual payment obligations, due by period.

($millions)	Total	2017	2018-2019	2020-2021	Thereafter
Long-term debt [a]	5,961	297	686	459	4,519
Operating leases	33	7	12	13	1
Purchase obligations[b]	2,737	578	509	358	1,292
Environmental obligations[c]	4	4	—	—	—
Retirement plan contributions[d]	16	16	—	—	—
Total contractual obligations[e]	8,751	902	1,207	830	5,812

[a] Includes estimated scheduled interest payments over the life of the associated debt.

[b] Includes: firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage; contractual obligations to purchase physical quantities of natural gas; contracts for software and consulting or advisory services; and contractual obligations for engineering, procurement and construction costs for pipeline projects. Due to a timing uncertainty, all procurement obligations have been included in 2017 as we are unable to reasonably estimate the payments due by period.

[c] Includes capital, operating and maintenance expenditures related to the ECA.

[d] We are unable to reasonably estimate retirement plan contributions beyond 2017 due primarily to uncertainties about market performance of plan assets.

[e] Excludes cash obligations for asset retirement activities. The amount of cash flows to be paid to settle the asset retirement obligations is not known with certainty as Union Gas may use internal resources or external resources to perform retirement activities. Amounts also exclude reserves for litigation, environmental remediation, annual insurance premiums that are necessary to operate the business and regulatory liabilities because Union Gas is uncertain as to the amount and/or timing of when cash payments will be required. Also, amounts exclude deferred income taxes and investment tax credits on the Balance Sheets since cash payments for income taxes are determined based primarily on taxable income for each discrete fiscal year. Our analysis also indicated that there are no expected payments and interest related to uncertain tax positions for 2017. We are unable to reasonably estimate the timing of uncertain tax positions and interest payments in years beyond 2017 due to uncertainties in the timing of cash settlements with taxing authorities.

NEW ACCOUNTING PRONOUNCEMENTS

In May 2014, the FASB issued ASU 2014-09, *“Revenue from Contracts with Customers (Topic 606),”* in an effort to improve revenue recognition practices across entities and industries. The ASU introduces a single, principles-based revenue recognition model which centers on the core principle of an entity recognizing revenue in a manner that depicts the transfer of goods and services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. Since its release, the FASB has issued multiple amendments clarifying and/or amending ASU 2014-09. We have substantially completed a review of contracts with customers in relation to the requirements of ASU 2014-09. While we have not identified any material difference in the amount or timing of revenue recognition for the categories we have reviewed to date, our evaluation is not complete and we have not concluded on the overall impacts of adopting this standard. In addition, we are in the process of implementing appropriate changes to our business processes, systems and controls to support the recognition and disclosure requirements under the new standard. ASU 2014-09 is effective for us on January 1, 2018 and allows for either full retrospective or modified retrospective adoption.

In January 2016, the FASB issued ASU 2016-01, “*Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financials Assets and Financial Liabilities,*” which amends the classification and measurement of financial instruments. Changes primarily affect the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. This ASU is effective for us beginning after December 15, 2017. Early adoption is not permitted. We are currently evaluating this ASU and its potential impact on us.

In February 2016, the FASB issued Accounting Standards Update (ASU) No. 2016-02, “*Leases (Topic 842),*” to improve the financial reporting around leasing transactions. The new guidance requires companies to begin recording assets and liabilities arising from those leases classified as operating leases under previous guidance. Furthermore, the new guidance will require significant additional disclosures about the amount, timing and uncertainty of cash flows from leases. Topic 842 retains a distinction between finance leases and operating leases. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in previous guidance. The result of retaining a distinction between finance leases and operating leases is that under the lessee accounting model in Topic 842, the effect of leases in the statement of comprehensive income and the statement of cash flows is largely unchanged from previous guidance. This ASU is effective for us January 1, 2019. We are currently evaluating this ASU and its potential impact on us.

In March 2016, the FASB issued ASU No. 2016-09, "*Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting,*" which simplifies several aspects of the accounting for share-based payment award transactions. The update requires classification changes for certain tax cash flows within the statement of cash flows and requires all excess tax benefits and tax deficiencies to be recorded through the Statement of Operations. In addition, the update provides an accounting policy election around forfeitures and raises the threshold for liability classification of share-based awards withheld for tax withholding requirements. This ASU is effective for us January 1, 2017. This ASU is not expected to have a material impact on our Financial Statements.

In June 2016, the FASB issued ASU No. 2016-13, "*Financial Instruments-Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments,*" to replace the incurred loss impairment methodology with a methodology that reflects expected credit losses and requires the consideration of a broader range of reasonable and supportable information to inform credit loss estimates. This ASU is effective for us January 1, 2020. We are currently evaluating this ASU and its potential impact on us.

In August 2016, the FASB issued ASU No. 2016-15, "*Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments,*" to provide guidance on specific cash flow issues with the objective of reducing the existing diversity in practice. This ASU is effective for us January 1, 2018. We are currently evaluating this ASU and its potential impact on us.

In November 2016, the FASB issued ASU No. 2016-18, *"Statement of Cash Flows (Topic 230): Restricted Cash,"* to address the diversity in the classification and presentation of changes in restricted cash and restricted cash equivalents on the statement of cash flows. The update requires that restricted cash and restricted cash equivalents be included with Cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the Statement of Cash Flows. This ASU is effective for us on January 1, 2018. We are currently evaluating this ASU and its potential impact on us.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure Controls and Procedures

We have established and maintained disclosure controls and procedures designed to provide reasonable assurance that: (a) material information required to be disclosed by us is accumulated and communicated to management to allow timely decisions regarding required disclosure; and (b) information required to be disclosed by us is recorded, processed, summarized, and reported within the time periods specified in applicable securities legislation.

Our management, with the participation of the President and the Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2016, and, based upon this evaluation, the President and the Chief Financial Officer have concluded that these disclosure controls and procedures, as defined by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings (NI 52-109), are effective for the purposes set out above.

Internal Control over Financial Reporting

Our management is responsible for designing, establishing and maintaining an adequate system of internal control over financial reporting. Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with U.S. GAAP. Because of 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 policies and procedures may deteriorate.

Our management, with the participation of our President and the Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2016 based on the framework in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting, as defined by NI 52-109, is effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with U.S. GAAP.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the President and Chief Financial Officer, we have evaluated changes in internal control over financial reporting that occurred during the fiscal quarter and year ended December 31, 2016 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

Our Board has reviewed and approved this MD&A and the attached Audited Financial Statements prior to their release.

CRITICAL ACCOUNTING POLICIES & ESTIMATES

The application of accounting policies and estimates is an important process that continues to evolve as Union Gas' operations change and accounting guidance is issued. Union Gas has identified a number of critical accounting policies and estimates that require the use of significant estimates and judgments.

Management bases its estimates and judgments on historical experience and on other various assumptions that they believe are reasonable at the time of application. The estimates and judgments may change as time passes and more information becomes available. If estimates and judgments are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information. Union Gas discusses its critical accounting policies and estimates and other significant accounting policies with senior members of management and the Board.

Regulatory Accounting

The economic effects of regulation can result in a regulated company recording assets for costs that have been or are expected to be approved for recovery from customers or recording liabilities for amounts that are expected to be returned to customers or for instances where the regulator provides current rates that are intended to recover costs that are expected to be incurred in the future. Accordingly, we record assets and liabilities that result from the regulated ratemaking process that may not be recorded under U.S. GAAP for non-regulated entities. We continually assess whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders to other regulated entities and the effect of competition. Based on this assessment, we believe our existing regulatory assets are probable of recovery. Total regulatory assets were $557 million as of December 31, 2016 and $499 million as of December 31, 2015. Total regulatory liabilities were $430 million as of December 31, 2016 and $432 million as of December 31, 2015.

Unbilled Revenue

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month. Gas sales and distribution revenue and Cost of gas are recorded on the basis of regular meter readings and estimates of the unbilled customer usage. The unbilled estimate covers the period of the last meter reading date to the end of each month and is calculated using the number of days unbilled, heating degree-days and historical consumption per heating degree-day. Unbilled revenue recorded at December

31, 2016 was $133 million (2015 – $106 million) which was included in Accounts receivable, net on the Balance Sheets. Included in unbilled revenue are natural gas costs passed through to customers without a mark-up. At December 31, 2016 $78 million (2015 – $62 million) was included in unbilled revenue for the cost of natural gas.

Pension and Other Post-Retirement Benefits

The calculations of pension and other post-retirement expense and liabilities require the use of numerous assumptions. Changes in these assumptions can result in different reported expense and liability amounts, and future actual experience can differ from the assumptions. We believe that the most critical assumptions used in the accounting for pension and other post-retirement benefits are the expected long-term rate of return on plan assets, the assumed discount rate, and medical and prescription drug cost trend rate assumptions.

Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in our pension and post-retirement plans will impact future pension expense and funding.

The expected return on plan assets is important since certain pension plans are funded. Expected long-term rates of return on plan assets are developed by using a weighted average of expected returns for each asset class to which the plan assets are allocated. For 2016, the assumed average return for the pension plan assets was 7.15%. A change in the rate of return of 25 basis points for these assets would impact annual benefit expense by approximately $2 million before tax. The other post-retirement benefit plans are not funded.

Since pension and other post-retirement benefit costs and obligations are measured on a discounted basis, the discount rates used to determine the net periodic benefit cost and the benefit obligation are significant assumptions. Discount rates used for our defined benefit and other post-retirement benefit plans are based on the yields constructed from a portfolio of high-quality bonds for which the timing and amount of cash outflows approximate the estimated payouts of the plans. A discount rate of 4.03% was used to calculate the 2016 net periodic benefit cost, and represents a weighted average of the applicable rates. A 25 basis-point change in the discount rate would impact annual before-tax net periodic benefit cost by approximately $3 million. A discount rate of 3.81% was used to calculate the 2016 year-end benefit obligation and represents a weighted average of the applicable rates. The weighted average discount rate decreased approximately 0.22% during 2016. The decrease in the discount rate and actuarial experience during 2016 resulted in an increase in benefit obligation at December 31, 2016 compared to December 31, 2015.

Asset Retirement Obligations

In determining the value of the asset retirement obligations, Union Gas must estimate such factors as timing of settlements and abandonment or remediation costs. These estimates require extensive judgment about the nature, cost and timing of the settlement. Any changes in the estimates can impact the Asset retirement obligations, Regulatory and other liabilities and Property, plant and equipment, net. To arrive at the timing of settlements of abandoning pipelines, Union Gas uses retirement dispersion parameters as estimated in its most recent depreciation rate study.

The Financial Statements and all information in this report have been prepared by and are the responsibility of management. The Financial Statements have been prepared in conformity with generally accepted accounting principles in the United States of America and include certain estimated amounts, which are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon Union Gas Limited's system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization. Management is also supported and assisted by a program of internal audit services.

The Board of Directors (the Board) is responsible for ensuring that management fulfils its responsibility for financial reporting and for final approval of the Financial Statements.

The Board meets regularly with management, the internal auditors and the shareholders' auditors to review the Financial Statements, the Independent Auditor's Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities.

The shareholders' auditors have full and free access to the Board, as does the Director of Internal Audit Services.

Deloitte LLP performed an independent audit of the 2016 and 2015 Financial Statements in this report. Their independent professional opinion on the fairness of these Financial Statements is included in the Independent Auditor's Report.

February 26, 2017

Stephen W. Baker	J. Patrick Reddy
President	Chief Financial Officer

Deloitte.

Deloitte LLP
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Independent Auditor's Report

To the Shareholders of
Union Gas Limited

We have audited the accompanying financial statements of Union Gas Limited, which comprise the balance sheets as at December 31, 2016 and December 31, 2015, and the statements of operations and comprehensive income, statements of equity, and statements of cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of 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 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 audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the 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 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 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 financial statements present fairly, in all material respects, the financial position of Union Gas Limited as at December 31, 2016 and December 31, 2015, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Deloitte LLP

Chartered Professional Accountants
Licensed Public Accountants
February 26, 2017

Filed: 2017-11-02
EB-2017-0306
Exhibit B
Tab 1
Attachment 10
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STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

For the Years Ended December 31 ($millions)	**2016**	2015
Gas sales and distribution revenue	**1,529**	1,675
Cost of gas (note 9)	**717**	875
Gas distribution margin	**812**	800
Storage and transportation revenue (note 9)	**278**	239
Other revenue, net	**21**	26
Net operating revenue	**1,111**	1,065
Expenses		
Operating and maintenance (note 9)	**414**	399
Depreciation and amortization	**239**	224
Property taxes and other	**71**	69
Total expenses	**724**	692
Income before interest and income taxes	**387**	373
Interest expense (notes 9 and 10)	**161**	157
Income before income taxes	**226**	216
Income tax expense (note 6)	**21**	28
Net income	**205**	188
Preferred shares dividends	**3**	3
Net income applicable to common stock	**202**	185
Other comprehensive (loss) income, net of tax		
Pension and benefits impact (net of tax of (3) and 6 respectively) (note 12)	**(7)**	16
Comprehensive income applicable to common stock	**195**	201

(See accompanying notes)

BALANCE SHEETS

As at December 31 ($millions)	**2016**	2015
Assets		
Current assets		
Cash and cash equivalents	**27**	5
Accounts receivable, net (notes 3, 4 and 9)	**816**	648
Income taxes receivable (note 6)	**29**	24
Inventories (note 5)	**245**	299
Total current assets	**1,117**	976
Property, plant and equipment (note 7)		
Cost	**9,270**	8,300
Accumulated depreciation and amortization	**2,762**	2,622
Property, plant and equipment, net	**6,508**	5,678
Regulatory and other assets (notes 2, 3 and 8)	**602**	536
Total Assets	**8,227**	7,190
Liabilities and Equity		
Current liabilities		
Short-term borrowings (note 9)	**253**	56
Commercial paper (note 10)	**333**	207
Accounts payable and accrued charges (notes 4 and 9)	**878**	793
Current maturities of long-term debt (note 10)	**125**	200
Total current liabilities	**1,589**	1,256
Long-term liabilities		
Long-term debt (note 10)	**3,295**	2,921
Deferred income taxes (note 6)	**516**	451
Asset retirement obligations (note 13)	**417**	440
Regulatory and other liabilities (notes 2 and 8)	**602**	509
Total long-term liabilities	**4,830**	4,321
Total Liabilities	**6,419**	5,577
Preferred Shares (note 11)	**110**	110
Equity		
Common stock, unlimited shares authorized, 57,822,650 outstanding	**627**	627
Retained earnings	**1,253**	1,051
Accumulated other comprehensive loss	**(186)**	(179)
Paid-in capital	**4**	4
Total Equity	**1,698**	1,503
Total Liabilities and Equity	**8,227**	7,190

(See accompanying notes)

Approved by the Board

Director
David Unruh

Director
Steve Baker

STATEMENTS OF CASH FLOWS

For the Years Ended December 31 ($millions)	**2016**	2015
Operating Activities		
Net income	**205**	188
Items not affecting cash		
Depreciation and amortization	**239**	224
Loss on disposal of assets	**1**	—
Deferred income taxes	**8**	(40)
Changes in working capital		
Accounts receivable	**(126)**	89
Inventories	**40**	(60)
Accounts payable, accrued charges and other	**35**	100
Net cash provided by operating activities	**402**	501
Investing Activities		
Capital expenditures	**(1,036)**	(701)
Net increase in restricted funds	**37**	—
Net cash used in investing activities	**(999)**	(701)
Financing Activities		
Net increase in short-term borrowings	**197**	8
Net increase (decrease) in commercial paper	**126**	(63)
Long-term debt issued	**499**	445
Long-term debt repayments	**(200)**	(150)
Purchase of subsidiary shares from non-controlling interest	**—**	(2)
Dividends paid	**(3)**	(53)
Net cash provided by financing activities	**619**	185
Change in cash and cash equivalents, during the year	**22**	(15)
Cash and cash equivalents, beginning of year	**5**	20
Cash and cash equivalents, end of year	**27**	5
Supplementary Disclosure of Cash Flow Information:		
Cash payments of interest, net of amounts capitalized	**158**	160
Cash payments of income taxes, net of refunds received	**9**	66
Property, plant and equipment noncash accruals	**24**	17

(See accompanying notes)

STATEMENTS OF EQUITY

($millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Paid-in Capital	Non-controlling Interest	Total
December 31, 2015	627	1,051	(179)	4	—	1,503
Net income	—	205	—	—	—	205
Other comprehensive loss	—	—	(7)	—	—	(7)
Dividends						
Preferred shares	—	(3)	—	—	—	(3)
December 31, 2016	627	1,253	(186)	4	—	1,698
December 31, 2014	627	916	(195)	—	8	1,356
Net income	—	188	—	—	—	188
Other comprehensive income	—	—	16	—	—	16
Dividends						
Preferred shares	—	(3)	—	—	—	(3)
Common stock	—	(50)	—	—	—	(50)
Purchase of subsidiary shares from non-controlling interest	—	—	—	4	(8)	(4)
December 31, 2015	627	1,051	(179)	4	—	1,503

(See accompanying notes)

UNION GAS LIMITED
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2016 AND 2015

1. Summary of Operations and Significant Accounting Policies

The terms "Union Gas" or "the Company" as used in these Financial Statements refer to Union Gas Limited unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Union Gas. Union Gas' common stock is held by Great Lakes Basin Energy L.P. (GLBE), a wholly-owned limited partnership of Westcoast Energy Inc. (Westcoast). Westcoast is an indirect wholly-owned subsidiary of Spectra Energy Corp (Spectra Energy).

On September 6, 2016, Spectra Energy announced that it entered into a definitive merger agreement with Enbridge Inc. (Enbridge). Under this agreement, Enbridge and Spectra Energy will combine in a stock-for-stock merger transaction, which values Spectra Energy's stock at approximately $37 billion, based on the closing price of Enbridge common shares as of September 2, 2016. This transaction was approved by the boards of directors and shareholders of both Spectra Energy and Enbridge and has received all necessary regulatory approvals. The transaction is expected to close on February 27, 2017.

Upon completion of the proposed merger, Spectra Energy shareholders will receive 0.984 Enbridge common shares for each share of Spectra Energy stock they own. The consideration to be received is valued at U.S. $40.33 per Spectra Energy share, based on the closing price of Enbridge common shares as of September 2, 2016, representing an approximate 11.5% premium to the closing price of Spectra Energy stock as of September 2, 2016. Upon completion of the merger, Enbridge shareholders are expected to own approximately 57% of the combined company and Spectra Energy shareholders are expected to own approximately 43%.

As a result of this transaction, Enbridge and its subsidiaries will own Union Gas through their ownership of Spectra Energy.

Nature of Operations

Union Gas owns and operates natural gas distribution, storage and transmission facilities in Ontario. The Company distributes natural gas to customers in northern, southwestern and eastern Ontario and provides natural gas storage and transportation services for other utilities and energy market participants. The property, plant and equipment of the Company consist primarily of pipeline, storage and compression facilities used in the distribution, storage and transportation of natural gas.

Basis of Presentation

The Financial Statements of the Company include the standalone accounts of the Company and have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). All amounts are presented in millions of Canadian dollars except where noted.

In 2014, Canadian securities regulators approved the extension of the Company's exemptive relief to continue reporting under U.S. GAAP instead of International Financial Reporting Standards (IFRS) until the earlier of January 1, 2019, and the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation.

Use of Estimates

The preparation of the Financial Statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual amounts could differ from these estimates.

Regulation

The Company is regulated by the Ontario Energy Board (OEB) pursuant to the provisions of the *Ontario Energy Board Act, (1998)*, which is part of a package of legislation known as the *Energy Competition Act, (1998)*. This legislation provides an opportunity for different forms of regulation and increased competition in the energy (electricity and natural gas) industry in Ontario. The Company is subject to regulation with respect to the rates that it may charge its customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting principles. The OEB has determined that it will forbear from regulating the prices for long-term storage services. The Storage Forbearance Decision created an unregulated storage operation within the Company and provides the framework required to support new storage investments.

The OEB is mandated to approve rates that are just and reasonable. Utility earnings are regulated by the OEB under cost of service regulation, on the basis of a return on rate base for a future period. Under cost of service regulation, a rate application process leads to the implementation of new rates intended to provide a utility with the opportunity to earn an allowed rate of return. The actual rate of return achieved by the Company may vary from the rate allowed by the OEB as a result of unexpected changes in weather, average use per customer, inflation, the price of competing fuels, interest rates, general economic conditions and its ability to achieve forecasted revenues and manage costs.

Effective January 1, 2014, the Company began a five year incentive regulation term. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts.

As part of the Company's OEB-approved incentive regulation framework, an earnings sharing mechanism exists whereby earnings in excess of 100 basis points above the benchmark return on equity are shared with ratepayers as a reduction in earnings during the year, if applicable.

The Company follows U.S. GAAP, which may differ for regulated operations from those otherwise expected in non rate-regulated businesses. As a result, the Company records assets and liabilities that result from the regulated ratemaking process that may not be recorded under U.S. GAAP for non rate-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate at the provincial and national levels, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs could be recognized in current period earnings.

Revenue Recognition

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered and collection is reasonably assured. Revenues related to these services provided or products delivered but not yet billed are estimated each month.

Gas Sales and Cost of Gas

Gas sales revenue is recorded on the basis of regular meter readings and estimates of customer volume usage since the last meter reading date to the end of the reporting period applied using OEB approved rates. Cost of gas is recorded using amounts approved by the OEB in the determination of customer sales rates. Differences between the OEB approved reference amounts and those costs actually incurred are deferred on the Balance Sheets for future disposition subject to approval by the OEB.

In determining the quantities of gas delivered and received, differences arise from the measurement process. The Company includes in the cost of gas an estimated amount of these differences based upon the methodology used by the OEB in the determination of rates for storage, transmission and distribution of gas. Annual fluctuations from the estimated level are recognized in earnings during the year.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term investments, with an original maturity of three months or less.

Income Taxes

Deferred income taxes are recognized for differences between the financial reporting and tax bases of assets and liabilities at enacted statutory tax rates in effect for the years in which the differences are expected to reverse. The effect on deferred taxes of a change in tax rates is recognized in income in the period that includes the enactment date. Actual income taxes could vary from these estimates due to the future changes in income tax law or results from the final review of tax returns by federal and provincial tax authorities.

Financial statement effects on tax positions are recognized in the period in which it is more likely than not that the position will be sustained upon examination, the position is effectively settled or when the statute of limitations to challenge the position has expired. Interest related to the unrecognized tax benefits is recorded as Interest expense on the Statements of Operations and Comprehensive Income.

Inventories

Gas in storage for resale to customers is carried at weighted average cost approved by the OEB in the determination of customer sales rates. The difference between the approved cost and the actual cost of the gas purchased is deferred on the Balance Sheets for future disposition subject to approval by the OEB. Inventories of materials and supplies are valued at the lower of average cost or net realizable value.

Property, Plant and Equipment and Depreciation

Property, plant and equipment is stated at historical cost less accumulated depreciation and amortization. The Company capitalizes all construction-related direct labour and material costs, as well as indirect construction costs. Indirect costs include general engineering and the cost of funds used during construction. The costs of renewals and betterments that extend the useful life or increase the expected output of property, plant and equipment are also capitalized. The cost of repairs, replacements and major maintenance projects that do not extend the useful life or increase the expected output of property, plant and equipment are expensed as incurred.

Regulated depreciation is computed based on the asset's average service life using the straight-line method. Unregulated depreciation is computed based on management's assumption of useful life using the straight-line method.

When regulated property, plant and equipment is retired, the original cost plus the cost of retirement, less salvage value, is charged to accumulated depreciation and amortization. When entire regulated operating units are sold or non-regulated property, plant and equipment is retired, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body.

Asset Retirement Obligations (AROs)

The Company recognizes AROs for legal commitments associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset and conditional AROs in which the timing or method of settlement are conditional on a future event that may or may not be within the Company's control. The fair value of a liability for an ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made and is added to the carrying amount of the associated asset. This additional carrying amount is depreciated over the estimated useful life of the asset.

Stock-Based Compensation

Union Gas employees participate in a stock-based compensation plan sponsored by Spectra Energy. For employee awards, equity-classified and liability-classified stock-based compensation cost is measured at the grant date based on the fair value of the award. Liability classified stock-based compensation cost is re-measured at each reporting period until settlement. Related compensation expense is recognized over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests, the date the employee becomes retirement-eligible, or the date the award market condition is met. Awards, including stock options, granted to employees that are already retirement-eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted.

Pension and Other Post-Retirement Benefits

The Company fully recognizes the overfunded or underfunded status of pension and other post-retirement benefit plans as Regulatory and other assets, Accounts payable and accrued charges, or Regulatory and other liabilities on the Balance Sheets. A plan's funded status is the difference between the fair value of plan assets and the plan's benefit obligation. The Company records deferred plan costs and income (unrecognized losses and gains, and unrecognized prior service costs and credits) in Accumulated other comprehensive loss, until they are amortized to be recognized as a component of benefit expense within Operating and maintenance expenses in the Statements of Operations and Comprehensive Income. See note 12 for further discussion.

New Accounting Pronouncements

In May 2014, the FASB issued ASU 2014-09, *"Revenue from Contracts with Customers (Topic 606),"* in an effort to improve revenue recognition practices across entities and industries. The ASU introduces a single, principles-based revenue recognition model which centers on the core principle of an entity recognizing revenue in a manner that depicts the transfer of goods and services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. Since its release, the FASB has issued multiple amendments clarifying and/or amending ASU 2014-09. The Company has substantially completed a review of contracts with customers in relation to the requirements of ASU 2014-09. While the Company has not identified any material difference in the amount or timing of revenue recognition for the categories the Company has reviewed to date, the evaluation is not complete and the Company has not concluded on the overall impacts of adopting this standard. In addition, the Company is in the process of implementing appropriate changes to business processes, systems and controls to support the recognition and disclosure requirements under the new standard. ASU 2014-09 is effective for the Company on January 1, 2018 and allows for either full retrospective or modified retrospective adoption.

In January 2016, the FASB issued ASU 2016-01, "*Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financials Assets and Financial Liabilities,*" which amends the classification and measurement of financial instruments. Changes primarily affect the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. This ASU is effective for the Company beginning after December 15, 2017. Early adoption is not permitted. The Company is currently evaluating this ASU and its potential impact.

In February 2016, the FASB issued Accounting Standards Update (ASU) No. 2016-02, "*Leases (Topic 842),*" to improve the financial reporting around leasing transactions. The new guidance requires companies to begin recording assets and liabilities arising from those leases classified as operating leases under previous guidance. Furthermore, the new guidance will require significant additional disclosures about the amount, timing and uncertainty of cash flows from leases. Topic 842 retains a distinction between finance leases and operating leases. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in previous guidance. The result of retaining a distinction between finance leases and operating leases is that under the lessee accounting model in Topic 842, the effect of leases in the statement of comprehensive income and the statement of cash flows is largely unchanged from previous guidance. This ASU is effective for the Company January 1, 2019. The Company is currently evaluating this ASU and its potential impact.

In March 2016, the FASB issued ASU No. 2016-09, "*Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting,*" which simplifies several aspects of the accounting for share-based payment award transactions. The update requires classification changes for certain tax cash flows within the statement of cash flows and requires all excess tax benefits and tax deficiencies to be recorded through the Statement of Operations. In addition, the update provides an accounting policy election around forfeitures and raises the threshold for liability classification of share-based awards withheld for tax withholding requirements. This ASU is effective for the Company January 1, 2017. This ASU is not expected to have a material impact on the Company's Financial Statements.

In June 2016, the FASB issued ASU No. 2016-13, "*Financial Instruments-Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments,*" to replace the incurred loss impairment methodology with a methodology that reflects expected credit losses and requires the consideration of a broader range of reasonable and supportable information to inform credit loss estimates. This ASU is effective for the Company January 1, 2020. The Company is currently evaluating this ASU and its potential impact.

In August 2016, the FASB issued ASU No. 2016-15, "*Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments,*" to provide guidance on specific cash flow issues with the objective of reducing the existing diversity in practice. This ASU is effective for the Company January 1, 2018. The Company is currently evaluating this ASU and its potential impact.

In November 2016, the FASB issued ASU No. 2016-18, *"Statement of Cash Flows (Topic 230): Restricted Cash,"* to address the diversity in the classification and presentation of changes in restricted cash and restricted cash equivalents on the statement of cash flows. The update requires that restricted cash and restricted cash equivalents be included with Cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the Statement of Cash Flows. This ASU is effective for the Company on January 1, 2018. The Company is currently evaluating this ASU and its potential impact.

2. Regulatory Matters

Regulatory Assets and Liabilities

The Company recorded the following assets and liabilities that result from the regulated ratemaking process that would not be recorded under U.S. GAAP for non-regulated entities. See note 1 for further discussion.

($millions)	Financial Statement Location	**December 31, 2016**	December 31, 2015	Recovery/Settlement Period
Regulatory assets[a]				
Customer deferrals	Accounts receivable, net	**82**	43	Less than 1 year
Gas in storage inventory	Inventories	**13**	53	Less than 1 year
Deferred income taxes – long-term[b]	Regulatory and other assets	**462**	403	2 years – exceeds remaining life of asset
Total regulatory assets		**557**	499	
Regulatory liabilities[a]				
Other deferrals – current[b]	Accounts payable and accrued charges	**7**	7	Less than 1 year
Customer deferrals	Accounts payable and accrued charges	**16**	1	Less than 1 year
Gas cost deferrals	Accounts payable and accrued charges	**13**	67	Less than 1 year
Asset removal costs[b]	Regulatory and other liabilities	**394**	357	Exceeds remaining life of asset
Total regulatory liabilities		**430**	432	

[a] All regulatory assets and liabilities are excluded from rate base unless otherwise noted.

[b] All or a portion of the balance is included in rate base.

The Company has regulatory assets of $462 million as of December 31, 2016 and $403 million as of December 31, 2015 related to deferred income tax liabilities. Under the current OEB-authorized rate structure, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since substantially all of these timing differences are related to property, plant and equipment costs, recovery of these regulatory assets is expected to occur over the life of those assets.

The Company has regulatory liabilities associated with plant removal costs of $394 million as of December 31, 2016 and $357 million as of December 31, 2015. These regulatory liabilities represent collections from customers under approved rates for future asset removal activities that are expected to occur associated with its regulated facilities.

In addition, the Company has regulatory liabilities of $13 million as of December 31, 2016 and $67 million as of December 31, 2015 representing gas cost collections from customers under approved rates that vary from the actual cost of gas for the associated periods. The Company files an application quarterly with the OEB to ensure that customers' rates are updated to reflect published forward-market prices. The difference between the approved and actual cost of gas is deferred for future repayment to or refund from customers.

Rate Related Information

The Company's distribution rates, beginning January 1, 2014 are set under a five-year incentive regulation framework. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The framework allows for:

- annual inflationary rate increases, offset by a productivity factor of 60% of inflation, such that the annual net rate escalator in each year is 40% of inflation,
- rate increases or decreases in the small volume customer classes where average use declines or increases,
- certain adjustments to base rates,
- the continued pass-through of gas commodity, upstream transportation and demand side management costs,
- the additional pass-through of costs associated with major capital investments and certain fuel variances,
- an allowance for unexpected cost changes that are outside of management's control,
- equal sharing of tax changes between the Company and its customers, and
- an earnings sharing mechanism that permits the Company to fully retain the return on equity from utility operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.

Annual Deferral Account Disposition

In April 2016, the Company filed an application with the OEB for the annual disposition of the 2015 deferral account balances. The impact was a net receivable from customers of approximately $23 million. In August 2016, a decision from the OEB was received approving recovery from ratepayers which began October 1, 2016.

Demand Side Management (DSM)

In June 2016, a decision from the OEB was received approving recovery of the 2014 DSM deferral and variance account balances from ratepayers. The Company began recovery of approximately $11 million from customers on October 1, 2016.

In March 2016, the Company filed a Draft Rate Order with the OEB for rates effective January 1, 2016 based on the OEB's February 24, 2016 updated Decision and Order on the 2015-2020 DSM Plan. In May 2016, a decision from the OEB was received approving recovery in rates of the incremental 2016 DSM related charges from ratepayers of approximately $24 million effective January 1, 2016. The impact on a typical residential customer ranged from an increase of $7 to $9 annually, depending on the customer's location within the Company's service territory. These charges are being recovered over a six month period which began July 1, 2016 for general service rate classes and as a one-time adjustment for contract rate classes that was made in July 2016.

As part of the Company's 2017 rates application, the Company has included an approved DSM budget of approximately $58 million in 2017 rates. The 2017 budget was approved as part of the OEB Revised Decision in the 2015-2020 DSM Plan proceeding.

3. Restricted Cash

The Company had $37 million of restricted funds at December 31, 2016, with $15 million classified as Accounts receivable net, and $22 million classified as Regulatory and other assets. These restricted funds are related to money received from the Province of Ontario (the Province) under the Green Investment Fund program. The funds from this program are to be used by May 31, 2019 to help eligible homeowners reduce their energy consumption and greenhouse gas emissions. The Company is acting as an intermediary for the transfer of funds between the Province and approximately 12,000 eligible homeowners.

Changes in restricted balances are presented within Investing Activities on the Company's Statements of Cash Flows.

4. Gas Imbalances

The Company, in the normal course of its operations, experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the Balance Sheet dates. As the settlement of imbalances is done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

At December 31, 2016 Accounts receivable, net and Accounts payable and accrued charges include $410 million (2015 – $350 million) related to gas imbalances and gas balancing services.

5. Inventories

Gas in storage includes gas for delivery to customers and for use in the Company's operations. Inventories of materials and supplies are for use in the Company's operations.

($millions)	**December 31, 2016**	December 31, 2015
Gas in storage	**222**	279
Materials and supplies	**23**	20
	245	299

6. Income Taxes

Income Tax Expense Components

($millions)	**2016**	2015
Current		
Federal	**12**	43
Provincial	**1**	25
Total current tax expense	**13**	68
Deferred		
Federal	**5**	(24)
Provincial	**3**	(16)
Total deferred tax expense	**8**	(40)
Total Income taxes	**21**	28

Reconciliation of Income Tax Expense at the Combined Federal and Ontario Statutory Tax Rate to Actual Income Tax Expense

($millions)	**2016**	2015
Income before income taxes	**226**	216
Statutory income tax rate	**26.5%**	26.5%
Statutory income tax rate applied to accounting income	**60**	57
Increase/(decrease) resulting from:		
Deferred income tax adjustments related to rate regulated operations	**(44)**	(33)
Other - net	**5**	4
Total income tax expense	**21**	28
Effective rate of income tax	**9.3%**	13.0%

Net Deferred Income Tax Liability Components

($millions)	**December 31, 2016**	December 31, 2015
Deferred income tax liabilities		
Accelerated depreciation rates	**405**	370
Regulatory asset	**121**	105
Reserves	**20**	(1)
Other	**(30)**	(23)
Total deferred income tax liabilities	**516**	451

Reconciliation of Gross Unrecognized Income Tax Benefits

($millions)	**December 31, 2016**	December 31, 2015
Balance, beginning of year	**28**	19
Increases related to prior year tax positions	**8**	11
Increases related to current year tax positions	**3**	2
Reductions due to lapse of statute of limitations	**(1)**	(4)
Balance, end of year	**38**	28

Unrecognized tax benefits totalled $38 million at December 31, 2016. Of this, $37 million would reduce the effective tax rate if recognized on or after January 1, 2017. The Company recorded a net increase of $10 million in gross unrecognized tax benefits in 2016. This was a result of $1 million attributable to deferred tax liability and $11 million increase in income tax expense.

The Company recognized potential accrued interest related to unrecognized tax benefits as interest expense. Nil was recorded to interest expense in 2016 compared to a $1 million benefit in 2015. Accrued interest totalled $1 million at December 31, 2016 and $1 million at December 31, 2015.

Although uncertain, the Company believes it is reasonably possible that the total amount of unrecognized tax benefits could decrease by $11 million prior to December 31, 2017. The anticipated changes in unrecognized tax benefits relate to the expiration of statutes of limitations and expected audit settlements.

The Company remains subject to examination for income tax returns for years 2009 through 2015.

7. Property, Plant and Equipment, net

($millions)	Useful Life	**December 31, 2016**	December 31, 2015
	(years)		
Plant			
Natural gas transmission	32 - 58	**2,734**	2,210
Natural gas distribution	25 - 60	**4,697**	4,494
Storage	10 - 50	**924**	887
Land rights and rights of way	48 - 61	**137**	120
Other buildings and improvements	2 - 42	**62**	62
Equipment	4 - 15	**82**	86
Vehicles	6	**57**	56
Land	—	**90**	78
Construction in progress	—	**382**	193
Software	4 - 10	**84**	89
Other	15 - 18	**21**	25
Total Property, plant and equipment		**9,270**	8,300
Total accumulated depreciation		**2,672**	2,545
Total accumulated amortization		**90**	77
Total Property, plant and equipment, net		**6,508**	5,678

The Company had no capital leases at December 31, 2016 or 2015.

95% of the Company's property, plant and equipment is regulated with estimated useful lives based on rates approved by the OEB. Composite weighted-average depreciation rates were 2.90% for 2016 and 2.97% for 2015.

The Company capitalized interest of $12 million in 2016 and $7 million in 2015.

Amortization expense of intangible assets totaled $17 million in 2016 and $18 million in 2015. Estimated amortization expense for the next five years is as follows:

($millions)	**2017**	**2018**	**2019**	**2020**	**2021**
Estimated amortization expense	15	12	10	8	7

8. Regulatory and Other Assets and Liabilities

($millions)	**December 31, 2016**	December 31, 2015
Regulatory assets	**462**	403
Restricted cash	**22**	—
Goodwill	**12**	12
Pension assets	**27**	28
Gas balancing	**67**	67
Material and supplies	**10**	10
Deposits on projects	**—**	14
Other	**2**	2
Total Regulatory and other assets	**602**	536
Regulatory liabilities	**394**	357
Pension liabilities	**147**	122
Unrecognized tax benefits	**38**	28
Accrued liabilities[(a)]	**22**	—
Other	**1**	2
Total Regulatory and other liabilities	**602**	509

[(a)]Includes $22 million (2015 - $nil) related to the Green Investment Fund program. See Note 3.

9. Related Party Transactions

The Company occasionally performs services for and incurs costs on behalf of the Company's affiliates, which are subsequently reimbursed. Likewise, certain affiliates may perform services for or incur costs on behalf of the Company, which are then reimbursed by the Company. These transactions are in the normal course of operations and are recorded at exchange amounts agreed to between the related parties.

In addition, Spectra Energy and its affiliates perform centralized corporate functions for the Company, pursuant to an agreement with Spectra Energy and its affiliates, including legal, accounting, compliance, treasury, information technology and other areas, as well as certain engineering and other services. The Company reimburses Spectra Energy and its affiliates for the expenses to provide these services as well as other expenses they incur on the Company's behalf. Spectra Energy and its affiliates charge such expenses based on the cost of actual services provided or using various allocation methodologies based on the Company's percentage of assets, employees, earnings or other measures, as compared to Spectra Energy's other affiliates.

The Company's transactions with affiliated companies are as follows:

($millions), net	**Transport and Storage Expenses**	**Corporate Charges (Receipts)[a]**	**Gas Purchases**
2016			
St Clair Pipelines 1996, a division of Westcoast	—	(2)	—
Pipeline and Field Services, a division of Westcoast	—	(4)	—
Spectra Energy Empress L.P.	—	—	21
Spectra Energy Gas Transmission LLC	—	21	—
Sarnia Airport Storage Pool Limited Partnership	4	—	—
2015			
St Clair Pipelines 1996, a division of Westcoast	—	(2)	—
Pipeline and Field Services, a division of Westcoast	—	(3)	—
Spectra Energy Empress L.P.	—	—	55
Spectra Energy Gas Transmission LLC	—	14	—
Sarnia Airport Storage Pool Limited Partnership	4	—	—

[a]Excludes compensation arrangements.

Net amounts due (to) from related affiliates are as follows:

($millions), net	**2016**	2015
Spectra Energy Empress L.P.	—	(6)
Spectra Energy Gas Transmission LLC	**(1)**	(7)
Total[a]	**(1)**	(13)

[a]At December 31, 2016, $5 million (2015 – $14 million) is recognized in Accounts payable and accrued charges and $4 million (2015 – $1 million) is recognized in Accounts receivable, net on the Balance Sheets.

In the normal course of operations, the Company provides or obtains funds from Westcoast on an unsecured basis. The balance outstanding at December 31, 2016 was a payable of $253 million (December 31, 2015 – payable of $56 million). During 2016, interest paid on these loans totalled less than $1 million (2015 – less than $1 million) and interest received on these loans totalled less than $1 million (2015 – less than $1 million). Interest on these loans is calculated based on the monthly average of 30-day banker's acceptance rates.

The Company also has a promissory note to borrow up to $150 million from GLBE on an unsecured basis. Funds from this promissory note are used for general corporate purposes. There was no balance outstanding at December 31, 2016 or December 31, 2015.

In 2016, no common stock dividend payments were made to GLBE (2015 – $50 million).

10. Debt and Credit Facilities

Summary of Debt and Related Terms

($millions)		**December 31, 2016**	December 31, 2015
4.64%	Series 5, due June 30, 2016	**—**	200
9.70%	1992 Series II debentures, due November 6, 2017	**125**	125
5.35%	Series 6, due April 27, 2018	**200**	200
8.75%	1993 Series debentures, due August 3, 2018	**125**	125
8.65%	Senior debentures, due October 19, 2018	**75**	75
2.76%	Series 11, due June 2, 2021	**200**	200
4.85%	Series 6, due April 25, 2022	**125**	125
3.79%	Series 10, due July 10, 2023	**250**	250
3.19%	Series 13, due September 17, 2025	**200**	200
8.65%	1995 Series debentures, due November 10, 2025	**125**	125
2.81%	Series 14, due June 1, 2026	**250**	—
5.46%	Series 6, due September 11, 2036	**165**	165
6.05%	Series 7, due September 2, 2038	**300**	300
5.20%	Series 8, due July 23, 2040	**250**	250
4.88%	Series 9, due June 21, 2041	**300**	300
4.20%	Series 12, due June 2, 2044	**500**	500
3.80%	Series 15, due June 1, 2046	**250**	—
Long-term debt principal (including current maturities)		**3,440**	3,140
Less: Unamortized debt discount		**7**	7
Less: Debt issue costs		**13**	12
Add: Commercial paper		**333**	207
Total debt		**3,753**	3,328
Less: Current maturities of long-term debt		**125**	200
Less: Commercial paper		**333**	207
Total Long-term debt		**3,295**	2,921

The Company's long-term debt is unsecured. Principal repayment requirements on long-term debt are as follows:

($millions)	**Total**	**2017**	**2018**	**2019**	**2020**	**2021**	**Thereafter**
Long-term debt[(a)]	3,440	125	400	—	—	200	2,715

(a) Excludes commercial paper of $333 million.

Under the terms of the trust indentures relating to certain debentures, the Company has agreed to several covenants including a limitation on the payment of dividends. As of December 31, 2016 and 2015, the Company is in compliance with all such covenants.

Total interest expense on long-term debt in 2016 was $169 million (2015 – $163 million).

Available Credit Facility and Restrictive Debt Covenants

			Commercial Paper Debt Outstanding at	
($millions)	**Expiration Date**	**Credit Facility Capacity**	**December 31, 2016**	December 31, 2015
Multi-year syndicated [(a), (b)]	2021	700	**333**	207

[(a)] The credit facility contains a covenant requiring the debt-to-total capitalization ratio, as defined in the agreement, to not exceed 75% and a provision which requires the Company to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 69.0% at December 31 2016 (December 31, 2015 – 67.8%).

[(b)] In April 2016, the Company amended the revolving credit agreement. The facility was increased from $500 million to $700 million and its expiration date was extended from 2019 to 2021.

The issuance of commercial paper, letters of credit and revolving borrowings reduce the amount available under the credit facility. As of December 31, 2016 and December 31, 2015 there were no letters of credit issued or revolving borrowings outstanding under the credit facility. The majority of the Company's short-term cash requirements are funded through the issuance of commercial paper. The weighted average rate on outstanding commercial paper as of December 31, 2016 was 0.87% (2015 – 0.86%). The weighted average days to maturity on outstanding commercial paper as of December 31, 2016 was 8 days (2015 – 9 days).

The Company's credit agreement contains various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreement. As of December 31, 2016 and December 31, 2015, the Company was in compliance with those covenants. In addition, the credit agreement allows for the acceleration of payments or termination of the agreement due to non-payment, or in some cases, due to the acceleration of other significant indebtedness of the borrower.

Total Interest paid on short term debt in 2016 was $1 million (2015 – $1 million).

11. Preferred Shares

		Outstanding			
	Authorized	**December 31, 2016**	December 31, 2015	**December 31, 2016**	December 31, 2015
	(shares)	*(shares)*		*($millions)*	
Class A	202,072				
5.5% Series A		**47,672**	47,672	**3**	3
6% Series B		**90,000**	90,000	**5**	5
5% Series C		**49,500**	49,500	**2**	2
4.88% Class B, Series 10	Unlimited	**4,000,000**	4,000,000	**100**	100
				110	110

The Class A, Series A and C Preferred shares are cumulative and redeemable at $50.50 per share. The Company is obligated to offer to purchase $170,000 of Series A and $140,000 of Series C shares annually at the lowest price obtainable, but not exceeding $50 per share.

The Class A, Series B Preferred shares are cumulative and redeemable at $55 per share at the option of the Company.

The Class B, Series 10 Preferred shares are cumulative and redeemable at $25 per share at the option of the Company and, at the option of the holders, convertible back into Series 11 shares once every five years commencing January 1, 2014. The holders of the Class B, Series 10 Preferred shares did not exercise their option on January 1, 2014 and their next optional conversion date is January 1, 2019. The Company may redeem at any time all, but not less than all, of the outstanding Series 10 Shares. The dividend rate of the Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2018.

The Company has an unlimited number of authorized 4.79% Class B, Series 11 Preferred shares. These shares are cumulative and redeemable at $25 per share at the option of the Company, and at the option of the holders, convertible back into Series 10 shares, commencing on January 15, 2026 and on each fifth anniversary thereafter (each such anniversary, a Series 11 Conversion Date). Additionally, these shares are redeemable at $25.50 per share at the option of the Company on any date after January 15, 2026 that is not a Series 11 Conversion Date. At December 31, 2016 and December 31, 2015 none of these shares were issued or outstanding.

The shares are not subject to any sinking fund or mandatory redemption and are not convertible into any other type of securities other than preferred shares. As these shares are not solely in the control of the Company, they have been classified as temporary equity on the Balance Sheets.

12. Employee Benefit Plans

Retirement Plans

The Company maintains registered and non-registered, contributory and non-contributory defined benefit (DB Plans) and defined contribution (DC Plan) retirement plans covering substantially all employees. The DB Plans provide retirement benefits based on each plan participant's years of service and final average earnings. Under the DC Plan, company contributions are determined according to the terms of the plan and based on each plan participant's age, years of service and current eligible earnings. The Company also provides non-registered DB Plans to all employees who retire under a registered DB Plan and whose pension is limited by the maximum pension limits under the Income Tax Act.

The Company's policy is to fund the retirement plans, where applicable, on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants or as required by legislation or plan terms. Total contributions to the DB Plans were $4 million during the twelve months ended December 31, 2016 and $6 million during the twelve months ended December 31, 2015. Contributions of $6 million in both 2016 and 2015 were made to the Company's DC Plan. The Company anticipates that in 2017 it will make total contributions of approximately $15 million to its DB Plans and $6 million to its DC Plan.

Actuarial gains and losses are amortized over the average remaining service period of active employees. The average remaining service periods of active employees covered by the registered and non-registered DB Plans is 13 years. The Company determines the market-related value of plan assets using a calculated value that recognizes changes in fair value of the plan assets over three years.

Registered and Non-Registered Pension Plans

Change in Projected Benefit Obligation and Change in Fair Value of Plan Assets

($millions)	**2016**	2015
Change in Projected Benefit Obligation		
Projected benefit obligation, beginning of year	**877**	863
Service cost	**19**	20
Interest cost	**35**	34
Actuarial (gain) loss	**22**	(5)
Participant contributions	**4**	4
Benefits paid	**(40)**	(39)
Projected benefit obligation, end of year	**917**	877
Change in Fair Value of Plan Assets		
Plan assets, beginning of year	**842**	829
Actual return on plan assets	**47**	45
Benefits paid	**(40)**	(39)
Employer contributions	**4**	6
Plan participants' contributions	**4**	4
Expected non-investment expenses	**(3)**	(3)
Plan assets, end of year	**854**	842
Net amount recognized	**(63)**	(35)

Accumulated Benefit Obligation	**866**	824

($millions)	**2016**	2015
Net amount recognized		
Current Liabilities - Other	**(2)**	(2)
Deferred Credits and Other Liabilities - Regulatory and Other	**(88)**	(61)
Other Assets - Other	**27**	28
Total net amount recognized	**(63)**	(35)

The table above includes non-registered pension plans that are not funded and had projected benefit obligations of $47 million at December 31, 2016 and $42 million at December 31, 2015. At December 31, 2016 plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations of $519 million, accumulated benefit obligations of $475 million and fair value of plan assets of $428 million.

Amounts Recognized in Accumulated Other Comprehensive Income (AOCI)

($millions)	**2016**	2015
Net actuarial loss	**257**	241
Prior service costs	**2**	4
Total amounts recognized in AOCI, pre-tax	**259**	245

Components of Net Periodic Pension Costs

($millions)	**2016**	2015
Net Periodic Pension Cost		
Service cost benefit earned	**22**	22
Interest cost on projected benefit obligation	**35**	34
Expected return on plan assets	**(57)**	(56)
Amortization of prior service cost	**1**	1
Amortization of loss	**17**	22
Net periodic pension cost	**18**	23
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Current year actuarial (gain) loss	**32**	7
Amortization of actuarial loss	**(17)**	(22)
Amortization of prior service cost	**(1)**	(1)
Total recognized in other comprehensive income	**14**	(16)
Total Recognized in Net Periodic Pension Cost and Other Comprehensive Income	**32**	7

At December 31, 2016, approximately $14 million of actuarial losses will be amortized from AOCI on the Balance Sheets into net periodic pension cost in 2017.

At December 31, 2016, approximately $1 million of prior service costs will be amortized from AOCI on the Balance Sheets into net periodic pension costs in 2017.

Assumptions Used for Pension Benefits Accounting

	2016	2015
Benefit Obligations		
Discount rate	**3.81%**	4.03%
Salary increase	**3.00%**	3.00%
Net Periodic Benefit Cost		
Discount rate	**4.03%**	4.00%
Salary increase	**3.00%**	3.25%
Expected long-term rate of return on plan assets	**7.15%**	7.40%

The discount rates used to determine the benefit obligations are the rates at which the benefit obligations could be effectively settled. The discount rates are developed from yields on available high-quality bonds and reflect each plan's expected cash flows.

The long-term rates of return for the plan assets in 2016 were developed using weighted-average calculations of expected returns based primarily on future expected returns across classes considering the use of active asset managers applied against the plans' respective targeted asset mix.

Registered Pension Plan Assets

Asset Category	Target Allocation	**December 31, 2016**	December 31, 2015
U.S. equity securities	15%	**16%**	18%
Canadian equity securities	23%	**28%**	24%
Other equity securities	15%	**15%**	13%
Fixed income securities	39%	**41%**	45%
Other investments	8%	**—%**	—%
Total	100%	**100%**	100%

Pension plan assets are maintained in a master trust. The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trust. Equities are held for their high expected return. Other equity and fixed income securities are held for diversification. Investments within asset classes are diversified to achieve broad market participation and reduce the effects of individual managers or investments. The Company regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate.

The following table summarizes the fair values of pension plan assets recorded at each fair value hierarchy level, as determined in accordance with the valuation techniques described in note 14:

($millions)	**Total**	**Level 1**	**Level 2**	**Level 3**
December 31, 2016				
Cash and cash equivalents	3	3	—	—
Fixed income securities	350	350	—	—
Equity securities	501	242	259	—
Total	854	595	259	—
December 31, 2015				
Cash and cash equivalents	3	3	—	—
Fixed income securities	375	375	—	—
Equity securities	464	205	259	—
Total	842	583	259	—

Expected Benefit Payments

($millions)	**2017**	**2018**	**2019**	**2020**	**2021**	**2022-2026**
Expected benefit payments	43	44	46	48	49	260

Other Post-Retirement Benefit Plans

The Company provides health care and life insurance benefits for retired employees on a non-contributory basis predominantly under defined contribution plans. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. The other post-retirement benefits are not funded.

Other Post-Retirement Benefit Plans - Change in Projected Benefit Obligation and Fair Value of Plan Assets

($millions)	**2016**	2015
Change in Benefit Obligation		
Accumulated post-retirement benefit obligation, beginning of year	**63**	67
Service cost	**1**	2
Interest cost	**3**	2
Actuarial (gains) losses	**(4)**	(6)
Benefits paid	**(2)**	(2)
Accumulated post-retirement benefit obligation, end of year	**61**	63
Change in Fair Value of Plan Assets		
Plan assets, beginning of year	**—**	—
Benefits paid	**(2)**	(2)
Employer contributions	**2**	2
Plan assets, end of year	**—**	—
Net amount recognized[a]	**(61)**	(63)

[a] $59 million is recognized in Regulatory and other liabilities and $2 million is recognized in Accounts payable and accrued charges on the Balance Sheets.

Other Post-Retirement Benefit Plans - Amounts Recognized in AOCI

($millions)	**December 31, 2016**	December 31, 2015
Net actuarial (gain) loss recognized in AOCI	**(6)**	(2)

($millions)	**2016**	2015
Other Post-Retirement Benefit Plans - Components of Net Periodic Benefit Cost		
Service cost benefit earned	**1**	2
Interest cost on accumulated post-retirement benefit obligation	**3**	2
Net periodic other post-retirement benefit cost	**4**	4
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Current year actuarial (losses) gains	**(4)**	(6)
Total recognized in other comprehensive income	**(4)**	(6)
Total recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**—**	(2)

Other Post-Retirement Benefits Plans - Assumptions Used for Benefits Accounting

	2016	2015
Benefit Obligations		
Discount rate for post-retirement plans	**3.81%**	4.03%
Salary increase	**3.00%**	3.00%
Net Periodic Benefit Cost		
Discount rate for post-retirement plans	**4.03%**	4.00%
Salary increase	**3.00%**	3.25%

The discount rates used to determine the post-retirement obligations are the rates at which the benefit obligations could be effectively settled. The discount rates for the plans are developed from yields on available high-quality bonds in Canada and reflect each plan's expected cash flows.

Assumed Health Care Cost Trend Rates

	2016	2015
Health care cost trend rate assumed for next year	**5.00%**	5.50%
Rate to which the cost trend rate is assumed to decline	**5.00%**	5.00%
Year that the rate reaches the ultimate trend rate	**2017**	2017

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

($millions)	**1% Point Increase**	1% Point Decrease
Effect on post-retirement benefit obligations	**3**	(3)

Other Post-Retirement Benefit Plans - Payments and Receipts

The Company expects to make future benefit payments, which reflect expected future service, as appropriate. The following benefit payments are expected to be paid over each of the next five years and thereafter.

($millions)	**2017**	**2018**	**2019**	**2020**	**2021**	**2022-2026**
Expected benefit payments	2	3	3	3	3	16

Retirement/Savings Plan

The Company has employee savings plans available to eligible employees. Employees may participate in a matching contribution where the Company matches a certain percentage of before tax employee contributions of up to 5% of eligible pay per pay period. The Company expensed pre-tax employer matching contributions of $8 million in both the twelve months ended December 31, 2016 and 2015.

13. Asset Retirement Obligations

The Company's AROs relate to the legal obligation to disconnect, purge and cap abandoned pipelines, capping abandoned storage wells, and in some buildings, special handling and disposition of asbestos if it is disturbed.

The Company has non-asbestos AROs which include easements and some railway license agreements relating to pipeline assets located on land which the Company does not own. The Company has not recognized a liability in regard to the non-asbestos ARO because the fair value of the ARO cannot be reasonably estimated. The Company's pipeline system is considered a critical component of its business and is expected to be maintained and remain in place indefinitely. Natural gas supplies are also considered sufficient for the Company to operate in the long-term. The Company has determined that sufficient information to estimate the fair value of an ARO is not available because the assets are considered permanent with indeterminate useful lives and that sufficient information is not available to estimate a range of potential settlement dates in order to employ a present value technique to estimate fair value.

AROs are adjusted each period for liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Reconciliation of Changes in Asset Retirement Obligation Liabilities

($millions)	**December 31, 2016**	December 31, 2015
Balance, beginning of year	**440**	368
Accretion expense	**20**	17
Liabilities settled	**(7)**	(7)
Revisions in estimated cash flows	**(36)**	62
Balance, end of year	**417**	440

14. Fair Value Measurements

Financial instruments recorded at fair value on the Balance Sheets are valued using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1

Level 1 valuations represent quoted unadjusted prices for identical instruments in active markets.

Level 2 Valuation Techniques

Fair values of the Company's financial instruments that are actively traded in the secondary market are determined based on market-based prices. These valuations may include inputs such as quoted market prices of the exact or similar instruments, broker or dealer quotations, or alternative pricing sources that may include models or matrix pricing tools, with reasonable levels of price transparency. The fair value of the Company's pension plan assets designated as Level 2 financial instruments is determined through the market approach valuation technique using observable inputs including matrix pricing and market corroborated pricing.

Level 3 Valuation Techniques

Level 3 valuation techniques include the use of pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation. The fair value of the Company's pension plan assets designated as Level 3 financial instruments is determined through the market approach valuation technique using unobservable inputs including investment manager pricing for private placements and private equities.

There were no transfers between levels during the year ended December 31, 2016.

Financial Instruments

The fair values of financial instruments that are recorded and carried at book value are summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. These estimates are not necessarily indicative of the amounts that could have been realized in current markets.

	December 31, 2016		December 31, 2015	
($millions)	**Book Value**	**Fair Value**	Book Value	Fair Value
Long-term debt, including current maturities[a]	**3,440**	**3,888**	3,140	3,538

[a] Excludes unamortized items.

The fair value of the Company's Long-term debt is determined based on market-based prices as described in the Level 2 valuation technique described above.

The fair values of Cash and cash equivalents, Accounts receivable, net, Accounts payable and accrued charges, Short-term borrowings and Commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates.

Credit risk

Credit risk is the risk of financial loss to the Company if a counterparty to a financial instrument fails to meet its contractual obligations. The maximum exposure to credit risk for the Company at period end is the carrying value of its financial assets. The Company's principal customers for natural gas transportation and storage services are industrial end-users, marketers, local distribution companies and utilities. The Company's distribution customers are primarily industrial and residential end-users. These concentrations of customers may affect the Company's overall credit risk.

The Company, in the normal course of its operations, provides gas loans to other parties from its holdings of gas in storage. The replacement cost of gas loans at December 31, 2016 is $84 million receivable (2015 – $51 million receivable). The Company manages its credit exposure related to gas loans by subjecting these parties to the same credit policies it uses for all customers, and obtaining collateral when appropriate.

The Company manages its credit risk on Cash and cash equivalents by dealing solely with reputable banks and financial institutions. To manage its credit risk on Accounts receivable, net the Company performs ongoing credit reviews of all its customers. In cases where the credit quality of a customer does not meet the Company's requirements, a cash deposit, letter of credit or parental guarantee is required. Deposits held by the Company at December 31, 2016 amounted to $39 million (2015 – $40 million). Significant financial difficulties of the debtor, the probability that the debtor will enter bankruptcy or financial reorganization, and default or delinquency in payments are considered indicators that the account receivable may be uncollectible and therefore should be included in the allowance for doubtful accounts.

The Company continues to utilize its established risk management policies and procedures to ensure the appropriate monitoring of customer credit positions and, based on current evaluations, does not expect any significant negative impacts associated with these positions.

The following table sets forth details of the age of trade receivables that are not impaired as well as the allowance for the doubtful accounts:

($millions)	**December 31, 2016**	December 31, 2015
Current	**275**	218
30 Days over due	**10**	10
60 Days over due	**3**	4
90+ Days over due	**6**	11
Total trade accounts receivable	**294**	243
Allowance for doubtful accounts	**(5)**	(6)
Total trade accounts receivable, net[a]	**289**	237

[a] The carrying amount of accounts receivable is impacted by changes in gas prices, which may fluctuate significantly from year to year.

For the years ended December 31, 2016 and 2015, no one customer accounted for more than 10% of sales or 10% of receivables.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its obligations as they become due. The Company manages its liquidity risk by forecasting cash flows from operations and anticipated investing and financing activities. The Company has credit facilities available to help meet short-term financing needs (note 10).

The following are the contractual maturities of the undiscounted cash flows of financial liabilities as at December 31, 2016:

($millions)	**Total**	**2017**	**2018-2019**	**2020-2021**	**Thereafter**
Commercial paper	333	333	—	—	—
Accounts payable and accrued charges	878	878	—	—	—
Long-term debt (including principal and interest)	5,961	297	686	459	4,519
Total	7,172	1,508	686	459	4,519

15. Stock Based Compensation

The Spectra Energy 2007 Long-Term Incentive Plan (the 2007 LTIP), as amended and restated, provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for Spectra Energy. A maximum of 53 million shares of common stock may be awarded under the 2007 LTIP. Union Gas employees participate in the 2007 LTIP.

Stock based performance awards generally vest over three years at the earliest, if performance metrics are met. Spectra Energy granted 35,950 performance awards in 2016, 36,100 in 2015, and 38,200 in 2014, with fair values of U.S. $2 million for 2016, 2015 and 2014 to Union Gas employees. The total fair value of performance awards vested was U.S. $1 million in both 2016 and 2014. No performance awards vested in 2015. As of December 31, 2016, the Company expects to recognize U.S. $2 million of future compensation cost related to performance awards over a weighted-average period of less than one year.

Stock based phantom awards generally vest over three years. Spectra Energy awarded 34,575 phantom awards in 2016, 22,650 in 2015, and 24,200 in 2014, with fair values of U.S. $1 million for 2016, 2015, and 2014 to Union Gas employees. The total fair value of the phantom awards vested was U.S. $1 million in 2016, 2015 and 2014. As of December 31, 2016, the Company expects to recognize U.S. $1 million of future compensation cost related to phantom awards over a weighted-average period of less than two years.

Options granted under the 2007 LTIP are issued with exercise prices equal to the fair market value of our common stock on the grant date, have ten-year terms and vest rateably over a three-year term. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible. The Company issues new shares upon exercising or vesting of share-based awards. The Black-Scholes option-pricing model is used to estimate the fair value of options at grant date.

Stock Awards

	Performance Awards		Phantom Awards	
	Units	Weighted-Average Grant Date Fair Value U.S. $	Units	Weighted-Average Grant Date Fair Value U.S. $
Outstanding, beginning of year	120,103	39	75,097	26
Transfers out	(1,850)	42	(2,390)	31
Granted	35,950	53	34,575	29
Vested	(32,664)	33	(29,481)	30
Forfeited	(19,182)	37	(3,763)	34
Outstanding, end of year	102,357	49	74,038	39
Awards expected to vest	99,192	49	72,797	39

Stock Options

	Options	Weighted-Average Exercise Price U.S.$	Weighted-Average Remaining Life (in years)	Aggregate Intrinsic Value U.S.$ (in millions)
Outstanding at beginning of year	66,100	26	1.1	—
Granted	36,600	28	—	—
Exercised	(54,300)	26	—	—
Outstanding at end of year	48,400	28	6.9	1
Options exercisable at year-end	11,800	26	0.1	—

The Company awarded 36,600 non-qualified stock options to employees during 2016, with a fair value of U.S. $1 million. We did not award any non-qualified stock options to employees during 2015 or 2014.

Weighted-Average Assumptions for Option Pricing

	2016
Risk-free rate of return	1.4%
Expected life	6 years
Expected volatility	22.7%
Expected dividend yield	5.7%

The risk-free rate of return was determined based on a yield curve of U.S. Treasury rates ranging from six months to ten years and a period commensurate with the expected life of the options granted. The expected volatility was established based on historical volatility over six years using daily stock price observations. The expected dividend yield was determined based on the most recent annual dividend and the stock price at the time of grant.

As of December 31, 2016, future compensation costs related to stock options over a weighted-average period of less than 2 years was not significant.

16. Guarantees

The Company has various financial guarantees which are issued in the normal course of business. The Company enters into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these agreements involve elements of performance and credit risk, which are not included on the Balance Sheets. The possibility of having to perform under these guarantees is largely dependent upon future operations of other third parties or the occurrence of certain future events. The Company's potential exposure under these agreements can range from a specific dollar amount to an unlimited dollar amount depending on the nature of the claim and the particular transaction. The Company is unable to estimate the total potential amount of future payments under these agreements due to several factors, such as unlimited exposure under certain guarantees.

17. Contingencies

The Company, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Accruals are made in instances where it is probable that liabilities will be incurred and where such liabilities can be reasonably estimated.

In April 2016, the Ontario Ministry of the Environment and Climate Change (MOECC) issued a Director's Order (Order) naming the Company, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of the Company in Hamilton. The Order requires all parties to act jointly to develop a Conceptual Site Model (CSM) to fully delineate the extent of the soil and groundwater contamination and to assess remedial measures, if necessary. In May 2016, the Company appealed the Order, which should have been issued to the party responsible for the contamination and the owner of the source of the contamination, as opposed to those parties impacted by the contamination. In June 2016, the Environmental Review Tribunal (Tribunal), on consent of the MOECC's Director, stayed the application of parts of the Order on the condition that a Preliminary CSM (PCSM) be provided to the MOECC's Director, which in fact was delivered (with cooperation from the owners of the immediately adjacent owners, including the Company) in December 2016. The MOECC has provided its preliminary responses to the PCSM. In February 2017, the Tribunal extended the stay of the Order until May 9, 2017, pending a technical conference to be attended by the MOECC and the owners of the immediately adjacent properties in order to determine next steps. The risk of material environmental liability is unknown at this time. No amount has been accrued.

Other than the potential contingency noted above, of which the impact is unknown, the Company has no reason to believe that the ultimate outcome of these matters could have a significant impact on its Financial Statements.

18. Subsequent Events

Management has evaluated significant events and transactions that occurred from January 1, 2017 through February 26, 2017. On January 31, 2017, the Company received a $30 million capital contribution from GLBE in respect of the common shares of the Company.

DIRECTORS

David G. Unruh

Stephen W. Baker

Bruce E. Pydee

OFFICERS

Stephen W. Baker
Chair and President

J. Patrick Reddy
Chief Financial Officer

David G. Simpson
Vice President, Regulatory, Lands and Public Affairs

Tanya Mushynski
Vice President and General Counsel

Janice L. Ferguson
Vice President, Human Resources

James G. Redford
Vice President, Business Development - Storage and Transmission

Paul Rietdyk
Vice President, Engineering, Construction and Storage and Transmission Operations

Michael G.P. Shannon
Vice President, Distribution Operations

Wendy H. Zelond
Vice President, Finance

Laura J. Buss Sayavedra
Vice President and Treasurer

Timothy J. Kennedy
Vice President, Government and Aboriginal Affairs

Mark J. Isherwood
Vice President, In-Franchise Sales, Marketing and Customer Care

Edward J. Koval
Vice President, Supply Chain

Paul K. Haralson
Assistant Treasurer

Annachiara Jones
Corporate Secretary

Kelly L. Gray
Assistant Corporate Secretary

CORPORATE INFORMATION

Transfer Agent and Registrar **CST Trust Company**

Union Gas Limited preferred stock are listed on the Toronto Stock Exchange

Class A Preferred, Series A - 5½% (UNG.PR.C)

Class A Preferred, Series B - 6% (UNG.PR.D)

REGISTERED OFFICE

50 Keil Drive North
Chatham, Ontario N7M 5M1

UNAUDITED *PRO FORMA* SUMMARIZED CONSOLIDATED FINANCIAL STATEMENTS

The following unaudited *pro forma* summarized consolidated financial statements ("Statements") of the combined entity, Amalco, represent the combination of stand-alone forward-looking financial plans for first full year following completion of the proposed amalgamation ("Amalgamation") of Enbridge Gas Distribution Inc. ("EGD") and Union Gas Limited ("Union"). These Statements are prepared in accordance with generally accepted accounting principles in the United States of America. The Statements are provided for the purposes of this EB-2017-0306 application to the Ontario Energy Board and include unregulated income, expenses and adjustments for assumptions related to the Amalgamation.

The Statements are comprised of forward-looking statements or forward-looking information. This information may not be appropriate for other purposes. Although EGD and Union believe that the Statements are reasonable based on the information available and processes used to prepare the Statements, the Statements do not guarantee future performance and readers are cautioned against placing undue reliance on the Statements.

The Statements are subject to risks and uncertainties pertaining, but not limited, to the impact of the proposed amalgamation, operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, changes in tax law and tax rate increases, exchange rates, interest rates, natural gas prices and supply of and demand for natural gas, including but not limited to those risks and uncertainties discussed in the respective filings of EGD and Union with Canadian securities regulators. The impact of any one risk, uncertainty or factor on the Statements is not determinable with certainty as these are interdependent and the combined entity's future course of action will depend on management's assessment of all information available at the relevant time. Except to the extent required by law, neither EGD nor Union assumes any obligation to publicly update or revise the Statements, whether as a result of new information, future events or otherwise.

Amalco
Pro Forma Summarized Income Statement
First Full Year Following Completion of Transaction

($ millions of Canadian dollars)	
Gas sales and distribution revenue	5,500
Storage and transportation revenue	250
Other revenue, net	66
Total operating revenue	**5,816**
Expenses	
Cost of Gas	3,141
Operating and administrative	925
Depreciation and amortization	675
Property taxes	131
Total expenses	**4,873**
Other income	**62**
Income before interest and income taxes	**1,005**
Interest expense, net	**417**
	588
Income tax expense	**76**
Earnings applicable to common shares	**512**

Amalco
Pro Forma Summarized Balance Sheet
First Full Year Following Completion of Transaction

($ millions of Canadian dollars)	
Assets	
Current assets	
Cash and cash equivalents	-
Accounts receivable, net	1,598
Inventories	622
Total current assets	2,220
Property, plant and equipment, net	17,804
Investment in affiliate	825
Regulatory and other assets	1,211
Total Assets	22,060
Liabilities and Equity	
Current liabilities	
Short-term borrowings	578
Accounts payable and accrued charges	1,513
Current maturities of long-term debt	400
Total current liabilities	2,492
Long-term liabilities	
Long-term debt	8,345
Deferred income taxes	992
Regulatory and other liabilities	4,168
Total long-term liabilities	13,505
Total Liabilities	15,997
Equity	
Common stock	5,362
Retained earnings	858
Accumulated other comprehensive loss	(157)
Total Equity	6,063
Total Liabilities and Equity	22,060

Amalco
Pro Forma Summarized Statement of Cash Flow
First Full Year Following Completion of Transaction

($ millions of Canadian dollars)	
Operating Activities	
Net income	512
Items not affecting cash	
Depreciation and amortization	675
Deferred income taxes	(8)
Changes in working capital	68
Net cash provided by operating activities	1,247
Investing Activities	
Capital expenditures	(1,350)
Net cash used in investing activities	(1,350)
Financing Activities	
Net cash provided by financing activities	103
Change in cash and cash equivalents, during the period	-
Cash and cash equivalents, beginning of period	-
Cash and cash equivalents, end of period	-

Capital Investment and High Level Estimated O&M Savings for Utility Integration

Integration Capital investment and O&M Savings Schedule ($ Millions)

Item	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Capex											
Customer Care		$ 2	$ 22	$ 32	$ 8	$ -	$ -	$ -	$ -	$ -	$ 65
Distribution work management	$ 7	$ 21	$ 21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 50
Utility Shared Services	$ 4	$ 5	$ 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13
Storage & transmission	$ -	$ 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8
Other functions	$ -	$ -	$ 5	$ 5	$ 5	$ -	$ -	$ -	$ -	$ -	$ 14
Sub-Total Costs	$ 11	$ 36	$ 53	$ 37	$ 13	$ -	$ -	$ -	$ -	$ -	$ 150
O&M savings											
Customer Care	$ -	$ 15	$ 15	$ 16	$ 16	$ 26	$ 26	$ 26	$ 26	$ 26	$ 192
Distribution work management	$ -	$ -	$ 11	$ 11	$ 11	$ 16	$ 16	$ 16	$ 16	$ 16	$ 113
Utility Shared Services		$ 2	$ 2	$ 3	$ 3	$ 5	$ 5	$ 5	$ 5	$ 5	$ 35
Storage & transmission	$ -	$ 1	$ 3	$ 3	$ 3	$ 4	$ 4	$ 4	$ 4	$ 4	$ 30
Management	$ -	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 180
Other functions						$ 14	$ 14	$ 14	$ 14	$ 14	$ 70
Sub-Total Savings	$ -	$ 38	$ 51	$ 53	$ 53	$ 85	$ 85	$ 85	$ 85	$ 85	$ 620
Additional unidentified efficiencies	$ 3	$ -	$ 12	$ 17	$ 28	$ -	$ -	$ -	$ -	$ -	$ 60
Sub-Total Savings	$ 3	$ 38	$ 63	$ 70	$ 81	$ 85	$ 85	$ 85	$ 85	$ 85	$ 680