Stephanie Allman
Regulatory Coordinator
Regulatory Affairs

tel 416 495 5499
stephanie.allman@enbridge.com

Enbridge Gas Distribution
500 Consumers Road
North York, Ontario M2J 1P8
Canada

May 9, 2017

VIA EMAIL, RESS, and COURIER

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

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. ("the Company")
2016 Earnings Sharing Mechanism and Other Deferral And Variance Accounts Clearance Review
Ontario Energy Board File No. EB-2017-0102

Enclosed is an Application and supporting evidence by Enbridge Gas Distribution Inc. for an order approving the clearance or disposition of amounts recorded within its 2016 Earnings Sharing Mechanism Deferral Account and within certain other deferral or variance accounts.

The Application has been filed through the Board's Regulatory Electronic Submission System and will be available on the Enbridge website at: www.enbridgegas.com/ratecase.

Please contact the undersigned if you have any questions.

Yours truly,

(Original Signed)

Stephanie Allman
Regulatory Coordinator

cc: Mr. D. Stevens, Aird & Berlis LLP
All Interested Parties EB-2016-0142 (via email)

EXHIBIT LIST

A – ADMINISTRATIVE

Exhibit	Tab	Schedule	Contents	Witness(es)
A	1	1	Exhibit List	L. Stickles
	2	1	Application	L. Stickles
	3	1	Overview and Approvals Requested	L. Stickles R. Small
	4	1	Draft Issues List	L. Stickles R. Small
	5	1	Curriculum Vitae	L. Stickles

B – 2016 ACTUAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	1	1	2016 Earnings Sharing Amount and Determination Process	R. Small
		2	ESM Calculations and Required Rate of Return 2016 Actuals	R. Small
		3	2016 Utility Earnings – Contributors to Utility Earnings and Earnings Sharing Amounts	R. Small
		4	Utility Earnings – Reconciliation of 2016 Utility Income to Audited EGDI Consolidated Income	R. Small
	2	1	Ontario Utility Rate Base – Comparison of 2016 Actuals to 2016 EB-2016-0142 Board Approved	R. Small
		2	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2016 Actuals	R. Small

EXHIBIT LIST

B – 2016 ACTUAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	2	3	Working Capital – 2016 Actuals	R. Small
		4	Comparison of Utility Capital Expenditures 2016 Actuals and 2016 EB-2016-0142 Board Approved	S. Fallis
	3	1	Utility Operating Revenue 2016 Actuals	R. Small
		2	Comparison of Gas Sales and Transportation Volume by Rate Class 2016 Actuals to 2016 EB-2016-0142 Board Approved	R. Cheung J. Shem
		3	Comparison of Gas Sales and Transportation Revenue by Rate Class 2016 Actuals to 2016 EB-2016-0142 Board Approved	R. Cheung
		4	Customers Meters, Volumes and Revenues by Rate Class 2016 Actuals	R. Cheung
		5	2016 Other Operating Revenue	A. Hui
	4	1	Operating Cost 2016 Actuals	R. Small
		2	Operating and Maintenance Expense by Department Ending December 2016	N. Verma D. Gagnon J. Yiu
	5	1	Required Rate of Return 2016 Actuals	R. Small
		2	Utility Income 2016 Actuals	R. Small
		3	Cost of Capital 2016 Actuals	R. Small

EXHIBIT LIST

C– EARNINGS SHARING MECHANISM and OTHER DEFERRAL & VARIANCE ACCOUNTS

EXHIBIT LIST

C– EARNINGS SHARING MECHANISM and OTHER DEFERRAL & VARIANCE ACCOUNTS

Exhibit	Tab	Schedule	Contents	Witness(es)
C	1	13	Ontario Energy Board Cost Assessment Variance Account	R. Small
		14	Greater Toronto Area Incremental Transmission Capital Revenue Requirement Deferral Account	R. Small
		15	Rate 332 Variance Account	R. Small A. Kacicnik
	2	1	Clearance of Deferral and Variance Account Balances	J. Collier A. Kacicnik B. So
		2	Derivation of Proposed Unit Rates	J. Collier A. Kacicnik B. So

D – REPORTING AND REFERENCE MATERIAL

Exhibit	Tab	Schedule	Contents	Witness(es)
D	1	1	Status Updates	L. Stickles
		2	Status of GTA Project	S. Dodd
		3	Status of WAMS Project	B. Misra
		4	Status of System Integrity Program	D. Broude
		5	Status of Benchmarking Study	K. Culbert
		6	Status of Asset Management Planning Process	H. Thompson
	2	1	Productivity Initiatives Summary	M. Yan
	3	1	April 11, 2017 Stakeholder Day Presentation	L. Stickles

EXHIBIT LIST

D – REPORTING AND REFERENCE MATERIAL

Exhibit	Tab	Schedule	Contents	Witness(es)
D	4	1	2016 RRR filings re. Service Quality Indicators	D. Brault D. McIlwraith
	5	1	Enbridge Gas Distribution Inc. Consolidated Financial Statements December 31, 2016	L. Uhyrek
		2	Enbridge Gas Distribution Inc. Management's Discussion & Analysis December 31, 2016	L. Uhyrek

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

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving the clearance or disposition of amounts recorded in certain deferral or variance accounts.

A P P L I C A T I O N

1. The Applicant, Enbridge Gas Distribution Inc. ("Enbridge", or the "Company") 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. Enbridge hereby applies to the Ontario Energy Board (the "Board"), pursuant to section 36 of the *Ontario Energy Board Act, 1998* (the "Act"), as amended, for an Order or Orders approving the clearance or disposition of amounts recorded in certain Deferral or Variance Accounts.

3. Within the Decision with Reasons in the EB-2012-0459 proceeding, the Board established a Custom IR framework to set Enbridge's rates over the period from 2014 to 2018. Among other things, this includes an Earnings Sharing Mechanism ("ESM") under which Enbridge is to share earnings above the Board-approved Return on Equity ("ROE") with ratepayers on a 50 / 50 basis. The Custom IR framework includes a number of Deferral and Variance Accounts to be maintained or created during the Custom IR term.

4. Under the Custom IR framework, after the release of its Audited Financial Statements for the prior year Enbridge is required to file an Application setting out the ESM calculation for that year. Within the Application, Enbridge is to set out its proposal for the clearance of amounts recorded in the Earnings Sharing Mechanism Deferral Account ("ESMDA") and other Deferral and Variance Accounts.

5. Pursuant to the EB-2012-0459 Decision with Reasons, Enbridge is also required to annually report upon the status of a number of initiatives and activities as part of the ESM Application.

6. In this Application, Enbridge seeks approval to clear the balance of the 2016 ESMDA, as well as the balances within certain of its 2016 Deferral and Variance accounts, 2015 DSM-related accounts, the 2017 Transactional Impact of Accounting Changes Deferral Account ("TIACDA"), and also seeks approval to carry forward the balances in certain of these accounts for review and approval in a later proceeding. The relevant balances are included within the table at Appendix A to this Application.

7. Enbridge therefore applies to the Board for such final, interim or other Orders as may be necessary or appropriate for the clearance or disposition of the 2016 ESMDA and the other Deferral and Variance accounts listed in Appendix A to this Application. Enbridge proposes to clear the balances in these accounts in conjunction with the October 1, 2017 QRAM Application.

8. Enbridge further applies to the Board pursuant to the provisions of the Act and the Board's *Rules of Practice and Procedure* for such final, interim or other Orders and directions as may be appropriate in relation to the Application and the proper conduct of this proceeding.

9. Enbridge requests that a copy of every document filed with the Board in this proceeding be served on the Applicant and the Applicant's counsel, as follows:

The Applicant:

Mr. Andrew Mandyam
Director, Regulatory Affairs and Financial Performance
Enbridge Gas Distribution Inc.

Address for personal service:	500 Consumers Road Willowdale, Ontario M2J 1P8
Mailing address:	P. O. Box 650 Scarborough, Ontario M1K 5E3
Telephone:	416-495-5499
Fax:	416-495-6072
Email:	EGDRegulatoryProceedings@enbridge.com

The Applicant's counsel:

Mr. David Stevens
Aird & Berlis LLP

Address for personal service and mailing address	Brookfield Place, P.O. Box 754 Suite 1800, 181 Bay Street Toronto, Ontario M5J 2T9
Telephone:	416-865-7783
Fax:	416-863-1515
Email:	dstevens@airdberlis.com

DATED: May 9, 2017 at Toronto, Ontario.

ENBRIDGE GAS DISTRIBUTION INC.

Per: (Original Signed)

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNT
ACTUAL & FORECAST BALANCES

			Col. 1	Col. 2	Col. 3	Col. 4	
			Actual at March 31, 2017		Forecast for clearance at October 1, 2017		
Line No.	Account Description	Account Acronym	Principal	Interest	Principal	Interest	
			($000's)	($000's)	($000's)	($000's)	
	Non Commodity Related Accounts						
1.	Demand Side Management V/A	2015 DSMVA	825.5	13.4	825.5	18.2	1
2.	Demand Side Management V/A	2016 DSMVA	(704.0)	(1.9)	-	-	2
3.	Lost Revenue Adjustment Mechanism	2015 LRAM	(72.3)	(0.2)	(72.3)	(0.8)	1
4.	Demand Side Management Incentive D/A	2015 DSMIDA	6,068.6	22.3	6,068.6	55.9	1
5.	Deferred Rebate Account	2016 DRA	7,712.2	62.5	7,712.2	105.1	3
6.	Manufactured Gas Plant D/A	2017 MGPDA	570.4	41.1	-	-	4
7.	Gas Distribution Access Rule Impact D/A	2016 GDARIDA	-	-	280.3	-	5
8.	Average Use True-Up V/A	2016 AUTUVA	13,152.5	36.2	13,152.5	108.8	6
9.	Earnings Sharing Mechanism Deferral Account	2016 ESMDA	(3,400.0)	(8.8)	(3,400.0)	(27.4)	7
10.	Customer Care CIS Rate Smoothing D/A	2016 CCCISRSDA	(779.9)	(8.1)	-	(14.1)	8
11.	Customer Care CIS Rate Smoothing D/A	2015 CCCISRSDA	1,124.2	8.3	-	16.7	8
12.	Customer Care CIS Rate Smoothing D/A	2014 CCCISRSDA	2,927.0	21.5	-	43.1	8
13.	Customer Care CIS Rate Smoothing D/A	2013 CCCISRSDA	4,634.9	34.1	-	68.3	8
14.	Transition Impact of Accounting Changes D/A	2017 TIACDA	70,972.8	-	4,435.8	-	9
15.	Post-Retirement True-Up V/A	2016 PTUVA	(9,660.7)	(26.6)	(5,000.0)	(80.0)	10
16.	Constant Dollar Net Salvage Adjustment D/A	2017 CDNSADA	37,853.9	-	-	-	11
17.	Credit Final Bill D/A	2016 CFBDA	(1,524.4)	(4.2)	(1,524.4)	(12.6)	12
18.	GTA Incremental Transmission Capital Rev. Req	2016 GTAITCRRDA	4,281.4	30.0	4,281.4	53.4	13
19.	Greenhouse Gas Emissions Impact D/A	2016 GGEIDA	939.8	6.9	840.3	12.3	14
20.	Rate 332 D/A	2016 R332DA	(1,651.6)	(5.0)	(1,651.6)	(14.0)	15
21.	OEB Cost Assessment V/A	2016 OEBCAVA	1,928.0	5.3	1,928.0	16.1	16
22.	Total non commodity Related Accounts		135,198.3	226.8	27,876.3	349.0	
	Commodity Related Accounts						
23.	Transactional Services D/A	2016 TSDA	(4,036.3)	(12.8)	(4,036.3)	(35.0)	17
24.	Storage and Transportation D/A	2016 S&TDA	9,618.3	80.3	9,618.3	133.1	17
25.	Unaccounted for Gas V/A	2016 UAFVA	7,921.4	26.9	7,921.4	70.7	18
26.	Unabsorbed Demand Cost D/A	2016 UDCDA	282.8	1.0	282.8	2.8	19
27.	Total commodity related accounts		13,786.2	95.4	13,786.2	171.6	
28.	Total Deferral and Variance Accounts		148,984.5	322.2	41,662.5	520.6	

Notes:
1. The final 2015 DSMVA, LRAM, and DSMIDA balances to be cleared will be those determined through the on-going Board review process of 2015 DSM results.
2. Clearance of the 2016 DSMVA will be requested through a separate process/application at a later date.
3. DRA evidence is found at Exhibit C, Tab 1, Schedule 8.
4. Clearance of the balance that was recorded in 2016 MGPDA is not being requested at this time. As was indicated in the EB-2016-0215 proceeding, the balance in the 2016 MGPDA was transferred to the 2017 MGPDA.
5. The clearance amount associated with the 2016 GDARIDA is the result of a revenue requirement calculation found in evidence at Exhibit C, Tab 1, Schedule 7.
6. AUTUVA evidence is found at Exhibit C, Tab 1, Schedule 5.
7. Evidence within the B-series of exhibits provides details of Enbridge's 2016 utility results and 2016 earnings sharing calculation.
8. CCCISRSDA evidence is found at Exhibit C, Tab 1, Schedule 10.
9. TIACDA evidence is found at Exhibit C, Tab 1, Schedule 9.
10. PTUVA evidence is found at Exhibit C, Tab 1, Schedule 6.
11. Clearance of the balance that was recorded in 2016 CDNSADA is not being requested at this time. In accordance with the scope of the account that was approved in EB-2012-0459, and as was also indicated in EB-2016-0215, the balance was transferred to the 2017 CDNSADA. The cumulative balance at the end of each year will be transferred to the following year's CDNSADA. At the end of 2018, any residual balance will be requested for clearance in a post 2018 true-up.
12. CFBDA evidence is found at Exhibit C, Tab 1, Schedule 12.
13. GTAITCRRDA evidence is found at Exhibit C, Tab 1, Schedule 14.
14. GGEIDA evidence is found at Exhibit C, Tab 1, Schedule 11.
15. R332DA evidence is found at Exhibit C, Tab 1, Schedule 15.
16. OEBCAVA evidence is found at Exhibit C, Tab 1, Schedule 13.
17. TSDA and S&TDA evidence is found at Exhibit C, Tab 1, Schedule 3.
18. UAFVA evidence is found at Exhibit C, Tab 1, Schedule 4.
19. UDCDA evidence is found at Exhibit C, Tab 1, Schedule 2.

OVERVIEW AND APPROVALS REQUESTED

1. This proceeding addresses Enbridge's request for clearance of the balances in its 2016 Earnings Sharing Mechanism Deferral Account ("ESMDA") and in certain other Deferral and Variance Accounts approved by the Board in prior proceedings.

2. The Board's EB-2012-0459 Decision with Reasons established a Custom IR framework to set Enbridge's rates over the period from 2014 to 2018. Among other things, this includes an ESM under which Enbridge is to share earnings above the Board-approved Return on Equity ("ROE") with ratepayers on a 50/50 basis. The Custom IR framework also includes a number of Deferral and Variance Accounts to be maintained or created during the Custom IR term. The Board has approved several other Deferral and Variance Accounts for Enbridge since the date of the Custom IR Decision with Reasons.

3. Under the Custom IR framework, after the release of its Audited Financial Statements for the prior year, Enbridge is required to file an Application setting out the ESM calculation for that year. Within the Application, Enbridge is to set out its proposal for the clearance of amounts within the ESMDA and other Deferral and Variance Accounts.

4. As set out within the EB-2012-0459 Decision with Reasons, Enbridge is also required to annually report upon the status of a number of initiatives and activities as part of its ESM Application.

5. The evidence filed with this Application addresses all required items.

Witnesses: R. Small
L. Stickles

6. The B-series of exhibits sets out Enbridge's utility financial results for 2016, and includes the calculation of the amount to be credited to ratepayers through the ESM.

7. The C-series of exhibits provides evidence and explanation for all of the Deferral and Variance Accounts that Enbridge proposes to clear through this Application. This evidence includes a description of the Board-approved scope of each account and an explanation of the balance recorded and being requested for clearance. Within those exhibits, Enbridge also sets out its proposal for the unit rates and timing associated with the clearance of the Deferral and Variance Account balances.

8. The D-series of exhibits provides the additional reporting information (beyond the overall financial results information) that Enbridge is required to file each year during the Custom IR term. Included within this evidence are the materials that were presented at Enbridge's 2017 Custom IR Stakeholder Day, which was held on April 11, 2017. Other evidence includes the Company's 2016 Productivity Initiatives Reporting, Status Updates on several major projects and initiatives and the Company's 2016 Service Quality Indicators results. The Company's 2017 Gas Supply Memorandum was previously filed in the 2017 Rate Proceeding, EB-2016-0215. As was the case in Enbridge's 2015 ESM proceeding (EB-2016-0142), Enbridge is not seeking any specific relief in this proceeding in relation to these reporting items.

9. The approvals requested in this proceeding relate to the clearance of the 2016 ESMDA and certain other Deferral and Variance Accounts.

Witnesses: R. Small
L. Stickles

10. The Company has filed the balances at March 31, 2017 for fiscal year 2016 Board-approved Deferral and Variance Accounts, as well as several other Deferral and Variance Accounts from other years. The Company requests approval for clearance of certain of these accounts commencing October 1, 2017, and approval to carry forward the balances in certain other of the accounts for review and approval in a later proceeding. The list of accounts, and relevant balances, is provided at Appendix A to the Application (Exhibit A, Tab 2, Schedule 1, Appendix A).

11. The Company's proposal for how the Deferral and Variance Account balances will be cleared is set out at Exhibit C, Tab 2, Schedule 1. The impacts of the clearance of the total Deferral and Variance Account balances by specific rate class are provided in evidence at Exhibit C, Tab 2, Schedule 2.

12. The Company requests a Board Decision or approval by August 15, 2017, in order to facilitate the clearance of the Deferral and Variance Accounts through a rate rider by specific rate classes within the Company's October 1, 2017 QRAM proceeding.

Witnesses: R. Small
L. Stickles

DRAFT ISSUES LIST

1. Is the amount proposed to be cleared in the 2016 Earnings Sharing Mechanism Deferral Account (“ESMDA”) appropriate?

2. Are the other Deferral and Variance Accounts balances proposed for disposition as set out in Appendix A to the Application (Exhibit A, Tab 2, Schedule 1, Appendix A) appropriate?

3. Are the proposed unit rates and timing for implementation of the clearances appropriate?

Witnesses: R. Small
L. Stickles

CURRICULUM VITAE OF
DEBORAH BRAULT

Experience:	Enbridge Gas Distribution Inc.
	Customer Safety & Compliance Manager, Eastern Region 2015
	Operations Manager, Gazifère Inc. 2010
	WMC Manager, Eastern Region 2004
	Operations Support Supervisor 1999
	Call Centre Supervisor 1993
	Customer Service Assistant Supervisor 1990
	Customer Service Clerk 1986
Education:	University of Ottawa
Memberships:	None
Appearances:	(Ontario Energy Board) None

CURRICULUM VITAE OF
DEIRDRE BROUDE, P.Eng

Experience: Enbridge Gas Distribution Inc.

Manager, Asset Classes, Asset Management
2016

Sr. Manager, Asset Management
2015

Sr. Manager System Integrity
2012

Manager Technical Training Projects
2011

Manager Extended Alliance Relationship
2010

Manager, Operations Business Support
2007

Manager, Operations, Central Region North
2005

Manager, Special Projects, Distribution Planning
2002

Manager, Drafting, Distribution Planning
2001

Project Manager, Engineering Construction
1998

Supervisor, Budgets
1997

Operations Engineer
1993

Education: Bachelor of Engineering, Mechanical (B.Eng, P.Eng.), 1993
Memorial University of Newfoundland

Diploma of Nursing, 1987
Western Memorial Hospital, Nfld

Memberships: Professional Engineers of Ontario

Appearances: (Ontario Energy Board)

EB-2012-0459
RP-2004-0015 (Leave to Construct)

CURRICULUM VITAE OF
RYAN CHEUNG

Experience: Enbridge Gas Distribution Inc.

Senior Advisor, Economics and Business Performance
2016

Senior Analyst, Gas Accounting and Analytics
2014

Senior Budget Analyst, Budget and Planning
2010

Supervisor, Margin Planning and Analytics
2006

Analyst, Volumetric Analysis and Budgets
2004

TD Canada Trust

Financial Service Advisor
2000

Education: Bachelor of Arts, in Economic and Statistics
University of Toronto

Appearances: (Ontario Energy Board)
EB-2016-0215
EB-2016-0142
EB-2015-0122
EB-2015-0114
EB-2014-0195
EB-2012-0459

CURRICULUM VITAE OF
JACKIE E. COLLIER

Experience: Enbridge Gas Distribution Inc.
Rate Design Specialist
2016

Manager, Rate Design
2003

Manager, Rate Research
2000

Senior Rate Research Analyst
1996

Centra Gas Ontario Inc.

Manager, Rate Design
1995

Supervisor, Cost of Service Studies
1990

Education: Bachelor of Business Management
Ryerson Polytechnical Institute, 1988

Appearances: (Ontario Energy Board)
EB-2016-0215
EB-2015-0114
EB-2015-0122
EB-2014-0276
EB-2013-0036
EB-2012-0459
EB-2012-0451
EB-2012-0055
EB-2011-0354
EB-2011-0277
EB-2011-0242
EB-2010-0146
EB-2009-0172
EB-2008-0219
EB-2007-0615
EB-2006-0034
EB-2005-0001
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2001-0032
RP-2000-0040
EBRO 489
EBRO 474-B, 483,484
EBRO 474-A
EBRO 474

EBRO 471

(Régie de l'énergie/Régie du gaz naturel)
R-3969-2016
R-3924-2015
R-3884-2014
R-3840-2013
R-3793-2012
R-3758-2011
R-3724-2010
R-3692-2009
R-3637-2008
R-3637-2007
R-3621-2006
R-3587-2005
R-3537-2004
R-3464-2001
R-3446-2000

CURRICULUM VITAE OF
KEVIN CULBERT

Experience: Enbridge Gas Distribution Inc.

Senior Manager Regulatory Policy, Strategy & Proceedings
July 2014

Senior Manager Regulatory Accounting
June 2014

Manager, Regulatory Accounting
2003

Senior Analyst, Regulatory Accounting
1998

Analyst, Regulatory Accounting
1991

Assistant Analyst, Regulatory Accounting
1989

Budgets – Capital Clerk, Budget Department
1987

Accounting Trainee, Financial Reporting
1984

Education: CMA (3rd level)
Seneca College 1987-89 (business/accounting)

Appearances: (Ontario Energy Board)

EB-2016-0215	EB-2011-0008
EB-2016-0142	EB-2010-0146
EB-2015-0114	EB-2010-0042
EB-2015-0122	EB-2009-0172
EB-2014-0276	EB-2009-0055
EB-2013-0046	EB-2008-0219
EB-2012-0459	EB-2008-0104/EB-2008-0408
EB-2012-0055	EB-2007-0615
EB-2011-0354	EB-2006-0034
EB-2011-0277	EB-2005-0001
EB-2011-0226	RP-2003-0203

CURRICULUM VITAE OF
GERALD SCOTT DODD

Experience:

Enbridge Gas Distribution Inc.
Director Business Development
2016

Enbridge Pipelines Inc.
Senior Project Director
MP Mainline Projects
2010

Enbridge Gas Distribution Inc.
Director Ontario Storage Development
2009

Enbridge Solutions Inc.
Director Power Generation
2006

Enbridge Inc.
Director Strategic Planning/Director of Corporate Development
2001

Enbridge Gas Distribution Inc.
Manager Financial Studies
1998

BCE Inc. Montreal, Quebec
Corporate Finance Manager
1997

Repap Enterprises Inc, Montreal, Quebec and Cambellton, New Brunswick
Finance Associate/ Operations Manager
1993

Education:

1993 MBA, University of Western Ontario
1988 BA (Hons) Business Administration, University of Western Ontario
1987 BA Economics, University of Western Ontario

Appearances: (Ontario Energy Board)

EB-2016-0142
RP-2000-0040
RP-1999-0001

CURRICULUM VITAE OF
SAM FALLIS

Experience:

Supervisor Capital Management
Operational Finance – Enbridge Gas Distribution
2016-Present

Finance Capital Lead
Operational Finance – Enbridge Gas Distribution
2016

Finance O&M Lead
Operational Finance – Enbridge Gas Distribution
2014-2015

Sr. Finance Analyst
Operational Finance – Enbridge Gas Distribution
2014

Reporting Analyst
Operational Finance – Enbridge Gas Distribution
2013-2014

Education:

Certified Management Accountant (CMA), 2011

Memberships:

Master of Business Administration, with CPA, CMA Designation
Schulich School of Business – York University
2008 - 2011

Honors, Bachelor of Management & Organizational Studies - Finance and Administration
University of Western Ontario
2002 - 2006

Memberships:

Certified Management Accountants of Ontario
2011

Appearances: None

CURRICULUM VITAE OF
DOMINIQUE GAGNON

Experience:	Enbridge Gas Distribution Inc. Lead Finance O&M, Financial Performance 2016
	Senior Financial Analyst, Financial Performance 2015
	Financial Analyst, Financial Performance 2012
	Permitting Coordinator, Drafting 2010
	Operations Support Clerk, Records 2009
Education:	Certified Management Accountant (CMA), 2014
Memberships:	Certified Management Accountants of Ontario
Appearances:	None

CURRICULUM VITAE OF
ALLISON HUI

Experience: Enbridge Gas Distribution Inc.

Lead, Internal Reporting Analysis and Cash Management
2015

Advisor, Internal Reporting
2014

Advisor, Working Capital
2013

Audit Advisor
2010

Ernst & Young

Senior Staff Accountant
2008

Staff Accountant
2006

Education: Chartered Accountant (CA), 2009
Certified Internal Auditor (CIA), 2011

Memberships: Institute of Chartered Accountants of Ontario
Institute of Internal Auditors

Appearances: None

CURRICULUM VITAE OF
KERRY LAKATOS-HAYWARD

Experience: Enbridge Gas Distribution

Director, Energy Supply & Gas Storage
2016

Director, Customer Care
2010

Director, Operations Services
2008

Director, Business Development & Strategy
2006

Manager, Business Development & Strategy
2003

Manager, Volumetric & Market Analysis
2000

Manager, Multi-Family Marketing
1997

Senior Economist, Economic Studies
1995

Ontario Hydro

End Use Economist, Load Forecasts
1994

Evaluation Analyst, Planning & Evaluation
1992

Education: Bachelor of Arts (Specialist in Economics)
University of Toronto, 1990

Master of Science in Planning (Environmental Planning)
University of Toronto, 1992

Queen's Executive Program, 2005

Certificate in Carbon Finance, 2008
University of Toronto

Certificate in Sustainable Management 2014
New York Institute of Finance

LEAD 3 Executive Development Program, Enbridge, 2016

Appearances: (Ontario Energy Board)

EB-2011-0354
EB-2011-0277
RP-2006-0034
RP-2005-0001
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2001-0032
RP-2000-0040

CURRICULUM VITAE OF
DARREN MCILWRAITH

Experience: Enbridge Gas Distribution Inc.

Manager, Customer Care
2016

Senior Manager, Customer Care, Finance and Contract Management
2014

Enbridge Gas Distribution Inc.

Senior Manager, Business Development and DSM Technology
2009

Enbridge Solutions Inc.

Manager, Product Development
2006

Direct Energy Marketing Limited

Director, Customer Analytics
2004

Director, Financial Services
2002

Enbridge Commercial Services Inc.

Director, Financial Services
2001

Enbridge Gas Distribution Inc.

Manager, Budgets
2000

Supervisor, Budgets & Forecasts
1998

Economic Analyst
1996

Education: Master of Arts: Business Economics, Wilfrid Laurier University – 1996
Bachelor of Commerce, University of Guelph - 1994

Appearances: (Ontario Energy Board)

EB-2016-0215	EB-2014-0276
EB-2016-0142	EB-2012-0459
EB-2015-0114	

CURRICULUM VITAE OF
BIJU MISRA

Experience: Enbridge Gas Distribution Inc.

Director, Enterprise Financial and Supply Chain Systems
2017

Director Information Technology,
2013

Sr. Manager Business Applications,
2009

IT Solution & Support Manager, Information Technology,
2008

Sr. Project Manager, Information Technology,
2007

Project Manager, Information Technology,
2006

Education: Bachelor of Science, Electrical Engineering. Kansas State University
Certificate, Business Management Fundamentals. University of Toronto

Memberships: Project Management Institute (PMI)

Appearances: (Ontario Energy Board)

EB-2011-0354

CURRICULUM VITAE OF
FIONA OLIVER-GLASFORD

Experience: Enbridge Gas Distribution Inc.

Manager, Carbon Strategy
2016

Senior Manager, Carbon Strategy and IRP
2016

Senior Manager, Market Policy and DSM
2013

Union Gas Distribution

Manager, CDM Business Development and Policy
2010

Manager, DSM Strategy
2008

Manager, DSM EM&V
2007

Manager, DSM Programs/Marketing
2006

Manager, Market Research & Analysis
2005

Canadian Energy Efficiency Alliance

Director, Operations

Summerhill Group

Marketing Manager

Corus Entertainment

Marketing Manager, YTV, Documentary Channel and Scream TV

Towers Watson

Associate/Analyst

Education:	York University – Schulich School of Business Masters of Business Administration With an International Exchange at Copenhagen School of Business Western University – Huron College Bachelor of Arts
Appearances:	(Ontario Energy Board)

EB-2016-0300	EB-2014-0277
EB-2015-0049	EB-2013-0352
EB-2014-0276	EB-2013-0430
EB-2013-0075	EB-2012-0459
EB-2012-0451	EB-2008-0346
EB-2012-0441	

CURRICULUM VITAE OF
JASON SHEM

Experience: Enbridge Gas Distribution Inc.

Supervisor, Gas Accounting
2016

Supervisor, Financial Reporting
2014

Senior Advisor, Financial Reporting
2012

Financial Analyst
2011

SF Partnership, LLP

Senior Accountant
2009

Ernst & Young

Senior Accountant
2008

Staff Accountant
2007

Education: Chartered Accountant (CA), 2010

Memberships: Institute of Chartered Accountants of Ontario

Appearances: (Ontario Energy Board)

EB-2015-0122
EB-2014-0276
EB-2012-0459

(Régie de l'énergie/Régie du gaz naturel)
R-3924-2015

CURRICULUM VITAE OF
RYAN SMALL

Experience: Enbridge Gas Distribution Inc.

Manager, Revenue and Regulatory Accounting
2016

Manager, Regulatory Accounting
2014

Senior Analyst, Regulatory Accounting
2006

Analyst, Regulatory Accounting
2004

Supervisor, Gas Cost Reporting
2001

Senior O&M Clerk
2000

Bank Reconciliation Clerk
1999

Accounting Trainee
1998

Education: Chartered Professional Accountant, Certified Management Accountant
Chartered Professional Accountants of Ontario, 2014
The Society of Management Accountants of Ontario, 2003

Diploma in Accounting,
Wilfrid Laurier University, 1997

Bachelor of Arts in Economics
The University of Western Ontario, 1996

Appearances: (Ontario Energy Board)

EB-2016-0215
EB-2015-0114
EB-2015-0122
EB-2014-0195
EB-2012-0055
EB-2011-0008
EB-2016-0142
EB-2015-0049
EB-2014-0276
EB-2012-0459
EB-2011-0354

CURRICULUM VITAE OF
DONALD R. SMALL

Experience: Enbridge Gas Distribution Inc.

Manager, Gas Costs and Budget
2010

Manager, Gas Cost Knowledge Centre
2003

Manager, Gas Costs and Budget
1989

Co-ordinator, Gas Costs
1984

Financial Statement Accountant
1980

Chief Clerk, Financial Statements
1979

Advanced Accounting Trainee
1978

Education: Business Administration Diploma
Ryerson Polytechnical Institute, 1978

Appearances: (Ontario Energy Board)

EB-2016-0215	EB-2008-0106
EB-2015-0114	EB-2006-0034
EB-2015-0122	EB-2005-0001
EB-2014-0276	RP-2003-0203
EB-2013-0046	RP-2003-0048
EB-2012-0459	RP-2002-0133
EB-2011-0354	RP-2001-0032
EB-2011-0277	RP-2000-0040
EB-2010-0146	RP-1999-0001
EB-2009-0172	EBRO 497
EB-2009-0055	EBRO 495
EB-2008-0219	EBRO 492
EBRO 490	EBRO 487
EBRO 485	EBRO 479
EBRO 473	EBRO 465

CURRICULUM VITAE OF
BRANDON SO

Experience:	Enbridge Gas Distribution Inc.
	Cost Allocation Specialist 2016
	Senior Gas Cost Accountant, Gas Accounting & Analytics 2009
	Senior Financial Analyst, Business Development & Customer Strategy 2007
	Toronto Hydro
	Senior Financial Analyst 2003
	Ballard Power Systems
	Senior Accountant 1999
Education:	Master of Business Administration Richard Ivy School of Business
	Bachelor of Business Administration (Accounting) University of Texas at Austin
	Bachelor of Arts (Economics) University of Texas at Austin
	Chartered Professional Accountant (CPA, CGA) Chartered Professional Accountants of Ontario
Memberships:	Charter Professional Accountants of Ontario
Appearances:	(Ontario Energy Board) None

CURRICULUM VITAE OF
LORI STICKLES

Experience: Enbridge Gas Distribution Inc.

Planning & Budgeting Technical Advisor
2017

Senior Manager Budgets and Financial Support
2014

Enbridge Gas New Brunswick Inc.

Manager Corporate Services
2014

Manager, Financial Reporting
2008

Staff Accountant
2004

Education: Chartered Professional Accountant
2014

Certified General Accountant
2003

Bachelor Business Administration
University of New Brunswick, Fredericton, New Brunswick
1990

Appearances: (New Brunswick Energy and Utilities Board)

Matter 253 – 2015 Rate Application / 2013 Annual Financial Results Review
Matter 225 – 2014 Rate Application / 2012 Annual Financial Results Review
Matter 178 – 2012 Rate Application
Matter 175 – 2011 Annual Financial Results Review
Matter 132 – 2010 Annual Financial Results and Natural Gas Sales Review / 2012 Proposed Budget
Matter 2010-007 – 2009 Annual Financial Results and Natural Gas Sales Review / 2011 Proposed Budget

(Ontario Energy Board)
None

CURRICULUM VITAE OF
MARGARITA SUAREZ-SHARMA

Experience: Enbridge Gas Distribution Inc.

Manager, Economics & Business Performance
2014

Manager, Economic & Market Analysis
2012

Manager, Cost Allocation
2008

Manager, DSM Reporting & Analysis
2005

Analyst, Rate Design
2004

Senior Analyst, DSM Planning and Evaluation
2002

Senior Economic Analyst, Economic & Financial Studies
1998

Margaret Chase Smith Center for Public Policy

Research Assistant
1995

Education: Master of Arts in Economics
University of Maine, 1995

Bachelor of Arts in Economics
University of Maine, 1993

Appearances: (ONTARIO ENERGY BOARD)
EB-2016-0215
EB-2015-0114
EB-2015-0122
EB-2014-0276
EB-2012-0459
EB-2011-0354
EB-2011-0277
EB-2010-0146
EB-2009-0172
EB-2008-0219
EB-2008-0106

(RÉGIE DE L'ÉNERGIE)
R-3758-2011
R-3724-2010
R-3692-2009
R-3665-2008

CURRICULUM VITAE OF
HILARY THOMPSON

Experience: Enbridge Gas Distribution Inc.

Director, Asset Management
2016

Manager, Distribution Planning
2014

Manager, Regulatory Projects
2012

Manager, Technical Services
2011

Field Manager, Measurement & Regulation
2011

Senior Engineering Project Leader, Measurement & Regulation
2010

Senior Engineering Project Leader, Special Projects
2008

Engineering Project Leader, Special Projects
2007

Engineering Project Leader, Engineering Standards & Technical Services
2006

Education: University of Toronto – Faculty of Law
Global Professional Master of Laws

Queen's University – Faculty of Applied Science
Bachelor of Science, Chemical Engineering

Memberships: Professional Engineers Ontario (P.Eng. Licence Holder)

Appearances: (Ontario Energy Board)

EB-2015-0049

CURRICULUM VITAE OF
LYNETTE UHYREK

Experience: Enbridge Gas Distribution Inc., Toronto, Ontario
Director Accounting
March 2017-Present

Assistant Controller
May 2014- March 2017

Enbridge Energy Company, Inc., Houston, Texas
Manager, Financial Reporting
July 2011 – May 2014

Supervisor, SEC Reporting
March 2011 – July 2011

Supervisor, Special Projects
May 2010 – March 2011

PricewaterhouseCoopers, Houston, Texas
Manager, External Auditing
August 2001 – May 2010

(Worked in the PricewaterhouseCoopers SpA office in Rome, Italy from June 2007 – April 2009 as an audit manager.)

Intern, External Auditing
January 2000 – April 2000

Education: Certified Public Accountant, 2002 - Texas State Certification

University of St. Thomas, Houston, Texas
M.B.A., Concentration: Accounting, May 2001

B.B.A., Accounting, May 2001
Minors: Finance and Philosophy
Graduated Magna Cum Laude

Memberships: American Institute of CPAs

Appearances: None

CURRICULUM VITAE OF
NICK VERMA

Experience: Enbridge Gas Distribution Inc.

Manager Operating Expenses & FP&A

Program Manager, Regulatory Policy & Reporting
2014

Program Manager, Operations PMO
2010

Senior Financial Analyst, Regional Operations
2007

Supervisor, Planning and Design
2007

Supervisor, WMC
2005

Education: Master of Business Administration (MBA), 2013
Wilfrid Laurier University

Human Resource Management, 2004
York University

Bachelor of Admin Studies, 2003
York University

Memberships: CFA Institute

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
MELINDA YAN

Experience:	Enbridge Gas Distribution Inc. Supervisor, Business Performance 2015
	Supervisor, Internal Audit 2012
	Manager, Internal Controls 2010
	Accenture Inc. Manager, Control Assurance 2008
	CAA South Central Ontario Senior Auditor 2005
Education:	Chartered Professional Accountant, Certified General Accountant (CPA, CGA) Chartered Professional Accountants of Ontario, 2014 Certified General Accountants of Ontario, 2007
	Certified Fraud Examiner (CFE), Association of Certified Fraud Examiners, 2012
	Certified Internal Auditor (CIA), Institute of Internal Auditors, 2010
	Bachelor of Business Administration (BBA) University of Toronto, 2003
Appearances:	(Ontario Energy Board) None

CURRICULUM VITAE OF
JOHNSON YIU

Experience: Enbridge Gas Distribution Inc.

Finance Lead, Operating Expenses and Cost Allocations
2015 – Present

Rogers Communications Inc.

Senior Financial Analyst, Controllers Group
2011 – 2015

Deloitte & Touche LLP

Senior Accountant, Assurance and Advisory
2008 - 2011

Education: Bachelor of Commerce – Specialist Commerce and Finance, 2008
University of Toronto, St. George

Chartered Professional Accountant, Chartered Accountant, 2011

Memberships: Chartered Professional Accountant of Ontario, 2011

Appearances: Ontario Energy Board
(None)

2016 EARNINGS SHARING AMOUNT AND DETERMINATION PROCESS

1. The 2016 Earnings Sharing amount included within Enbridge Gas Distribution Inc.'s ("Enbridge", or "the Company") Fiscal 2016 year-end audited statements was $3.2 million, which was slightly lower than the amount being requested for approval and clearance within this application of $3.4 million. In order to meet year end timing obligations, estimates for elements impacting the accrual are sometimes required in lieu of complete or detailed analyses along with the rounding of various actual amounts into millions of dollars for regulatory presentation. Following the year end close process, however, completion of analyses are performed for elements where estimates were used along with rounding finalizations, in order to ensure the earnings sharing amount is accurate. If required and appropriate, an adjustment is made to the earnings sharing results, which ultimately is reflected in following year financial statements. In certain other instances, new information becomes available which requires the earnings sharing amount to be recalculated.

2. The process followed is the same as that which was followed for earnings sharing amounts calculated for 2014 and 2015, and during the 2008 through 2012 incentive regulation term. For 2016, the year-end earnings sharing calculation did not properly consider the allocation of $5.6 million of base pressure gas to unregulated storage operations (resulting from the use of fully allocated costs for base pressure gas), as was agreed to as part of the Board Approved EB-2015-0114 (2016 Rate Adjustment proceeding) Settlement Agreement. Updating the earnings sharing calculation to reflect the approved allocation resulted in a $5.6 million rate base reduction, which creates a $0.4 million increase in the gross sufficiency to be

shared with rate payers, and a corresponding $0.2 million increase to the earnings sharing amount.

3. The amounts for each of the cost elements of utility rate base, utility income and taxes, and the utility capital structure components, which were used in the calculation of the earnings sharing amount, are summarized within Exhibit B, Tab 1, Schedule 2.

4. The earnings sharing amount was determined in accordance with the following prescribed methodology as identified within the EB-2012-0459 Board Decision, dated July 17, 2014, at pages 13 through 15, and within the pre-filed evidence at Exhibit A2, Tab 7, Schedule 1;

   - if in any calendar year during the customized incentive regulation term, Enbridge's actual utility ROE, calculated on a weather normalized basis, is more than the allowed ROE included in that year's rates (updated annually by the application of the Board's ROE Formula), then the resultant amount shall be shared equally (ie., 50 / 50) between Enbridge and its ratepayers;
   - for the purposes of the ESM, Enbridge shall calculate its earnings using the regulatory rules prescribed by the Board, from time to time, and shall not make any material changes in accounting practices that have the effect of reducing utility earnings;
   - all revenues that would otherwise be included in revenue in a cost of service application shall be included in revenues in the calculation of the earnings calculation and only those expenses (whether operating or capital) that would be otherwise allowable as deductions from earnings in a cost of service application, shall be included in the earnings calculation.

5. In addition, the following are examples of shareholder incentives and other amounts which are outside the ambit of the ESM: amounts related to Demand Side Management incentives, amounts related to Transactional Services incentives, and amounts related to Open Bill program incentives.

6. As shown within the summary of return on equity and earnings sharing determination, Exhibit B, Tab 1, Schedule 2, the Company has calculated earnings for sharing in two ways for confirmation purposes.

7. In part A) of the summary, a return on rate base method is shown, while in part B), a return on equity from a deemed equity embedded within rate base perspective is shown. Column 2 within the exhibit provides references indicating where additional evidence in support of the determination of the amounts in the summary can be found. Column 3 contains results shown in millions of dollars, or percentages.

Part A)

8. The level of utility income, $377.3 million (Line 17) divided by the level of utility rate base, $5,909.0 million (Line 22) generates a utility return on rate base of 6.385% (Line 23).

9. When compared to the Company’s required rate of return of 6.301% (Line 24), as determined within the capital structure required in support of the determined rate base amount, there is a resulting sufficiency of 0.084% (Line 25) on total rate base.

10. As shown in Lines 26 through 28, the sufficiency of 0.084% multiplied by the rate base of $5,909.0 million, produces a net over earnings or sufficiency of $4.97 million which from a pre-tax perspective, ($4.97 million divided by the reciprocal, 73.5%, of

the corporate tax rate which is 26.5%) shows a $6.76 million total amount of over earnings to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

<u>Part B) (Confirming the Calculated Earnings Sharing)</u>

11. Net utility income applicable to common equity is first determined.

12. The $394.6 million (Line 31) of utility income before income tax, less utility taxes of $17.3 million (Line 36), produces the $377.3 million of utility income used in part A) above (at Line 17).

13. In order to determine utility net income applicable to a deemed common equity percentage within rate base, all long term debt, short term debt and preference share costs must also be reduced against the part A) $377.3 million utility income.

14. These reductions are shown at Lines 32, 33 and 34 which along with the utility income tax reduction already mentioned and shown at Line 36, results in a net income applicable to common equity of $200.5 million, shown at Line 37.

15. The $200.5 million, divided by the deemed common equity level of $2,127.2 million (Line 38, calculated as 36% of the $5,909.0 million rate base) produces a return on equity of 9.423% (Line 40). When comparing the 9.423% achieved return on equity to the threshold ROE percentage of 9.19% (Line 39), which is the Board approved formula return on equity for 2016, there is a sufficiency in ROE of 0.233% (Line 41).

16. The 0.233% multiplied by the common equity level of $2,127.2 million (Line 38) produces a net over earnings or sufficiency of $4.97 million which from a pre-tax

perspective ($4.97 million divided by the reciprocal, 73.5%, of the corporate tax rate), shows a $6.76 million total amount of over earnings to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

Process Description

17. The calculation of utility earnings and any sharing requirement starts with financial results contained within the Enbridge Ontario corporate trial balance.

18. From there, in order to calculate the Ontario utility rate base, income, and capital structure results, and supporting evidence exhibits, various adjustments, regroupings or eliminations are required. This is accomplished by following and applying regulatory rules as prescribed by the Board and the standards associated with cost of service rate related accounting processes. Examples are:
    - determination of rate base amounts using the average of monthly averages value concept,
    - elimination of corporate interest expense due to the treatment of interest expense as embedded in the capital structure balanced to rate base, and
    - elimination of corporate income taxes due to the determination of income taxes specific to utility results,

19. In addition, Enbridge has made the appropriate adjustments in relation to non-standard rate regulated items which the Board has either decided in the past, or are required in order to determine an appropriate utility return on equity. Examples are:
    - rate base disallowance from EBRO 473 and 479 Decisions (Mississauga Southern Link project amounts),
    - rate base disallowance from RP-2002-0133 (shared assets),

- exclusion of non-utility or unregulated activities,
- elimination of approved shareholder incentives.

20. As shown in the Column 2 references in the summary exhibit, supporting rate base information is found in Exhibit B, Tab 2, supporting revenue, volumes, customers and cost information is found in Exhibit B, Tabs 3 and 4, and supporting capital structure, required rate of return, utility income, and cost of capital information is found in Exhibit B, Tab 5.

SUMMARY
RETURN ON EQUITY & EARNINGS SHARING DETERMINATION
ENBRIDGE GAS DISTRIBUTION

ONTARIO UTILITY
FOR THE YEAR ENDED DECEMBER 31, 2016

Line No.	Col. 1 Description	Col. 2 Reference	Col. 3 Actual Normalized ($millions) & (%'s)
1.	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2.	Gas Sales	(Ex.B,T5,S2,P1,Col.1,line 1)	2,311.8
3.	Transportation Revenue	(Ex.B,T5,S2,P1,Col.1,line 2)	319.2
4.	Transmission, Compr. and Storage Revenue	(Ex.B,T5,S2,P1,Col.1,line 3)	6.4
5.	Less Cost of Gas	(Ex.B,T5,S2,P1,Col.1,line 8)	1,497.1
6.	Gas Distribution Margin		1,140.3
7.	Other Revenue	(Ex.B,T5,S2,P1,Col.1,line 4)	41.9
8.	Other Income	(Ex.B,T5,S2,P1,Col.1,line 6)	1.1
9.	Total - Other Revenue & Income		43.0
10.	Operations & Maintenance (incl. CC/CIS rate smoothing adj.)	(Ex.B,T5,S2,P1,Col.1,line 9)	449.7
11.	Depreciation & amortization	(Ex.B,T5,S2,P1,Col.1,line 10)	292.7
12.	Fixed financing costs	(Ex.B,T5,S2,P1,Col.1,line 11)	3.2
13.	Municipal & capital taxes	(Ex.B,T5,S2,P1,Col.1,line 12)	43.1
14.	Total O&M, Depr., & other		788.7
15.	Utility Income before Income Tax	(line 5 + line 9 - line 14)	394.6
16.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 17)	17.3
17.	Utility Income		377.3
18.	Gross plant	(Ex.B,T2,S1,P1,Col.1,line 1)	8,588.4
19.	Accumulated depreciation	(Ex.B,T2,S1,P1,Col.1,line 2)	(3,017.4)
20.	Net plant		5,571.0
21.	Working capital	(Ex.B,T2,S1,P1,Col.1,line 11)	338.0
22.	Utility Rate Base		5,909.0
23.	Indicated Return on Rate Base %	(line 17 / line 22)	6.385%
24.	Less: Required Rate of Return %	(Ex.B,T5,S1,P1,Col.4,line 6)	6.301%
25.	(Deficiency) / Sufficiency %		0.084%
26.	Net Earnings (Deficiency) / Sufficiency	(line 25 x line 22)	4.97
27.	Provision for Income Taxes		1.79
28.	Gross Earnings (Deficiency) / Sufficiency	(line 26 divide by 73.5%)	6.76
29.	50% Earnings sharing to ratepayers	(line 28 x 50%)	3.38
30.	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
31.	Utility Income before Income Tax	(Ex.B,T5,S2,P1,Col.1,line 16)	394.6
32.	Less: Long Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 1)	171.9
33.	Less: Short Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 2)	2.8
34.	Less: Cost of Preferred Capital	(Ex.B,T5,S1,P1,Col.5,line 4)	2.2
35.	Net Income before Income Taxes		217.8
36.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 17)	17.3
37.	Net Income Applicable to Common Equity	(line 35 - line 36)	200.5
38.	Common Equity	(Ex.B,T5,S1,P1,Col.1,line 5)	2,127.2
39.	Approved ROE %		9.190%
40.	Achieved Rate of Return on Equity %	(line 37 divide by line 38)	9.423%
41.	Resulting (Deficiency) / Sufficiency in Return on Equity %		0.233%
42.	Net Earnings (Deficiency) / Sufficiency	(line 38 x line 41)	4.97
43.	Provision for Income Taxes		1.79
44.	Gross Earnings (Deficiency) / Sufficiency	(line 42 divide by 73.5%)	6.76
45.	50% Earnings sharing to ratepayers	(line 44 x 50%)	3.38

ENBRIDGE GAS DISTRIBUTION
CONTRIBUTORS TO UTILITY EARNINGS
AND EARNINGS SHARING AMOUNTS (INCLUDING CUSTOMER CARE & CIS)
2016 ACTUAL

Line No.		Col. 1 2016 Actual Normalized $Millions	Col. 2 2016 Board Approved $Millions	Col. 3 Over/ (Under) Earnings Impact $Millions	Col. 4 Attached Pages Refer.
1.	Sales revenue	2,311.8	2,624.8		
2.	Transportation revenue	319.2	279.7		
3.	Transmission, compression & storage (incl. Rate 332)	6.4	6.7		
4.	Gas costs	1,497.1	1,764.8		
5.	Distribution margin	1,140.3	1,146.4	(6.1)	a)
6.	Other revenue	41.9	42.7	(0.8)	b)
7.	Other income	1.1	0.1	1.0	b)
8.	O&M (incl. CC/CIS rate smoothing adj.)	449.7	457.4	7.7	c)
9.	Depreciation expense	292.7	288.9	(3.8)	d)
10.	Other expense	46.3	47.4	1.1	e)
11.	Income taxes	17.3	23.6	6.3	f)
12.	Utility Income	377.3	371.9	5.4	
13.	LTD & STD costs	174.7	177.8	3.1	g)
14.	Preference share costs	2.2	2.2	0.0	
15.	Return on Equity @ 9.19% in 2016 Board Approved	195.5	191.9	(3.6)	
16.	Net Earnings Over / (Under) (aft. prov for taxes)	5.0	(0.0)	5.0	
17.	Provision for taxes on Earnings Over / (Under)	1.8	(0.0)	1.8	
18.	Gross Earnings Over / (Under)	6.8	(0.0)	6.8	
19.	EGD Equity Level @ 36% (B-5-1, Col.1. line 5)	2,127.2			
20.	EGD normalized Earnings (Line12 - line 13 - line 14)	200.5			
21.	EGD normalized Return on Equity	9.42%			

Witness: R. Small

2016 EARNINGS SHARING AMOUNT AND CONTRIBUTORS

The following are explanations of the Utility Normalized Earnings results as compared to the 2016 Board approved amounts. The reference letters are in relation to those identified on page 1 of this Schedule.

a) The distribution margin decrease of $6.1M was driven primarily due to a lower than forecast average number of customer unlocks attributable to lower than forecast customer additions, and, lower than forecast gas in storage carrying charges reflected in rates as a result of lower than forecast PGVA reference prices approved through the 2016 Quarterly Rate Adjustment Mechanism (“QRAM”) proceedings. The unfavourable variances were partially offset by lower fuel costs required to manage storage operations and the transmission of volumes on Union’s system, and higher Large Volume customer contract demand revenues resulting from higher than forecast migration from interruptible to firm rate classes. Lower margin resulted in a negative earnings impact.

b) The net increase in other revenue and other income of $0.2M was mainly due to the gain on sale of land recognized during 2016. This resulted in a positive earnings impact. Details of other revenue and other income are presented in Exhibit B, Tab 3, Schedule 5.

c) Utility O&M was $7.7M lower than the 2016 Board approved level which resulted in a positive earnings impact. Explanations of the major changes between actual O&M and Board approved are presented in Exhibit B, Tab 4, Schedule 2.

d) The increase in depreciation expense of $3.8M was predominantly due to the cumulative impact of capital variances (level and mix of capital spending and level of retirements) from prior years (2012 to 2015) which were not reflected in the 2016 depreciable balances approved by the Board for rate setting as part of the customized incentive rate proceeding. The increase in depreciation resulted in a negative earnings impact.

e) The decrease in other expenses of $1.1M was due to lower municipal taxes of $2.4M, partially offset by higher fixed financing charges of $1.3M. The favourable municipal tax variance was attributable to lower than forecast municipal tax rate increases, and due to the impact of the delayed GTA project in-service timing. The unfavourable variance in fixed financing charges was attributable to the unforecast increase in the Company's credit facility which occurred in 2014. The net decrease resulted in a positive earnings impact.

f) The decrease in income taxes of $6.3M was primarily attributable to higher than forecast tax deductible amounts, predominantly due to higher cost of retirements. The decrease resulted in a positive earnings impact.

g) The interest cost of utility long and short term debt decreased by $3.1M primarily as a result of a lower than forecast average of monthly average long-term debt balance outstanding (or component % of capital structure), partially offset by a higher short term debt balance outstanding (or component % of capital structure). The lower average long term debt balance resulted from issuing debt later in the year, August 2016 as compared to March 2016 as forecast, but partially offset by a higher issuance amount, $300M as compared to $250M as forecast. The net decrease has a positive earnings impact.

Witness: R. Small

RECONCILIATION OF AUDITED EGDI
CONSOLIDATED INCOME TO UTILITY INCOME
2016 ACTUAL

Line no.		Col. 1 Audited Consolidated Income ($millions)	Col. 2 Utility Income ($millions)	Col. 3 Difference ($millions)	Col. 4 Reference
1.	Gas commodity and distribution revenue	2,437.1	2,311.8	(125.3)	a)
2.	Transportation of gas for customers	329.8	319.2	(10.6)	b)
3.	Other revenue and income	172.3	49.4	(122.9)	c)
4.		2,939.2	2,680.4	(258.8)	
	Expenses				
5.	Gas commodity and distribution costs	1,635.5	1,497.1	(138.4)	d)
6.	Operation and maintenance	533.9	449.7	(84.2)	e)
7.	Earnings sharing	3.2	-	(3.2)	f)
8.	Depreciation	321.6	292.7	(28.9)	g)
9.	Municipal and other taxes	-	43.1	43.1	h)
10.		2,494.2	2,282.6	(211.6)	
11.	Income before undernoted items	445.0	397.8	(47.2)	
12.	Interest and financing expenses	(205.9)	(3.2)	202.7	i)
13.	Income before income taxes	239.1	394.6	155.5	
14.	Income taxes	(9.3)	(17.3)	(8.0)	j)
15.	Net Income	229.8	377.3	147.5	

Witness: R. Small

RECONCILIATION OF 2016
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
a)	2,437.1	**Consolidated gas commodity and distribution revenue**
	(33.3)	Amounts related to St. Lawrence Gas
	44.0	Normalization adjustment
	(139.5)	US GAAP adjustment elimination - deferral clearance adjustment
	3.5	Gazifere T-service regrouped to gas commodity and distribution revenue
	2,311.8	**Utility gas commodity and distribution revenue**
b)	329.8	**Consolidated transportation of gas for customers**
	(11.9)	Amounts related to St. Lawrence Gas
	4.7	Normalization adjustment
	(3.5)	Gazifere T-service regrouped to gas commodity and distribution revenue
	0.1	Rounding
	319.2	**Utility transportation of gas for customers**
c)	172.3	**Consolidated other revenue and income**
	(24.2)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(62.7)	Elimination of non-utility dividend income from the Board Approved financing transaction
	(0.2)	Foreign exchange gain and other misc. expenses regrouped to O&M
	14.1	Allowable interest during construction regrouped to revenues from interest and financing expenses
	1.5	Interest on deferral accounts regrouped to revenues from interest and financing expenses
	(1.4)	ABC administration and bad debt costs regrouped against program revenues from O&M
	(13.3)	Open Bill expenses regrouped against program revenues from O&M
	(2.0)	Elimination of transactional services revenue above base amount included in rates
	(1.1)	To adjust OBA costs to reflect the EB-2013-0099 approved unit costs for determining net revenues
	(1.2)	Elimination of Open Bill revenues to reflect the shareholder incentive
	(0.8)	Elimination of 3rd party asset use revenue considered non-utility
	(1.5)	Elimination of net ABC revenue considered non-utility
	(2.9)	Elimination of interest income from investments not included in rate base
	(14.1)	Elimination of allowable interest during construction
	(1.5)	Elimination of interest on deferral accounts
	(6.1)	Elimination of shareholder incentive income associated with the DSMIDA
	(5.3)	Elimination of revenue indemnification from Enbridge Inc. related to part V1.1 tax transfer
	(0.2)	Rounding
	49.4	**Utility other revenue and income**

RECONCILIATION OF 2016
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
d)	1,635.5	**Consolidated gas commodity and distribution costs**
	(33.2)	Elimination of amounts related to St. Lawrence Gas, unregulated storage
	30.4	Normalization adjustment
	(135.6)	US GAAP adjustment elimination - deferral clearance adjustment
	1,497.1	**Utility gas commodity and distribution costs**
e)	533.9	**Consolidated operation and maintenance**
	(46.7)	Municipal and other taxes included within O&M costs in the corp. financial statements
	(15.1)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(13.3)	Open Bill expenses regrouped against program revenues
	(1.4)	ABC administration and bad debt costs regrouped against program revenues and eliminated
	(0.2)	Foreign exchange gain and other misc. expenses regrouped from other income
	0.6	Interest on security deposits added to utility O&M
	(0.9)	Elimination of donations
	(0.8)	Elimination of non-utility costs of supporting the ABC program
	(3.9)	US GAAP adjustment elimination - deferral clearance adjustment
	(2.6)	Elimination of Corporate Cost Allocations above RCAM amount
	0.1	Rounding
	449.7	**Utility operation and maintenance**
f)	3.2	**Consolidated earnings sharing**
	(3.2)	Elimination of 2016 earnings sharing amount within year end financials from utility income calculation
	-	**Utility earnings sharing**
g)	321.6	**Consolidated depreciation**
	(5.5)	Amounts related to St. Lawrence Gas, unregulated storage, and oil and gas
	(22.5)	Elimination of the amortization of PPD
	(0.1)	Elimination of depreciation on disallowed Mississauga Southern Link
	(0.8)	Elimination of depreciation related to shared assets
	292.7	**Utility depreciation**

RECONCILIATION OF 2016
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
h)	-	**Consolidated municipal and other taxes**
	46.7	Municipal and other taxes included within O&M costs in the corp. financial statements
	(3.4)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(0.2)	Elimination of municipal taxes related to shared assets
	43.1	**Utility municipal and other taxes**
i)	205.9	**Consolidated interest and financing expenses**
	(3.6)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(26.8)	Elimination of non-utility interest expense from the Board Approved financing transaction
	14.1	Allowable interest during construction regrouped to revenues and eliminated
	1.5	Interest on deferral accounts regrouped to revenues and eliminated
	(187.8)	Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure
	(0.1)	Rounding
	3.2	**Utility interest and financing expenses**
j)	9.3	**Consolidated income taxes**
	(2.6)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(6.7)	Elimination of corporate income taxes
	17.3	Addition of income taxes calculated on a utility "stand-alone" basis
	17.3	**Utility income taxes**

UTILITY RATE BASE (INCLUDING CUSTOMER CARE & CIS)
COMPARISON OF 2016 ACTUAL TO 2016 BOARD APPROVED

Line No.		Col. 1 2016 Actual	Col. 2 EB-2015-0114 2016 Board Approved	Col. 3 Variance
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	8,588.4	8,549.0	39.4
2.	Accumulated depreciation	(3,017.4)	(3,105.8)	88.4
3.	Net property, plant, and equipment	5,571.0	5,443.2	127.8
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.4	1.4	-
5.	Materials and supplies	37.7	34.6	3.1
6.	Mortgages receivable	-	-	-
7.	Customer security deposits	(56.5)	(64.6)	8.1
8.	Prepaid expenses	1.7	1.0	0.7
9.	Gas in storage	354.4	391.1	(36.7)
10.	Working cash allowance	(0.7)	0.2	(0.9)
11.	Total Working Capital	338.0	363.7	(25.7)
12.	Utility Rate Base	5,909.0	5,806.9	102.1

Witness: R. Small

UTILITY PROPERTY, PLANT, AND EQUIPMENT (INCLUDING CUSTOMER CARE & CIS)
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2016 ACTUAL

Line No.		Col. 1 Gross Property, Plant, and Equipment	Col. 2 Accumulated Depreciation	Col. 3 Net Property, Plant, and Equipment
		($Millions)	($Millions)	($Millions)
1.	Underground storage plant	385.0	(129.1)	255.9
2.	Distribution plant	7,715.0	(2,587.4)	5,127.6
3.	General plant	499.2	(300.8)	198.4
4.	Other plant	-	-	-
5.	Total plant in service	8,599.2	(3,017.3)	5,581.9
6.	Plant held for future use	1.7	(1.2)	0.5
7.	Sub- total	8,600.9	(3,018.5)	5,582.4
8.	Affiliate Shared Assets Value	(12.5)	1.1	(11.4)
9.	Total property, plant, and equipment	8,588.4	(3,017.4)	5,571.0

UTILITY GROSS UNDERGROUND STORAGE PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2015	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2016	Col. 5 Regulatory Adjustments (Note 1)	Col. 6 Utility Balance Dec.2016	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	4.2	-	-	4.2	-	4.2	4.2
2.	Land and gas storage rights (450/451)	46.0	-	-	46.0	(1.0)	45.0	45.0
3.	Structures and improvements (452.00)	14.9	15.4	(0.8)	29.5	(0.1)	29.5	25.9
4.	Wells (453.00)	46.5	6.6	-	53.1	-	53.1	50.2
5.	Well equipment (454.00)	9.5	1.5	-	11.1	-	11.1	10.5
6.	Field Lines (455.00)	86.3	7.3	-	93.6	-	93.6	87.1
7.	Compressor equipment (456.00)	114.9	9.2	-	124.0	(0.5)	123.6	117.6
8.	Measuring and regulating equipment (457.00)	11.2	-	-	11.2	-	11.2	11.2
9.	Base pressure gas (458.00)	33.4	-	-	33.4	-	33.4	33.4
10.	Total	366.8	40.0	(0.8)	406.0	(1.5)	404.5	385.0

Note 1: Adjustments associated with previously established non-utility items and disallowances.
Note 2: Base pressure gas balances reflect the allocation of $5.56 million to unregulated storage operations, as per the. EB-2015-0114 approved settlement agreement.

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2015	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2016	Col. 7 Regulatory Adjustments (Note 1)	Col. 8 Utility Balance Dec.2016	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	(2.4)	(0.1)	-	-	-	(2.5)	-	(2.5)	(2.5)
2.	Land and gas storage rights (451.00)	(23.3)	(0.5)	-	-	-	(23.8)	-	(23.8)	(23.5)
3.	Structures and improvements (452.00)	(3.5)	(0.5)	-	0.8	-	(3.2)	0.1	(3.2)	(3.1)
4.	Wells (453.00)	(19.1)	(0.8)	(0.0)	-	-	(19.9)	-	(19.9)	(19.5)
5.	Well equipment (454.00)	(5.7)	(0.6)	-	-	-	(6.3)	-	(6.3)	(6.0)
6.	Field Lines (455.00)	(26.0)	(1.4)	(0.0)	-	-	(27.5)	-	(27.5)	(26.7)
7.	Compressor equipment (456.00)	(39.9)	(3.1)	(0.1)	-	-	(43.1)	0.2	(42.9)	(41.3)
8.	Measuring and regulating equipment (457.00)	(6.4)	(0.3)	(0.0)	-	-	(6.8)	-	(6.8)	(6.6)
9.	Total	(126.3)	(7.4)	(0.1)	0.8	-	(133.1)	0.3	(132.8)	(129.1)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY GROSS DISTRIBUTION PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2015	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2016	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2016	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land (470.00)	19.5	4.0	(0.3)	23.2	-	23.2	22.4
2.	Offers to purchase (470.01)	-	-	-	-	-	-	-
3.	Land rights intangibles (471.00)	11.2	52.7	-	63.9	-	63.9	51.7
4.	Structures and improvements (472.00)	120.7	5.7	(2.6)	123.8	(0.3)	123.5	123.8
5.	Services, house reg & meter install. (473/474)	2,605.0	143.3	(9.0)	2,739.3	-	2,739.3	2,667.2
6.	NGV station compressors (476)	3.3	0.3	(0.1)	3.6	-	3.6	3.5
7.	Meters (478)	422.2	17.4	(13.2)	426.4	-	426.4	427.2
8.	Sub-total	3,181.9	223.4	(25.1)	3,380.2	(0.3)	3,379.9	3,295.8
9.	Mains (475)	3,296.6	905.5	(4.3)	4,197.7	(2.2)	4,195.5	3,940.3
10.	Measuring and regulating equip. (477)	412.1	111.2	(0.2)	523.0	(0.5)	522.5	479.0
11.	Sub-total	3,708.6	1,016.7	(4.5)	4,720.8	(2.7)	4,718.0	4,419.3
12.	Total	6,890.5	1,240.1	(29.7)	8,100.9	(3.1)	8,097.9	7,715.0

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witness: R. Small

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 ACTUAL

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
Line No.		Opening Balance Dec.2015	Additions	Net Salvage Adjustment	Retirements	Costs Net of Proceeds	Closing Balance Dec.2016	Regulatory Adjustment (Note 1)	Utility Balance Dec.2016	Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(2.1)	(0.6)	-	-	-	(2.7)	-	(2.7)	(2.4)
2.	Structures and improvements (472.00)	(9.8)	(6.8)	-	2.6	2.3	(11.8)	0.2	(11.6)	(12.1)
3.	Services, house reg & meter install. (473/474)	(1,025.3)	(61.1)	28.4	9.0	14.7	(1,034.2)	-	(1,034.2)	(1,026.1)
4.	NGV station compressors (476)	(2.2)	(0.2)	-	0.1	-	(2.3)	-	(2.3)	(2.3)
5.	Meters (478)	(163.8)	(39.6)	-	13.2	(0.8)	(191.1)	-	(191.1)	(178.5)
6.	Mains (475)	(1,160.9)	(88.6)	55.3	4.3	22.0	(1,167.8)	1.7	(1,166.1)	(1,155.3)
7.	Measuring and regulating equip. (477)	(206.8)	(10.6)	0.4	0.2	-	(216.9)	0.5	(216.3)	(210.8)
8.	Total	(2,570.9)	(207.5)	84.1	29.4	38.2	(2,626.7)	2.5	(2,624.3)	(2,587.4)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY GROSS GENERAL PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2015	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2016	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2016	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	4.5	-	(3.3)	1.3	(0.2) [1]	1.1	2.1
2.	Office furniture and equipment (483.00)	17.5	4.4	(1.9)	20.0	-	20.0	19.0
3.	Transportation equipment (484.00)	54.9	1.8	(7.1)	49.6	(0.1) [1]	49.6	51.8
4.	NGV conversion kits (484.01)	4.0	0.7	(2.6)	2.1	-	2.1	3.0
5.	Heavy work equipment (485.00)	17.1	0.2	(1.3)	15.9	-	15.9	16.6
6.	Tools and work equipment (486.00)	49.2	1.7	(2.8)	48.1	-	48.1	50.1
7.	Rental equipment (487.70)	1.3	0.3	-	1.6	-	1.6	1.4
8.	NGV rental compressors (487.80)	2.2	5.7	(1.1)	6.9	-	6.9	2.2
9.	NGV cylinders (484.02 and 487.90)	0.6	-	-	0.6	-	0.6	0.6
10.	Communication structures & equip. (488)	4.7	0.8	(2.6)	2.9	-	2.9	3.1
11.	Computer equipment (490.00)	30.7	6.4	(8.9)	28.1	-	28.1	29.0
12.	Software Aquired/Developed (491.00)	175.4	19.4	(16.2)	178.5	-	178.5	175.5
13.	CIS (491.00)	127.1	-	-	127.1	-	127.1	127.1
14	WAMS (489.00)	-	90.1	-	90.1	-	90.1	17.7
15	Total	489.1	131.5	(47.8)	572.8	(0.3)	572.6	499.2

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY GENERAL PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2015 ($Millions)	Col. 2 Additions ($Millions)	Col. 3 Retirements ($Millions)	Col. 4 Costs Net of Proceeds ($Millions)	Col. 5 Closing Balance Dec.2016 ($Millions)	Col. 6 Regulatory Adjustment ($Millions)	Col. 7 Utility Balance Dec.2016 ($Millions)	Col. 8 Average of Monthly Averages ($Millions)
1.	Lease improvements (482.50)	(3.7)	(0.7)	3.3	-	(1.2)	0.2 [1]	(1.0)	(1.8)
2.	Office furniture and equipment (483.00)	(4.7)	(2.2)	1.9	-	(5.0)	-	(5.0)	(4.9)
3.	Transportation equipment (484.00)	(18.4)	(5.4)	7.1	(0.7)	(17.4)	0.1 [1]	(17.4)	(17.7)
4.	NGV conversion kits (484.01)	(1.4)	(0.2)	2.6	-	1.0	-	1.0	(0.0)
5.	Heavy work equipment (485.00)	(5.1)	(0.6)	1.3	(0.0)	(4.4)	-	(4.4)	(4.8)
6.	Tools and work equipment (486.00)	(15.8)	(2.1)	2.8	-	(15.1)	-	(15.1)	(16.7)
7.	Rental equipment (487.70)	(1.0)	(0.0)	-	-	(1.1)	-	(1.1)	(1.1)
8.	NGV rental compressors (487.80)	(1.6)	(0.3)	1.1	(0.1)	(0.8)	-	(0.8)	(1.2)
9.	NGV cylinders (484.02 and 487.90)	(0.4)	(0.0)	-	-	(0.4)	-	(0.4)	(0.4)
10.	Communication structures & equip. (488)	(2.5)	(0.6)	2.6	-	(0.5)	-	(0.5)	(0.6)
11.	Computer equipment (490.00)	(21.6)	(11.1)	8.9	-	(23.8)	-	(23.8)	(23.9)
12.	Software Aquired/Developed (491.00)	(127.6)	(41.1)	16.2	-	(152.5)	-	(152.5)	(141.8)
13.	CIS (491.00)	(79.5)	(12.7)	-	-	(92.2)	-	(92.2)	(85.8)
14	WAMS (489.00)	-	(1.6)	-	-	(1.6)	-	(1.6)	(0.1)
15.	Total	(283.2)	(78.5)	47.8	(0.8)	(314.8)	0.2	(314.5)	(300.8)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY GROSS OTHER PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2015	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2016	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2016	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	-	-	-	-	-	-	-
2.	Total	-	-	-	-	-	-	-

UTILITY OTHER PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2015	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2016	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2016	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	-	-	-	-	-	-	-	-
2.	Total	-	-	-	-	-	-	-	-

UTILITY GROSS PLANT HELD FOR FUTURE USE
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2015	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2016	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2016	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (102.00)	1.7	-	-	1.7	-	1.7	1.7
2.	Total	1.7	-	-	1.7	-	1.7	1.7

Witness: R. Small

UTILITY PLANT HELD FOR FUTURE USE
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2015	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2016	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2016	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (105.02)	(1.2)	(0.0)	-	-	(1.3)	-	(1.3)	(1.2)
2.	Total	(1.2)	(0.0)	-	-	(1.3)	-	(1.3)	(1.2)

WORKING CAPITAL COMPONENTS
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 ACTUAL

Line No.		Col. 1 Account Receivable Rebillable Projects	Col. 2 Materials and Supplies	Col. 3 Mortgages Receivable	Col. 4 Customer Security Deposits	Col. 5 Prepaid Expenses	Col. 6 Gas in Storage	Col. 7 Working Cash Allowance	Col. 8 Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	January 1	1.4	39.5	-	(60.3)	0.6	513.8	(0.7)	494.3
2.	January 31	1.4	37.7	-	(60.4)	0.7	343.9	(0.7)	322.6
3.	February	1.4	39.2	-	(60.0)	1.3	228.0	(0.7)	209.2
4.	March	1.4	37.0	-	(60.1)	1.1	159.4	(0.7)	138.1
5.	April	1.4	37.1	-	(59.8)	1.0	137.3	(0.7)	116.3
6.	May	1.4	36.1	-	(59.0)	0.9	192.1	(0.7)	170.8
7.	June	1.4	36.8	-	(56.8)	3.2	264.4	(0.7)	248.3
8.	July	1.3	38.8	-	(55.6)	2.8	363.5	(0.7)	350.1
9.	August	1.3	38.0	-	(54.4)	2.5	440.2	(0.7)	426.9
10.	September	1.3	38.9	-	(53.3)	2.2	509.9	(0.7)	498.3
11.	October	1.3	39.5	-	(52.3)	1.9	570.9	(0.7)	560.6
12.	November	1.3	36.4	-	(51.3)	1.6	549.3	(0.7)	536.6
13.	December	1.3	35.2	-	(50.0)	1.3	472.8	(0.7)	459.9
14.	Avg. of monthly avgs.	1.4	37.7	-	(56.5)	1.7	354.4	(0.7)	338.0

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2016 ACTUAL

Line No.		Col. 1 Disbursements	Col. 2 Net Lag-Days	Col. 3 Allowance
		($Millions)	(Days)	($Millions)
1.	Gas purchase and storage and transportation charges	1,541.3	2.4	10.1
2.	Items not subject to working cash allowance (Note 1)	(44.2)		
3.	Gas costs charged to operations	1,497.1		
4.	Operation and Maintenance	449.7		
5.	Less: Storage costs	(8.4)		
6.	Operation and maintenance costs subject to working cash	441.3		
7.	Ancillary customer services	-		
8.		441.3	(10.9)	(13.2)
9.	Sub-total			(3.1)
10.	Storage costs	8.4	58.4	1.3
11.	Storage municipal and capital taxes	1.4	22.9	0.1
12.	Sub-total			1.4
13.	Harmonized Sales Tax			1.0
14.	Total working cash allowance			(0.7)

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

Witness; R. Small

COMPARISON OF UTILITY CAPITAL EXPENDITURES 2016 ACTUALS VS. 2016 BOARD APPROVED BUDGET

Table 1
Summary of Capital Expenditures 2016 Actual and 2016 Board Approved Budget
($millions)

		Col 1	Col 2	Col 3
Item		Actual 2016	Board Approved Budget 2016	Actual Over/(Under) 2016
A	Customer Related Distribution Plant	153.0	140.8	12.2
B	System Improvements and Upgrades	224.0	242.6	(18.6)
C	General and Other Plant	45.6	48.4	(2.8)
D	Underground Storage Plant	18.2	10.5	7.7
E	**Sub total Core Capital Expenditures**	**440.7**	**442.3**	**(1.6)**
F	Work and Asset Management Solution (WAMS)	38.3	8.1	30.2
G	GTA Reinforcement	114.8	-	114.8
H	**Sub total Core Special Initiatives**	**153.1**	**8.1**	**145.0**
I	**Total Capital Expenditures**	**593.8**	**450.4**	**143.4**

1. The 2016 Actual expenditures for Work and Asset Management (“WAMS”) and GTA projects totaled $153.1 million versusa 2016 Budget of $8.1 million. Some of the variance results from carryover costs from 2015 due to delays experienced with these multi-year initiatives. Both projects were budgeted to be in-service by end of 2015.

2. The 2016 Actual core capital expenditures were $440.7 million, which was $1.6 million less than the 2016 Budget of $442.3 million. Core capital amounts also include overheads (i.e., departmental labour costs, capitalized administrative and general, and interest during construction). Excluding overheads, the 2016 Actual core capital spend was $328.5 million or $6.3 million greater than the 2016 Budget of $322.2 million.

3. Table 2 below shows the major drivers of the $143.4 million overspend vs. Board approved budget and includes high-level commentary. Further details are provided below.

Table 2
Summary of Capital Expenditures 2016 Actual and 2016 Board Approved Budget
($millions)

		Actual Over/(Under)	% tage	Commentary
	Total 2016 Variance	143.4	31.8%	
A	GTA Reinforcement	114.8	N/A	Due to permit & construction challenages
B	Customer Growth	6.7	6.6%	Due to customer mix
C	Storage	6.4	72.2%	Compressor Plant delay
D	Facilities and Genl Plant	7.1	40.9%	Due to Building Improvements and Work Space Alterations
E	Work and Asset Mgt (WAMS)	30.2	372.9%	Longer duration of solution design and increased scope to ensure quality of design
F	Reinforcements	(0.9)	-10.5%	Deferral of Alliston and Harmony Colin projects
G	Overheads - Departmental Labour Costs, AG and IDC	(7.9)	-6.6%	Due to an overall reduction in costs
H	Relocations	1.2	9.9%	Due to large scale infrastructure work
I	Information Technology	(8.9)	-32.3%	IT Infrastructure Consolidation with EI and project delay/deferral
J	Business Development	2.0	52.8%	NGV program deferred from 2015
K	System Integrity and Reliability	(7.3)	-5.2%	Portfolio prioritization via risk based assessments
		143.44	**31.8%**	

A. GTA Reinforcement – Overspent by $114.8 Million

4. The GTA Reinforcement project is a multi-year infrastructure project with Segments A and B. Variance is due to delay of Segment A and B into 2016. The project was delayed several months due to permitting issues and construction complexities. The project total is expected to be $870.3 Million, versus the project budget of $686.5 million.

B. Customer Growth - Overspent by $6.7 Million

5. The cost of adding new customers increased due to higher direct costs related to customer mix and higher unit costs. The cost pressure challenges include increased municipal fees, full year construction and managing geographic sectors. Rising municipal and permitting fees are costs that are beyond the Company’s control. Geographic challenges have a direct impact

on the unit cost of adding new customers. The mix of more expensive replacement customers vs. new construction (subdivision) customers also factor heavily into the cost equation.

C. Storage – Overspent by $6.4 Million

6. The overage is primarily driven by maintenance relating to the degrading compressor foundations. The remaining overage is due to movement from the old building to a new facility and upgrades to Scada.

D. Facilities and General Plant – Overspent by $7.1 Million

7. This variance is primarily due to higher spend in Facilities associated with Building Improvements and Workspace Alterations.

E. Work and Asset Management Solution ("WAMS") – Overspent by $30.2 Million

8. WAMS is a fundamental business tool, foundational to providing safe and reliable service to Enbridge's utility customers. This is a multi-year initiative which began with planning and design in 2014, design, build and test occurred throughout 2015, 2016 and "go live" was implemented in October 2016. Delayed spend in 2014 and 2015 was due to a delay in starting the implementation phase. The overall project spend is $90.1 million, which exceeds the project budget of $70.1 million.

F. Reinforcements – Underspent by $0.9 Million

9. Reinforcements are primarily driven by customer growth and system reliability considerations to meet the anticipated peak hourly demand. The 2016 variance is due to the Alliston Reinforcement project deferral due to specific load additions not realized ($2.1 million) and Harmony / Conlin Reinforcement deferral ($3.7 million). The remaining variance is due to several smaller reinforcement projects.

Witness: S. Fallis

G. Departmental Labour Costs, A&G and IDC – Underspent by $7.9 Million

10. From an overall perspective, these three cost categories were $7.9 Million less than budget. The Company reduced the workforce and delayed filling vacancies as part of its productivity efforts as per its commitment under the Customized IR application. This productivity effort with Departmental Labour Costs accounts for $8.9 million of the underage. Interest during construction (“IDC”) is a function of the timing of actual construction costs. Due to the delay of several projects and a lower interest rate, actual IDC was $2.4 million less than the budget. The variance is partially offset by a $3.4 million overage in capitalized administrative and general (“A&G”).

H. Relocations - Overspent by $1.2 Million

11. Enbridge is required to relocate its infrastructure to accommodate 3rd party construction. The 2016 variance is primarily due to large scale infrastructure work such as York Region Rapid Transit and Metrolinx. The Company works closely with external agencies to establish long range timelines.

I. Information Technology – Underspent by $8.9 Million

12. This variance is due to IT Infrastructure Consolidation with Enbridge Inc., WAMS project delay and CIS Software project deferral rescheduled to 2018/2019.

J. Business Development – Overspent by $2.0 Million

13. The variance in the NGV rental program in 2016 is due to the undertaking of the City of Toronto garbage truck project that was originally scheduled to begin in 2015.

K. <u>System Integrity and Reliability (SIR) – Underspent by $7.3 Million</u>

14. The SIR work was the result of portfolio prioritization using risk based assessments. Mains capital dollars were re-allocated across the portfolio through risk-based assessments and portfolio prioritization. Incremental capital spent on mains replacement and assessment of high risk assets led to an underspend in SIR of $13 million. Services capital dollars were re-allocated to higher risk leaking / poorly performing assets rather than the anticipated proactive programs that were designed to stay ahead of the failure curve which led to an overspend in SIR of ($16 million). Finally, capacity related to Stations projects have been deferred which led to an underspend in SIR of $6.2 million.

UTILITY OPERATING REVENUE (INCLUDING CUSTOMER CARE & CIS)
2016 ACTUAL

		Col. 1	Col. 2	Col. 3
Line No.		Utility Revenue	Normalizing and Other Adjustments	Adjusted Utility Revenue
		($Millions)	($Millions)	($Millions)
1.	Gas sales	2,267.8	44.0	2,311.8
2.	Transportation of gas	314.5	4.7	319.2
3.	Transmission, compression & storage	6.4	-	6.4
4.	Other operating revenue	41.9	-	41.9
5.	Interest and property rental	-	-	-
6.	Other income	1.1	-	1.1
7.	Total operating revenue	2,631.7	48.7	2,680.4

EXPLANATION OF ADJUSTMENTS TO UTILITY REVENUE
2016 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease)	Explanation
	($Millions)	
1.	44.0	Gas sales Adjustment to gas sales revenue required to reflect normal weather.
2.	4.7	Transportation of gas Adjustment to gas transportation revenue required to reflect normal weather.

UTILITY REVENUE (INCLUDING CUSTOMER CARE & CIS)
2016 ACTUAL

Line No.		Col. 1 EGDI Ont. Corporate Revenue	Col. 2 Adjustment	Col. 3 Utility Revenue
		($Millions)	($Millions)	($Millions)
1.	Residential	1,666.5	(139.5)	1,527.0
2.	Commercial	639.7	-	639.7
3.	Industrial	71.0	-	71.0
4.	Wholesale	30.1	-	30.1
5.	Gas sales	2,407.3	(139.5)	2,267.8
6.	Transportation of gas	314.5	-	314.5
7.	Transmission, compression & storage	6.4	-	6.4
8.	Service charges & DPAC	13.0	-	13.0
9.	Rent from NGV rentals	0.5	-	0.5
10.	Late payment penalties	10.4	-	10.4
11.	Transactional services	14.0	(2.0)	12.0
12.	Open bill revenue	7.8	(2.4)	5.4
13.	Dow Moore recovery	0.6	-	0.6
14.	Affiliate asset use revenue	-	-	-
15.	ABC T-service (net)	1.5	(1.5)	-
16.	Other operating revenue	47.8	(5.9)	41.9
17.	Income from investments	2.9	(2.9)	-
18.	Interest during construction	14.1	(14.1)	-
19.	Interest income from affiliates	-	-	-
20.	Interest on (net) deferral accounts	1.5	(1.5)	-
21.	Property/asset use revenue 3rd party	0.8	(0.8)	-
22.	Interest and property rental	19.3	(19.3)	-
23.	Miscellaneous	20.1	(20.0)	0.1
24.	Dividend income	62.7	(62.7)	-
25.	Profit on sale of property/assets	1.0	-	1.0
26.	NGV merchandising revenue (net)	-	-	-
27.	Other income	83.8	(82.7)	1.1
28.	Total revenue	2,879.1	(247.4)	2,631.7

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2016 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
1.	(139.5)	Residential gas sales	
		US GAAP adjustment elimination, deferral & variance clearance recognition.	
11.	(2.0)	Transactional services	
		To eliminate transactional services revenues above the base amount included in rates. Ratepayer and shareholder amounts above the base are treated outside of utility results and returns.	
12.	(2.4)	Open bill revenue	
		To adjust OBA costs to reflect the EB-2013-0099 approved unit costs agreed to be used for determining net revenues.	(1.1)
		To eliminate the Open Bill shareholder incentive.	(1.2)
			(2.4)
15.	(1.5)	ABC T-Service (net)	

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2016 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
17.	(2.9)	Income from investments	
		To eliminate interest income from investments not included in Utility rate base.	
18.	(14.1)	Interest during construction	
		To eliminate interest calculated on funds used for purposes of construction during the year.	
20.	(1.5)	Interest on (net) deferral accounts	
		To eliminate interest income from assets not included in Utility rate base.	
21.	(0.8)	Property/asset use revenue 3rd party	
		To eliminate asset use revenue (RP-2002-0133) and rental revenue from Tecumseh farm properties considered to be non-utility. (EBRO 464 & 365)	
23.	(20.0)	Miscellaneous	
		To eliminate net revenue from the Company's oil & gas and unregulated storage divisions.	(8.6)
		To eliminate the revenue indemnification received from Enbridge Inc. related to a non-utility Corporate tax planning Part V1.1 tax transfer to EGD.	(5.3)
		To eliminate the shareholders' incentive income recorded as a result of calculating the 2015 DSMIDA amount.	(6.1)
			(20.0)
24.	(62.7)	Dividend income	
		To eliminate non-utility inter-company dividend income from the financing transaction (EBO 179-16).	

Witness: R. Small

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2016 ACTUAL AND 2016 BOARD APPROVED BUDGET
($10^6 m^3$)

Item No.		Col. 1 2016 Actual	Col. 2 2016 Board Approved Budget	Col. 3 2016 Actual Over (Under) 2016 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	4 214.9	4 510.5	(295.6)
1.1.2	Rate 1 - T-Service	291.8	358.8	(67.0)
1.1	Total Rate 1	4 506.7	4 869.3	(362.6)
1.2.1	Rate 6 - Sales	2 583.6	3 104.9	(521.3)
1.2.2	Rate 6 - T-Service	1 905.0	1 690.1	214.9
1.2	Total Rate 6	4 488.6	4 795.0	(306.4)
1.3.1	Rate 9 - Sales	0.2	0.5	(0.3)
1.3.2	Rate 9 - T-Service	0.0	0.1	(0.1)
1.3	Total Rate 9	0.2	0.6	(0.4)
1.	Total General Service Sales & T-Service	8 995.5	9 664.9	(669.4)
Contract Sales				
2.1	Rate 100	1.5	0.0	1.5
2.2	Rate 110	47.9	81.3	(33.4)
2.3	Rate 115	0.0	0.0	0.0
2.4	Rate 135	1.2	3.8	(2.6)
2.5	Rate 145	8.2	11.2	(3.0)
2.6	Rate 170	32.6	34.1	(1.5)
2.7	Rate 200	169.6	170.8	(1.2)
2.	Total Contract Sales	261.0	301.2	(40.2)
Contract T-Service				
3.1	Rate 100	1.7	0.0	1.7
3.2	Rate 110	779.7	622.1	157.6
3.3	Rate 115	497.6	517.1	(19.5)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	63.4	55.5	7.9
3.6	Rate 145	37.5	77.3	(39.8)
3.7	Rate 170	269.6	291.6	(22.0)
3.8	Rate 300	21.1	35.0	(13.9)
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 670.6	1 598.6	72.0
4.	Total Contract Sales & T-Service	1 931.6	1 899.8	31.8
5.	Total	10 927.1	11 564.7	(637.6)

* There is no distribution volume for Rate 125 customers.

Witnesses: R. Cheung
J. Shem

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2016 ACTUAL AND 2016 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2016 Actual	Col. 2 2016 Board Approved Budget	Col. 3 2016 Actual Over (Under) 2016 Budget (1-2)	Col. 4 2016* Adjustments	Col. 5 2016 Actual Over (Under) 2016 Budget with Adjustments (3+4)
General Service						
1.1.1	Rate 1 - Sales	4 214.9	4 510.5	(295.6)	184.7	(110.9)
1.1.2	Rate 1 - T-Service	291.8	358.8	(67.0)	13.0	(54.0)
1.1	Total Rate 1	4 506.7	4 869.3	(362.6)	197.7	(164.9)
1.2.1	Rate 6 - Sales	2 583.6	3 104.9	(521.3)	112.1	(409.2)
1.2.2	Rate 6 - T-Service	1 905.0	1 690.1	214.9	68.8	283.7
1.2	Total Rate 6	4 488.6	4 795.0	(306.4)	180.9	(125.5)
1.3.1	Rate 9 - Sales	0.2	0.5	(0.3)	0.0	(0.3)
1.3.2	Rate 9 - T-Service	0.0	0.1	(0.1)	0.0	(0.1)
1.3	Total Rate 9	0.2	0.6	(0.4)	0.0	(0.4)
1.	Total General Service Sales & T-Service	8 995.5	9 664.9	(669.4)	378.6	(290.8)
Contract Sales						
2.1	Rate 100	1.5	0.0	1.5	0.0	1.5
2.2	Rate 110	47.9	81.3	(33.4)	0.1	(33.3)
2.3	Rate 115	0.0	0.0	0.0	0.0	0.0
2.4	Rate 135	1.2	3.8	(2.6)	0.0	(2.6)
2.5	Rate 145	8.2	11.2	(3.0)	0.4	(2.6)
2.6	Rate 170	32.6	34.1	(1.5)	2.6	1.1
2.7	Rate 200	169.6	170.8	(1.2)	(1.0)	(2.2)
2.	Total Contract Sales	261.0	301.2	(40.2)	2.1	(38.1)
Contract T-Service						
3.1	Rate 100	1.7	0.0	1.7	0.0	1.7
3.2	Rate 110	779.7	622.1	157.6	0.8	158.4
3.3	Rate 115	497.6	517.1	(19.5)	0.1	(19.4)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	63.4	55.5	7.9	0.0	7.9
3.6	Rate 145	37.5	77.3	(39.8)	0.2	(39.6)
3.7	Rate 170	269.6	291.6	(22.0)	0.3	(21.7)
3.8	Rate 300	21.1	35.0	(13.9)	0.0	(13.9)
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 670.6	1 598.6	72.0	1.4	73.4
4.	Total Contract Sales & T-Service	1 931.6	1 899.8	31.8	3.5	35.3
5.	Total	10 927.1	11 564.7	(637.6)	382.1	(255.5)

*Note: Weather normalization adjustments have been made to the 2016 Actual utilizing the 2016 Board Approved Budget Degree Days .

** Less than 50,000 m^3

Witnesses: R. Cheung
J. Shem

The principal reasons for the variances contributing to the weather normalized decrease of 255.5 10^6m^3 in the 2016 Actual over the 2016 Board Approved Budget are as follows:

1. The volumetric decrease of 164.9 10^6m^3 in Rate 1 was due to a lower average use per customer totalling 154.8 10^6m^3 and unfavourable customer variance of 10.1 10^6m^3;

2. The volumetric decrease of 125.5 10^6m^3 in Rate 6 was primarily due to a lower average use per customer totaling 91.2 10^6m^3;and unfavourable customer variance of 34.9 10^6m^3;

3. The volumetric decrease of 0.4 10^6m^3 in Rate 9 was due to a lower average use per station;

4. The volumetric increase for Contract Sales and T-Service of 35.3 10^6m^3 was due to increase in the apartment sector of 2.3 10^6m^3 and industrial sector of 185.1 10^6m^3; partially offset by the decrease in commercial sector of 149.8 10^6m^3 and Rate 200 of 2.2 10^6m^3 .

COMPARISON OF GAS SALES AND
TRANSPORTATION REVENUE BY RATE CLASS
2016 HISTORICAL YEAR AND 2016 BOARD APPROVED BUDGET
($ MILLIONS)

Item No.		Col. 1 2016 Actual	Col. 2 2016 Board Approved Budget	Col. 3 2016 Actual Over (Under) 2016 Budget (1-2)	Col. 4 2016* Adjustments	Col. 5 2016 Actual Over (Under) 2016 Budget with Adjustments (3+4)
General Service						
1.1.1	Rate 1 - Sales	1 465.3	1 663.9	(198.6)	45.3	(153.3)
1.1.2	Rate 1 - T-Service	76.0	74.6	1.4	1.4	2.8
1.1	Total Rate 1	1 541.3	1 738.5	(197.2)	46.7	(150.5)
1.2.1	Rate 6 - Sales	693.9	898.7	(204.8)	28.6	(176.2)
1.2.2	Rate 6 - T-Service	182.7	150.9	31.8	6.9	38.7
1.2	Total Rate 6	876.6	1 049.6	(173.0)	35.5	(137.5)
1.3.1	Rate 9 - Sales	0.1	0.1	0.0 **	0.0	0.0 **
1.3.2	Rate 9 - T-Service	0.0 **	0.0 **	0.0 **	0.0	0.0 **
1.3	Total Rate 9	0.1	0.1	0.0	0.0	0.0
1.	Total General Service Sales & T-Service	2 418.0	2 788.2	(370.2)	82.2	(288.0)
Contract Sales						
2.1	Rate 100	0.3	0.0	0.3	0.0	0.3
2.2	Rate 110	9.1	17.0	(7.9)	0.0 **	(7.9)
2.3	Rate 115	0.0	0.0	0.0	0.0	0.0
2.4	Rate 135	0.2	0.7	(0.5)	0.0	(0.5)
2.5	Rate 145	1.6	2.3	(0.7)	0.0 **	(0.7)
2.6	Rate 170	5.2	6.2	(1.0)	0.1	(0.9)
2.7	Rate 200	28.3	31.9	(3.6)	(0.1)	(3.7)
2.	Total Contract Sales	44.7	58.1	(13.4)	0.0	(13.4)
Contract T-Service						
3.1	Rate 100	0.2	0.0	0.2	0.0	0.2
3.2	Rate 110	35.5	26.9	8.6	0.0 **	8.6
3.3	Rate 115	7.9	8.5	(0.6)	0.0 **	(0.6)
3.4	Rate 125	11.0	10.9	0.1	0.0	0.1
3.5	Rate 135	3.3	2.3	1.0	0.0	1.0
3.6	Rate 145	1.8	2.7	(0.9)	0.0 **	(0.9)
3.7	Rate 170	7.5	3.7	3.8	0.0 **	3.8
3.8	Rate 300	0.1	0.2	(0.1)	0.0	(0.1)
3.9	Rate 315	0.4	0.0	0.4	0.0	0.4
3.	Total Contract T-Service	67.7	55.2	12.5	0.0	12.5
4.	Total Contract Sales & T-Service	112.4	113.3	(0.9)	0.0	(0.9)
5.	Total	2 530.4	2 901.5	(371.1)	82.2	(288.9)

* Note: Weather normalization adjustments have been made to the 2016 Actuals utilizing the 2016 Board Approved Budget degree days. Please refer to Exhibit B, Tab 3, Schedule 2, Page 2, for the corresponding volumetric adjustments.

** Less than $50,000

1. Gas sales and transportation of gas revenues for the 2015 Test Year Budget were developed on the basis of EB-2015-0114 rates.

2. The principal reasons for the variance contributing to the decrease of $371.1 million in the 2016 Actual compared to the 2016 Budget are as follows:

3. <u>Gas Sales - decrease of $416.8 Million</u>

   The decrease in gas sales revenue was mainly due to lower volume than budgeted and lower actual commodity charges than budgeted

   Details on volumes are at Exhibit B, Tab 3, Schedule 2, Pages 1-3.

4. <u>Transportation of Gas - Increase of $45.7 Million</u>

   The increase in T-service revenue was mainly due to higher T-service volume than budgeted

   Details on volumes are at Exhibit B, Tab 3, Schedule 2, Pages 1-3.

CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
2016 ACTUAL

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)	Col. 3 Revenues ($Millions)	
General Service					
1.1.1	Rate 1 - Sales	1 835 998	4 214.9	1 465.3	
1.1.2	Rate 1 - T-Service	123 571	291.8	76.0	
1.1	Total Rate 1	1 959 569	4 506.7	1 541.3	
1.2.1	Rate 6 - Sales	140 094	2 583.6	693.9	
1.2.2	Rate 6 - T-Service	24 598	1 905.0	182.7	
1.2	Total Rate 6	164 692	4 488.6	876.6	
1.3.1	Rate 9 - Sales	6	0.2	0.1	
1.3.2	Rate 9 - T-Service	0	0.0	0.0	**
1.3	Total Rate 9	6	0.2	0.1	
1.	Total General Service Sales & T-Service	2 124 267	8 995.5	2 418.0	
Contract Sales					
2.1	Rate 100	0	1.5	0.3	
2.2	Rate 110	40	47.9	9.1	
2.3	Rate 115	0	0.0	0.0	
2.4	Rate 135	1	1.2	0.2	
2.5	Rate 145	5	8.2	1.6	
2.6	Rate 170	4	32.6	5.2	
2.7	Rate 200	1	169.6	28.3	
2.	Total Contract Sales	51	261.0	44.7	
Contract T-Service					
3.1	Rate 100	2	1.7	0.2	
3.2	Rate 110	229	779.7	35.5	
3.3	Rate 115	27	497.6	7.9	
3.4	Rate 125	5	0.0 *	11.0	
3.5	Rate 135	44	63.4	3.3	
3.6	Rate 145	33	37.5	1.8	
3.7	Rate 170	21	269.6	7.5	
3.8	Rate 300	2	21.1	0.1	
3.9	Rate 315	2	0.0	0.4	
3.	Total Contract T-Service	365	1 670.6	67.7	
4.	Total Contract Sales & T-Service	416	1 931.6	112.4	
5.	Total	2 124 683	10 927.1	2 530.4	

* There is no distribution volume for Rate 125 customers.

** Less than $50,000.

Witness: R. Cheung

DETAILS OF OTHER REVENUE AND OTHER INCOME
2016 ACTUAL AND 2016 BOARD APPROVED

		Col. 1	Col. 2	Col. 3
Item No.		2016 Actual ($Millions)	2016 Board Approved Budget ($Millions)	2016 Actual Over/(Under) 2016 Board Approved ($Millions)
1.1	Service Charges & DPAC	13.0	12.3	0.7
1.2	Rental Revenue - NGV Program	0.5	1.1	(0.6)
1.3	Late Payment Penalties	10.4	10.1	0.3
1.4	Dow Moore Recovery	0.6	0.3	0.3
1.5	Transactional Services (net)	12.0	12.0	-
1.6	Miscellaneous and Other Income	1.1	1.6	(0.5) *
1.7	Open Bill Revenue	5.4	5.4	-
1.8	Total Other Revenue	43.0	42.8	0.2

Notes:
* Including Gain on sale of land in 2016 actual and $1.5M budget adjustment from EB-2012-0459.

Witness: A. Hui

COST OF SERVICE (INCLUDING CUSTOMER CARE & CIS)
2016 ACTUAL

Line No.		Col. 1 Utility Costs and Expenses	Col. 2 Normalizing and Other Adjustments	Col. 3 Adjusted Utility Costs and Expenses
		($Millions)	($Millions)	($Millions)
1.	Gas costs	1,466.7	30.4	1,497.1
2.	Operation and maintenance (incl. CC/CIS rate smoothing adj.)	449.7	-	449.7
3.	Depreciation and amortization expense	292.7	-	292.7
4.	Fixed financing costs	3.2	-	3.2
5.	Municipal and other taxes	43.1	-	43.1
6.	Operating costs	2,255.4	30.4	2,285.8
7.	Income tax expense			17.3
8.	Cost of service			2,303.1

Witness: R. Small

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS
2016 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease)	Explanation
	($Millions)	
1.	30.4	Gas costs
		Adjustment required to gas costs to reflect normal weather.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2016 ACTUAL

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	394.6	394.6	
	Add			
2.	Depreciation and amortization	292.7	292.7	
3.	Accrual based pension and OPEB costs	34.6	34.6	
4.	Other non-deductible items	1.4	1.4	
5.	Total Add Back	328.7	328.7	
6.	Sub-total	723.3	723.3	
	Deduct			
7.	Capital cost allowance	313.9	313.9	
8.	Items capitalized for regulatory purposes	71.9	71.9	
9.	Deduction for "grossed up" Part VI.1 tax	3.0	3.0	
10.	Amortization of share/debenture issue expense	5.8	5.8	
11.	Amortization of cumulative eligible capital	3.0	3.0	
12.	Amortization of C.D.E. and C.O.G.P.E	0.2	0.2	
13.	Site Rest Costs adjustment	83.9	83.9	
14.	Cash based pension and OPEB costs	4.7	4.7	
15.	50% of capital gain on sale of assets	0.5	0.5	
16.	Total Deduction	486.9	486.9	
17.	Taxable income	236.4	236.4	
18.	Income tax rates	15.00%	11.50%	
19.	Provision	35.5	27.2	62.7
20.	Part VI.1 tax			0.9
21.	Total taxes excluding interest shield			63.6
	Tax shield on interest expense			
22.	Rate base	5,909.0		
23.	Return component of debt	2.96%		
24.	Interest expense	174.7		
25.	Combined tax rate	26.500%		
26.	Income tax credit			(46.3)
27.	Total utility income taxes			17.3

Witness: R. Small

COST OF SERVICE (INCLUDING CUSTOMER CARE & CIS)
2016 ACTUAL

Line No.		Col. 1 EGDI Ont. Corporate Costs and Expenses ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Costs and Expenses ($Millions)
1.	Gas costs	1,602.3	(135.6)	1,466.7
2.	Operation and maintenance (incl. CC/CIS rate smoothing adj.)	460.5	(10.8)	449.7
3.	Depreciation	293.6	(0.9)	292.7
4.	Amortization	22.5	(22.5)	-
5.	Depreciation and amortization	316.1	(23.4)	292.7
6.	Fixed financing costs	3.2	-	3.2
7.	Municipal and other taxes	43.3	(0.2)	43.1
8.	Capital taxes	-	-	-
9.	Municipal and other taxes	43.3	(0.2)	43.1
10.	Interest on long-term debt	175.7	(175.7)	-
11.	Amortization of preference share issue costs and debt discount and expense	5.7	(5.7)	-
				-
12.	Interest and financing amortization	181.4	(181.4)	-
13.	Interest on short-term debt	9.0	(9.0)	-
14.	Interest due affiliates	26.8	(26.8)	-
				-
15.	Other interest expense	35.8	(35.8)	-
16.	Total operating costs	2,642.6	(387.2)	2,255.4
17.	Current taxes	32.4	(32.4)	-
18.	Deferred taxes	(24.1)	24.1	-
19.	Income tax expense	8.3	(8.3)	-
20.	Cost of service	2,650.9	(395.5)	2,255.4

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2016 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
1	(135.6)	Gas costs	
		US GAAP adjustment elimination, deferral & variance clearance recognition.	
2.	(10.8)	Operation and maintenance expense	
		Interest paid on security deposits held during the year and included in the elimination of interest expense. The expense is incurred to reduce bad debts. The average amount of the security deposits held during the year is applied as a reduction to the allowance for working capital in rate base.	0.6
		To eliminate donations (EBRO 490).	(0.9)
		To eliminate non-utility costs and expenses relating to the support of the ABC T-service program.	(0.8)
		US GAAP adjustment elimination, deferral & variance clearance recognition.	(3.9)
		To eliminate Corporate Cost allocations above RCAM amount.	(2.6)
		To eliminate earnings sharing recorded in the financial statements	(3.2)
			(10.8)
3.	(0.9)	Depreciation expense	
		Removal of depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479).	(0.1)
		Removal of depreciation related to shared assets (RP-2002-0133).	(0.8)
			(0.9)
4.	(22.5)	Amortization expense	
		To eliminate the amortization of PPD.	
7.	(0.2)	Municipal and other taxes	
		Removal of municipal taxes related to shared assets (RP-2002-0133).	

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2016 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
10.	(175.7)	Interest on long-term debt Expense of capital.
11.	(0.7)	Amortization of preference share issue costs and debt discount and expense Expense of capital.
13.	(14.0)	Interest on short-term debt Expense of capital.
14.	(26.8)	Interest due affiliates To eliminate non-utility inter-company interest expense from the financing transaction (EBO 179-16).
17.	(32.4)	Income taxes - current Income tax expense related to corporate earnings.
18.	24.1	Income taxes - deferred Income tax expense related to corporate earnings.

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2016 ACTUAL

Capital Cost Allowance - Federal

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2016	UCC Carry Forward
1	1,647,857,868	-	-	-	4.00%	(65,914,315)	1,581,943,553
51	2,013,965,195	1,139,268,571	-	569,634,286	6.00%	(155,015,969)	2,998,217,797
2	98,491,322	-	-	-	6.00%	(5,909,479)	92,581,843
6	9,950	-	-	-	10.00%	(995)	8,955
8	9,025,525	13,071,097	-	6,535,549	20.00%	(3,112,215)	18,984,407
10	25,021,951	4,391,069	-	2,195,535	30.00%	(8,165,246)	21,247,774
12	5,565,757	106,565,766	-	53,282,883	100.00%	(28,848,640)	53,282,883
17	25,218	-	-	-	8.00%	(2,017)	23,201
38	5,313,839	-	-	-	30.00%	(1,594,152)	3,719,687
41	25,724,943	30,482,233	-	15,241,117	25.00%	(10,241,515)	45,965,661
13	994,190	-	-	-	-	(249,000)	745,190
3	202,957	-	-	-	5.00%	(10,148)	192,809
45	81,482	-	-	-	45.00%	(36,667)	44,815
50	5,695,071	9,203,126	-	4,601,563	55.00%	(5,663,149)	9,235,048
Total	3,837,975,268	1,302,981,862	-	141,853,377		(314,763,506)	4,826,193,624

Non-utility and shared asset eliminations	875,385
Utility Federal CCA	(313,888,121)

Capital Cost Allowance - Ontario

Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2016	UCC Carry Forward
1	1,647,857,868	-	-	-	4.00%	(65,914,315)	1,581,943,553
51	2,013,965,195	1,139,268,571	-	569,634,286	6.00%	(155,015,969)	2,998,217,797
2	98,491,322	-	-	-	6.00%	(5,909,479)	92,581,843
6	9,950	-	-	-	10.00%	(995)	8,955
8	9,025,525	13,071,097	-	6,535,549	20.00%	(3,112,215)	18,984,407
10	25,021,951	4,391,069	-	2,195,535	30.00%	(8,165,246)	21,247,774
12	5,565,757	106,565,766	-	53,282,883	100.00%	(28,848,640)	53,282,883
17	25,218	-	-	-	8.00%	(2,017)	23,201
38	5,313,839	-	-	-	30.00%	(1,594,152)	3,719,687
41	25,724,943	30,482,233	-	15,241,117	25.00%	(10,241,515)	45,965,661
13	994,190	-	-	-	-	(249,000)	745,190
3	202,957	-	-	-	5.00%	(10,148)	192,809
45	81,482	-	-	-	45.00%	(36,667)	44,815
50	5,695,071	9,203,126	-	4,601,563	55.00%	(5,663,149)	9,235,048
Total	3,837,975,268	1,302,981,862	-	141,853,377		(314,763,506)	4,826,193,624

Non-utility and shared asset eliminations	375,385
Utility Provincial CCA and UCC	(314,388,121)

2016 UTILITY O&M

Line No.	Particulars (in millions)	Actuals 2016	IR 2016	Actual Under/(Over)
1	Total Compensation	251.7	228.0	(23.6)
2	Employee Training and Development	5.5	4.8	(0.7)
3	Materials and Supplies	5.0	5.3	0.4
4	Outside Services	83.3	91.2	7.8
5	Consulting	2.1	5.2	3.1
6	Repairs and Maintenance	1.4	2.4	1.1
7	Fleet	7.1	10.7	3.6
8	Rents and Leases	5.8	7.8	2.1
9	Telecommunications	0.0	3.9	3.9
10	Travel and Other Business Expenses	1.9	5.1	3.2
11	Memberships	4.8	5.2	0.4
12	Claims, Damages and Legal Fees	(0.1)	1.0	1.0
13	Interest on Security Deposits	0.6	2.5	1.9
14	Provision for Uncollectibles	7.1	9.5	2.4
15	Natural Gas Vehicles (NGV)	0.7	0.0	(0.7)
16	Legal Fees	1.5	2.9	1.4
17	Audit Fees	1.9	1.7	(0.2)
18	Other	0.1	(3.4)	(3.5)
19	Internal Allocations and Recoveries	(20.4)	(30.1)	(9.7)
20	Capitalization (A&G)	(44.0)	(37.1)	6.9
21	Capitalization	(89.1)	(80.7)	8.5
22	Regulatory Eliminations	(2.7)	(3.3)	(0.6)
23	Other O&M Subtotal	$ 224.0	$ 232.6	$ 8.6
24	Customer Care/CIS Service Charges	85.6	100.0	14.4
25	Pensions and OPEB	34.6	34.6	0.0
26	RCAM	49.1	33.8	(15.3)
27	Demand Side Management Programs (DSM)	56.4	56.4	0.0
28	Conservation Services	-	-	0.0
29	Total Net Utility O&M Expense before Eliminations	$ 449.7	$ 457.4	$ 7.7

Witnesses: D. Gagnon
N. Verma
J. Yiu

EXPLANATION OF MAJOR CHANGES
ACTUAL 2016 O&M EXPENSES COMPARED TO OEB APPROVED 2016 O&M EXPENSES

The 2016 Actual Utility O&M was $449.7 million, which was $7.7 million lower than the 2016 OEB approved Utility O&M. The decrease was driven by the following areas:

Line No:

1	Increase in Total Compensation mainly due to severance and STIP partially offset by fewer FTEs from labour reductions.
4	Decrease in Outside Services mainly due to lower in-line inspection activity, savings in IT software and hardware maintenance, savings in Locates due to lower volumes and reduced building maintenance costs for the new Tecumseh building
5	Decrease in Consulting mainly due to lower vendor cost and other cost management initiatives.
7	Decrease in Fleet due to lower maintenance and refurbishing costs as a result of replacing vehicles.
8	Decrease in Rents and Leases due to the purchase of previously leased sites.
9	Decrease in Telecommunications due to the centralization of telecommunication costs under Enbridge Inc.
10	Decrease in Travel and Other Business Expenses due to saving initiatives.
13	Interest on Security Deposits decreased by $1.9M from having lower security deposits as a result of higher refunding of the excess deposits over $250 as per a new policy effective 2014. This reduced aging on AR balances resulting in less security deposits required, and a higher number of customers on Pre-Authorized Payments (PAP) which does not require a security deposit
14	Decrease in Provision for Uncollectibles due to continued improvements in collections.
18	Primarily due to $8.4M reduction to IR budget based on OEB decision.
19	Decrease mainly due to lower recoveries from shared service costs which have been centralized under Enbridge Inc.
20	Capitalization (Admin and General) increased $6.9M due to higher HR related costs (i.e. STIP and Benefits), and support costs related to the GTA project.
21	Higher capitalization primarily due to the nature of work attributable to higher Capital centric cost centres, and creation of the Asset Management group which is primarily Capital
24	Customer Care is $14.4M lower due to reduced CIS support costs, better collections, postage savings from higher number of customers on e-bill, and system improvements reducing manual work
26	RCAM is $15.3M higher due to the centralization of IT and HR services to Enbridge Inc.

Witnesses: D. Gagnon
N. Verma
J. Yiu

REVENUE SUFFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN (INCLUDING CUSTOMER CARE & CIS)
2016 ACTUAL

Line No.		Col. 1 Principal	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component	Col. 5 (col 1x col 3) Interest & pref share Expense
		($Millions)	%	%	%	
1.	Long and Medium-Term Debt	3,472.8	58.77	4.95	2.909	171.9
2.	Short-Term Debt	209.0	3.54	1.33	0.047	2.8
3.		3,681.8	62.31		2.956	
4.	Preference Shares	100.0	1.69	2.16	0.037	2.2
						176.8
5.	Common Equity	2,127.2	36.00	9.19	3.308	
6.		5,909.0	100.00		6.301	
7.	Rate Base	($Millions)			5,909.0	
8.	Utility Income	($Millions)			377.3	
9.	Indicated Rate of Return				6.385	
10.	Sufficiency in Rate of Return				0.084	
11.	Net Sufficiency	($Millions)			5.0	
12.	Gross Sufficiency	($Millions)			6.8	
13.	Revenue at Existing Rates	($Millions)			2,637.4	
14.	Allowed Revenue	($Millions)			2,630.6	
15.	Gross Revenue Sufficiency	($Millions)			6.8	
	Common Equity					
16.	Allowed Rate of Return				9.190	
17.	Earnings on Common Equity				9.422	
18.	Sufficiency in Common Equity Return				0.232	

Witness: R. Small

UTILITY INCOME (INCLUDING CUSTOMER CARE & CIS)
2016 ACTUAL

Line No.		Col. 1 Utility Income Incl. CIS & Customer Care
		($Millions)
1.	Gas sales	2,311.8
2.	Transportation of gas	319.2
3.	Transmission, compression and storage revenue	6.4
4.	Other operating revenue	41.9
5.	Interest and property rental	-
6.	Other income	1.1
7.	Total operating revenue (Ex. B-3-1-pg.1)	2,680.4
8.	Gas costs	1,497.1
9.	Operation and maintenance (incl. CC/CIS rate smoothing adj.)	449.7
10.	Depreciation and amortization expense	292.7
11.	Fixed financing costs	3.2
12.	Municipal and other taxes	43.1
13.	Interest and financing amortization expense	-
14.	Other interest expense	-
15.	Cost of service (Ex. B-4-1-pg.1)	2,285.8
16.	Utility income before income taxes	394.6
17.	Income tax expense (Ex. B-4-1-pg.3)	17.3
18.	Utility income	377.3

CALCULATION OF COST RATES
FOR CAPITAL STRUCTURE COMPONENTS
2016 ACTUAL

Line No.		Col. 1 Average of Monthly Averages	Col. 2	Col. 3 Carrying Cost
		($Millions)		($Millions)
	Long and Medium-Term Debt			
1.	Debt Summary	3,492.5		172.9
2.	Unamortized Finance Costs	(19.7)		-
3.	(Profit)/Loss on Redemption	-		-
4.		3,472.8		172.9
5.	Calculated Cost Rate		4.95%	
	Short-Term Debt			
6.	Calculated Cost Rate		1.33%	
	Preference Shares			
7.	Preference Share Summary	100.0		2.2
8.	Unamortized Finance Costs	-		-
9.	(Profit)/Loss on Redemption	-		-
10.		100.0		2.2
11.	Calculated Cost Rate		2.16%	
	Common Equity			
12.	Board Formula ROE		9.19%	

SUMMARY STATEMENT OF PRINCIPAL
AND CARRYING COST OF
TERM DEBT
2016 ACTUAL

Line No.	Coupon Rate	Maturity Date	Col. 1 Average of Monthly Averages Principal ($Millions)	Col. 2 Effective Cost Rate	Col. 3 Carrying Cost ($Millions)
Medium Term Notes					
1.	8.85%	October 2, 2025	20.0	8.970%	1.8
2.	7.60%	October 29, 2026	100.0	8.086%	8.1
3.	6.65%	November 3, 2027	100.0	6.711%	6.7
4.	6.10%	May 19, 2028	100.0	6.161%	6.2
5.	6.05%	July 5, 2023	100.0	6.383%	6.4
6.	6.90%	November 15, 2032	150.0	6.950%	10.4
7.	6.16%	December 16, 2033	150.0	6.180%	9.3
8.	5.21%	February 25, 2036	300.0	5.183%	15.5
9.	4.77%	December 17, 2021	175.0	5.310%	9.3
10.	5.16%	December 4, 2017	200.0	5.220%	10.4
11.	4.04%	November 23, 2020	200.0	5.209%	10.4
12.	4.95%	November 22, 2050	200.0	4.990%	10.0
13.	4.95%	November 22, 2050	100.0	4.731%	4.7
14.	4.04%	November 23, 2020	200.0	2.801%	5.6
15.	4.50%	November 23, 2043	200.0	4.198%	8.4
16.	1.85%	April 24, 2017	-	1.967%	- [1]
17.	3.15%	August 22, 2024	215.0	3.241%	7.0
18.	4.00%	August 22, 2044	215.0	3.889%	8.4
19.	4.00%	August 22, 2044	170.0	4.436%	7.5
20.	3.31%	September 11, 2025	400.0	3.619%	14.5
21.	2.50%	August 5, 2026	112.5	3.423%	3.9
22.			3,407.5		164.5
Long-Term Debentures					
23.	9.85%	December 2, 2024	85.0	9.910%	8.4
24.			85.0		8.4
25.	Total Term Debt		3,492.5		172.9

Notes:

1. Enbridge's April 2014 issuance of a $300 million three-year note has been removed from the calculation of long and medium-term debt costs, and has been re-categorized to short-term debt in a manner consistent with the treatment approved within the Settlement Agreement in Enbridge's 2015 Rate Adjustment proceeding, EB-2014-0276.

UNAMORTIZED DEBT DISCOUNT AND EXPENSE
AVERAGE OF MONTHLY AVERAGES
2016 ACTUAL

Line No.		Col. 1 Unamortized Debt Discount and Expense
		($Millions)
1.	January 1	11.4
2.	January 31	11.2
3.	February	11.1
4.	March	11.0
5.	April	10.8
6.	May	10.7
7.	June	10.6
8.	July	10.4
9.	August	34.9
10.	September	34.7
11.	October	34.4
12.	November	34.1
13.	December	33.7
14.	Average of Monthly Averages	19.7

DEFERRAL & VARIANCE ACCOUNTS
<u>REQUESTED FOR CLEARANCE OCTOBER 1, 2017</u>

1. The Company requests approval for clearance of the Deferral and Variance Account balances shown in the Table on page 3, Columns 3 and 4 of this Exhibit, commencing October 1, 2017. The balances requested for clearance total approximately $42.2 million, which is the combination of principal and interest amounts shown in Columns 3 and 4.

2. Included within the accounts requested for clearance are the 2015 DSM related deferral account balances (2015 DSMVA, LRAM, and DSMIDA) which are currently under review as part of the Board's review of the 2015 DSM results. While the Company proposes clearing these accounts in conjunction with the account balances approved as part of this proceeding, which assists in minimizing the number of occasions of deferral and variance account balance clearances, the actual timing and 2015 DSM related account balances to be cleared will be approved by the Board as part of its review process. The 2016 DSM related accounts are anticipated to be cleared at a later date, as will be determined through the Board's review of 2016 DSM results.

3. Within the remainder of the Exhibit C, Tab 1 evidence, Enbridge has provided explanatory information for each of the accounts for which clearance is sought.

4. The interest on the principal balances in the Deferral and Variance Accounts has been calculated using the Board's prescribed interest rates for deferral and variance accounts, including the April 1, 2017 prescribed rate. The eventual interest amounts to be cleared will be calculated using any updated Board prescribed quarterly interest rate that becomes effective before the approved date of clearance. Note

Witness: R. Small

that the Customer Care CIS Rate Smoothing Deferral Account ("CCCISRSDA") interest has been calculated using a fixed rate of 1.47%, as stipulated in the EB-2011-0226 CC / CIS Settlement Agreement.

5. The Company notes that at this time it is not requesting clearance of the balances which were recorded within the 2016 Manufactured Gas Plant Deferral Account ("MGPDA"), or the 2016 Constant Dollar Net Salvage Adjustment Deferral Account ("CDNSADA").

6. The December 31, 2016 MGPDA principal and interest balances were transferred to corresponding 2017 accounts in accordance with the 2017 account descriptions approved within EB-2016-0215. Clearance of amounts recorded in the MGPDA will be requested in a future proceeding.

7. The December 31, 2016 CDNSADA principal balance was transferred to the corresponding 2017 account in accordance with the account scope and methodology that was approved within EB-2012-0459, and as further documented within the 2017 account description approved within EB-2016-0215.

8. In EB-2012-0459, the Board approved a total refund to ratepayers of $379.8 million in net salvage reserve funds related to the adoption of the Constant Dollar Net Salvage ("CDNS") approach. It was expected that all refunds to ratepayers (to be effected through Rider D) would be completed by the end of the Custom IR term (2018), at which time there would be a final true-up of the balance in the CDNSADA to ensure that the amount returned to ratepayers is equivalent to the required amount. The balance in the CDNSADA represents the annual variance between the net salvage reserve amounts approved for refund to customers during the subject year and the actual amounts refunded, plus the cumulative effect of variances from

prior years. The Company now expects that the total refund to ratepayers of $379.8 million approved by the Board will be completed by the end of 2017. As a result, the Company expects to bring forward a proposal for completion of the CDNSADA and Rider D and related items within its 2018 Rate Adjustment Application.

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNT
ACTUAL & FORECAST BALANCES

Line No.	Account Description	Account Acronym	Col. 1 Actual at March 31, 2017 Principal ($000's)	Col. 2 Actual at March 31, 2017 Interest ($000's)	Col. 3 Forecast for clearance at October 1, 2017 Principal ($000's)	Col. 4 Forecast for clearance at October 1, 2017 Interest ($000's)
	Non Commodity Related Accounts					
1.	Demand Side Management V/A	2015 DSMVA	825.5	13.4	825.5	18.2 [1]
2.	Demand Side Management V/A	2016 DSMVA	(704.0)	(1.9)	-	- [2]
3.	Lost Revenue Adjustment Mechanism	2015 LRAM	(72.3)	(0.2)	(72.3)	(0.8) [1]
4.	Demand Side Management Incentive D/A	2015 DSMIDA	6,068.6	22.3	6,068.6	55.9 [1]
5.	Deferred Rebate Account	2016 DRA	7,712.2	62.5	7,712.2	105.1 [3]
6.	Manufactured Gas Plant D/A	2017 MGPDA	570.4	41.1	-	- [4]
7.	Gas Distribution Access Rule Impact D/A	2016 GDARIDA	-	-	280.3	- [5]
8.	Average Use True-Up V/A	2016 AUTUVA	13,152.5	36.2	13,152.5	108.8 [6]
9.	Earnings Sharing Mechanism Deferral Account	2016 ESMDA	(3,400.0)	(8.8)	(3,400.0)	(27.4) [7]
10.	Customer Care CIS Rate Smoothing D/A	2016 CCCISRSDA	(779.9)	(8.1)	-	(14.1) [8]
11.	Customer Care CIS Rate Smoothing D/A	2015 CCCISRSDA	1,124.2	8.3	-	16.7 [8]
12.	Customer Care CIS Rate Smoothing D/A	2014 CCCISRSDA	2,927.0	21.5	-	43.1 [8]
13.	Customer Care CIS Rate Smoothing D/A	2013 CCCISRSDA	4,634.9	34.1	-	68.3 [8]
14.	Transition Impact of Accounting Changes D/A	2017 TIACDA	70,972.8	-	4,435.8	- [9]
15.	Post-Retirement True-Up V/A	2016 PTUVA	(9,660.7)	(26.6)	(5,000.0)	(80.0) [10]
16.	Constant Dollar Net Salvage Adjustment D/A	2017 CDNSADA	37,853.9	-	-	- [11]
17.	Credit Final Bill D/A	2016 CFBDA	(1,524.4)	(4.2)	(1,524.4)	(12.6) [12]
18.	GTA Incremental Transmission Capital Rev. Req	2016 GTAITCRRDA	4,281.4	30.0	4,281.4	53.4 [13]
19.	Greenhouse Gas Emissions Impact D/A	2016 GGEIDA	939.8	6.9	840.3	12.3 [14]
20.	Rate 332 D/A	2016 R332DA	(1,651.6)	(5.0)	(1,651.6)	(14.0) [15]
21.	OEB Cost Assessment V/A	2016 OEBCAVA	1,928.0	5.3	1,928.0	16.1 [16]
22.	Total non commodity Related Accounts		135,198.3	226.8	27,876.3	349.0
	Commodity Related Accounts					
23.	Transactional Services D/A	2016 TSDA	(4,036.3)	(12.8)	(4,036.3)	(35.0) [17]
24.	Storage and Transportation D/A	2016 S&TDA	9,618.3	80.3	9,618.3	133.1 [17]
25.	Unaccounted for Gas V/A	2016 UAFVA	7,921.4	26.9	7,921.4	70.7 [18]
26.	Unabsorbed Demand Cost D/A	2016 UDCDA	282.8	1.0	282.8	2.8 [19]
27.	Total commodity related accounts		13,786.2	95.4	13,786.2	171.6
28.	Total Deferral and Variance Accounts		148,984.5	322.2	41,662.5	520.6

Notes:

1. The final 2015 DSMVA, LRAM, and DSMIDA balances to be cleared will be those determined through the on-going Board review process of 2015 DSM results.
2. Clearance of the 2016 DSMVA will be requested through a separate process/application at a later date.
3. DRA evidence is found at Exhibit C, Tab 1, Schedule 8.
4. Clearance of the balance that was recorded in 2016 MGPDA is not being requested at this time. As was indicated in the EB-2016-0215 proceeding, the balance in the 2016 MGPDA was transferred to the 2017 MGPDA.
5. The clearance amount associated with the 2016 GDARIDA is the result of a revenue requirement calculation found in evidence at Exhibit C, Tab 1, Schedule 7.
6. AUTUVA evidence is found at Exhibit C, Tab 1, Schedule 5.
7. Evidence within the B-series of exhibits provides details of Enbridge's 2016 utility results and 2016 earnings sharing calculation.
8. CCCISRSDA evidence is found at Exhibit C, Tab 1, Schedule 10.
9. TIACDA evidence is found at Exhibit C, Tab 1, Schedule 9.
10. PTUVA evidence is found at Exhibit C, Tab 1, Schedule 6.
11. Clearance of the balance that was recorded in 2016 CDNSADA is not being requested at this time. In accordance with the scope of the account that was approved in EB-2012-0459, and as was also indicated in EB-2016-0215, the balance was transferred to the 2017 CDNSADA. The cumulative balance at the end of each year will be transferred to the following year's CDNSADA. At the end of 2018, any residual balance will be requested for clearance in a post 2018 true-up.
12. CFBDA evidence is found at Exhibit C, Tab 1, Schedule 12.
13. GTAITCRRDA evidence is found at Exhibit C, Tab 1, Schedule 14.
14. GGEIDA evidence is found at Exhibit C, Tab 1, Schedule 11.
15. R332DA evidence is found at Exhibit C, Tab 1, Schedule 15.
16. OEBCAVA evidence is found at Exhibit C, Tab 1, Schedule 13.
17. TSDA and S&TDA evidence is found at Exhibit C, Tab 1, Schedule 3.
18. UAFVA evidence is found at Exhibit C, Tab 1, Schedule 4.
19. UDCDA evidence is found at Exhibit C, Tab 1, Schedule 2.

2016 UNABSORBED DEMAND CHARGE DEFERRAL ACCOUNT
REQUESTED FOR CLEARANCE OCTOBER 1, 2017

2016 Unabsorbed Demand Charges Deferral Account (2016 UDCDA)

1. The purpose of the 2016 UDCDA is to record the actual cost consequences of unutilized contracted capacity contracted by the Company to meet its Peak Day requirements in 2016. A consequence of contracting for incremental long haul capacity is the possibility of unabsorbed demand charges (“UDC”).

Background

2. As part of its 2016 Rate Adjustment Application (EB-2015-0114), the Company requested the establishment of the 2016 UDCDA to record actual UDC for 2016. In the Application, Enbridge forecast 2016 UDC to be $15.7 million (Exhibit D1, Tab 2, Schedule 1, Appendix A), which was based upon 7.7 PJ’s of unutilized capacity. Enbridge committed to using its best efforts to mitigate the UDC that would be otherwise recorded in the 2016 UDCDA.

Utilization of capacity in 2016

3. During the month of April 2016, Enbridge personnel reviewed the projected summer injection schedule. This review led Enbridge to make the decision to utilize as much as possible of the 7.7 PJ’s of the previously forecasted unutilized capacity for the June to September period.

4. The Company was able to avoid use almost all of the previously forecasted unutilized capacity. However, despite the Company's best efforts, the Company did incur UDC on one day late in the injection season of 0.1 PJ's, due to above forecast storage balances. Therefore the Company is seeking to recover a 2016 UDCDA balance of $0.3 million from customers.

5. Attached is a copy of the 2016 UDC Management Report filed with interested parties on January 3, 2017.

Witnesses: K. Lakatos-Hayward
D. Small

ENBRIDGE

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Director, Regulatory Affairs
and Financial Performance

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Enbridge Gas Distribution
500 Consumers Road
North York, Ontario M2J 1P8
Canada

January 3, 2017

VIA RESS, EMAIL and COURIER

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

Dear Ms. Walli:

Re: Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application
Ontario Energy Board File No. EB-2012-0459 / EB-2015-0114

As per the Settlement Agreement in EB-2012-0459 (Exhibit N1, Tab 2, Schedule 1, page 6 of 19) the Company committed to provide a report to the parties of the Settlement Agreement to allow for the ongoing monitoring of UDC impacts in 2014.

The Company, as part of its 2015 Rate Application (EB-2014-0276, Exhibit D1, Tab 2, Schedule 1, page 6 of 11) committed to continue to provide monthly reporting in 2015. Also, the Company developed and filed a 2015 UDC Mitigation Strategy as part of the Supplemental Agreement in EB-2014-0276 and committed to file monthly updates to that mitigation strategy (Exhibit N, Tab 1, Schedule 2, page 6, paragraph 4).

As discussed in EB-2015-0114, the Company is committed to providing monthly reporting of the on-going amounts in the 2016 UDCDA as well as a copy of its 2016 UDC mitigation plan. To the extent there is an update to the mitigation plan as originally filed it will be provided in the March 2016 Report. Please see the attached Report for December 2016.

The Company informed parties as a part of its March report that based upon its anticipated requirements for the summer of 2016 it would be forecasting that it will be able to avoid any cost consequences of unutilized TCPL – FT capacity. The forecast underpinning the April to October reports continued to show that the Company would be avoiding any cost consequences of unutilized TCPL-FT capacity in the summer of 2016. The attached report for December 2016 reflects a small forecasted amount being recorded in the 2016 Unabsorbed Demand Charges Deferral Account (2016 UDCDA) in the month of December. This was primarily due to the delay in the in-service date of TCPL’s Kings North pipeline.

Please do not hesitate to contact me with any questions.

Yours Truly,

(Original Signed)

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

Attach.

cc: EB-2015-0114 Interested Parties

December 2016 UDC Report

	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Estimate November	Estimate December	
Forecasted Monetary Impacts in the 2016 UDCDA													
$ millions	-	-	-	-	-	-	-	-	-	-	0.3	-	0.3 (1)
Revenue From Unutilized Capacity Released													
- Seasonal	-	-	-	-	-	-	-	-	-	-	-	-	-
- Monthly	-	-	-	-	-	-	-	-	-	-	-	-	-
- Daily	-	-	-	-	-	-	-	-	-	-	(0.0)	-	(0.0)
Net Impact on Deferral Account	-	-	-	-	-	-	-	-	-	-	0.3	-	0.3

	January	February	March	April	May	June	July	August	September	October	November	December	
Forecasted Monthly Unutilized Capacity													
PJ's -	-	-	-	-	-	-	0.0	0.0	(0.0)	-	0.1	-	0.2
Unutilized Capacity Released													
- Seasonal	-	-	-	-	-	-	(0.0)	(0.0)	0.0	-	-	-	(0.0)
- Monthly	-	-	-	-	-	-	-	-	-	-	-	-	-
- Daily	-	-	-	-	-	-	(0.0)	(0.0)	-	-	(0.1)	-	(0.1)
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-

2016 Summer UDC Management Plan

Item #		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8		
		April	May	June	July	August	September	October	Total		
	Days in the month	30	31	30	31	31	30	31	214		
1.	Forecasted Cost of UDC - $ millions	-	-	-	-	-	-	-	-		
	PJs										
2.	Forecasted UDC To Be Mitigated	-	-	-	0.0	0.0	(0.0)	-	0.0		
3.	Forecasted Dawn Discretionary Requirement Replaced with Utilization of Long Haul Capacity	-	-	-	-	-	-	-	-		
4.	Potential UDC Shed	-	-	-	0.0	0.0	(0.0)	-	0.0		
5.	Forecasted Added Utility Requirement	-	-	-	-	-	-	-	-		
6.	Forecasted Summer Unutilized Capacity	-	-	-	0.0	0.0	(0.0)	-	0.0	Daily Quantity R	% of remaining capacity released
7.	June to August Release (Target)	-	-	-	-	-	-	-	-	-	-
8.	July to September Release (Target)	-	-	-	0.0	0.0	(0.0)	-	0.0	-	(0.00)
9.	Remaining Daily/Monthly Release Capacity	-	-	-	0.0	0.0	-	-	0.0		
10.	Total Targeted Daily Capactiy to be Released Daily/Monthly	-	-	-	0	0	-	-			

2016 STORAGE & TRANSPORTATION DEFERRAL ACCOUNT, 2016 TRANSACTIONAL SERVICES DEFERRAL ACCOUNT, REQUESTED FOR CLEARANCE OCTOBER 1, 2017

2016 Storage and Transportation Deferral Account (2016 S&TDA)

1. The purpose of the 2016 S&TDA is to record the difference between the forecast of Storage and Transportation rates (both cost of service and market based pricing) included in the Company's approved rates and the final Storage and Transportation rates (both cost of service and market based pricing) incurred by the Company.

2. The S&TDA will also record the variance between the forecast Storage and Transportation demand levels and the actual Storage and Transportation demand levels. In addition the S&TDA will be used to record amounts received by the Company related to deferral account dispositions of other utilities deferral accounts.

3. The balance in the 2016 S&TDA that the Company is proposing to collect from customers is $9.6 million plus interest.

4. The primary driver for the balance in the 2016 S&TDA is an increase in Union M12 tolls of approximately 10 % effective January 1, 2016 compared to the January 1, 2015 tolls that the 2016 gas cost budget was based upon.

2016 Transactional Services Deferral Account (2016 TSDA)

5. The concept of Transactional Services operates under the premise that if circumstances arise where the assets acquired by Enbridge to meet customer demand are not fully required then those assets can be made available to generate third party revenue. Transactional Services are the optimization of these assets.

Witnesses: K. Lakatos-Hayward
D. Small

6. Transactional services optimization can be grouped into two different categories – storage optimization and transportation optimization. Storage optimization transactions typically rely on storage or the loan of gas between two points in time at the same location (i.e., Dawn). Transportation optimization transactions typically rely on the exchange of gas on the day between two locations.

7. Any revenues received from transactional services are to be shared 90:10 between the ratepayer and the Company. The rates designed by the Company include an upfront benefit of $ 12.0 million in Transactional Services revenue that has been applied to reduce the overall costs to be collected from ratepayers. The purpose of the TSDA is to capture the difference between the total ratepayer share of transactional services revenue and the amount already included in rates.

8. During 2016, the Company was able to generate a total of $17.7 million in net Transactional Services revenue through a combination of Storage and Transportation Optimization. The attached schedule provides a breakdown of Transactional Services revenue by type of transaction, and sets out the details of the amount, $ 4.04 million proposed to be cleared through the 2016 TSDA.

9. The transactions that Enbridge entered into in 2016 contained the three elements of Transactional Services as were described in the Company's evidence in EB-2013-0046 in that they were Unplanned, the result of a Third Party Service Request and were available because of Temporarily Surplus Capacity.

2016 TRANSACTIONAL SERVICES REVENUE

Item #		$ 000's
1.0	Storage Optimization	7,277.2
2.0	Transportation Optimization	10,463.5
3.0	Transactional Services Revenue	17,740.6
4.0	Ratepayer Portion of TS	15,966.6
5.0	Less Guarantee in Rates	12,000.0
6.0	TSDA sub-total	3,966.6
7.0	ETT Revenue - Rider H	69.7
8.0	TSDA Total	4,036.3

Witnesses: K. Lakatos-Hayward
D. Small

UNACCOUNTED-FOR GAS VARIANCE ACCOUNT

1. This evidence provides the volumetric variance underpinning the balance in the Unaccounted-For Gas Variance Account (“UAFVA”). It will describe the 2016 variance relative to historical Unaccounted-For Gas (“UAF”) volumes.

2. UAF is the difference between natural gas delivered into the distribution system as billed by third-party transmission entities (namely, TransCanada Pipelines and Union Gas) and natural gas that is billed as consumption to over two million customers. Owing to its residual nature, UAF cannot be measured directly. UAF can arise from meter differences, operational or external factors such as line leakage, unmetered uses, and third party damages. In addition, because gas volumes are affected by temperature and pressure, measurement is made more difficult.

3. In the Company’s UAF study filed in 2013 (EB-2011-0354, Exhibit D2, Tab 6, Schedule 1), results identified meter uncertainty as the main source of UAF. Custody transfer meters, residential diaphragm meters, rotary meters and other meters are inspected by Measurement Canada to be within +/-2% depending on the type of meter. 2016 UAF is within the tolerance levels, at 1.18% of total 2016 throughput volumes.

4. The 2016 level of UAF was determined to be 133,112 10^3m^3. The variance of 48,346 10^3m^3, which is the difference between actual UAF volume and the forecast UAF volume of 84,766 10^3m^3, underpins the \$7.9M account balance that is captured in the UAFVA.

5. Although the root causes of UAF are generally known as noted earlier, it continues to be difficult to quantify the individual factors due to their nature. The Company

Witnesses: J. Shem
M. Suarez

has estimated the increase in line pack and venting associated with the GTA Project. Estimates show the combined impact to be 2% of the 2016 UAF. No significant factors are known to have occurred in 2016 that would have contributed to a higher UAF than recently experienced.

6. As shown in Tables 1 and 2 in the following pages, UAF has been quite volatile over the years, showing some stability from 2010-2012, and followed by higher levels especially in 2014 and 2016. The 2016 UAF level falls within the 95% confidence interval, bounded by (17,701) 10^3m^3 and 153,998 10^3m^3.

Witnesses: J. Shem
M. Suarez

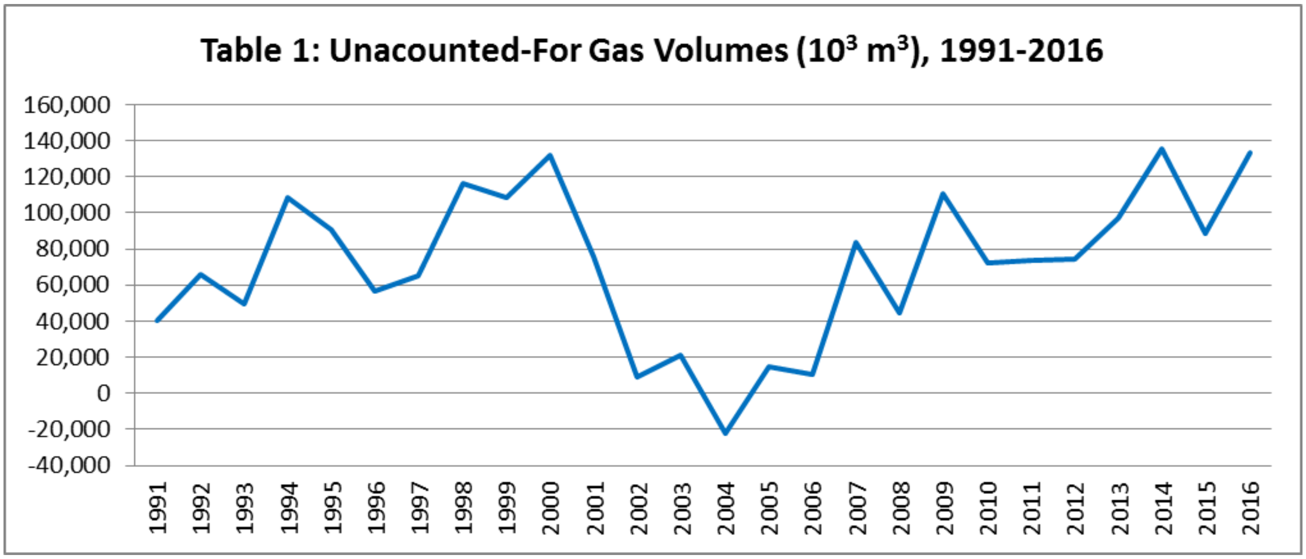
Table 1: Unacounted-For Gas Volumes (10^3 m^3), 1991-2016
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
-20,000
-40,000
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016

Table 2

Col.1	*Col.2*
Calendar Year	**UAF Volumes (10^3 m^3)**
1991	40,662
1992	66,028
1993	49,782
1994	108,765
1995	90,655
1996	56,739
1997	65,228
1998	116,376
1999	108,201
2000	132,021
2001	75,606
2002	9,284
2003	21,412
2004	-22,406
2005	14,815
2006	10,274
2007	83,823
2008	44,424
2009	110,917
2010	72,104
2011	73,355
2012	74,762
2013	97,361
2014	135,380
2015	88,438
2016	133,112
	1991-2015
Standard Deviation	40,822
Mean	68,960
Lower bound*	-15,296
Upper bound*	153,216

*95% confidence interval with 24 degrees of freedom (number of observations-1)

Witnesses: J. Shem
M. Suarez

2016 ACTUAL AVERAGE USE TRUE-UP VARIANCE ACCOUNT

1. The purpose of this evidence is to provide information in support of the 2016 Average Use True-up Variance Account ("AUTUVA") balance.

2. Table 1 of Appendix A details the calculations that result in the amount of $13.15 million that will constitute a collection from ratepayers. The collection is attributable to actual Rate 1 (residential) and Rate 6 average (apartment, small commercial and industrial) uses being lower than 2016 forecast levels.

3. Lower 2016 actual weather-normalized average is not consistent with Rate 1's historical average use trend in 2016. Since 1990, Rate 1 average use has followed a consistent downward trend, averaging an annual decline of 1% per year. The rate of decline was 3.8% in 2016, the pace of which was matched only in 2001. The Rate 1 decline experienced in 2016 could not have been predicted by the historical trend.

4. Similarly, residential average use ran counter to the general expectation of consumption increasing with a price decrease. Gas prices were lower than forecast and should have contributed to a higher average use particularly for residential customers.

5. Calculating a 95% confidence interval around the Rate 1 average decline of 1% establishes an upper bound of 1.3% and a lower bound of -3.3% for average use change. That is, there is a 0.95 probability that the average use change falls within a -3.3% decrease and a 1.3% increase.

Witnesses: R. Cheung
M. Suarez

This confirms that the 2016 decline in Rate 1 is an outlier.

6. Rate 6 average use consumption has remained relatively flat although some volatility is experienced from year to year. Historical Rate 6 average use was particularly volatile in the 2006 to 2010 period due to the recession and from the impacts of customer migration from the contract market. Although economic conditions were less favorable than anticipated, the inflating effect of a lower gas price was expected to have partially offset any average use declines in the commercial and industrial sectors.

7. For both Rate 1 and Rate 6, average use declines were deeper than expected. While it is acknowledged that there may be contributing factors not captured in historical results (e.g., heat content impacts of gas supply, Building Code effectivity, changes in customer behaviors), the subsequent inclusion of 2016 results for future average use projections will allow those factors to be weighted alongside traditional drivers to inform the overall trend for future years.

8. The purpose of the AUTUVA is to record or “true-up” the revenue impact (exclusive of gas costs) of the normalized volumetric difference between the forecast of average use per customers in Rate 1 and Rate 6 and the actual weather-normalized average use experienced during the year. The revenue impact is calculated using a unit rate determined in the same manner as the impact used in the derivation of the Lost Revenue Adjustment Mechanism (“LRAM”).

9. As detailed in Table 1, the calculation of the volumetric variance between forecast average use and actual normalized average use subtracts the volumetric impact of Demand Side Management (“DSM”) programs in the year. As has been the case in

previous applications, since the audited actual volume savings of 2016 DSM activities will not be available until a later date, the 2016 Board Approved Budget DSM volumes are used as an estimate of 2016 actuals. Without the exclusion of a DSM volumetric variance in the AUTUVA calculation, the impacts of DSM are inherently included. As a result, 2016 LRAM amounts which will be filed at a later date, will exclude the impact of Rate 1 and Rate 6 customers.

Exhibit Reference:

TABLE 1
2016 ACTUAL AVERAGE USE TRUE UP VARIANCE ACCOUNT

Rate Class	Col. 1 2016 Budget Annual Use (m^3)	Col. 2 2016 Normalized Actual Annual Use (m^3)	Col. 3 =Col. 2-1 Normalized Usage Variance (m^3)	Col. 4 Budget Customer Meters	Col. 5 =Col. 3*4 Normalized Volumetric Variance (10^6m^3)	Col. 6 2016 DSM Budget (10^6m^3)	Col. 7 2016 DSM Actual (10^6m^3)	Col. 8 =Col. 7-6 DSM Volumetric Variance (10^6m^3)	Col. 9 =Col. 5-8 Normalized Volumetric Variance Excluding DSM (10^6m^3)	Unit Rate of the Revenue Impact, exclusive of gas costs Col. 10 Unit Rate ($/m^3$)	Col. 11 =Col. 9*10 AUTUVA: Revenue Impact, Exclusive of Gas Costs - ($ millions)
1	2,480	2,401	(78.80)	1964199.00	(154.79)	(4.80)	(4.80)	0.00	(154.79)	0.06	(9.54)
6	28,753	28,203	(549.96)	165855.00	(91.21)	(17.00)	(17.00)	0.00	(91.21)	0.04	(3.61)
Total					(246.00)	(21.80)	(21.80)	0.00	(246.00)		(13.15)

Witnesses: R. Cheung
M. Suarez

2016 POST-RETIREMENT TRUE-UP VARIANCE ACCOUNT ("PTUVA")

1. In accordance with the EB-2015-0114 Final Accounting Order, page 23, the purpose of PTUVA is to record the differences between the 2016 forecast pension and post-employment benefit expenses of $34.6 million and the actual pension and post-employment benefit expenses (both determined on an accrual basis).

2. As of December 31, 2016 the actual pension and post-employment benefit ("OPEB") expense was $24.9 million, as calculated by Mercer. A breakdown of the $24.9 million is as follows:

	$ million
Registered Pension Plan	17.7
Supplementary Executive Retirement Plan	0.0
Senior Supplementary Executive Retirement Plan	(0.1)
Supplementary Pension Plan	1.4
Defined contribution	0.8
Total pension expense	19.8
OPEB expense	5.1
Total pension and OPEB expense	24.9

3. Please refer to Appendix 1 for an extract of the 2016 Final Accounting Mercer Reports that supports the figures above.

4. Therefore, the PTUVA balance that relates to the 2016 year is a $9.7 million credit amount, which is the difference between the Board-approved forecast of $34.6 million and the actual expense of $24.9 million.

Witnesses: J. Shem
L. Uhyrek

5. As was agreed in Enbridge's 2013 Rate Application (EB-2011-0354) Settlement Agreement (p. 20), the maximum clearance from the PTUVA (credit or debit) in any one year is $5 million. Any remaining balance is to be carried forward to the following year, so that large variances can be cleared over time (smoothed). This treatment for the PTUVA has remained in place since 2013, and is reflected in the EB-2015-0114 approved 2016 PTUVA.

6. In this proceeding, the Company is requesting to refund and clear the maximum $5 million amount from the 2016 PTUVA (to be refunded to ratepayers), with the remaining amount ($4.7 million) being transferred to the 2017 PTUVA for future treatment and disposition.

Witnesses: J. Shem
L. Uhyrek

MERCER

Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2016
Final US GAAP - January 16, 2017
Enbridge Gas Distribution Pension Plans - EGD RPP

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
E. Reconciliation of amounts recognized in statement of financial position				
Initial net asset(obligation)	-	-	-	-
Prior service credit (cost)	-	-	-	-
Net gain (loss)	(297,466,300)	(5,790,200)	(2,827,900)	(306,084,400)
Accumulated other comprehensive income (loss)	(297,466,300)	(5,790,200)	(2,827,900)	(306,084,400)
Accumulated contributions in excess of net periodic benefit cost	204,092,300	440,100	(1,390,500)	203,141,900
Net asset (obligation) recognized in statement of financial position	(93,374,000)	(5,350,100)	(4,218,400)	(102,942,500)
F. Components of net periodic benefit cost				
Service cost	29,210,000	889,700	848,000	30,947,700
Interest cost	33,069,300	628,000	404,100	34,101,400
Expected return on plan assets	(58,011,800)	(923,900)	(566,600)	(59,502,300)
Amortization of initial net obligation (asset)	-	-	-	-
Amortization of prior service cost	-	-	-	-
Amortization of net (gain) loss	13,610,600	228,600	79,100	13,918,300
Net periodic benefit cost	17,878,100	822,400	764,600	19,465,100
Headcounts for expense[1]				
EGD RPP - DB service cost provision	2,021	81	79	2,181

[1] Note the 2016 expense is based on headcount as at December 31, 2014

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
G. Changes recognized in other comprehensive income				
Changes in plan assets and benefit obligations recognized in other comprehensive income				
New prior service cost	-	-	-	-
Net loss (gain) arising during the year	36,604,600	1,181,300	704,000	38,489,900
Amounts recognized as a component of net periodic benefit cost				
Amortization or curtailment recognition of prior service credit (cost)	-	-	-	-
Amortization or settlement recognition of net gain (loss)	(13,610,600)	(228,600)	(79,100)	(13,918,300)
Total recognized in other comprehensive loss (income)	22,994,000	952,700	624,900	24,571,600
Total recognized in net periodic benefit and other comprehensive loss (income)	40,872,100	1,775,100	1,389,500	44,036,700
Estimated amounts that will be amortized from accumulated other comprehensive income over the next fiscal year				
Initial net asset (obligation)	-	-	-	-
Prior service credit (cost)	-	-	-	-
Net gain (loss)	(14,661,800)	(285,400)	(139,400)	(15,086,600)

Witnesses: J. Shem, L. Uhyrek

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2016

Final US GAAP - January 16, 2017

Enbridge Inc. Pension Plans - EI RPP

	Enbridge Inc.	Enbridge Employee Services Canada Inc.	Enbridge Technology Inc.	Enbridge International Inc.	Enbridge Saskatchewan Operating Services Inc.	Enbridge Operational Services Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas New Brunswick Inc.	Tidal Energy Marketing Inc.	Total
E. Reconciliation of amounts recognized in statements of financial position										
Initial net asset (obligation)	-	-	-	-	-	-	-	-	-	-
Prior service credit (cost)	-	-	-	-	-	-	-	-	-	-
Net gain (loss)	(34,010,300)	(181,824,500)	(731,900)	(1,354,200)	(25,500)	(7,482,100)	(1,849,000)	(66,700)	(1,470,300)	(228,814,500)
Accumulated other comprehensive income (loss)	(34,010,300)	(181,824,500)	(731,900)	(1,354,200)	(25,500)	(7,482,100)	(1,849,000)	(66,700)	(1,470,300)	(228,814,500)
Accumulated contributions in excess of net periodic benefit cost	15,678,300	95,883,800	1,660,300	1,987,800	897,500	439,300	3,218,100	79,100	352,100	120,196,300
Net asset (obligation) recognized in statement of financial position	(18,332,000)	(85,940,700)	928,400	633,600	872,000	(7,042,800)	1,369,100	12,400	(1,118,200)	(108,618,200)
F. Components of net periodic benefit cost										
Service cost	18,321,500	57,138,200	33,000	428,600	2,353,800	3,456,700	-	-	1,131,800	82,863,600
Interest cost	4,932,000	23,225,700	170,200	248,700	775,200	885,200	220,100	4,700	202,700	30,664,500
Expected return on plan assets	(8,733,800)	(39,854,000)	(322,400)	(499,100)	(1,259,100)	(1,290,900)	(483,600)	(9,500)	(353,700)	(52,806,100)
Amortization of initial net obligation (asset)	-	-	-	-	-	-	-	-	-	-
Amortization of prior service cost	1,300	38,300	300	500	300	-	300	-	-	41,000
Amortization of net (gain) loss	1,452,900	7,936,100	43,800	69,800	208,200	320,600	92,000	3,200	48,800	10,175,400
Net periodic benefit cost	15,973,900	48,484,300	(75,100)	248,500	2,078,400	3,371,600	(171,200)	(1,600)	1,029,600	70,938,400
Headcounts for expense[1]										
EI RPP - DB service cost provision	660	2,316	2	11	115	164	-	-	39	3,307
G. Changes recognized in other comprehensive income										
Changes in plan assets and benefit obligations recognized in other comprehensive income										
New prior service cost	-	-	-	-	-	-	-	-	-	-
Net loss (gain) arising during the year	4,380,300	19,983,300	(161,800)	(70,300)	(4,220,800)	945,100	(26,900)	2,100	474,600	21,305,600
Amounts recognized as a component of net periodic benefit cost										
Amortization or curtailment recognition of prior service credit (cost)	(1,300)	(38,300)	(300)	(500)	(300)	-	(300)	-	-	(41,000)
Amortization or settlement recognition of net gain (loss)	(1,452,900)	(7,936,100)	(43,800)	(69,800)	(208,200)	(320,600)	(92,000)	(3,200)	(48,800)	(10,175,400)
Total recognized in other comprehensive loss (income)	2,926,100	12,008,900	(205,900)	(140,600)	(4,429,300)	624,500	(119,200)	(1,100)	425,800	11,089,200
Total recognized in net periodic benefit and other comprehensive loss (income)	18,900,000	60,493,200	(281,000)	107,900	(2,350,900)	3,996,100	(290,400)	(2,700)	1,455,400	82,027,600
Estimated amounts that will be amortized from accumulated other comprehensive income over the next fiscal year										
Initial net asset (obligation)	-	-	-	-	-	-	-	-	-	-
Prior service credit (cost)	-	-	-	-	-	-	-	-	-	-
Net gain (loss)	(1,494,200)	(7,988,200)	(32,200)	(59,500)	(1,100)	(328,700)	(81,200)	(2,900)	(64,600)	(10,052,600)
H. Weighted-average assumptions to determine benefit obligations										
Discount rate	4.05%	4.05%	4.05%	4.05%	4.05%	4.05%	4.05%	4.05%	4.05%	4.05%
Rate of compensation increase	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%
Measurement date	31-Dec-2016	31-Dec-2016	31-Dec-2016	31-Dec-2016	31-Dec-2016	31-Dec-2016	31-Dec-2016	31-Dec-2016	31-Dec-2016	31-Dec-2016
I. Assumptions to determine net cost										
Effective discount rate for benefit obligations	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%
Effective rate for interest on benefit obligations	3.76%	3.76%	3.76%	3.76%	3.76%	3.76%	3.76%	3.76%	3.76%	3.76%
Effective rate for service cost	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%
Effective rate for interest on service cost	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Expected return on assets	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Rate of compensation increase	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%

[1] Note the 2016 expense is based on headcount as at December 31, 2014

Witnesses: J. Shem, L. Uhyrek

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Disclosure Information by Plan for Fiscal Year Ending December 31, 2016

US GAAP - January 16, 2017
Enbridge Canadian Pension Plans

Plan Name:	Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates		Supplemental Executive Retirement Plan of Enbridge Gas Distribution and Affiliates		Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc.		Retirement Plan for the Employees of Enbridge Inc. and Affiliates		The Enbridge Supplemental Pension Plan (without CGT Assets)		All Plans	
Fiscal year ending on	12/31/2016	12/31/2015	12/31/2016	12/31/2015	12/31/2016	12/31/2015	12/31/2016	12/31/2015	12/31/2016	12/31/2015	12/31/2016	12/31/2015
C. Reconciliation of funded status												
1. Fair value of plan assets	963,450,800	937,095,800	16,698,200	17,022,900	8,112,800	8,125,900	823,527,800	727,144,300	206,133,300	196,809,100	2,017,922,900	1,886,198,000
2. Benefit obligations	1,066,393,300	996,001,600	15,742,000	15,301,600	4,161,000	4,082,000	932,146,000	826,569,500	250,906,800	222,236,500	2,269,349,100	2,064,191,200
3. Funded status (plan assets less benefit obligations)	(102,942,500)	(58,905,800)	956,200	1,721,300	3,951,800	4,043,900	(108,618,200)	(99,425,200)	(44,773,500)	(25,427,400)	(251,426,200)	(177,993,200)
4. Contributions and distributions made by company from measurement date to fiscal year end	-	-	-	-	-	-	-	-	-	-	-	-
5. Net asset (obligation) recognized in statement of financial position	(102,942,500)	(58,905,800)	956,200	1,721,300	3,951,800	4,043,900	(108,618,200)	(99,425,200)	(44,773,500)	(25,427,400)	(251,426,200)	(177,993,200)
D. Amounts recognized on the consolidated balance sheet position consists of												
1. Noncurrent assets	-	-	956,200	1,721,300	3,951,800	4,043,900	-	-	-	-	4,908,000	5,765,200
2. Current liabilities	-	-	-	-	-	-	-	-	-	-	-	-
3. Noncurrent liabilities	(102,942,500)	(58,905,800)	-	-	-	-	(108,618,200)	(99,425,200)	(44,773,500)	(25,427,400)	(256,334,200)	(183,758,400)
4. Net asset (obligation) recognized in statement of financial position	(102,942,500)	(58,905,800)	956,200	1,721,300	3,951,800	4,043,900	(108,618,200)	(99,425,200)	(44,773,500)	(25,427,400)	(251,426,200)	(177,993,200)
E. Reconciliation of amounts recognized in statement of financial position												
1. Initial net asset(obligation)	-	-	-	-	-	-	-	-	-	-	-	-
2. Prior service credit (cost)	-	-	-	-	-	-	-	(41,000)	(16,300)	(18,100)	(16,300)	(59,100)
3. Net gain (loss)	(306,084,400)	(281,512,800)	(3,773,200)	(3,020,200)	102,800	337,900	(228,814,500)	(217,684,300)	(80,374,600)	(76,651,800)	(618,943,900)	(578,531,200)
4. Accumulated other comprehensive income (loss)	(306,084,400)	(281,512,800)	(3,773,200)	(3,020,200)	102,800	337,900	(228,814,500)	(217,725,300)	(80,390,900)	(76,669,900)	(618,960,200)	(578,590,300)
5. Accumulated contributions in excess of net periodic benefit cost	203,141,900	222,607,000	4,729,400	4,741,500	3,849,000	3,706,000	120,196,300	118,300,100	35,617,400	51,242,500	367,534,000	400,597,100
6. Net asset (obligation) recognized in statement of financial position	(102,942,500)	(58,905,800)	956,200	1,721,300	3,951,800	4,043,900	(108,618,200)	(99,425,200)	(44,773,500)	(25,427,400)	(251,426,200)	(177,993,200)
F. Components of net periodic benefit cost												
1. Service cost	30,947,700	34,110,000	-	-	-	-	82,863,600	87,198,400	14,340,800	15,146,200	128,152,100	136,454,600
2. Interest cost	34,101,400	39,882,100	476,900	623,400	110,800	165,600	30,664,500	31,575,800	8,062,600	8,665,700	73,416,200	80,912,600
3. Expected return on plan assets	(59,502,300)	(61,402,500)	(531,500)	(542,200)	(253,800)	(256,000)	(52,806,100)	(47,092,500)	(10,887,900)	(10,129,200)	(123,981,600)	(119,422,400)
4. Amortization of initial net obligation (asset)	-	-	-	-	-	-	-	-	-	-	-	-
5. Amortization of prior service cost	-	-	-	-	-	-	41,000	163,100	1,800	1,800	42,800	164,900
6. Amortization of net (gain) loss	13,918,300	18,556,100	77,600	423,400	-	-	10,175,400	15,412,700	4,107,800	5,155,300	28,279,100	39,547,500
7. Curtailment (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-
8. Settlement (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-
9. Special termination benefit recognized	-	-	-	-	-	-	-	-	-	-	-	-
10. Net periodic benefit cost	19,465,100	31,145,700	23,000	504,600	(143,000)	(90,400)	70,938,400	87,257,500	15,625,100	18,839,800	105,908,600	137,657,200

Witnesses: J. Shem, L. Uhyrek

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2016

Final US GAAP - January 16, 2017

Enbridge Inc. Pension Plans - EI SPP

	Enbridge Inc.	Enbridge Employee Services Canada Inc.	Enbridge Technology Inc.	Enbridge International Inc.	Enbridge Saskatchewan Operating Services Inc.	Enbridge Operational Services Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas New Brunswick Inc.	Gazifere Inc.	Tidal Energy Marketing Inc.	Total
E. Reconciliation of amounts recognized in statement of financial position											
Initial net asset (obligation)	-	-	-	-	-	-	-	-	-	-	-
Prior service credit (cost)	(16,300)	-	-	-	-	-	-	-	-	-	(16,300)
Net gain (loss)	(47,808,300)	(22,979,300)	(641,700)	(932,700)	(435,800)	(230,100)	(6,187,900)	(128,400)	(31,800)	(998,600)	(80,374,600)
Accumulated other comprehensive income (loss)	(47,824,600)	(22,979,300)	(641,700)	(932,700)	(435,800)	(230,100)	(6,187,900)	(128,400)	(31,800)	(998,600)	(80,390,900)
Accumulated contributions in excess of net periodic benefit cost	26,352,000	684,100	327,000	3,707,300	(422,300)	105,800	4,395,300	435,900	(4,900)	37,200	35,617,400
Net asset (obligation) recognized in statement of financial position	(21,472,600)	(22,295,200)	(314,700)	2,774,600	(858,100)	(124,300)	(1,792,600)	307,500	(36,700)	(961,400)	(44,773,500)
F. Components of net periodic benefit cost											
Service cost	6,743,000	5,262,300	-	368,900	43,300	63,800	1,481,600	12,400	11,700	353,800	14,340,800
Interest cost	4,857,600	2,274,000	23,900	211,400	28,200	15,100	590,100	700	700	60,900	8,062,600
Expected return on plan assets	(6,711,200)	(2,602,400)	(45,000)	(459,700)	(8,700)	(20,700)	(935,800)	(17,200)	(800)	(86,400)	(10,887,900)
Amortization of initial net obligation (asset)	-	-	-	-	-	-	-	-	-	-	-
Amortization of prior service cost	1,800	-	-	-	-	-	-	-	-	-	1,800
Amortization of net (gain) loss	2,437,700	1,219,300	8,100	67,800	15,000	13,000	299,000	7,900	1,000	39,000	4,107,800
Net periodic benefit cost	7,328,900	6,153,200	(13,000)	188,400	77,800	71,200	1,434,900	3,800	12,600	367,300	15,625,100
Headcounts for expense[1]											
EI SPP (Only Senior Management Employees)	92	90	-	7	1	1	38	1	1	7	238
G. Changes recognized in other comprehensive income											
Changes in plan assets and benefit obligations recognized in other comprehensive income											
New prior service cost	-	-	-	-	-	-	-	-	-	-	-
Net loss (gain) arising during the year	4,758,200	1,447,100	499,400	(265,400)	170,300	1,100	907,600	(10,800)	13,300	309,800	7,830,600
Amounts recognized as a component of net periodic benefit cost											
Amortization or curtailment recognition of prior service credit (cost)	(1,800)	-	-	-	-	-	-	-	-	-	(1,800)
Amortization or settlement recognition of net gain (loss)	(2,437,700)	(1,219,300)	(8,100)	(67,800)	(15,000)	(13,000)	(299,000)	(7,900)	(1,000)	(39,000)	(4,107,800)
Total recognized in other comprehensive loss (income)	2,318,700	227,800	491,300	(333,200)	155,300	(11,900)	608,600	(18,700)	12,300	270,800	3,721,000
Total recognized in net periodic benefit and other comprehensive loss (income)	9,647,600	6,381,000	478,300	(144,800)	233,100	59,300	2,043,500	(14,900)	24,900	638,100	19,346,100
Estimated amounts that will be amortized from accumulated other comprehensive income over the next fiscal year											
Initial net asset (obligation)	-	-	-	-	-	-	-	-	-	-	-
Prior service credit (cost)	(1,800)	-	-	-	-	-	-	-	-	-	(1,800)
Net gain (loss)	(2,443,200)	(1,174,400)	(32,800)	(47,700)	(22,300)	(11,800)	(316,200)	(6,600)	(1,600)	(51,000)	(4,107,600)
H. Weighted-average assumptions to determine benefit obligations											
Discount rate	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%
Rate of compensation increase	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%
Measurement date	31-Dec-2016	31-Dec-2016	31-Dec-2016	31-Dec-2016	31-Dec-2016	31-Dec-2016	31-Dec-2016	31-Dec-2016	31-Dec-2016	31-Dec-2016	31-Dec-2016
I. Assumptions to determine net cost											
Effective discount rate for benefit obligations	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%
Effective rate for interest on benefit obligations	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%
Effective rate for service cost	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%
Effective rate for interest on service cost	4.08%	4.08%	4.08%	4.08%	4.08%	4.08%	4.08%	4.08%	4.08%	4.08%	4.08%
Expected return on assets	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%
Rate of compensation increase	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.90%	3.68%

[1] Note the 2016 expense is based on headcount as at December 31, 2014

Witnesses: J. Shem, L. Uhyrek

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2016
Final US GAAP - January 16, 2017
Enbridge Gas Distribution Pension Plans - EGD RPP

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
P. Reconciliation of net (gain) loss				
Amount as disclosed as of prior year end	274,472,300	4,837,500	2,203,000	281,512,800
Amounts recognized as a component of net periodic benefit cost				
Amortization	(13,610,600)	(228,600)	(79,100)	(13,918,300)
Effect of settlement	-	-	-	-
Total amount recognized as a component of net periodic benefit cost	(13,610,600)	(228,600)	(79,100)	(13,918,300)
Changes in plan assets and benefit obligations recognized in other comprehensive income				
Liability experience	47,919,300	1,371,800	809,900	50,101,000
Asset experience	(11,314,700)	(190,500)	(105,900)	(11,611,100)
Effect of curtailment	-	-	-	-
Extraordinary event that adjusts assets	-	-	-	-
Total amount recognized as a change in plan assets and benefit obligations	36,604,600	1,181,300	704,000	38,489,900
Other changes (adjustment to accumulated comprehensive income, retained earnings)				
Plan combinations	-	-	-	-
Adjustment to match local books	-	-	-	-
Difference between prior year end and beginning of current year	-	-	-	-
Difference between calculated year-end gain/loss and amount using events that occurred during the year	-	-	-	-
Total amount recognized as other change in accumulated other comprehensive income	-	-	-	-
Exchange rate adjustment	-	-	-	-
Amount at end of year	297,466,300	5,790,200	2,827,900	306,084,400
Actual net return on assets assuming middle of period cash flows	7.77%	7.80%	7.75%	7.77%
Q. DC Current service cost	808,700	53,500	37,500	899,700
Projected DC current service cost for fiscal year ending:				
31-Dec-2017 :	763,900	49,000	38,800	851,700
31-Dec-2018 :	790,400	50,700	40,200	881,300
31-Dec-2019 :	817,800	52,500	41,600	911,900
31-Dec-2020 :	846,200	54,300	43,000	943,500
31-Dec-2021 :	875,600	56,200	44,500	976,300
31-Dec-2022 :	906,000	58,100	46,100	1,010,200
31-Dec-2023 :	937,400	60,100	47,700	1,045,200
31-Dec-2024 :	969,900	62,200	49,300	1,081,400
31-Dec-2025 :	1,003,600	64,400	51,000	1,119,000
31-Dec-2026 :	1,038,400	66,600	52,800	1,157,800

Witnesses: J. Shem, L. Uhyrek

1/13/2017

Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2016
US GAAP - January 13, 2017
Enbridge Gas Distribution Non-Pension Post Retirement Benefit Plan

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
Components of net periodic benefit cost				
Service cost	1,314,000	41,000	58,000	1,413,000
Interest cost	3,655,000	72,000	44,000	3,771,000
Expected return on plan assets	-	-	-	-
Amortization of initial net obligation (asset)	-	-	-	-
Amortization of prior service cost	103,000	2,000	1,000	106,000
Amortization of net (gain) loss	-	-	-	-
Net periodic benefit cost	5,072,000	115,000	103,000	5,290,000
Changes recognized in other comprehensive income				
Changes in plan assets and benefit obligations recognized in other comprehensive income				
New prior service cost	-	-	-	-
Net loss (gain) arising during the year	2,275,000	55,000	36,000	2,366,000
Amounts recognized as a component of net periodic benefit cost				
Amortization or curtailment recognition of prior service credit (cost)	(103,000)	(2,000)	(1,000)	(106,000)
Amortization or settlement recognition of net gain (loss)	-	-	-	-
Total recognized in other comprehensive loss (income)	2,172,000	53,000	35,000	2,260,000
Total recognized in net periodic benefit and other comprehensive loss (income) (income)	7,244,000	168,000	138,000	7,550,000
Estimated amounts that will be amortized from accumulated other comprehensive income over the next fiscal year				
Initial net asset (obligation)	-	-	-	-
Prior service credit (cost)	(103,000)	(2,000)	(1,000)	(106,000)
Net gain (loss)	-	-	-	-
Weighted-average assumptions to determine benefit obligations				
Effective discount rate for benefit obligations	3.94%	3.94%	3.94%	3.94%
Rate of compensation increase	3.47%	3.47%	3.47%	3.47%
Measurement date	31-Dec-16	31-Dec-16	31-Dec-16	31-Dec-16
Additional information for post-retirement medical plans				
Assumed health care trend rate				
a. Immediate Trend Rate	5.55%	5.77%	6.17%	5.55%
b. Ultimate Trend Rate	4.34%	4.48%	4.48%	4.34%
c. Year that the rate reaches ultimate trend rate	2034	2034	2034	2034
Assumed Drug trend rate				
a. Immediate Trend Rate	6.50%	6.73%	6.74%	6.51%
b. Ultimate Trend Rate	4.26%	4.49%	4.50%	4.27%
c. Year that the rate reaches ultimate trend rate	2034	2034	2034	2034

GAS DISTRIBUTION ACCESS RULE IMPACT DEFERRAL ACCOUNT

1. Within the EB-2015-0114 Final Accounting Order, the Board approved the 2016 Gas Distribution Access Rule Impact Deferral Account ("GDARIDA") to record impacts associated with the Company maintaining compliance with the Board's Gas Distribution Access Rule ("GDAR") directives.

2. While there were no amendments to GDAR directives during 2016, the Company has included for recovery within the 2016 GDARIDA, the 2016 revenue requirement impact resulting from the Low Income Customer Service Rule ("LICSR") changes which came into effect on January 1, 2013 through an amendment to GDAR which the Board adopted on September 6, 2012.

3. Within Enbridge's Clearance of 2013 Deferral and Variance Accounts and 2012 DSM Related Accounts proceeding, EB-2014-0195, the Company requested and received Board approval to credit to ratepayers the 2013 revenue requirement resulting from the capital spending incurred to implement the LICSR changes. As was indicated within that proceeding, at Exhibit B, Tab 3, Schedule 3, Enbridge was not able to include a forecast of the impacts of the change in the GDAR low income customer service rule at the time of forecasting its 2013 revenue requirement within its 2013 Test Year rate proceeding, EB-2011-0354, which also served as the base for the 2014 through 2018 Customized Incentive Regulation plan approved in EB-2012-0459. Within that proceeding, the Company also indicated that there would be 2014 through 2018 revenue requirement impacts resulting from the LICSR capital spending to be recovered through the GDAR deferral account.

4. Consistent with what was indicated within EB-2014-0195, as part of each of Enbridge's 2014 and 2015 Earnings Sharing Mechanism and Deferral Account

Clearance proceedings, EB-2015-0122 and EB-2016-0142, the Company requested and received approval to recover the 2014 and 2015 revenue requirements resulting from the LICSR changes.

5. As mentioned above, within this proceeding the Company has included for recovery within the 2016 GDARIDA, the 2016 revenue requirement, determined through a cost of service type calculation, which results from the LICSR changes. The Company is proposing to recover from ratepayers $0.280 million as part of the requested one time rate rider adjustment in October 2017, as shown in the proposed clearance balances at Exhibit C, Tab 1, Schedule 1, page 3, Columns 3 and 4.

6. The determination of the 2016 revenue requirement amount is shown on pages 3 through 7 of this schedule. Included within the revenue requirement calculation requested for recovery are the typical items included within a cost of service revenue requirement, such as depreciation, taxes, and total return on rate base (including interest and return on equity). The Company has used the 2016 actual required capital structure within the 2016 revenue requirement calculation. The approved 2013, 2014 and 2015 revenue requirement amounts credited to and recovered from ratepayers as part of the EB-2014-0195, EB-2015-0122 and EB-2016-0142 proceedings, are also shown for continuity.

UTILITY CAPITAL STRUCTURE
2016 GDARIDA IMPACTS

Line No.		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		2013 Actual Capital Structure			2014 Actual Capital Structure			2015 Actual Capital Structure			2016 Actual Capital Structure		
		Component	Indicated Cost Rate	Return Component	Component	Indicated Cost Rate	Return Component	Component	Indicated Cost Rate	Return Component	Component	Indicated Cost Rate	Return Component
		%	%	%	%	%	%	%	%	%	%	%	%
1.	Long-term debt	56.16	5.84	3.28	57.55	5.41	3.11	58.78	5.15	3.03	58.77	4.95	2.91
2.	Short-term debt	5.51	1.11	0.06	4.32	1.38	0.06	3.25	1.32	0.04	3.54	1.33	0.05
3.		61.67		3.34	61.87		3.17	62.03		3.07	62.31		2.96
4.	Preference shares	2.33	2.40	0.06	2.13	2.40	0.05	1.97	2.24	0.04	1.69	2.16	0.04
5.	Common equity	36.00	8.93	3.21	36.00	9.36	3.37	36.00	9.30	3.35	36.00	9.19	3.31
6.	Required Return on Rate Base	100.00		6.61	100.00		6.59	100.00		6.46	100.00		6.30

Line No.	($000's)	2013	2014	2015	2016
7.	Ontario Utility Income	70.9	(63.7)	(181.5)	(183.1)
8.	Rate base	238.4	736.0	550.0	364.0
9.	Indicated rate of return	29.74 %	(8.65)%	(33.00)%	(50.30)%
10.	(Def.) / suff. in rate of return	23.13 %	(15.24)%	(39.46)%	(56.60)%
11.	Net (def.) / suff.	55.1	(112.2)	(217.0)	(206.0)
12.	Gross (def.) / suff.	75.0	(152.7)	(295.2)	(280.3)

Witnesses: D. McIlwraith
R. Small

UTILITY RATE BASE
2016 GDARIDA IMPACTS

($000's)

Line No.		2013	2014	2015	2016
	Property, plant, and equipment				
1.	Cost or redetermined value	260.1	876.3	876.3	876.3
2.	Accumulated depreciation	(21.7)	(140.3)	(326.3)	(512.3)
3.		238.4	736.0	550.0	364.0
	Allowance for working capital				
4.	Accounts receivable merchandise finance plan	-	-	-	-
5.	Accounts receivable rebillable projects	-	-	-	-
6.	Materials and supplies	-	-	-	-
7.	Mortgages receivable	-	-	-	-
8.	Customer security deposits	-	-	-	-
9.	Prepaid expenses	-	-	-	-
10.	Gas in storage	-	-	-	-
11.	Working cash allowance	-	-	-	-
12.		-	-	-	-
13.	Ontario utility rate base	238.4	736.0	550.0	364.0

UTILITY INCOME
2016 GDARIDA IMPACTS

($000's)

Line No.		2013	2014	2015	2016
	Revenue				
1.	Gas sales	-	-	-	-
2.	Transportation of gas	-	-	-	-
3.	Transmission and compression	-	-	-	-
4.	Other operating revenue	-	-	-	-
5.	Other income	-	-	-	-
6.	Total revenue	-	-	-	-
	Costs and expenses				
7.	Gas costs	-	-	-	-
8.	Operation and Maintenance	-	-	-	-
9.	Depreciation and amortization	47.3	186.0	186.0	186.0
10.	Municipal and other taxes	-	-	-	-
11.	Total costs and expenses	47.3	186.0	186.0	186.0
12.	Utility income before inc. taxes	(47.3)	(186.0)	(186.0)	(186.0)
	Income taxes				
13.	Excluding interest shield	(116.1)	(116.1)	-	-
14.	Tax shield on interest expense	(2.1)	(6.2)	(4.5)	(2.9)
15.	Total income taxes	(118.2)	(122.3)	(4.5)	(2.9)
16.	Ontario utility net income	70.9	(63.7)	(181.5)	(183.1)

Witnesses: D. McIlwraith
R. Small

UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2016 GDARIDA IMPACTS

Line No.	($000's)	2013	2014	2015	2016
1.	Utility income before income taxes	(47.3)	(186.0)	(186.0)	(186.0)
	Add Backs				
2.	Depreciation and amortization	47.3	186.0	186.0	186.0
3.	Large corporation tax	-	-	-	-
4.	Other non-deductible items	-	-	-	-
5.	Any other add back(s)	-	-	-	-
6.	Total added back	47.3	186.0	186.0	186.0
7.	Sub total - pre-tax income plus add backs	-	-	-	-
	Deductions				
8.	Capital cost allowance - Federal	438.2	438.1	-	-
9.	Capital cost allowance - Provincial	438.2	438.1	-	-
10.	Items capitalized for regulatory purposes	-	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-	-
12.	Amortization of share and debt issue expense	-	-	-	-
13.	Amortization of cumulative eligible capital	-	-	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-	-
15.	Any other deduction(s)	-	-	-	-
16.	Total Deductions - Federal	438.2	438.1	-	-
17.	Total Deductions - Provincial	438.2	438.1	-	-
18.	Taxable income - Federal	(438.2)	(438.1)	-	-
19.	Taxable income - Provincial	(438.2)	(438.1)	-	-
20.	Income tax provision - Federal	(65.7)	(65.7)	-	-
21.	Income tax provision - Provincial	(50.4)	(50.4)	-	-
22.	Income tax provision - combined	(116.1)	(116.1)	-	-
23.	Part V1.1 tax	-	-	-	-
24.	Investment tax credit	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(116.1)	(116.1)	-	-
	Tax shield on interest expense				
26.	Rate base as adjusted	238.4	736.0	550.0	364.0
27.	Return component of debt	3.34%	3.17%	3.07%	2.96%
28.	Interest expense	8.0	23.3	16.9	10.8
29.	Combined tax rate	26.500%	26.500%	26.500%	26.500%
30.	Income tax credit	(2.1)	(6.2)	(4.5)	(2.9)
31.	Total income taxes	(118.2)	(122.3)	(4.5)	(2.9)

Witnesses: D. McIlwraith
R. Small

UTILITY REVENUE REQUIREMENT
2016 GDARIDA IMPACTS

($000's)

Line No.		2013	2014	2015	2016
	Cost of capital				
1.	Rate base	238.4	736.0	550.0	364.0
2.	Required rate of return	6.61%	6.59%	6.46%	6.30%
3.	Cost of capital	15.8	48.5	35.5	22.9
	Cost of service				
4.	Gas costs	-	-	-	-
5.	Operation and Maintenance	-	-	-	-
6.	Depreciation and amortization	47.3	186.0	186.0	186.0
7.	Municipal and other taxes	-	-	-	-
8.	Cost of service	47.3	186.0	186.0	186.0
	Misc. & Non-Op. Rev				
9.	Other operating revenue	-	-	-	-
10.	Other income	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-
	Income taxes on earnings				
12.	Excluding tax shield	(116.1)	(116.1)	-	-
13.	Tax shield provided by interest expense	(2.1)	(6.2)	(4.5)	(2.9)
14.	Income taxes on earnings	(118.2)	(122.3)	(4.5)	(2.9)
	Taxes on (def) / suff.				
15.	Gross (def.) / suff.	75.0	(152.7)	(295.2)	(280.3)
16.	Net (def.) / suff.	55.1	(112.2)	(217.0)	(206.0)
17.	Taxes on (def.) / suff.	(19.9)	40.5	78.2	74.3
18.	**Revenue requirement**	(75.0)	152.7	295.2	280.3
	Revenue at existing Rates				
19.	Gas sales	0.0	0.0	0.0	0.0
20.	Transportation service	0.0	0.0	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0	0.0	0.0
22.	Rounding adjustment	0.0	0.0	0.0	0.0
23.	Revenue at existing rates	0.0	0.0	0.0	0.0
24.	**Gross revenue (def.) / suff.**	75.0	(152.7)	(295.2)	(280.3)

Witnesses: D. McIlwraith
R. Small

2016 DEFERRED REBATE ACCOUNT
REQUESTED FOR CLEARANCE OCTOBER 1, 2017

1. The 2016 Deferred Rebate Account ("DRA") was approved by the Board within the EB-2015-0114 Accounting Order, at page 17. The description and scope of the 2016 account, consistent with prior fiscal years, was to record any amounts payable to, or receivable from, customers as a result of clearing Deferral and Variance Accounts, which remain outstanding due to the inability to locate such customers.

2. The $7.7 million recorded in the 2016 DRA and requested for clearance, reflects the outstanding amount resulting from the clearance of deferral and variance accounts which occurred during 2016, and the inability to locate all the intended customers. In October and November 2016, the Company cleared 2015 deferral and variance accounts and the 2014 DSM related accounts, which were approved within the EB-2016-0142 and EB-2015-0267 proceedings.

Witness: R. Small

2017 TRANSITION IMPACT OF ACCOUNTING CHANGES DEFERRAL ACCOUNT
REQUESTED FOR CLEARANCE OCTOBER 1, 2017

1. The purpose of the Transition Impact of Accounting Changes Deferral Account ("TIACDA") is to track the un-cleared Other Post Employment Benefit ("OPEB") costs which the Board has approved for recovery. Within EB-2011-0354, the Board approved the recovery of OPEB costs, which were forecast to be $90 million at the end of 2012, evenly over a 20 year period, commencing in 2013. The OPEB costs needed to be recognized as a result of Enbridge having to account for post-employment expenses on an accrual basis, upon transition to USGAAP for corporate reporting purposes in 2012. The use of USGAAP for regulatory purposes was approved within the 2013 rate proceeding, EB-2011-0354.

2. The final amount recorded in the TIACDA as of the end of 2012 was $88.716 million. The first four installments (for each of 2013 through 2016) of $4.436 million each (1/20 of $88.716 million), were approved for recovery within the EB-2013-0046, EB-2014-0195, EB-2015-0122, and EB-2016-0142 proceedings.

3. Enbridge is now requesting recovery of the fifth, or 2017 installment of the Board-Approved TIACDA amount, in the amount of $4.436 million (1/20 of $88.716 million).

4. As per the approved description and scope of the account, interest is not applicable to the balances to be cleared from the TIACDA.

Witnesses: R. Small
L. Uhyrek

2013, 2014, 2015, AND 2016 CUSTOMER CARE CIS RATE SMOOTHING DEFERRAL ACCOUNTS
REQUESTED FOR CLEARANCE OCTOBER 1, 2017

1. Within the Customer Care and CIS Costs Settlement Agreement and proceeding EB-2011-0226, the Board approved of a Customer Care CIS Rate Smoothing Deferral Account (“CCCISRSDA”), for each of 2013 through 2018. The purpose of the account is to capture the difference between the forecast customer care and CIS costs (as approved in EB-2011-0226) versus the amount to be collected in revenues in each year. The amount to be debited or credited to the Deferral Account in each year will be calculated by multiplying the difference in approved cost per customer and smoothed cost per customer for that year, by the updated customer forecast for that year.

2. The Settlement Agreement also specified that the balances in the account will not be cleared during the 2013 through 2018 period. The cumulative balance will build up during the years 2013 to 2015 when the approved cost per customer exceeds the smoothed cost per customer being collected in rates, and then will be drawn down during the years 2016 to 2018 when the approved cost per customer is lower than the smoothed cost per customer being collected in rates. After 2018, any remaining balance in the account is to be cleared along with the clearance of other Deferral and Variance Accounts.

3. The Settlement Agreement also specified that Enbridge would be entitled to collect interest, at a fixed annual rate of 1.47%, on the balances in the CCCISRSDAs, and that interest would be cleared annually at the same time as other Deferral and Variance Account clearings.

Witnesses: D. McIlwraith
R. Small

4. Within the EB-2011-0354 Final Rate Order, EB-2012-0459 Final Accounting Order, EB-2014-0276 Final Accounting Order, and EB-2015-0114 Decision and Accounting Order, the Board approved of the 2013, 2014, 2015, and 2016 CCCISRSDAs. The principal balance recorded within each of the 2013, 2014, 2015, and 2016 accounts ($4.6 million, $2.9 million, $1.1 million, and credit of $0.8 million), reflects each year's approved variance between the forecast customer care and CIS costs and the amount incorporated into rates.

5. In accordance with the EB-2011-0226 Settlement Agreement methodology (described above), the Company is not requesting clearance of the net principal balance at this time, as the net balance will be offset by amounts to be recorded within the 2017 and 2018 CCCISRSDAs, and if required, any net cumulative balance will be requested for clearance after 2018.

6. Within this proceeding, the Company is requesting clearance of the interest balances on the 2013, 2014, 2015, and 2016 CCCISRSDAs, in the amounts of $68.3 thousand, $43.1 thousand, $16.7 thousand, and ($14.1) thousand as shown in Exhibit C, Tab 1, Schedule 1, page 3. The annual clearance of accumulated interest amounts over 2013 to 2018, the term covered by the EB-2011-0226 Settlement Agreement, is consistent with the approach approved in that case.

Witnesses: D. McIlwraith
R. Small

2016 GREENHOUSE GAS EMISSIONS IMPACT DEFERRAL ACCOUNT
REQUESTED FOR CLEARANCE OCTOBER 1, 2017

1. Under the *Climate Change Act* and Cap and Trade Regulation, Enbridge is required to acquire sufficient emission allowances related to greenhouse gas (“GHG”) emissions from its customers’ natural gas use and natural gas used in its own operations. The Greenhouse Gas Emission Impact Deferral Account (“GGEIDA”) was approved to record Enbridge’s costs arising from regulations related to GHG emission requirements, such as the Cap and Trade Program.

2. In order to ensure Enbridge was ready to implement Cap and Trade on January 1, 2017, the Company spent time and resources to ensure business readiness. Enbridge’s costs related to business and regulatory readiness include incremental resourcing requirements, billing system reconfigurations, customer communications, compliance plan development, procurement capability development and general as well as specific knowledge attainment. These costs were not included in the base amounts upon which Enbridge’s 2016 rates are determined. Enbridge’s costs for these activities have been recorded in the 2016 GGEIDA.

3. The 2016 GGEIDA which Enbridge seeks to clear in this proceeding has a balance of $0.840 million (exclusive of interest). The amounts included in the 2016 GGEIDA are broken down as follows:

Cost Element	Actual Amount
IT billing system – revenue requirement	$(99,500)
Staff Resources	$533,321
Market Intelligence, and Consulting Support	$268,199
Customer Education and Outreach	$44,783
External Legal Counsel (Compliance Readiness and C&T Regulatory Proceeding Preparations)	$93,533
Total	**$840,336**

4. The above amounts do not include the actual total installed capital costs associated with the IT billing system of $564,200 the majority of which was spent in 2016 with a small remainder spent in 2017. The IT billing system was put into service in late 2016 and the impact of the capital costs is appropriately being sought to be recovered through a revenue requirement calculation. The resulting revenue requirement for 2016 is a credit of $99,500 (because of the impact of accelerated depreciation for tax purposes) – the revenue requirement for the IT billing system will be a debit amount in future years.

5. Enbridge notes that some services that were rendered in 2016 towards Cap and Trade readiness were not invoiced until early 2017. Those costs will be recorded in the 2017 GGEIDA.

2016 CREDIT FINAL BILL DEFERRAL ACCOUNT
REQUESTED FOR CLEARANCE OCTOBER 1, 2017

1. The 2016 Credit Final Bill Deferral Account ("CFBDA") was approved by the Board within Enbridge's 2016 Rate Adjustment proceeding, EB-2015-0114. The purpose of the CFBDA is to address a billing related issue which the Company had previously identified as resulting from the 2009 CIS implementation, specifically final bills with credit balances. The account is being used to track un-refunded customer final bill credit amounts, aged two years or more, while continuing efforts are made to return as much of the amounts as possible to the former account holders. Therefore, un-refunded final bill credit balances aged two years or more are being credited to the account.

2. The Company previously credited $5.5 million to customers within the 2015 CFBDA within the EB-2015-0122, 2014 ESM and Deferral and Variance Accounts proceeding. The CFBDA was continued into 2016 in order to record any further un-refunded final bill credit amounts not returned as part of this original amount.

3. As part of an analysis completion exercise in late 2016, the Company identified a further $1.5 million in credit balances that date back to the original timeframe. These amounts were not included in the $5.5 million previously refunded, because at the time the relevant analysis was completed the associated accounts showed no credit balance due to Enbridge's standard cheque refund process. These accounts were in the process of an attempted refund, via a mailed cheque to the last known address. As a result, there was no balance on these accounts when a query of the sub-ledger was performed to determine the amount to refund. At this point, Enbridge has exhausted its attempts to return these balances to the specific customers associated with the relevant accounts and the Company is now proposing

to credit the $1.5 million balance to all customers in the rate classes associated with the relevant accounts via the 2016 CFBDA.

4. As of December 2016, a final sub-section of accounts that had locks placed on them dating back to when the CFBDA was originally finalized was identified. These accounts had a balance of $640,000, and have now had a further attempt to validate and refund the amount owing. As of the date of this filing, this process is near completion. The Company proposes to credit any resulting additional balance into the 2016 CFBDA, to be refunded along with the $1.5 million identified above. The impact of this additional refund balance in the 2016 CFBDA will be identified in the rate order and materials prepared to implement the outcome of this proceeding.

2016 ONTARIO ENERGY BOARD COST ASSESSMENT VARIANCE ACCOUNT
REQUESTED FOR CLEARANCE OCTOBER 1, 2017

1. The purpose of the 2016 Ontario Energy Board Cost Assessment Variance Account ("OEBCAVA") was to record any material variances between the OEB costs assessed to Enbridge through application of the revised Cost Assessment Model ("revised CAM"), which became effective April 1, 2016, and the OEB costs which were included in rates during the Custom IR term, which were determined through application of the prior Cost Assessment Model ("prior CAM"). The 2016 OEBCAVA was approved by Board letter dated February 9, 2016 entitled *Revisions to the Ontario Energy Board Cost Assessment Model*, as confirmed by its EB-2016-0367 Decision and Order, dated April 6, 2017, approving Enbridge's formal accounting order request for the establishment of a 2016 OEBCAVA.

2. The amount recorded within the 2016 OEBCAVA is $1,928.0 thousand. This amount reflects the variance between OEB costs assessed to Enbridge for each of the first three quarters of the Board's 2016/17 fiscal year, utilizing the revised CAM, and Enbridge's average quarterly OEB cost assessment for the Board's 2015 / 16 fiscal year, which utilized the prior CAM. The amount was calculated by taking the 2016 / 17 OEB costs invoiced to Enbridge on April 1, July 1, and October 1, 2016, utilizing the revised CAM, of $1,342.5 thousand, $1,342.5 thousand, and $1,342.6 thousand respectively, and then subtracting from each Enbridge's average quarterly cost assessment received for 2015 / 16, utilizing the prior CAM, of $699.8 thousand (($656,800 + $656,800 + $655,137 + $830,646)/4).

3. Within this proceeding, the Company is requesting clearance of the principal and interest balances recorded in the 2016 OEBCAVA, in the amount of $1.928 million

Witness: R. Small

and $16.1 thousand respectively, as shown in Exhibit C, Tab 1, Schedule 1, page 3.

2016 GREATER TORONTO AREA INCREMENTAL TRANSMISSION CAPITAL REVENUE REQUIREMENT DEFERRAL ACCOUNT
REQUESTED FOR CLEARANCE OCTOBER 1, 2017

1. Within the Board's EB-2012-0451 Decision and Order, Enbridge's Leave to Construct GTA Project proceeding, the OEB approved of the construction of the GTA project, including the upsizing of segment A (from an NPS 36 to an NPS 42 pipeline) to accommodate distribution and transportation requirements. The decision also approved the rate methodology for transportation service on Segment A under Rate 332. Rate 332 would be designed to recover 60% of the annual revenue requirement of Segment A, through contract demand charges to transportation customers. Finally, the decision also addressed the circumstance where Segment A is completed, but transportation service is unused / unavailable due to the timing of completion of other required third party infrastructure (Union's Brantford-Kirkwall / Parkway D Project and / or TransCanada's King's North Project).

2. While Enbridge proposed to recover the full Segment A revenue requirement from in-franchise / bundled customers under such a situation, the Board's Decision and Order directed that the Company's customers should not automatically bear the costs associated with the incremental pipeline capacity (i.e., the cost of incremental capacity being the cost difference between NPS 36 and NPS 42 pipelines) which was required to provide Rate 332 service. Specifically, the Decision directed that once Segment A is in service, if there is no Rate 332 service / Rate 332 customers, the annual revenue requirement impact of $55 million (representing the forecast cost difference between the NPS 36 and the NPS 42 pipelines) will be recorded in a deferral account for eventual recovery from Rate 332 customers.

3. Subsequently, the Board approved the creation of the GTA Incremental Transmission Capital Revenue Requirement Deferral Account (“GTAITCRRDA”) for this purpose, through the issuance of the Accounting Order in the EB-2012-0451 proceeding.

4. As originally approved within EB-2012-0451, and confirmed through the EB-2016-0114 approved Accounting Order, the purpose of the 2016 GTAITCRRDA was to record the revenue requirement related to an incremental $55 million of forecast capital costs which resulted from the upsizing of Segment A of the GTA project to an NPS 42 pipeline from an NPS 36 pipeline. The account would only be required if at the time Segment A was put into service there were no transportation customers, or no ability for transportation customers to utilize Segment A. The revenue requirement would represent revenue to be collected from appropriate transportation service customers once they were able to take service under Rate 332.

5. As was indicated within Enbridge’s 2016 rate proceeding (EB-2015-0114) evidence (Exhibits D2, Tab 1, Schedule1, page 23, D2, Tab 1, Schedule 2, G1, Tab 1, Schedule 1, page 3 to 5, and H1, Tab 1, Schedule 1, page 8 to 10), at the time of filing the application there was uncertainty as to whether the Company would be able to offer Rate 332 transportation service during 2016, due to uncertainty as to whether construction of TransCanada’s King’s North Project would be completed and in-service at any point during 2016. Therefore, no Rate 332 revenues were forecast as part of the 2016 rate application.

6. As a result of forecasting that transportation service on Segment A would not be available during 2016, the Company forecast and the OEB approved the recovery of $4.893 million from eventual transportation customers, through the 2016 GTAITCRRDA, while the remainder of the forecast Segment A revenue requirement

would be recovered from the Company's bundled customers. The $4.893 million was the forecast 2016 revenue requirement in association with $55 million of incremental Segment A capacity upsizing costs.

7. However, the final amount recorded in the GTAITCRRDA as of the end of 2016 was $4.281 million. This amount reflects 10.5 /12ths (or January 1 to November 15, 2016) of the approved $4.893 million forecast to be recovered through the 2016 GTAITCRRDA. The difference results from the fact that TransCanada's King's North Project was completed and placed into service in November 2016, which allowed Rate 332 transportation service to commence on November 16, 2016. Therefore, for the final 1.5 months of 2016, the Company was able to charge and collect daily Rate 332 contract demand charges from its Rate 332 transportation customer, thus eliminating the need to record amounts into the 2016 GTAITCRRDA for that time period.

8. Within this proceeding, the Company is requesting clearance (from its Rate 332 transportation customer) of the principal and interest balances recorded in the 2016 GTAITCRRDA, in the amount of $4.281 million and $53.4 thousand respectively, as shown in Exhibit C, Tab 1, Schedule 1, page 3.

2016 RATE 332 DEFERRAL ACCOUNT
REQUESTED FOR CLEARANCE OCTOBER 1, 2017

1. Within the Board's EB-2012-0451 Decision and Order, Enbridge's Leave to Construct GTA Project proceeding, the OEB approved of the construction of the GTA project, including the upsizing of segment A (from an NPS 36 to an NPS 42 pipeline) to accommodate distribution and transportation requirements. The Decision also approved the rate methodology for transportation service on Segment A under Rate 332. Rate 332 would be designed to recover 60% of the annual revenue requirement of Segment A, through contract demand charges to transportation customers. Finally, the Decision also addressed the circumstance where Segment A is completed, but transportation service is unused / unavailable due to the timing of completion of other required third party infrastructure (Union's Brantford-Kirkwall / Parkway D Project and / or TransCanada's King's North Project).

2. While Enbridge proposed to recover the full Segment A revenue requirement from in-franchise/bundled customers under such a situation, the Board's Decision and Order directed that the Company's customers should not automatically bear the costs associated with the incremental pipeline capacity (i.e., the cost of incremental capacity being the cost difference between NPS 36 and NPS 42 pipelines) which was required to provide Rate 332 service. Specifically, the Decision directed that once Segment A is in service, if there is no Rate 332 service / Rate 332 customers, the annual revenue requirement impact of $55 million (representing the forecast cost difference between the NPS 36 and the NPS 42 pipelines) will be recorded in a deferral account for eventual recovery from Rate 332 customers.

Witnesses: A. Kacicnik
R. Small

3. Subsequently, the Board approved the creation of the GTA Incremental Transmission Capital Revenue Requirement Deferral Account ("GTAITCRRDA") for this purpose, through the issuance of the Accounting Order in the EB-2012-0451 proceeding.

4. As was indicated within Enbridge's 2016 rate proceeding (EB-2015-0114) evidence (Exhibits D2, Tab 1, Schedule 1, page 23, D2, Tab 1, Schedule 2, G1, Tab 1, Schedule 1, page 3 to 5, and H1, Tab 1, Schedule 1, page 8 to 10), at the time of filing the application there was uncertainty as to whether the Company would be able to offer Rate 332 transportation service during 2016, due to uncertainty as to whether construction of TransCanada's King's North Project would be completed and in-service at any point during 2016. Therefore, no Rate 332 revenues were forecast as part of the 2016 rate application.

5. As a result of forecasting that transportation service on Segment A would not be available during 2016, the Company forecast and the OEB approved, the recovery of $4.893 million from eventual transportation customers, through the 2016 GTAITCRRDA (representing the forecast 2016 revenue requirement in association with $55 million of incremental Segment A capacity upsizing costs), while the remainder of the forecast Segment A revenue requirement would be recovered from the Company's bundled customers. As such, 2016 rates for bundled customers were designed to recover an incremental $13.1 million ($18.0 million representing 60% of the forecast 2016 Segment A revenue requirement, less $4.9 million representing the forecast 2016 revenue requirement of $55 million in upsizing costs to be recovered through the 2016 GTAITCRRDA), than had Rate 332 service been forecast to be available for all of 2016.

6. Given that there was uncertainty as to whether the Company would be able to offer Rate 332 transportation service at any point during 2016, the Company also proposed the establishment of the 2016 Rate 332 Deferral Account ("R332DA"), which the Board approved. The purpose of the R332DA was to record for refund to the Company's bundled customers, any Rate 332 revenues collected from transportation customers, net of any reduction in the amount forecast to be recovered through the 2016 GTAITCRRDA, should Rate 332 transportation service on Segment A of the GTA project become available at any point during 2016, as a result of the completion of all associated interconnected third party facilities. The R332DA would ensure that the Company's bundled customers only pay for the revenue requirement for the transportation component of Segment A, net of the revenue requirement on the incremental $55 million, until such time as transportation service became available. The R332DA would also ensure that the Company did not over recover the forecast revenue requirement for Segment A of the GTA Project.

7. During 2016, following the completion of TransCanada's King's North Project, Rate 332 transportation service commenced on November 16, 2016, and as such Rate 332 customers began being charged daily contract demand charges from that point onward. The daily contract demand charge was designed to recover 60% of the forecast 2016 Segment A revenue requirement on an annualized basis. The amount actually billed through Rate 332 contract demand charges, from the time transportation service became available through to December 31, 2016, was $2,263.2 thousand. In conjunction with the commencement of Rate 332 charges, recognition of amounts to be recovered through the 2016 GTAITCRRDA ceased, resulting in a lower than forecast recovery amount through the 2016 GTAITCRRDA of $611.6 thousand (1.5 / 12^{ths}, or from November 16 through December 31, 2016,

of $4,893.1 thousand). As a result, the variance between the amount recovered through Rate 332 contract demand charges of $2,263.2 thousand, and the under recovery through the 2016 GTAITCRRDA of $611.6 thousand, equaling $1,651.6 thousand, has been recorded in the 2016 R332DA.

8. Within this proceeding, the Company is requesting to refund to bundled customers the principal and interest balances recorded in the 2016 R332DA, in the amount of ($1.652) million and ($14.0) thousand respectively, as shown in Exhibit C, Tab 1, Schedule 1, page 3.

Witnesses: A. Kacicnik
R. Small

CLEARANCE OF 2016 DEFERRAL AND VARIANCE ACCOUNT BALANCES

1. The Company is proposing to clear 2016 Deferral and Variance Account balances (as well as other balances set out at Appendix A to the Application – see Exhibit A, Tab 2, Schedule 1, Appendix A) to customers during the October and November 2017 billing cycles.

2. The unit rates for each type of service are shown at Exhibit C, Tab 2, Schedule 2, page 1. These unit rates will be applied to each customer's actual 2016 consumption volume for the period January 1, 2016 to December 31, 2016, and will be recovered or refunded as two equal billing adjustments in the months of October and November 2017.

3. Exhibit C, Tab 2, Schedule 2 shows the derivation of the proposed unit rates:
   - page 2 determines the balance (principal and interest) to be cleared for each Board-approved 2016 Deferral and Variance Account;
   - page 3 allocates account balances to the rate classes based on cost drivers for each type of account;
   - page 4 summarizes the allocation of account balances by rate class and type of service; and
   - page 5 derives the unit rates for the clearance / disposition by rate class and type of service. The unit rates are derived using actual 2016 consumption volumes for each rate class and each type of service.

4. The table on page 6 displays the bill adjustments in October and November 2017 for typical customers resulting from the clearance of the 2016 Deferral and Variance Account balances. These bill adjustments will be shown as a separate line item on customers' October and November 2017 bills.

Witnesses: J. Collier
A. Kacicnik
B. So

5. Although, the allocation of the balances within the Deferral and Variance Accounts to be cleared will be performed in the same manner as previous years, the Company would like to highlight proposed clearance methodology for the following four accounts which will be cleared for the first time as part of this application: 1) GTA Incremental Transmission Capital Revenue Requirement Deferral Account ("GTAITCRRDA"), 2) Rate 332 Deferral Account ("R332DA"), 3) Greenhouse Gas Emission Impact Deferral Account ("GGEIDA"), and 4) OEB Cost Assessment Variance Account ("OEBCAVA").

<u>GTAITCRRDA:</u>

6. The GTAITCRRDA was first approved by OEB within EB-2014-0276 Final Accounting Order. The purpose of the GTAITCRRDA is to record the revenue requirement related to the upsizing of Segment A of the GTA project from NPS 36 pipeline to NPS 42 pipeline, resulting an incremental $55 million of forecast capital costs. The incremental capital costs was incurred to provide transportation service to Rate 332 transportation service customers. The balance in the account represents revenue requirement to be collected from Rate 332 transportation service customers. Thus, the Company proposes to clear the balance of the GTAITCRRDA directly to Rate 332 transportation service customers.

<u>R332DA</u>

7. The purpose of the 2016 R332DA is to ensure that the Company's bundled customers only pay for the revenue requirement on the transportation component of Segment A (of the GTA project), net of the revenue requirement on the incremental $55 million in upsizing costs where Rate 332 transportation service was not available. In the 2016 rate application, the assumption was that Rate 332 transportation service would not be able to be offered during 2016. As a result,

bundled customers were allocated the costs of the transportation component of Segment A, net of the revenue requirement on the incremental $55 million in upsizing costs (which was to be recovered through the 2016 GTAITCRRDA). The 2016 R332DA would therefore be utilized should Rate 332 transportation service be offered at any point during 2016, to refund bundled customers Rate 332 billings received, net of any reduction in the amount forecast to be recovered through the 2016 GTAITCRRDA. In 2016, Rate 332 transportation service was offered in the months of November and December.

8. In other words, $1.67M would need to be refunded to bundled customers in 2016. The Company proposes to clear the balance of 2016 R332DA to all bundled customers (system gas and direct purchase customers) based on total deliveries allocator under the Board approved cost allocation and rate design methodology.

GGEIDA:

9. The purpose of the GGEIDA is to record any financial impacts to Enbridge resulting from federal and provincial regulations related to greenhouse gas emission requirements.

10. In reference to the Regulatory Framework for the Assessment of Costs of Natural Gas Utilities’ Cap and Trade Activities (EB-2015-0363), the Ontario Energy Board determined that administrative costs relating to the implementation and ongoing operation of the Cap and Trade program will be allocated and recovered from all customers in the same manner as existing administrative costs. Thus, the Company proposes to clear the balance of the GGEIDA to various customer classes based on the number of customers in each rate class.

Witnesses: J. Collier
A. Kacicnik
B. So

<u>OEBCAVA</u>

11. The purpose of 2016 OEBCAVA is to record any variance between the Board costs assessed to Enbridge under the previous cost assessment model which is included in rates during the custom IR term, and the latest Board cost assessment model.

12. The Company proposes to clear the balance to all customers based on the rate base factor under the Board approved cost allocation and rate design methodology. This approach mimics how the Ontario Hearing Costs Variance Account was cleared in previous similar proceedings (EB-2012-0055 and EB-2013-0046), 2011 Earnings Sharing and Deferral and Variance Account Clearances and 2012 Earnings Sharing and Deferral and Variance Account Clearances respectively.

<u>Other</u>

13. The Company is proposing to clear the 2016 balances in two equal installments since the total balance and bill adjustments are substantial relative to other years. In prior proceedings, with similar balances and bill adjustments (EB-2007-0615 and EB-2016-0142), the Ontario Energy Board directed the Company to clear the balance in two installments.

Witnesses: J. Collier
A. Kacicnik
B. So

UNIT RATE AND TYPE OF SERVICE: CLEARING IN OCTOBER & NOVEMBER 2017

		COL.1	COL. 2	COL. 3
		Unit Rate (¢/m³)	October Unit Rate	November Unit Rate
Bundled Services:				
RATE 1	- SYSTEM SALES	0.6004	0.3002	0.3002
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.6278	0.3139	0.3139
	- WESTERN T-SERVICE	0.6004	0.3002	0.3002
RATE 6	- SYSTEM SALES	0.2337	0.1168	0.1168
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.2611	0.1306	0.1306
	- WESTERN T-SERVICE	0.2337	0.1168	0.1168
RATE 9	- SYSTEM SALES	(0.6304)	(0.3152)	(0.3152)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000	0.0000	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000
RATE 100	- SYSTEM SALES	0.1588	0.0794	0.0794
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000	0.0000	0.0000
	- WESTERN T-SERVICE	0.1588	0.0794	0.0794
RATE 110	- SYSTEM SALES	0.1630	0.0815	0.0815
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.1904	0.0952	0.0952
	- WESTERN T-SERVICE	0.1630	0.0815	0.0815
RATE 115	- SYSTEM SALES	0.0000	0.0000	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0549	0.0275	0.0275
	- WESTERN T-SERVICE	0.0275	0.0137	0.0137
RATE 135	- SYSTEM SALES	(0.1153)	(0.0577)	(0.0577)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0878)	(0.0439)	(0.0439)
	- WESTERN T-SERVICE	(0.1153)	(0.0577)	(0.0577)
RATE 145	- SYSTEM SALES	(2.2411)	(1.1205)	(1.1205)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(2.2136)	(1.1068)	(1.1068)
	- WESTERN T-SERVICE	(2.2411)	(1.1205)	(1.1205)
RATE 170	- SYSTEM SALES	(0.3219)	(0.1610)	(0.1610)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.2945)	(0.1472)	(0.1472)
	- WESTERN T-SERVICE	(0.3219)	(0.1610)	(0.1610)
RATE 200	- SYSTEM SALES	0.1571	0.0785	0.0785
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.1846	0.0923	0.0923
	- WESTERN T-SERVICE	0.1571	0.0785	0.0785
Unbundled Services:				
RATE 125	- All	(0.1668)	(0.0834)	(0.0834)
	- Customer-specific ($)	$0		
RATE 300	- All	(2.3160)	(1.1580)	(1.1580)
RATE 332	- All	361.2333	180.6167	180.6167

Witnesses: J. Collier
A. Kacicnik
B. So

DETERMINATION OF BALANCES TO BE CLEARED FROM THE 2016 DEFERRAL AND VARIANCE ACCOUNTS

ITEM NO.		COL. 1 PRINCIPAL For CLEARING ($000)	COL. 2 INTEREST ($000)	COL. 3 TOTAL For CLEARING ($000)
1.	TRANSACTIONAL SERVICES D/A	(4,036.3)	(35.0)	(4,071.3)
2.	UNACCOUNTED FOR GAS V/A	7,921.4	70.7	7,992.1
3.	STORAGE AND TRANSPORTATION D/A	9,618.3	133.1	9,751.4
4.	DEFERRED REBATE ACCOUNT	7,712.2	105.1	7,817.3
5.	DEMAND SIDE MANAGEMENT 2015	825.5	18.2	843.7
6.	LOST REVENUE ADJ MECHANISM 2015	(72.3)	(0.8)	(73.1)
7.	DEMAND SIDE MANAGEMENT INCENTIVE 2015	6,068.6	55.9	6,124.5
8.	RATE 332 VARIANCE ACCOUNT	(1,651.6)	(14.0)	(1,665.6)
9.	CREDIT FINAL BILL D/A	(1,524.4)	(12.6)	(1,537.0)
10.	GTA INCREMNTL TRANSMISSIONAL CAPITAL RR D/A	4,281.4	53.4	4,334.8
11.	OEB COST ASSESSMENT VARIANCE ACCOUNT	1,928.0	16.1	1,944.1
12.	GAS DISTRIBUTION ACCESS RULE D/A 2016	280.3	0.0	280.3
13.	AVERAGE USE TRUE-UP V/A	13,152.5	108.8	13,261.3
14.	POST-RETIREMENT TRUE-UP V/A	(5,000.0)	(80.0)	(5,080.0)
15.	2016 CUSTOMER CARE CIS RATE SMOOTHING D/A		(14.1)	(14.1)
16.	2015 CUSTOMER CARE CIS RATE SMOOTHING D/A		16.7	16.7
17.	2014 CUSTOMER CARE CIS RATE SMOOTHING D/A		43.1	43.1
18.	2013 CUSTOMER CARE CIS RATE SMOOTHING D/A		68.3	68.3
19.	GREEN HOUSE GAS EMISSIONS IMPACT D/A	840.3	12.3	852.6
20.	UNABSORBED DEMAND COST D/A	282.8	2.8	285.6
21.	DESIGN DAY CRITERIA TRANSPORTATION D/A	0.0	0.0	0.0
22.	TRANSITION IMPACT OF ACCT CHANGE D/A	4,435.8	0.0	4,435.8
23.	EARNINGS SHARING MECHANISM	(3,400.0)	(27.4)	(3,427.4)
	TOTAL	41,662.5	520.6	42,183.1

Witnesses: J. Collier
A. Kacicnik
B. So

CLASSIFICATION AND ALLOCATION OF DEFERRAL AND VARIANCE ACCOUNT BALANCES

ITEM NO.	CLASSIFICATION	COL.1 TOTAL ($000)	COL. 2 SALES AND WBT ($000)	COL. 3 TOTAL SALES ($000)	COL. 4 TOTAL DELIVERIES ($000)	COL. 5 SPACE ($000)	COL. 6 DELIVE-RABILITY ($000)	COL. 7 DISTRIBUTION REV REQ (DRR) ($000)	COL. 8 DIRECT ($000)	COL. 9 NUMBER OF CUSTOMERS ($000)	COL. 10 RATE BASE ($000)
	PGVA:										
1.1	COMMODITY	0.0		0.0							
1.2	SEASONAL PEAKING-LOAD BALANCING	0.0					0.0				
1.3	SEASONAL DISCRETIONARY-LOAD BALANCING	0.0				0.0					
1.4	TRANSPORTATION TOLLS	0.0	0.0								
1.5	CURTAILMENT REVENUE	0.0					0.0		0.0		
1.6	RIDER C 2009 DIRECT ALLOCATION	0.0							0.0		
1.7	INVENTORY ADJUSTMENT	0.0									
1.		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.	TRANSACTIONAL SERVICES D/A	(4,071.3)	(2,359.8)			(538.3)	(1,173.3)				
2.	UNACCOUNTED FOR GAS V/A	7,992.1			7,992.1						
3.	STORAGE AND TRANSPORTATION D/A	9,751.4				3,066.7	6,684.7				
4.	DEFERRED REBATE ACCOUNT	7,817.3			7,817.3						
5.	DEMAND SIDE MANAGEMENT 2015	843.7							843.7		
6.	LOST REVENUE ADJ MECHANISM 2015	(73.1)							(73.1)		
7.	DEMAND SIDE MANAGEMENT INCENTIVE 2015	6,124.5							6,124.5		
8.	RATE 332 VARIANCE ACCOUNT	(1,665.6)			(1,665.6)					0.0	
9.	CREDIT FINAL BILL D/A	(1,537.0)							(1,537.0)		
10.	GTA INCREMNTL TRANSMISSIONAL CAPITAL RR D/A	4,334.8							4,334.8		
11.	OEB COST ASSESSMENT VARIANCE ACCOUNT	1,944.1									1,944.1
12.	GAS DISTRIBUTION ACCESS RULE D/A 2016	280.3								280.3	
13.	AVERAGE USE TRUE-UP V/A	13,261.3							13,261.3		
14.	POST-RETIREMENT TRUE-UP V/A	(5,080.0)									(5,080.0)
15.	2016 CUSTOMER CARE CIS RATE SMOOTHING D/A	(14.1)								(14.1)	
16.	2015 CUSTOMER CARE CIS RATE SMOOTHING D/A	16.7								16.7	
17.	2014 CUSTOMER CARE CIS RATE SMOOTHING D/A	43.1								43.1	
18.	2013 CUSTOMER CARE CIS RATE SMOOTHING D/A	68.3								68.3	
19.	GREEN HOUSE GAS EMISSIONS IMPACT D/A	852.6			0.0					852.6	
20.	UNABSORBED DEMAND COST D/A	285.6					285.6				
21.	DESIGN DAY CRITERIA TRANSPORTATION D/A	0.0					0.0				
22.	TRANSITION IMPACT OF ACCT CHANGE D/A	4,435.8						0.0			4,435.8
23.	EARNINGS SHARING MECHANISM	(3,427.4)						0.0			(3,427.4)
	TOTAL	42,183.1	(2,359.8)	0.0	14,143.8	2,528.5	5,797.0	0.0	22,954.2	1,246.9	(2,127.5)
	ALLOCATION										
1.1	RATE 1	27,096.6	(1,198.2)	0.0	5,844.6	1,226.1	3,193.4	0.0	18,312.6	1,150.0	(1,431.9)
1.2	RATE 6	10,742.9	(978.3)	0.0	5,821.2	1,186.4	2,491.7	0.0	2,743.2	96.7	(618.0)
1.3	RATE 9	(1.1)	(0.0)	0.0	0.2	0.0	0.0	0.0	0.2	0.0	(1.4)
1.4	RATE 100	5.1	(0.9)	0.0	4.2	0.5	1.8	0.0	0.0	0.0	(0.4)
1.5	RATE 110	1,488.2	(87.7)	0.0	1,073.3	46.7	46.6	0.0	434.8	0.2	(25.6)
1.6	RATE 115	267.4	(6.0)	0.0	645.3	0.1	9.0	0.0	(368.5)	0.0	(12.6)
1.7	RATE 125	(16.6)	0.0	0.0	0.0	0.0	0.0	0.0	6.4	0.0	(22.9)
1.8	RATE 135	(67.6)	(10.8)	0.0	83.8	0.0	0.0	0.0	(139.4)	0.0	(1.3)
1.9	RATE 145	(1,015.3)	(3.8)	0.0	59.3	5.5	0.0	0.0	(1,073.5)	0.0	(2.9)
1.10	RATE 170	(918.6)	(28.7)	0.0	391.9	21.1	0.0	0.0	(1,299.0)	0.0	(3.9)
1.11	RATE 200	267.6	(45.5)	0.0	220.0	42.0	54.5	0.0	2.2	0.0	(5.7)
1.12	RATE 300	(0.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	(0.8)
1.13	RATE 332	4,334.8							4,334.8		
1.		42,183.1	(2,359.8)	0.0	14,143.8	2,528.5	5,797.0	0.0	22,954.2	1,246.9	(2,127.5)

Witnesses: J. Collier
A. Kacicnik
B. So

ALLOCATION BY TYPE OF SERVICE

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DISTRIBUTION REV REQ (DRR)	DIRECT	NUMBER OF CUSTOMERS	RATE BASE
		($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Bundled Services:											
RATE 1	- SYSTEM SALES	25,305.2	(1,157.7)	0.0	5,466.2	1,146.7	2,986.6	0.0	17,127.0	1,075.6	(1,339.2)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	907.5			187.5	39.3	102.4	0.0	587.4	36.9	(45.9)
	- WBT	883.9	(40.4)		190.9	40.1	104.3	0.0	598.2	37.6	(46.8)
RATE 6	- SYSTEM SALES	6,037.0	(709.7)	0.0	3,350.7	682.9	1,434.2	0.0	1,579.0	55.6	(355.7)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	2,421.0			1,202.3	245.0	514.7	0.0	566.6	20.0	(127.6)
	- WBT	2,284.9	(268.6)		1,268.2	258.5	542.8	0.0	597.6	21.1	(134.6)
RATE 9	- SYSTEM SALES	(1.1)	(0.0)	0.0	0.2	0.0	0.0	0.0	0.2	0.0	(1.4)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	0.0			0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- WBT	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0
RATE 100	- SYSTEM SALES	2.3	(0.4)	0.0	1.9	0.2	0.8	0.0	0.0	0.0	(0.2)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	0.0			0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- WBT	2.8	(0.5)		2.3	0.3	1.0	0.0	0.0	0.0	(0.2)
RATE 110	- SYSTEM SALES	78.0	(13.1)	0.0	62.1	2.7	2.7	0.0	25.2	0.0	(1.5)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	967.9			659.2	28.7	28.6	0.0	267.1	0.1	(15.7)
	- WBT	442.2	(74.5)		352.0	15.3	15.3	0.0	142.6	0.1	(8.4)
RATE 115	- SYSTEM SALES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	261.3			616.9	0.1	8.6	0.0	(352.2)	0.0	(12.0)
	- WBT	6.0	(6.0)		28.4	0.0	0.4	0.0	(16.2)	0.0	(0.6)
RATE 135	- SYSTEM SALES	(1.4)	(0.3)	0.0	1.6	0.0	0.0	0.0	(2.6)	0.0	(0.0)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(22.2)			32.8	0.0	0.0	0.0	(54.6)	0.0	(0.5)
	- WBT	(43.9)	(10.5)		49.4	0.0	0.0	0.0	(82.2)	0.0	(0.7)
RATE 145	- SYSTEM SALES	(183.8)	(2.3)	0.0	10.6	1.0	0.0	0.0	(192.7)	0.0	(0.5)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(709.4)			41.6	3.9	0.0	0.0	(752.8)	0.0	(2.1)
	- WBT	(122.2)	(1.5)		7.1	0.7	0.0	0.0	(128.0)	0.0	(0.3)
RATE 170	- SYSTEM SALES	(105.0)	(9.0)	0.0	42.3	2.3	0.0	0.0	(140.2)	0.0	(0.4)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(582.4)			256.5	13.8	0.0	0.0	(850.2)	0.0	(2.6)
	- WBT	(231.2)	(19.7)		93.1	5.0	0.0	0.0	(308.6)	0.0	(0.9)
RATE 200	- SYSTEM SALES	204.9	(35.8)	0.0	169.1	32.3	41.9	0.0	1.7	0.0	(4.4)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	7.6			5.4	1.0	1.3	0.0	0.1	0.0	(0.1)
	- WBT	55.1	(9.6)		45.5	8.7	11.3	0.0	0.5	0.0	(1.2)
Unbundled Services:											
RATE 125		(16.6)	0.0	0.0	0.0	0.0	0.0	0.0	6.4	0.0	(22.9)
RATE 300		(0.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	(0.8)
RATE 332		4,334.8							4,334.8		
		42,183.1	(2,359.8)	0.0	14,143.8	2,528.5	5,797.0	0.0	22,954.2	1,246.9	(2,127.5)

Witnesses: J. Collier
A. Kacicnik
B. So

UNIT RATE AND TYPE OF SERVICE

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10	COL. 11
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DISTRIBUTION REV REQ (DRR)	DIRECT	NUMBER OF CUSTOMERS	RATE BASE	NUMBER OF CUSTOMERS
		(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	($000/user)
Bundled Services:												
RATE 1	- SYSTEM SALES	0.6004	(0.0275)	0.0000	0.1297	0.0272	0.0709	0.0000	0.4063	0.0255	(0.0318)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.6278			0.1297	0.0272	0.0709	0.0000	0.4063	0.0255	(0.0318)	0.0000
	- WESTERN T-SERVICE	0.6004	(0.0275)		0.1297	0.0272	0.0709	0.0000	0.4063	0.0255	(0.0318)	0.0000
RATE 6	- SYSTEM SALES	0.2337	(0.0275)	0.0000	0.1297	0.0264	0.0555	0.0000	0.0611	0.0022	(0.0138)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.2611			0.1297	0.0264	0.0555	0.0000	0.0611	0.0022	(0.0138)	0.0000
	- WESTERN T-SERVICE	0.2337	(0.0275)		0.1297	0.0264	0.0555	0.0000	0.0611	0.0022	(0.0138)	0.0000
RATE 9	- SYSTEM SALES	(0.6304)	(0.0275)	0.0000	0.1297	0.0000	0.0027	0.0000	0.0995	0.0021	(0.8368)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 100	- SYSTEM SALES	0.1588	(0.0275)	0.0000	0.1297	0.0148	0.0555	0.0000	0.0000	0.0000	(0.0138)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- WESTERN T-SERVICE	0.1588	(0.0275)		0.1297	0.0148	0.0555	0.0000	0.0000	0.0000	(0.0138)	0.0000
RATE 110	- SYSTEM SALES	0.1630	(0.0275)	0.0000	0.1297	0.0056	0.0056	0.0000	0.0525	0.0000	(0.0031)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.1904			0.1297	0.0056	0.0056	0.0000	0.0525	0.0000	(0.0031)	0.0000
	- WESTERN T-SERVICE	0.1630	(0.0275)		0.1297	0.0056	0.0056	0.0000	0.0525	0.0000	(0.0031)	0.0000
RATE 115	- SYSTEM SALES	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0549			0.1297	0.0000	0.0018	0.0000	(0.0740)	0.0000	(0.0025)	0.0000
	- WESTERN T-SERVICE	0.0275	(0.0275)		0.1297	0.0000	0.0018	0.0000	(0.0740)	0.0000	(0.0025)	0.0000
RATE 135	- SYSTEM SALES	(0.1153)	(0.0275)	0.0000	0.1297	0.0000	0.0000	0.0000	(0.2156)	0.0000	(0.0019)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0878)			0.1297	0.0000	0.0000	0.0000	(0.2156)	0.0000	(0.0019)	0.0000
	- WESTERN T-SERVICE	(0.1153)	(0.0275)		0.1297	0.0000	0.0000	0.0000	(0.2156)	0.0000	(0.0019)	0.0000
RATE 145	- SYSTEM SALES	(2.2411)	(0.0275)	0.0000	0.1297	0.0121	0.0000	0.0000	(2.3491)	0.0000	(0.0064)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(2.2136)			0.1297	0.0121	0.0000	0.0000	(2.3491)	0.0000	(0.0064)	0.0000
	- WESTERN T-SERVICE	(2.2411)	(0.0275)		0.1297	0.0121	0.0000	0.0000	(2.3491)	0.0000	(0.0064)	0.0000
RATE 170	- SYSTEM SALES	(0.3219)	(0.0275)	0.0000	0.1297	0.0070	0.0000	0.0000	(0.4299)	0.0000	(0.0013)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.2945)			0.1297	0.0070	0.0000	0.0000	(0.4299)	0.0000	(0.0013)	0.0000
	- WESTERN T-SERVICE	(0.3219)	(0.0275)		0.1297	0.0070	0.0000	0.0000	(0.4299)	0.0000	(0.0013)	0.0000
RATE 200	- SYSTEM SALES	0.1571	(0.0275)	0.0000	0.1297	0.0248	0.0321	0.0000	0.0013	0.0000	(0.0033)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.1846			0.1297	0.0248	0.0321	0.0000	0.0013	0.0000	(0.0033)	0.0000
	- WESTERN T-SERVICE	0.1571	(0.0275)		0.1297	0.0248	0.0321	0.0000	0.0013	0.0000	(0.0033)	0.0000
Unbundled Services:												
RATE 125	- All	(0.1668)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0641	0.0000	(0.2309)	0.0000
	- Customer-specific **											
RATE 300	- All	(2.3160)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	2.7193	0.0000	(5.0354)	0.0000
	- Customer-specific **											
RATE 332	- All	361.23	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	361.23	0.0000	0.0000	0.0000

Notes:
* Unit Rates derived based on 2016 actual volumes

Witnesses: J. Collier
A. Kacicnik
B. So

ENBRIDGE GAS DISTRIBUTION INC.
2016 DEFERRAL AND VARIANCE ACCOUNT CLEARING
BILL ADJUSTMENT IN OCTOBER AND NOVEMBER 2016 FOR TYPICAL CUSTOMERS

Item No.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Unit Rates			Bill Adjustment		
	GENERAL SERVICE	Annual Volume m3	Sales cents/m3	Ontario TS cents/m3	Western TS cents/m3	Sales Customers $	Ontario TS Customers $	Western TS Customers $
1.1	RATE 1 RESIDENTIAL							
1.2	Heating & Water Heating	2,400	0.3002	0.3139	0.3002	7.2	7.5	7.2
2.1	RATE 6 COMMERCIAL							
2.2	General Use	43,285	0.1168	0.1306	0.1168	51	57	51
	CONTRACT SERVICE							
3.1	RATE 100							
3.2	Industrial - small size	339,188	0.0794	0.0000	0.0794	269	-	269
4.1	RATE 110							
4.2	Industrial - small size, 50% LF	598,568	0.0815	0.0952	0.0815	488	570	488
4.5	Industrial - avg. size, 75% LF	9,976,121	0.0815	0.0952	0.0815	8,128	9,498	8,128
5.1	RATE 115							
5.2	Industrial - small size, 80% LF	4,471,609	0.0000	0.0275	0.0137	-	1,228	614
6.1	RATE 135							
6.2	Industrial - Seasonal Firm	598,567	(0.0577)	(0.0439)	(0.0577)	(345)	(263)	(345)
7.1	RATE 145							
7.2	Commercial - avg. size	598,568	(1.1205)	(1.1068)	(1.1205)	(6,707)	(6,625)	(6,707)
8.1	RATE 170							
8.2	Industrial - avg. size, 75% LF	9,976,121	(0.1610)	(0.1472)	(0.1610)	(16,058)	(14,688)	(16,058)

Notes:
Col. 6 = Col. 2 x Col. 3
Col. 7 = Col. 2 x Col. 4
Col. 8 = Col. 2 x Col. 5

Witnesses: J. Collier
A. Kacicnik
B. So

STATUS UPDATES

1. Within the EB-2012-0459 Decision, the Board indicated various annual reporting requirements which were either proposed or agreed to by the Company and also further requirements determined by the Board. The evidence location and status of each of such items is described in the following paragraphs.

2. The Decision highlighted that Enbridge proposed and would be required to file annually a Productivity Report within its ESM Application and to provide a Status Report of a required Benchmarking Study which is to be filed at the end of the Custom IR term. The Productivity Report is found at Exhibit D, Tab 2, Schedule 1 and the Status of the Benchmarking Study is found at Exhibit D, Tab 1, Schedule 5.

3. The Decision highlighted that Enbridge agreed to annually provide the same information as Union Gas provides in relation to section 12.1 of the Union Gas 2014 to 2018 Settlement Agreement, and also to provide the same RRR filings as Union Gas files, such as SQR results. All of that information is provided in this application within the B-series of exhibits, the C-series of exhibits, within Exhibit D, Tab 5, Schedule 1 and within Exhibit D, Tab 6.

4. Enbridge also agreed to hold an Annual Stakeholder Day each year during the Custom IR term. Enbridge held its third Stakeholder Day on April 11, 2017 and the materials presented that day are filed in evidence at Exhibit D, Tab 3, Schedule 1.

5. The Decision also required Enbridge to report annually on the status of major projects such as the GTA and WAMS, on the progress of the System Integrity Program, on the progress of an updated Asset Management Planning process and to report on and provide a Gas Supply Planning Memorandum. The Gas Supply

Planning Memorandum for 2017 was filed within the EB-2016-0215, 2017 Rate Proceeding. The WAMS project was complete and in use in October 2016 as outlined in the Annual Stakeholder Day presentation materials. Information on each of the other requirements is found in evidence at;

- GTA – Exhibit D-1-2
- System Integrity – Exhibit D-1-4
- Asset Management Plan – Exhibit D-1-6

6. The materials noted above are filed within this proceeding for information purposes. Enbridge is not seeking any relief on these items.

STATUS OF GTA PROJECT

1. Within the EB-2012-0459 Custom IR Decision (p. 81), the Board indicated that Enbridge was to report on the status, progress and cost versus schedule of the GTA project.

2. The GTA project entered into service on March 31, 2016 with the exception of the Ashtonbee station which is currently in the final stages of energization and the Buttonville station which is delayed and pending review of various circumstances.

3. As indicated in EB-2016-0142, the project has experienced some timing delays and cost challenges due to the complexity of permitting in urban areas. The pipeline is currently energized and minor residual and closeout costs will continue to occur throughout 2017.

4. Some siting issues have also been experienced, which delayed the installation of the originally scoped Buttonville and Jonesville stations. The Jonesville Station was relocated to the Ashtonbee site (EB-2016-0034) and is currently in the final stages of energization.

5. The actual 2016 actual costs incurred were $114.8 million versus the forecast of $0.0 million approved by the Board. This variance is the result of the project being planned to be completed in October 2015 with no budgeted costs for 2016 and also due to increased construction costs.

6. The current forecast of remaining costs to complete the project are approximately $6.5 million for a total project cost of $870.3 million. This is higher than the forecast total project cost of $686.5 million that was presented in the GTA project LTC

application (EB-2012-0451).

7. The overall cost increase is driven by a number of factors, including:
    a. escalation of construction bid price, relative to what was filed in EB-2012-0451;
    b. increased costs associated with greater construction complexity, relative to the design basis used to estimate the costs in EB 2012-0451; and
    c. increased project duration due to longer permit acquisition timelines.

8. The Company will file its Post Construction Financial Report (paragraph 1.5 of EB-2012-0451 Conditions of Approval) no later than June 30, 2017.

9. The Company will file further evidence about the GTA project costs within a rebasing application where such evidence is relevant and required.

STATUS OF WAMS PROJECT

1. Within the EB-2012-0459 Custom IR Decision (p. 81), the Board indicated that Enbridge was to report on the status, progress and cost versus schedule of the WAMS project.

2. Enbridge provided such information at the recent April 11, 2017 Stakeholder Day. (See pages 71 to 75 of the Stakeholder Day materials found at Exhibit D, Tab 3, Schedule 1).

3. As indicated at the Stakeholder Day, the project experienced some timing delays mainly due to the technology and business complexity involved with this project, whereby additional time was spent ensuring the design was correct and each component was sufficiently tested before commencing integration and user acceptance testing. The project was completed with WAMS going into service and being live in October 2016.

4. The total actual costs of the project was $90.1 million versus the $70.6 million forecast of total costs presented in the EB-2012-0459 proceeding.

5. The cost variances are mostly the result of timing delays due to the competitive bid processes, and a greater level of detail in relation to technology and business complexities within the design, construct and quality assurance phases as noted above.

Witness: B. Misra

STATUS OF SYSTEM INTEGRITY PROGRAM

1. Within the EB-2012-0459 Custom IR Decision (p. 81), the Board indicated that Enbridge was to report on the status and expenditures for the System Integrity Program.

2. In the Decision, the Board approved Enbridge's forecasts of required capital expenditures for each of the 2014 through 2018 fiscal years. With respect to the System Integrity Program, the Board indicated its concerns about uncertainty and lack of external evidence in relation to the program drivers and estimates. The Board indicated that it expected these concerns to be addressed through future refinements within Enbridge's Asset Management Planning and Benchmarking processes. In the meantime, the Board required Enbridge to report annually on the status and expenditures of System Integrity Program.

3. Enbridge's System Integrity and Reliability program remains a key priority for the Company in terms of understanding and proactively mitigating potential threats to the distribution system.

4. System Integrity and Reliability consists of those programs, projects and activities focused on:
    - Maintaining the entire natural gas storage, transmission and distribution pressurized system at or above adopted standards for continued safe and effective operation (System Integrity);
    - Ensuring the dependable delivery of natural gas to Enbridge's customers and end-users (Reliability);

5. The Company undertook many initiatives in 2016 to continue to address known issues and proactively maintain a safe and reliable distribution and storage system. Over the period of 2014 to 2016, significant efforts were focused on:
    - Gaining a better understanding of the health and condition of assets as it pertains to risk and risk reduction
    - designing appropriate risk reduction strategies
    - developing risk based assessment methodologies
    - developing an asset management framework in order to make effective decisions in terms of prioritizing capital spend with the outcomes being spending the right money on the right asset at the right time.

6. As shown below within Table 1, Enbridge's actual System Integrity spend within 2016 was $134M versus the $141.1M which the Board approved within the EB-2012-0459 proceeding.

Table 1

	2014			2015			2016			Cumulative
ASSET CATEGORY	ACT	IRM	VAR	ACT	IRM	VAR	ACT	IRM	VAR	VAR
Mains	31,584	24,594	(6,990)	26,762	24,088	(2,674)	35,833	22,099	(13,734)	(23,398)
Services	20,661	21,128	467	24,744	25,021	277	22,651	41,227	18,576	19,320
Stations	12,690	23,990	11,301	23,823	26,442	2,619	26,319	24,517	(1,802)	12,118
Meters/Records/Envision	42,142	41,808	(334)	45,885	42,650	(3,235)	34,388	35,810	1,422	(2,147)
SIR Direct Resource Costs	18,347	20,813	2,466	12,419	16,925	4,506	14,610	17,449	2,839	9,811
Total	**125,424**	**132,333**	**6,909**	**133,632**	**135,127**	**1,494**	**133,801**	**141,102**	**7,301**	**15,705**

	2014			2015			2016			Cumulative
ASSET CATEGORY	ACT	IRM	VAR	ACT	IRM	VAR	ACT	IRM	VAR	VAR
Reinforcements	3,595	11,393	7,798	4,715	16,958	12,243	7,879	8,743	864	20,905
Relocations	767	15,236	14,470	4,954	13,386	8,431	13,844	12,603	(1,241)	21,660

7. The Company continues to evaluate the System Integrity program work relative to the anticipated requirements as outlined in the EB-2012-0459 proceeding. Where there are changes in circumstances such as delays in readiness by third parties, or

land acquisition issues, or as more information becomes known, Enbridge may be required to re-prioritize originally anticipated program work.

8. The 2016 $7.3M underspend variance represents a 5.2% variance versus the approved budget of $141.1M.

9. Mains: Capital dollars were re-allocated across the mains portfolio through risk-based assessments and portfolio prioritization. A capital overspend of $13.7M occurred on mains replacement and integrity mains assessments.

10. Services: Capital was re-allocated to higher risk leaking / poorly performing assets rather than the anticipated proactive programs that were designed to stay ahead of the failure curve. Spend in leaking services exceeded the approved budget by $15M, while an underspend of $31M occurred on proactive service replacement. Spend in the Sewer Safety program ($1.69M) was allocated to the Customer Growth spend as this is where the program is executed.

11. Stations: Efforts were focused on high risk initiatives such as Regulators located inside Customers' buildings, Risk prioritization of District & Header stations, Records, Station Capacity and Compliance items such as: Fire Protection, Access, Communications, and Gas Pre-Heat system Mitigation.

12. SIR Direct Resource Costs: Departmental labour costs are primarily capitalized salaries and employee expenses. The favorable variance is due to a reduced workforce. The Company committed in its CIR application to find productivity in this area. Targeted hiring practices in place have led to delays in filling vacancies which also factors into the variance.

Witness: D. Broude

STATUS OF BENCHMARKING STUDY

1. Within the EB-2012-0459 Custom IR Decision (p. 81), the Board indicated that Enbridge was to report on an annual basis about the progress on the Benchmarking Study (capital and O&M) which Enbridge is required to file within the 2019 re-basing rate application, including reporting on stakeholder consultation and independent third-party involvement.

2. Enbridge issued a request for Proposal ("RFP") for an external expert consultant to perform a Total Factor Productivity and Benchmarking Study (capital & O&M) in late 2016 and commencement of the study is anticipated to begin in May, 2017.

3. Within the preparation and performance of the study, the Company and the expert consultant will be engaging with a stakeholder representative group to discuss progress and anticipated next steps.

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Witness: K Culbert

STATUS OF ASSET MANAGEMENT PLANNING PROCESS

Background

1. In its Decision with Reasons related to EB-2012-0459, the Board acknowledged Enbridge's Asset Management ("AM") development but noted some shortcomings. The Board was clear in its view that robust asset management planning at Enbridge should:

   - Include all the Company's assets; and
   - Have a direct linkage to the budget

   Furthermore, the Board noted that an asset plan should:

   - Be the vehicle to perform rationalization, prioritization, and optimization, and
   - Be based upon a comprehensive process of condition assessment, risk evaluation, and prioritization

2016 / 2017 Progress Update

2. At the April 11, 2017 Stakeholder Day, the Company reported on the status of the AM initiatives. This is set out at pages 44 to 53 of Exhibit D, Tab 3, Schedule 1.

3. As explained, the Company has made significant progress in the design and implementation of its AM system over the past years. The Company's AM process now includes all of the Company's assets. The AM system is an important input for budgeting decisions and supports the optimization of all asset related investments over a multi-year planning horizon. The Company has procured multiple software solutions to enable the end-to-end process.

Witness: H. Thompson

4. Enbridge has contracted a third party, UMS Group Inc., who has assisted with completing a comprehensive Asset Health Review ("AHR") and has developed a sustainable methodology for establishing condition and probability of failure for gas-carrying assets. Currently, Enbridge is applying this methodology to its 2018 to 2027 Asset Plan along with quantitative risk assessments for all assets. In late 2016, Enbridge engaged a third party, KPMG to conduct an assurance review on the AHR noted above which will be completed in Q2 2017.

5. The Company has an aspirational goal of ISO 55000 compliance. In Q4 2016, Enbridge engaged an ISO 55000 certified assessor, KPMG, to benchmark the Company's overall approach to AM, provide an initial gap analysis, and provide follow-up review(s) as appropriate. To date, an interim Asset Management Assessment has been completed by KPMG with the intent of conducting a final Assessment in Q3 2017. This will allow the Company to understand its progress in relation to ISO 55000 requirements and to determine next steps.

Witness: H. Thompson

PRODUCTIVITY INITIATIVES SUMMARY

Introduction

1. The purpose of this evidence is to present the 2016 Productivity Report as part of the performance measurement framework required by the Board in its July 17, 2014 Decision with Reasons for EB-2012-0459. This framework is comprised of two reporting mechanisms: the Annual Productivity Report, and the Benchmarking Report.

2. The status of the Benchmarking Report is set out at Exhibit D, Tab 1, Schedule 5.

3. Within this document, Enbridge addresses the following:

   (i) In its Custom IR Application, Enbridge identified productivity savings that it would have to achieve during the IR term;

   (ii) In the Custom IR Decision, the Board approved Enbridge's capital and O&M budgets for future years, but required reporting of the Company's productivity initiatives relative to what was identified in Enbridge's evidence;

   (iii) Enbridge has made productivity improvements a strong focus during the Custom IR term;

   (iv) During the 3rd year of the Custom IR term, Enbridge found ways to achieve some, but not all of the embedded productivity savings targets identified in the Custom IR evidence;

   (v) Enbridge also found other productivity savings, reported through incremental initiatives;

(vi) In total, productivity savings during the 3rd year of the Custom IR term are as anticipated and the Company will work to continue to find ongoing opportunities;

(vii) Enbridge's performance metrics show that it continues to offer safe, reliable, customer-centered service.

4. This evidence is structured as follows:

   (i) Embedded O&M and Capital Reductions

   (ii) Incremental Productivity Initiatives

   (iii) Excluded Variable Capital Costs

   (iv) Summary and Sustainability of Savings

   (v) Performance Measures

<u>Background</u>

5. The Company issued its 2014 Productivity Report in EB-2015-0122 where it laid out the background to the productivity targets to be met during the Custom IR term, and the ways that this would be approached. Enbridge maintained a similar approach in the subsequent 2015 Report, and the current 2016 Productivity Report. For details on the productivity background and methodology please refer to EB-2015-0122, Exhibit D, Tab 2, Schedule 1, paragraphs 4 through 17.

6. Tables 1 and 2 show the Core Capital and Other O&M amounts approved over the Custom IR term with emphasis on the 2016 budget. Productivity commitments in the form of embedded savings and excluded variable capital costs are similarly shown. The OEB Adjustment in Table 2 kept O&M increases to a level of 1% per year, resulting in a cumulative reduction of $42.2 million over the IR term.

Table 1

Capital Amounts Approved						
	2014	2015	2016	2017	2018	Total IR Term
Core Capital without Productivity	495.1	538.3	544.9	527.1	537.2	2,642.7
Less: Embedded Savings	(26.2)	(28.7)	(27.1)	(35.2)	(45.3)	(162.5)
Less: Variable Costs	(25.1)	(63.0)	(75.9)	(50.0)	(50.0)	(264.5)
Approved Core Capital Expenditures	443.8	446.6	441.9	441.9	441.9	2,216.1

Table 2:

Other O&M Amounts Approved						
	2014	2015	2016	2017	2018	Total IR Term
Proposed "Other" O&M	252.1	261.6	276.6	287.8	299.5	1,377.6
Less: Embedded Savings	(24.1)	(30.1)	(35.6)	(39.3)	(43.2)	(172.3)
Less: OEB Adjustment	-	(1.2)	(8.4)	(13.6)	(19.0)	(42.2)
Approved "Other" O&M	228.0	230.3	232.6	234.9	237.3	1,163.1

7. This evidence will describe the work items, initiatives, and programs sustained from 2014 and 2015, as well as those newly implemented by the Company in 2016 to deliver on the combined embedded reduction of $71.1 million ($27.1 million in capital, $35.6 million in O&M and $8.4 O&M OEB Adjustment). It will also describe the status of the excluded variable capital costs ($75.9 million) which were uncertain cost requirements excluded from the proposed capital amount.

Embedded O&M and Capital Reductions (Productivity)

8. Embedded productivity reductions represent the anticipated cost pressures that were eliminated or held flat within the capital and O&M budgets filed in the Custom IR proceeding as guaranteed savings which serve as a productivity assurance to ratepayers. While the Company was aware of the challenge of delivering to this commitment, the up-front cost reduction forced it to seek efficiencies that would mitigate those cost pressures or find savings elsewhere.

9. Table 3 lists the embedded productivity reductions in 2016 O&M and capital that were described in evidence and testimony provided at the EB-2014-0459 proceeding for the 2014 to 2018 Custom IR Rate Application. The detailed list was provided as an undertaking at the hearing to summarize the productivity commitments embedded in the Company's forecasts (EB-2012-0459, Exhibit J1.6).

Table 3

2016 Embedded O&M Reductions	Embedded Commitment ($M)
Merit increase	(2.5)
Employee Benefits	(2.3)
Incremental cost to service new customers	(1.7)
Incremental safety and integrity work	(9.3)
External contractor rate increases	(1.7)
Increased volume of locates-compliance with Bill 8	(3.8)
FTEs	(8.7)
Bad Debt expenses	(5.6)
Total O&M Productivity Guarantee	(35.6)
2016 Embedded Capital Reductions	**Embedded Commitment ($M)**
Customer Attachments	(24.4)
Departmental Labour	(2.7)
Total Capital Productivity Guarantee	(27.1)

10. The following paragraphs describe Enbridge's actions which allowed it to deliver savings and how results compared to the embedded cost reduction targets. The savings are costs Enbridge would have otherwise incurred. While Enbridge found productivity savings, it was not able to achieve all savings targets identified.

11. Merit increases were budgeted on the basis of a 2% increase in annual salaries although 3% increases were believed to be necessary to remain competitive (EB-2012-0459 Reply, p. 92). Actual 2016 results had a weighted increase of 2.5% in an effort to balance financial pressures and the Company's competitive position in the market. Total savings for merit increase was about $0.5 million which was $2.0 million short of the embedded reduction for 2016.

12. Benefit costs continue to rise and are still expected to increase at the projected rate of 6% per year. The approved budget reflected an increase of only 2%. Although actual spending was higher than budget, it was below the expected rate of increase, allowing savings of $1.1 million. The Company remains committed to managing to the lower rate of increase to mitigate cost increases.

13. Incremental costs to service new customers represent the costs to carry out Fuel Safety Branch Inspections ("FSBIs") which are required when gas is introduced to a premise for the first time. These costs were higher than budgeted as a result of an Operations policy change effective January 1, 2016 requiring builders to contact Enbridge for residential construction heat activation as 3rd party activations are no longer permitted. Costs were $0.1 million in excess of the committed level.

14. Distribution Operations and Pipeline Integrity & Engineering continued to find efficiencies throughout 2016 that contributed to embedded commitments in incremental safety and integrity work. Through collaborative efforts between Integrity group and a key vendor, savings of over $0.6 million were achieved for the inspection work in 2016. Previous reorganization along functional lines of accountability continues to drive greater streamlining, consistency and efficiencies through greater integration between work planning and work execution processes. Minor changes in new plant leak survey policy have similarly enabled savings and efficiency. Previously, an initial leak survey had to be completed in the first 12 months after the installation of a pressure tested gas main or gas service. The change involved incorporating that initial survey into the current 5-year leak survey program with only minor additional risk. This change improved the ability to provide leak survey support for activities outside the standard programs and also reduce the contractor unit costs because of increased standard survey volume. For this

overall area of commitment, the Company identified embedded savings of $2.6 million.

15. By centralizing the oversight of contract management functions, the Company has generated external contractor savings estimated at $0.4 million in 2016.

16. The passage of Bill 8 has imposed significant cost pressures on the Company to manage costs associated with incremental locate volumes. While locate volumes were expected to increase by 4% over 2015 volumes, locate budgets increased by only 2.3% in 2016.

17. In addition, Damage Prevention (1) increased the number of Alternative Locate Agreements ("ALAs") by 16% to improve locate efficiency and reduce the cost of carrying out standard field locates, and (2) increased participation in the Locate Alliance Consortium ("LAC") to further realize savings through locate contracts and through reduced Ontario One Call Notification Fees. These initiatives have resulted in savings of $3.0 million in 2016.

18. A key industry benchmark measuring Damage Prevention program effectiveness is the Damages per 1000 Locates metric. Damage Prevention demonstrated continuous improvement by reducing the measure from 2.43 in 2015 to 2.17 in 2016 representing a 11% decrease. Over the past ten years, this ratio has declined from 11.1 in 2004 to its current standing. The Company continues to be committed to safety improvements by reducing damages through a financially prudent and cost-effective approach.

19. By year-end, FTEs were lower than the 2016 budgeted amount of 2,361 by 238 positions, reducing both O&M and capital costs. Departmental Labour Costs ("DLC") are capitalized salaries and wages relating to back-office type functions such as planning, drafting, pipeline inspections, field operations and records

management within the Operations and Engineering departments. These functions are not impacted by delays in capital projects. FTE savings are the salary & wage reductions in O&M expected to be sustained throughout the Custom IR term and are exclusive of severance costs. The combination of these efforts resulted in O&M FTE savings of $15 million and Capitalized Departmental Labour savings of $11.6 million.

20. Bad debt expense was held flat at $9.5 million within the 2016 O&M budget, although indications were that this expense would be around $15.1 million on the basis of commodity forecasts and the overall level of consumer indebtedness. Actual 2016 bad debt expense was $7 million resulting in savings of $8.1 million. The Company has improved collections performance and management of accounts driving reductions in bad debt expense.

21. Embedded productivity commitments in the area of Customer Attachment capital were partially met in 2016. Customer Attachment capital was overspent by $6.7 million, reducing its savings to $17.7 million from the embedded target due to varying costs associated with the particular customer segment and the geographical mix of projects. Third party fees, material costs and pipeline contractor labor costs continue to exert upward pressure on costs.

22. To help mitigate these pressures, the Company continues to establish long-term construction contracts in order to stabilize or reduce costs. Further, the Company continues to look for ways to manage timing of construction projects to avoid future winter premiums and utilizes an internal cross-functional team comprised of Operations, Construction, Planning, and Legal personnel to coordinate and manage third party fees.

23. Table 4 details the estimated savings for each embedded productivity area in O&M and capital, respectively.

Table 4

2016 Embedded O&M and Actual and Capital Reductions		Embedded Commitment ($M)	Actual ($M)
1.	O&M: Merit increase	(2.5)	(0.5)
2.	O&M: Employee Benefits	(2.3)	(1.1)
3.	O&M: Incremental cost to service new customers	(1.7)	0.1
4.	O&M: Incremental safety and integrity work	(9.3)	(2.6)
5.	O&M: External contractor rate increases	(1.7)	(0.4)
6.	O&M: Increased volume of locates-compliance with Bill 8	(3.8)	(3.0)
7.	O&M: FTEs	(8.7)	(15.0)
8.	O&M: Bad Debt expenses	(5.6)	(8.1)
9.	Total Estimated O&M Reductions	(35.6)	(30.5)
10.	Capital: Customer Attachments	(24.4)	(17.7)
11.	Capital: Departmental Labour	(2.7)	(11.6)
12.	Total Estimated Capital Reductions	(27.1)	(29.3)
13.	Total Estimated Embedded O&M & Capital Reductions	(62.7)	(59.8)

24. Of the $35.6 million guaranteed O&M savings, cost mitigation efforts achieved $30.5 million most effectively through FTE management. Of the $27.1 million guaranteed capital savings, cost mitigation efforts achieved $29.3 million. Relative to the total O&M and capital guaranteed savings, the Company achieved $59.8 million of the $62.7 million target.

Incremental Productivity Initiatives

25. O&M and capital productivity actions or initiatives that are in addition to the items set out in Table 4 were pursued in all areas of the Company, across all levels of employees. There were no OEB commitments for incremental initatives, however they serve to augment embedded O&M and Capital Savings.

26. Productivity initiatives were tracked centrally to ensure consistency in the application of productivity criteria and the measurement of results. To the extent that sustainable savings were realized relative to budget amounts through incremental changes to the way work was carried out, the action was captured as a productivity initiative.

27. Over one hundred and eighty (180) productivity initiatives were identified throughout the organization. Only initiatives that were determined to have sustainable and measurable productivity savings are reported herein. They are grouped into the following categories:

    (i) Labour Optimization

    (ii) Process Optimization

    (iii) Materials/Space/Equipment Rationalization

    (iv) Policy Changes and Improvements

28. In addition to the $15 million in O&M FTE reductions and $11.6 million in capital DLC savings identified in the earlier part of this evidence (and in Table 4), other labour optimization efforts were pursued that enabled the shedding of costs through the absorption of work by existing labour capacity, the reallocation of tasks, the targeted hiring of specific skill sets to offset outside services, and the management of overtime hours. For example, in the Technical Training group, by hiring 3 employees with specific skillsets in 2014, the group was able to save outside services costs by developing training material internally instead. In addition, the conversion of selected EHS courses from instructor-led to web-based saved significant employee travel time and related costs, including outside vendor training delivery costs. Additionally, savings were also achieved by creating electronic training material and eliminating the costs associated with printed material. The

savings of these efficiencies have not only been sustained, but have increased from $144,000 in O&M in 2015 to $720,000 in O&M, and $486,000 in Capital in 2016.

29. A new 2016 initiative includes the Operator Qualification ("OQ") Recertification program which allows existing employees who require OQ recertification to do so online. Only new employees will require traditional instructor-led training. The program eliminates the need for travel and related costs associated with recertification every three years, for close to 400 employees requiring over 5,000 recertifications. In addition to these savings, online training modules were updated and developed in-house, further saving contractor costs. The savings from these types of initiatives were estimated at $1.9 million in O&M and $1.3 million in capital.

30. Process Optimization initiatives relate to changes in the way work is organized to achieve efficiencies. These included system changes, more efficient work flows, streamlined tools, and the elimination of redundant reports. The savings from these types of initiatives were estimated at $5.9 million in O&M and $2.0 million in capital. For example, the e-bill initiative continues to provide cumulative sustainable savings starting from $0.4 million in 2014 and growing to $2.4 million in 2016. The number of e-bill adoptions continues to grow through active conversion strategies as well as an improved web interface which has facilitated the sign-up process generating savings by eliminating increasing postage and print costs. A new initiative in 2016 was the use of email in lieu of the post to send Warning Tag letters to customers. Prior to 2016, work management clerks mailed warning tag letters to customers through Canada Post, informing them of their obligations to address the deficiencies tagged. This mode of customer communication required intensive manual effort and incurred printing and mailing costs. The change in business process has saved printing and postage costs by $24,000 and is responsive to the growing preference of customers to receive utility communications electronically.

It also allows Work Management Center clerks to focus on other activities, thereby optimizing labour resources and providing for sustained savings in the future.

31. In addition to the optimization of labour and the processes employed by labour resources, costs and requirements related to materials, equipment, and space were rationalized to achieve greater efficiency. The area of greatest sustained savings is in workspace optimization. Starting in 2014 and continuing through to 2017, the Company's head office is undergoing workspace alterations to increase the utilization of existing office space. This is accomplished by reducing workstation/office footprints and recognizing current work styles that leverage mobility and roles that require less time in the office. Through increased utilization, savings are enabled through the reduction in leasing costs as employees currently in leased space can move back to the head office. Space optimization has facilitated additional benefits in the form of enhanced office safety from the relocation of the meter shop, increased efficiencies as all office staff will be housed centrally, and improved employee engagement. The workspace optimization initiative achieved O&M savings of $1.0 million in 2016 and savings are expected to increase in 2017 upon completion of the project. This group of initiatives achieved an estimated savings of $4.1 million in O&M and $1.3 million in capital for 2016.

32. In the area of policy changes or improvements, the Company sought to reallocate and prioritize program spending through more cost-effective means while ensuring customer safety. These actions either leveraged existing labour capacity to carry out additional tasks, changed the manner in which services were contracted or delivered, or changed the type of material approved for use. For example, the policy change made to the Company's Carbon Monoxide ("CO") Alarm Response Policy sustained savings of $125,000 in 2014 to $243,000 in 2016. Another example is the warning tag improvement initiative which improved work efficiency

by reducing the need for multiple follow-ups which had contributed to more frequent field visits and costs. In the non-peak summer months, when weather–sensitive demand and gas process loads are not critical, field technicians issue A tags (shut off) for a wider range of identified deficiencies during inspections to improve customer response and resolution. Every tag cleared by the customer's contractor results in one less follow up field visit. By implementing this policy, the Company has seen approximately 4,000 fewer field visits and saved $200,000. Savings in this category of initiatives amounted to $0.9 million in O&M and $0.3 million in capital for 2016.

33. The total 2016 O&M savings from new and sustained productivity actions are estimated at $12.8 million. As shown in Table 5, in 2015 the Company reported $10.2 million in savings from incremental O&M initiatives; ninety-seven percent of those savings were sustained, and increased to $10.9 million in 2016. In addition, $2 million in savings have been added through new initiatives. Enbridge's 2016 results demonstrate productivity sustainment and growth from the first two years of targetted productivity implementation.

Table 5

2016 Incremental O&M Productivity Initiatives				
Amounts reported in millions	2015 Cumulative Initiative Results	2015 Sustained to 2016	New 2016 Initiative Results	Total 2016
Labour Optimization	(1.6)	(1.6)	(0.4)	(1.9)
Process Optimization	(5.7)	(5.9)	(0.04)	(5.9)
Materials/Space/Equipment Rationalization	(2.1)	(2.6)	(1.5)	(4.1)
Policy Change and Improvements	(0.8)	(0.9)	- -	(0.9)
Total Reductions from Incremental O&M Initiatives	(10.2)	(10.9)	(2.0)	(12.8)

34. Total capital savings from sustainable productivity actions in 2016 are estimated at $4.9 million. As seen in Table 6, some of these savings ($1.0 million) are from new initiatives. The balance of these savings ($3.9 million) is from the sustainment of specific 2014 and 2015 productivity initiatives that resulted in capital savings. Due to the project nature of some of the capital expenditures, not all initiatives identified each year are expected to be sustained in the remaining Custom IR term. In addition, capital savings frees up capital budget to be allocated to other areas ensuring capital expenditures are optimized for the most efficient and effective use of capital resources.

Table 6

2016 Incremental Capital Productivity Initiatives				
Amounts reported in millions	**2015 Initiative Results**	**2015 Sustained to 2016**	**New 2016 Initiative Results**	**Total 2016**
Labour Optimization	(0.6)	(0.9)	(0.4)	(1.3)
Process Optimization	(2.0)	(2.0)	(0.02)	(2.0)
Materials/Space/Equipment Rationalization	(3.2)	(0.7)	(0.5)	(1.3)
Policy Change and Improvements	(0.9)	(0.3)	-	(0.3)
Total Reductions from Incremental Capital Initiatives	(6.7)	(3.9)	(1.0)	(4.9)

Variable Costs (Capital)

35. Within the capital budgets filed in the Custom IR proceeding, the Company excluded capital costs which it characterized as "variable" on the basis of their being subject to future developments that would only manifest with information not otherwise known at the time capital budgets were developed. The excluded capital costs are pre-emptive savings within the total capital budget approved.

36. Similar to 2014 and 2015, most of the variable capital costs identified for 2016 in the Custom IR filing have been determined to not have materialized.[1] Because of the uncertain nature of these variable cost elements, a number of projects have had subsequent changes in scope and/or timing that make it challenging to determine how these work items have ultimately been captured in the budget or in actual spend. The variable costs that did arise were mitigated or absorbed within the overall capital spending for 2016.

[1] See undertaking EB-2012-0459, Exhibit J1.6 for the detailed list of identified variable costs that were excluded from the final Capital budget.

Summary and Sustainability of Savings:

37. Through pooled efforts at all levels of the organization, the Company achieved its embedded reductions target of $71.1 million in 2016 through the combination of savings in embedded areas of productivity and incremental productivity initiatives. Table 7 provides a breakdown of the 2016 reductions achieved within the areas identified for productivity enhancement.

Table 7

	2016					
	O&M ($M)		Capital ($M)		Total ($M)	
	Commitment	Actual	Commitment	Actual	Commitment	Actual
Embedded	(35.6)	(30.5)	(27.1)	(29.3)	(62.7)	(59.8)
Incremental		(12.8)		(4.9)		(17.7)
OEB Adjustment	(8.4)				(8.4)	
2016 Total Savings	(44.0)	(43.4)	(27.1)	(34.2)	(71.1)	(77.5)

38. The Embedded Reductions and Incremental Initiatives are expected to continue throughout the Custom IR term. Through consistent messaging and continued focus within the organization, the Company has seen heightened self-reporting of productivity efforts as employees and management drive to measurable results.

39. To ensure continued success, the Company will need to pursue additional improvements to augment those achieved thus far. In 2017 Enbridge is pursuing process improvements in the area of business process performance from the WAMS solution. Enbridge expects to start realizing some of the benefits in 2017.

Performance Measures (metrics)

40. Table 8 and Table 9 compare 2016 operational metrics and customer service quality indicators (Exhibit D, Tab 5, Schedule 1) against baseline 2013 results to assess Enbridge's performance in light of the cost reductions achieved. As seen in the trending columns, productivity efforts have not compromised Enbridge's service levels. Time to Reschedule a Missed Appointment, though below target has a stable trend. Enbridge's overall performance measures show that it continues to offer safe and reliable service while improving its value offering to customers.

Table 8

Operational Performance	2013	2014	2015	2016	Trending
1. Employees Health and Safety: Total Reportable Injury Frequency Rate	2.01	2.00	1.06	0.93	⬆
2. Damage Prevention: Number of Excavation Damages per 1000 locates	2.84	2.49	2.43	2.17	⬆
3. Leak Management: Service leaks Repaired per Mile of service	0.09	0.06	0.06	0.06	⬌
4. Leak Management: Total Number of Grade 1 (A) leaks repaired during the year	1280	661	905	991	⬌
5. Operational Effectiveness: All Outages per 1000 Customers	6.09	5.31	4.84	4.60	⬆

Table 9

Customer Relationship Performance	OEB Target	2013	2014	2015	2016	Trending
1. Overall Customer Satisfaction Index	NA	78%	77%	79%	79%	⬆
2. Call Answering Service Level (SQR)	75%	75.9%	79%	79.7%	82.4%	⬆
3. Percentage of Emergency Calls Responded to within One Hour (SQR)	90%	96.1%	96.9%	96.7%	95.2%	⬌
4. Appointments Met within the Designated Time Period (SQR)	85%	94.2%	95.1%	95.2%	95.3%	⬆
5. Time to Reschedule a Missed Appointments (SQR)	100%	95.0%	95.5%	94.8%	95.0%	⬌
6. Number of Days to Reconnect a Customer (SQR)	85%	92.6%	94.0%	94.6%	94.8%	⬆
7. Number of Calls Abandon Rate (SQR)	10%	2.8%	1.9%	2.3%	1.8%	⬆
8. Meter Reading Performance (SQR)	0.5%	0.50%	0.69%	0.51%	0.40%	⬆
9. Number of Days to provide a Written Response (SQR)	80%	94.5%	93.3%	100.0%	95.5%	⬌

⬆ – Improving
⬌ – Maintained
⬇ – Decreasing

Witness: M. Yan

2017 Custom IR Stakeholder Day

April 11th, 2017

Moderated by:
Andrew Mandyam
Kevin Culbert

ENBRIDGE

Witness: L. Stickles

Agenda

Topic	Presenter	Time (incl. questions)
Company Overview	Andrew Mandyam & Kevin Culbert	9:30 – 9:55
2016 Year end financial results	Ryan Small & Nick Verma	9:55 – 10:15
Productivity review - results	Melinda Yan & Margarita Suarez	10:15 – 10:30
Cap & Trade impacts on volumetric forecasting	Margarita Suarez & Hulya Sayyan	10:30 – 10:45
Break		10:45 – 11:00
Asset Management & System Integrity and Reliability	Hilary Thompson, Erik Naczynski & Deirdre Broude	11:00 – 11:35
Gas Supply	Kerry Lakatos-Hayward & Andrew Welburn	11:35 – 11:50
WAMS	Will Akkermans	11:50 – 12:00
Community Expansion	Steve McGill	12:00 – 12:20
Closing Remarks	Andrew Mandyam	12:20 – 12:30

2016 Stakeholder Day Survey Results

- Survey sent to 25 participants
- Response rate: 52%
- Highlights:
  - 84% of the responses indicate that the day mostly - greatly met expectations
  - 91% of the responses indicate the info - detail in presentations was greatly - mostly sufficient
  - 95% of the responses indicate presenters greatly - mostly had a good understanding of their topic
  - 87% of the responses indicate sufficient amount of time mostly – greatly spent on each topic
  - 100% of the responses thought the day was well structured – organized
- Comments from the survey, improvements - topics for next stakeholder day:
  - Year end financial information – helpful to describe upfront what limitations for answering detailed questions in this forum
  - Carbon Cap & Trade / Community Expansion plans / Gas Supply Plan
  - More coffee

Company Overview

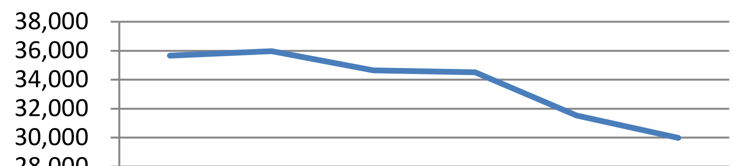
Andrew Mandyam
Kevin Culbert

Witness: L. Stickles

2016 What we did

– 29,991 Customers Attached.

Customer Adds 2011-2016



	2011	2012	2013	2014	2015	2016
Customer Adds	35,657	35,971	34,644	34,504	31,533	29,991

– 2,083,513 active customers at year end 2014 (EGD)

– 2,112,445 active customers at year end 2015

– 2,142,476 active customers at year end 2016

– Over 300 Km of Main related work in 2014 (installation, replacement, retired)

– Over 400 Km of Main related work in 2015

– Over 400 Km of Main related work in 2016

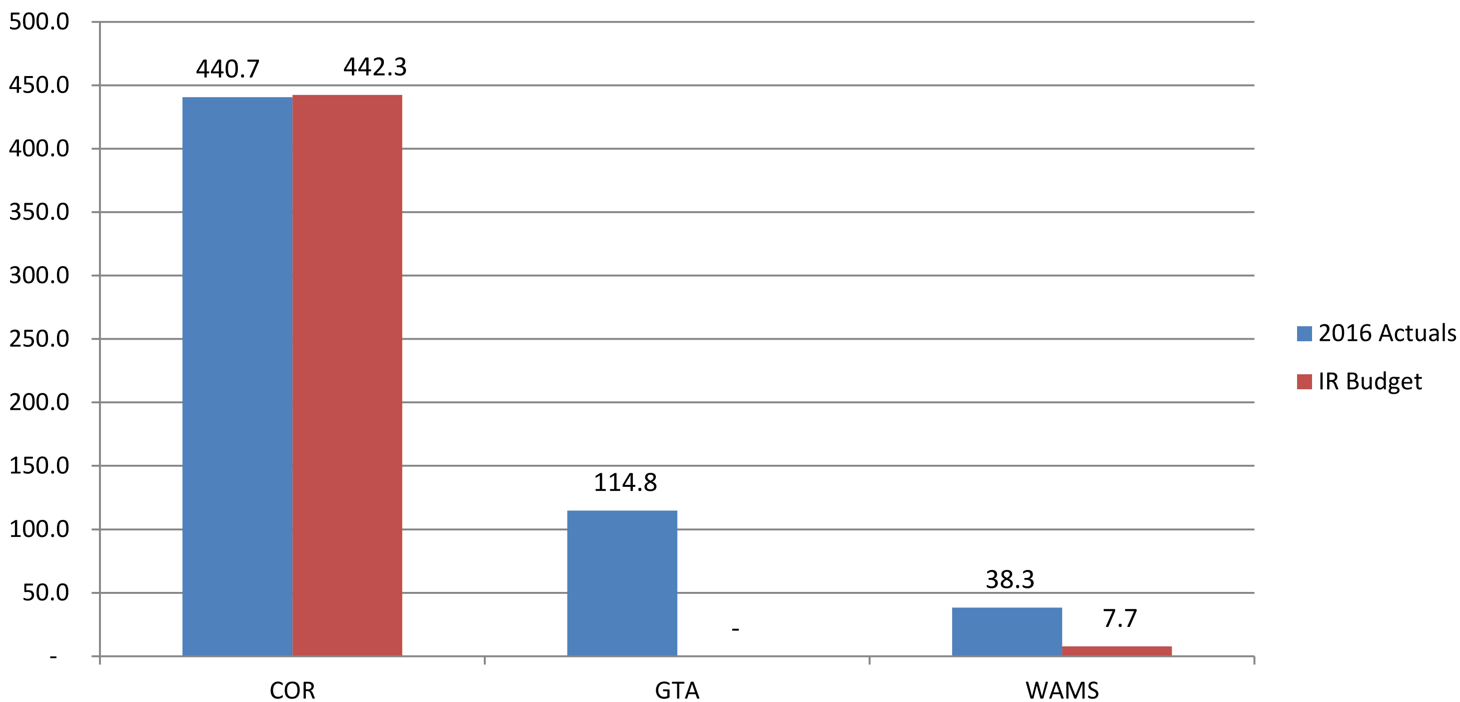
– Volumes throughput 2013-2016:

(Volumes in 10^6m^3)	2013 Actual Norm.	2013 Actual	2014 Actual Norm.	2014 Actual	2015 Actual Norm.	2015 Actual	2016 Actual Norm.	2016 Actual
Total Vols, Sales Transp.	11,491.2	11,558.0	11,297.8	12,657.6	11,299.3	11,931.8	11,309.2	10,927.1

ENBRIDGE

2016 What We Did : Capital Management

$ Millions

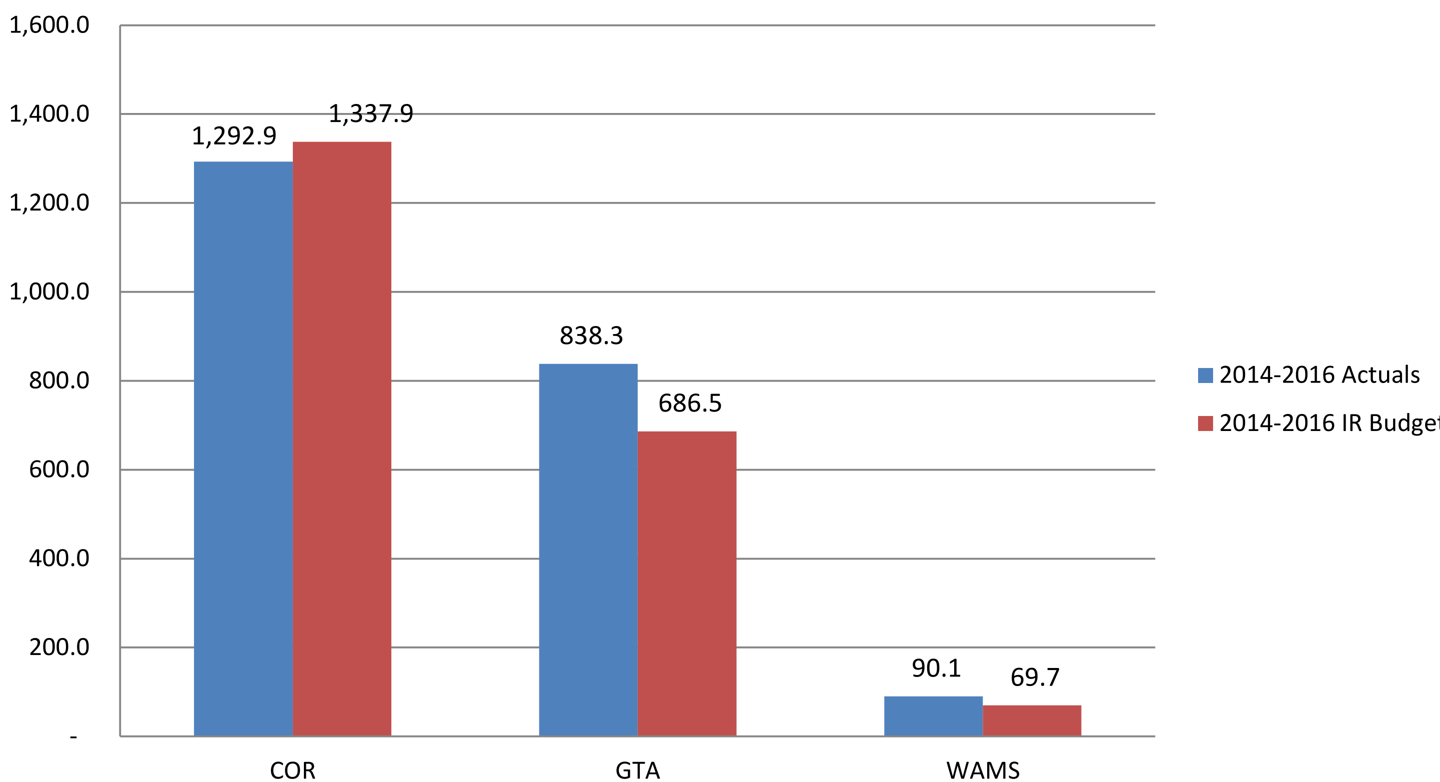


- Total CAPEX higher spend ($143.8) due to GTA ($114.8) and WAMS ($30.6) projects higher than IR Budget, partially offset by COR spending ($1.6) lower than IR Budget

Witness: L. Stickles

Capital Management : Total CAPEX Cumulative 2014-2016

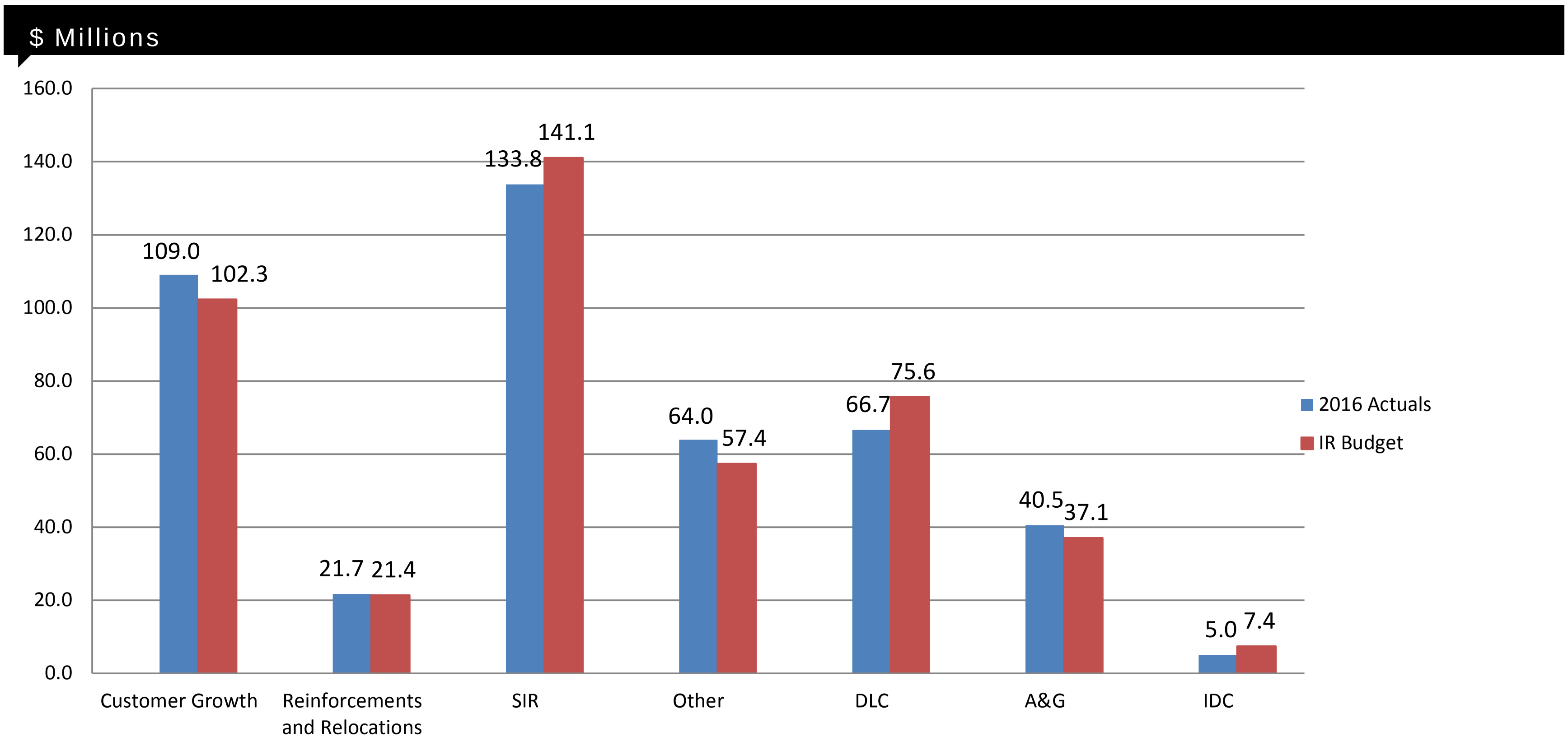
$ Millions



NOTE: GTA IR Budget includes $20.5M of approved Pre-2014 spend

- Total 3 year cumulative CAPEX spend greater than IR Budget ($127.2) due to GTA project ($151.8) and WAMS project ($20.4), partially offset by lower Core spending ($45.0)

2016 What We Did : Capital Management



Total Core CAPEX – Major Drivers

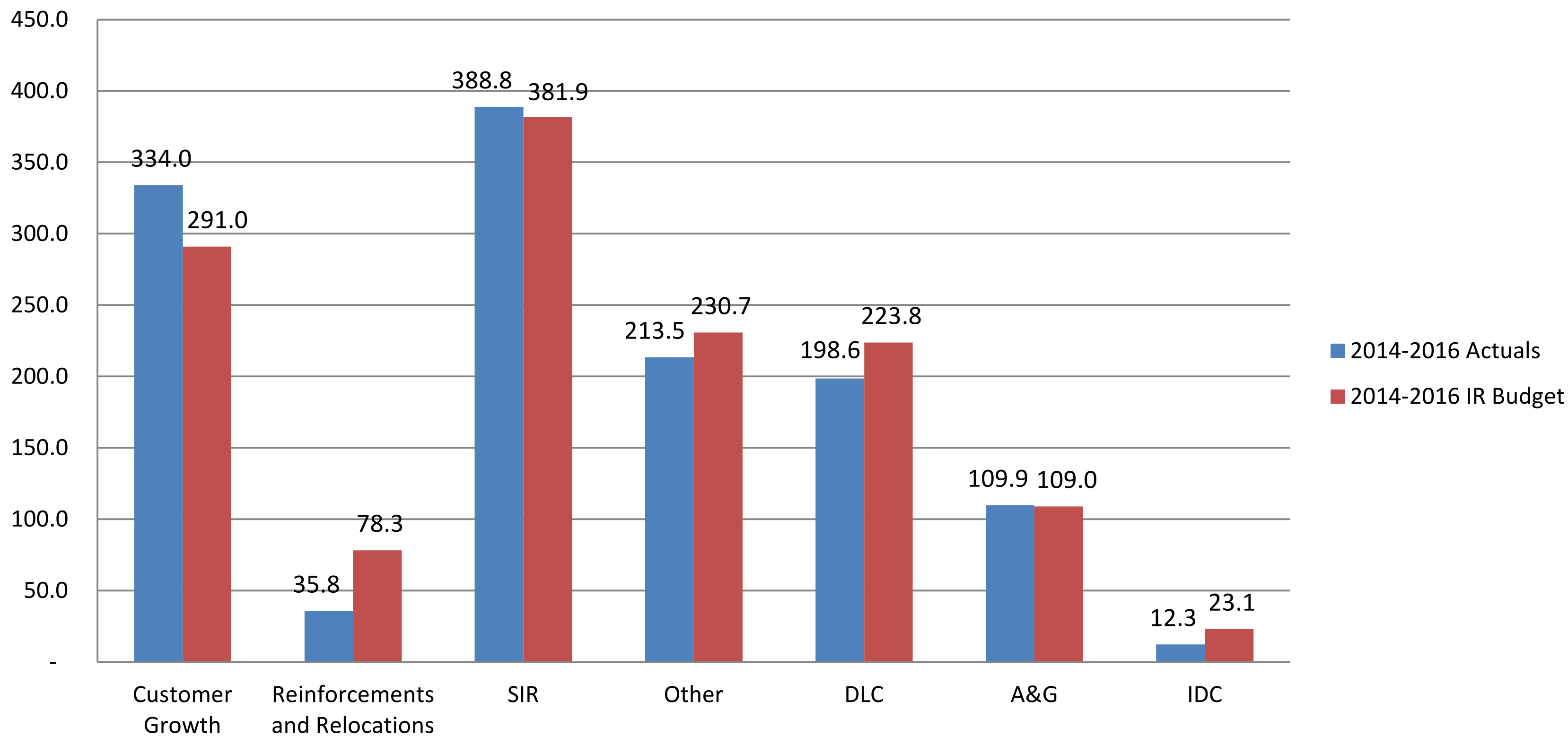
- Customer Growth $6.7M higher due to mix of work
- SIR $7.3M lower – refer to System Integrity and Reliability section for details
- Other $6.6M higher primarily due to higher spend in Facilities ($7.1M) associated with Building Improvements and Workspace Alterations and Storage ($6.4M), partially offset by lower spend in IT ($8.9M) – refer to Appendix for details on Information Technology
- DLC and A&G combined $5.5M under due to an overall reduction in costs

Witness: L. Stickles

Witness: L. Stickles

Capital Management : Total Core Cumulative 2014-2016

$ Millions



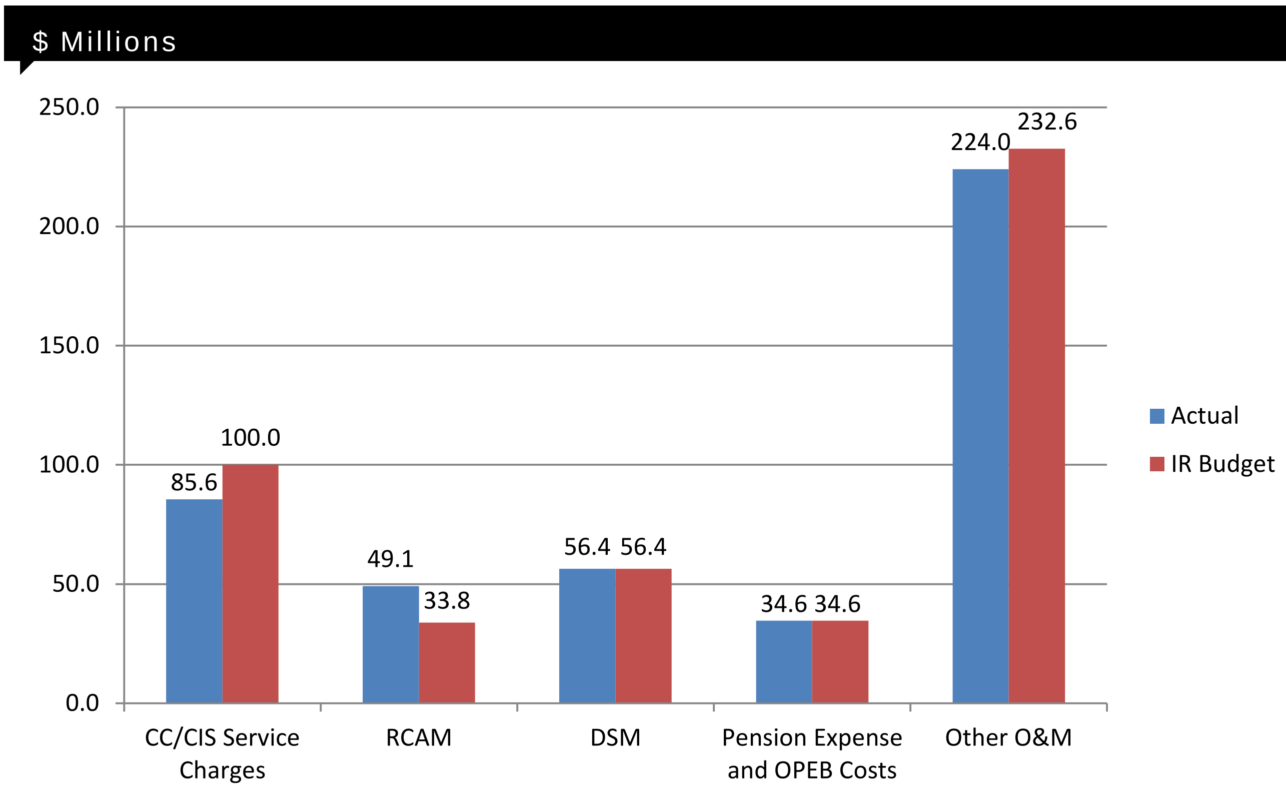
Witness: L. Stickles

2016 Utility O&M

Line No.	Cost Categories ($ Millions)	2016 Actual	2016 IR Budget	Variance
1.	CC/CIS Service Charges	85.6	100.0	(14.4)
2.	RCAM	49.1	33.8	15.3
3.	DSM	56.4	56.4	-
4.	Pension Expense and OPEB Costs	34.6	34.6	-
5.	Other O&M	224.0	232.6	(8.6)
6.	**Total Net Utility O&M Expense**	**449.7**	**457.4**	**(7.7)**

Witness: L. Stickles

2016 Utility O&M



Major Drivers:

1. Customer Care $14.4M lower primarily due to reduced CIS support costs, postage savings from higher number of customers on e-bill, and lower back office costs

2. RCAM $15.3M higher primarily due to centralization of IT and HR services ($13M)

3. Other O&M $8.6M lower primarily driven by IT and HR (primarily shared services offset to increase in RCAM ($14M)); other labour reductions, lower Bad Debt, and other ($14.6M), partially offset by higher severance costs due to workforce reductions ($20.0M)

Witness: L. Stickles

2017 Regulatory Activity

– Cap and Trade, 2017 Compliance Plan Proceeding	Current
– Nat. Gas Expansion Applications & Proceedings	
– DSM Midterm Review	
– Framework for Assessment of Gas Supply Plans -2017	EB-2017-0129
– Regulatory Consultative Pension / OPEB costs (pending)	EB-2015-0040
– EGD 2016 ESM & Def / Var accounts filing	April 2017
– 2018 Cap & Trade Compliance Plan filing	August 2017
– EGD 2018 Rate Proceeding (final CIR model year)	Sept. 2017
– QRAM applications for July & October 2017	June & Sept. 2017
– 2019 & beyond Incentive Regulation Filing	Q4 2017

2016 Year End Financial Results

Ryan Small
Nick Verma

2016 Utility Return on Equity – Actual vs. Approved

- 2016 Gross Revenue Sufficiency = $6.8M
- 2016 ESM = $3.4M
- 2016 Actual Normalized ROE Before ESM = 9.42%
- 2016 Actual Normalized ROE After ESM = 9.31%
- 2016 Board Approved ROE = 9.19%

2016 Allowed Revenue & Sufficiency – Actual vs. Approved

Line No.	($Millions)	Actual (Incl. CIS)	EB-2015-0114 / EB-2015-0049 Approved (Incl. CIS)	Variance
1.	Rate base	5,909.0	5,806.9	102.1
2.	Required rate of return	6.301%	6.405%	(0.104)%
3.	Cost of capital	372.3	371.9	0.4
	Cost of service			
4.	O&M (incl. CC/CIS rate smoothing adj.)	449.7	457.4	(7.7)
5.	Depreciation and amortization expense	292.7	288.9	3.8
6.	Fixed financing costs	3.2	1.9	1.3
7.	Municipal and other taxes	43.1	45.5	(2.4)
8.	Other revenues	(43.0)	(42.8)	(0.2)
9.	Income taxes on earnings	17.3	23.6	(6.3)
10.	Taxes on sufficiency	(1.8)	-	(1.8)
11.	Allowed revenue (excl. gas costs)	1,133.5	1,146.4	(12.9)
12.	Revenue at existing rates, net of gas costs	1,140.3	1,146.4	(6.1)
13.	Gross revenue sufficiency	6.8	-	6.8

* 2016 earnings sharing payable to ratepayers = $3.4M

Witness: L. Stickles

Witness: L. Stickles

2016 Utility Rate Base – Actual vs. Approved

Line No.	($Millions)	Actual (Incl. CIS)	EB-2015-0114 / EB-2015-0049 Approved (Incl. CIS)	Variance
1.	Net property, plant, & equip.	5,571.0	5,443.2	127.8
2.	Gas in storage	354.4	391.1	(36.7)
3.	Other working capital items	(16.4)	(27.4)	11.0
4.	Utility Rate Base	5,909.0	5,806.9	102.1

- PP&E – higher predominantly due to variances from prior years reflected in opening 2016 balances.
- Gas in storage – lower primarily due to lower QRAM approved PGVA reference prices.

2016 Utility Capital Structure – Actual vs. Approved

2016 ACTUAL UTILITY CAPITAL STRUCTURE

Line No.		Principal Incl. CC/CIS	Component	Indicated Cost Rate	Return Component	Return
		($Millions)	%	%	%	($Millions)
1.	Long term debt	3,472.8	58.77	4.95	2.909	171.9
2.	Short term debt	209.0	3.54	1.33	0.047	2.8
3.	Preference shares	100.0	1.69	2.16	0.037	2.2
4.	Common equity	2,127.2	36.00	9.19	3.308	195.5
5.		5,909.0	100.00		6.301	372.3

EB-2015-0114 / EB-2015-0049 2016 APPROVED UTILITY CAPITAL STRUCTURE

Line No.		Principal Incl. CC/CIS	Component	Indicated Cost Rate	Return Component	Return
		($Millions)	%	%	%	($Millions)
1.	Long term debt	3,566.8	61.42	4.96	3.048	177.0
2.	Short term debt	49.6	0.85	1.57	0.013	0.8
3.	Preference shares	100.0	1.72	2.16	0.037	2.2
4.	Common equity	2,090.5	36.00	9.19	3.307	192.0
5.		5,806.9	100.00		6.405	371.9

Witness: L. Stickles

2016 Utility Income – Actual vs. Approved

Line No.	($Millions)	Actual (Incl. CIS)	EB-2015-0114 / EB-2015-0049 Approved (Incl. CIS)	Variance
1.	Distribution margin (dist. rev. - gas costs)	1,140.3	1,146.4	(6.1)
2.	Other revenues	43.0	42.8	0.2
3.		1,183.3	1,189.2	(5.9)
4.	O&M (incl. CC/CIS rate smoothing adj.)	449.7	457.4	(7.7)
5.	Depreciation and amortization expense	292.7	288.9	3.8
6.	Fixed financing costs	3.2	1.9	1.3
7.	Municipal and other taxes	43.1	45.5	(2.4)
8.	Total costs and expenses	788.7	793.7	(5.0)
9.	Utility income before income taxes	394.6	395.5	(0.9)
10.	Income tax expense	17.3	23.6	(6.3)
11.	Utility net income	377.3	371.9	5.4

- Margin – lower customer unlocks, lower gas in storage carrying costs reflected in rates (QRAM updates), and lower variable trans., comp., & storage revenues, partially offset by higher LV CD revenues.
- O&M – lower CC & CIS, HR & IT costs, offset by higher RCAM and severance costs.
- Depreciation – impact of higher gross PP&E balances.
- Fixed financing costs – impact of increased credit facility.
- Municipal taxes – lower than forecast municipal tax rate increases, and GTA timing impacts.
- Income tax expense – higher than forecast net tax deductions.

Utility Return on Equity – Actual vs. Approved

	2016	2015	2014
- Gross Revenue Sufficiency	$6.8M	$12.9M	$25.3M
- ESM Amount	$3.4M	$6.45M	$12.65M
- Actual Normalized ROE Before ESM	9.42%	9.82%	10.46%
- Actual Normalized ROE After ESM	9.31%	9.56%	9.91%
- Board Approved ROE	9.19%	9.30%	9.36%

Witness: L. Stickles

Productivity

Melinda Yan
Margarita Suarez

Witness: L. Stickles

2016 Productivity Agenda

1. Overview of Productivity Reporting
2. 2016 Custom IR Capital and O&M Commitments
3. Embedded Initiatives
4. Productivity Results
5. Performance Measures Results

1. Overview of Productivity Reporting

- In 2016, safety and operational reliability remains the Company's number one priority, underpinning our pursuit of productivity improvements
- Building on the productivity work established in 2014 and 2015, the Company continued to engage all employees in productivity actions and reporting on initiatives to facilitate reporting to the OEB, as required
- The commitment will continue throughout the rest of the Custom IR term and beyond

1. Overview of Productivity Reporting

- To qualify as a sustainable Productivity gain, the following guidelines have been used:
  - Output and / or quality must be maintained at a lower cost
  - Output and / or quality must be improved at the same cost
  - Productivity actions should be those that have been embedded in IR budgets or incremental savings relative to the IR budget
  - Enbridge's required operational and customer service levels must not be compromised
  - All productivity actions matter. No materiality threshold was defined
- This resulted in over 150 reported (sustained and new) initiatives, which underpin the remainder of the presentation

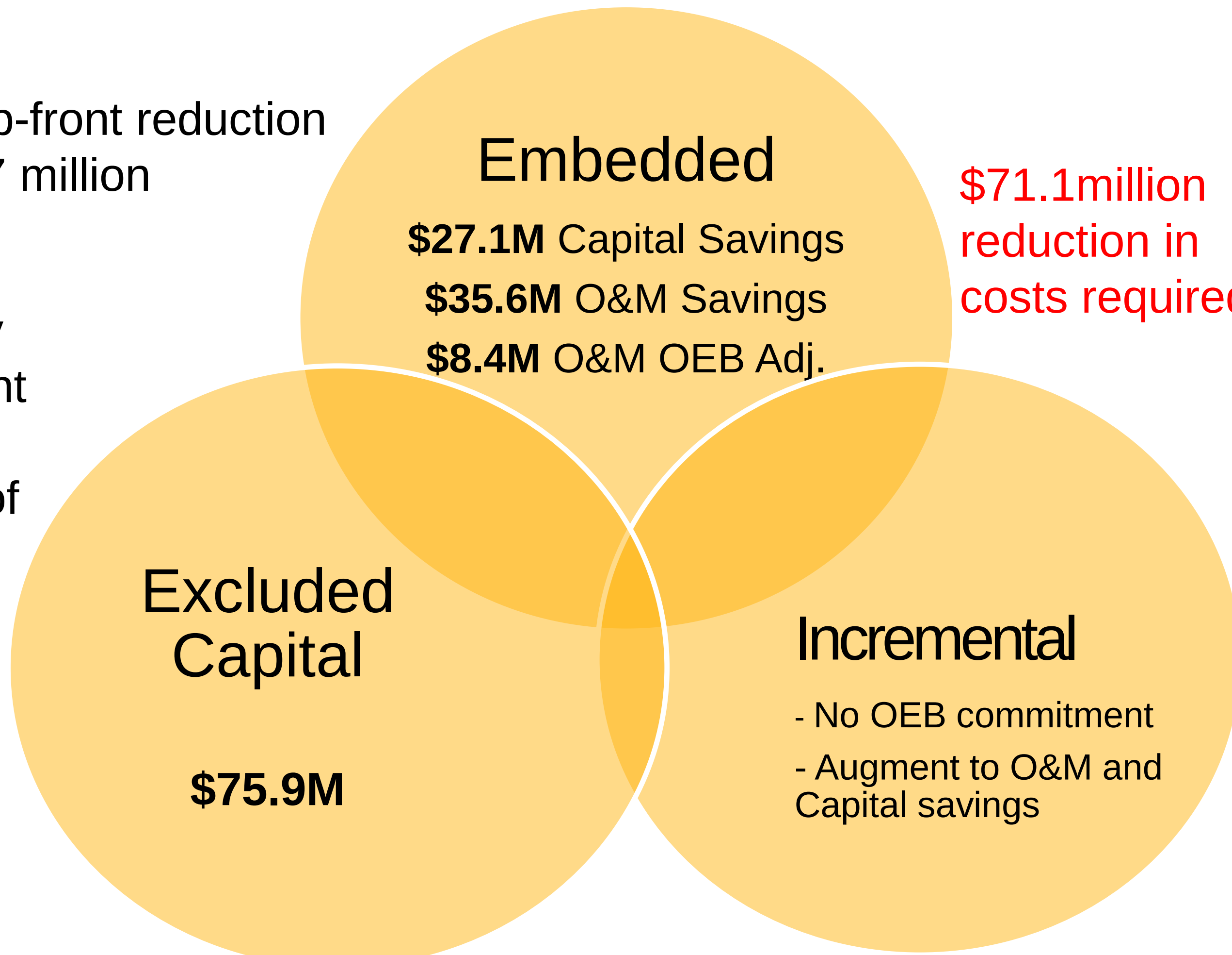
2. 2016 Custom IR Capital and O&M Commitments

2016

Total up-front reduction of $147 million

Productivity Commitment increases each year of the IR term

$71.1million reduction in costs required



Witness: L. Stickles

Witness: L. Stickles

2. 2016 Custom IR Capital and O&M Commitments

IR Budgets & EGD's Productivity Commitment

Capital Amounts Approved						
	2014	2015	2016	2017	2018	Total IR Term
Core Capital without Productivity	495.1	538.3	544.9	527.1	537.2	2,642.7
Less: Embedded Reduction	(26.2)	(28.7)	(27.1)	(35.2)	(45.3)	(162.5)
Less: Variable Costs	(25.1)	(63.0)	(75.9)	(50.0)	(50.0)	(264.5)
Approved Core Capital Expenditures	443.8	446.6	441.9	441.9	441.9	2,216.1

Other O&M Amounts Approved						
	2014	2015	2016	2017	2018	Total IR Term
Proposed "Other" O&M	252.1	261.6	276.6	287.8	299.5	1,377.6
Less: Embedded Reduction	(24.1)	(30.1)	(35.6)	(39.3)	(43.2)	(172.3)
Less: OEB Adjustment	-	(1.2)	(8.4)	(13.6)	(19.0)	(42.2)
Approved "Other" O&M	228.0	230.3	232.6	234.9	237.3	1,163.1

Witness: L. Stickles

3. Embedded Initiatives

O&M and Capital Embedded Productivity Results

	2016 Embedded O&M and Actual and Capital Reductions	Embedded Commitment ($M)	Actual ($M)
1.	O&M: Merit increase	(2.5)	(0.5)
2.	O&M: Employee Benefits	(2.3)	(1.1)
3.	O&M: Incremental cost to service new customers	(1.7)	0.1
4.	O&M: Incremental safety and integrity work	(9.3)	(2.6)
5.	O&M: External contractor rate increases	(1.7)	(0.4)
6.	O&M: Increased volume of locates-compliance with Bill 8	(3.8)	(3.0)
7.	O&M: FTEs	(8.7)	(15.0)
8.	O&M: Bad Debt expenses	(5.6)	(8.1)
9.	Total Estimated O&M Reductions	(35.6)	(30.5)
10.	Capital: Customer Attachments	(24.4)	(17.7)
11.	Capital: Departmental Labour	(2.7)	(11.6)
12.	Total Estimated Capital Reductions	(27.1)	(29.3)
13.	Total Estimated Embedded O&M & Capital Reductions	(62.7)	(59.8)

4. Overall 2016 Productivity Results

	2016					
	O&M ($M)		Capital ($M)		Total ($M)	
	Commitment	Actual	Commitment	Actual	Commitment	Actual
Embedded	(35.6)	(30.5)	(27.1)	(29.3)	(62.7)	(59.8)
Incremental		(12.9)		(4.9)		(17.8)
OEB Adjustment	(8.4)				(8.4)	
2016 Total Savings	(44.0)	(43.4)	(27.1)	(34.2)	(71.1)	(77.6)

Witness: L. Stickles

5. Performance Measures

Customer Relationship (SQRs)	Operational Performance
• Customer Satisfaction Index • Call Answering Service Level • % Emergency Calls Resp. to within 1Hr • Appointments Met within Designated Time • Time to Reschedule Missed Appointments • # Days to Reconnect Customer • # Calls Abandon Rate • Meter Reading Performance • # Days to provide a Written Response	• EHS: TRIF Rate • # Excavation Damages per 1k locates • Service Leaks Repaired per Mile of service • Total # Grade 1 (A) leaks repaired during Yr. • Operational Effectiveness: All Outages per 1000 Customers

Witness: L. Stickles

5. Customer Relationship Performance Measure Results

All Customer Relationship metrics are achieving strong performance

Customer Relationship Performance	OEB Target	2013	2014	2015	2016	Trending
1. Overall Customer Satisfaction Index	NA	78%	77%	79%	79%	↑
2. Call Answering Service Level (SQR)	75%	75.9%	79%	79.7%	82.4%	↑
3. Percentage of Emergency Calls Responded to within One Hour (SQR)	90%	96.1%	96.9%	96.7%	95.2%	↔
4. Appointments Met within the Designated Time Period (SQR)	85%	94.2%	95.1%	95.2%	95.3%	↑
5. Time to Reschedule a Missed Appointments (SQR)	100%	95.0%	95.5%	94.8%	95.0%	↔
6. Number of Days to Reconnect a Customer (SQR)	85%	92.6%	94.0%	94.6%	94.8%	↑
7. Number of Calls Abandon Rate (SQR)	10%	2.8%	1.9%	2.3%	1.8%	↑
8. Meter Reading Performance (SQR)	0.5%	0.50%	0.69%	0.51%	0.40%	↑
9. Number of Days to provide a Written Response (SQR)	80%	94.5%	93.3%	100.0%	95.5%	↔

↑ – Improving
↔ – Stable
↓ – Decreasing

5. Operational Performance Measure Results

All Operational Performance metrics are achieving strong performance

Operational Performance	2013	2014	2015	2016	Trending
1. Employees Health and Safety: Total Reportable Injury Frequency Rate	2.01	2.00	1.06	0.93	↑
2. Damage Prevention: Number of Excavation Damages per 1000 locates	2.84	2.49	2.43	2.17	↑
3. Leak Management: Service leaks Repaired per Mile of service	0.09	0.06	0.06	0.06	↔
4. Leak Management: Total Number of Grade 1 (A) leaks repaired during the year	1280	661	905	991	↔
5. Operational Effectiveness: All Outages per 1000 Customers	6.09	5.31	4.84	4.60	↑

↑ – Improving
↔ – Stable
↓ – Decreasing

Cap & Trade Impacts on Volumetric Forecasting

Margarita Suarez
Hulya Sayyan

Why is an adjustment being considered for 2018 volumes

Cap and Trade Policy-Desired Outcome

- Putting a price on carbon creates the incentive to cut emissions
- Law of demand and supply
- Incent behaviors that bring about lasting change
- Consistent with OEB Framework, single price signal increases all-in fuel cost, reduces demand

2017 Application & Settlement

- Developed in early 2016, prior to Cap and Trade Framework
- No experience with which to base appropriate volumetric adjustment; risk of premature & arbitrary adjustment
- No adjustment applied for Cap and Trade impact
- Commitment at Settlement to assess impact of Cap and Trade on 2018 volumes

Proposed for 2018

- Leverage approved, existing methodology
- Utilize estimated price elasticities as proxies
- Allows for future refinement of Cap and Trade estimated impacts as more actual information becomes available

ENBRIDGE

Board-Approved Volumetric Forecast Methodology

Approved Methods consistently applied since 2001

General Service Customers:

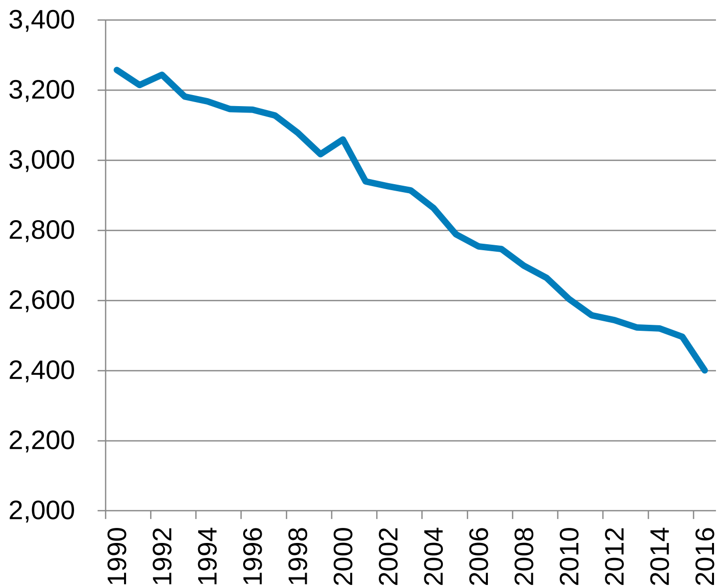
- Regression Models to forecast Average Use for residential and small commercial customers
- Currently, over 30 years of historical data
- About 40 models, each unique for each Revenue Class and Region combination
- Primary Driver Variables:
  - Weather
  - Price of Gas
  - Vintage
  - Employment

Contract Market Customers:

- Grassroots forecast in communication with Key Account Executives
- Uses recent history and expected operational changes to estimate load
- Large volume communication used to potentially adjust Rate 6 Industrial average use forecast
- Primary Drivers considered:
  - Weather
  - Economic conditions

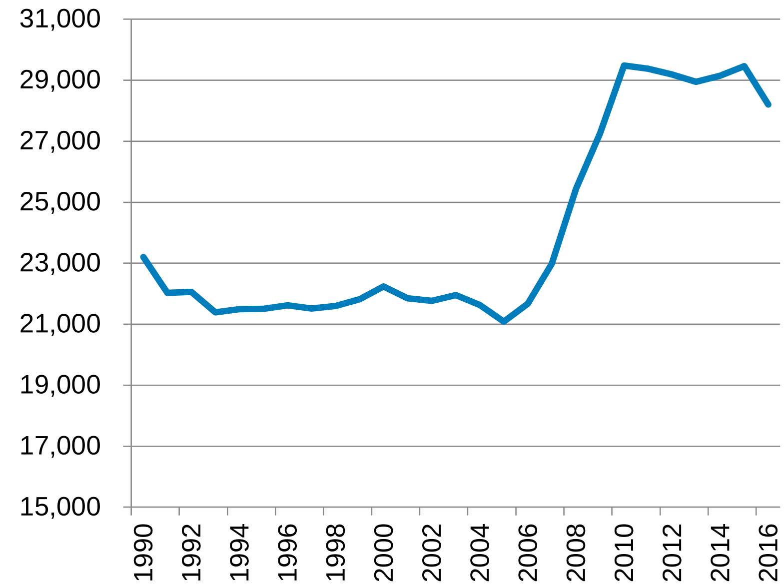
Actual Normalized Average Use: 1990-2016

Rate 1



- Consistent decline in average use consumption

Rate 6



- Relatively flat average use consumption
- History characterized by migration of Contract Market customers into General Service

ENBRIDGE

Witness: L. Stickles

Witness: L. Stickles

Average Use Regression Models: Rate 1 General Service (Residential)

- Revenue Class 20 Residential Rate 1 in Central Region
  - Represents close to 70% of volumes and customers

- Log-Log Model specification to measure elasticity impacts

$\log(average\ use) = \log(gas\ price) + \log(weather) + etc.$

- Gas Price coefficient interpretation
  - Significant at 90% level of confidence
  - Negative sign shows inverse relationship of demand to price
  - Magnitude shows low sensitivity or inelastic demand response to price change

- Gas Price coefficient present in all revenue classes within Rate 1

Dependent Variable: LOG(Average Use_CEN20)		
Sample: 1985 2015		
Variable	Coefficient	t-Prob.
C	0.78	0.32
LOG(Degree Day)	0.70	0.00
LOG(Real Gas Price)	-0.03	0.08
LOG(Vintage)	0.54	0.00
LOG(Employment)	0.21	0.02
R-squared	0.99	

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Witness: L. Stickles

Average Use Regression Models: Rate 1 – Accuracy results

- Average variance of 0.6% since 2001
- 2016 had the largest average use variance since regression models were used
- Based on most recent trend, 2016 considered an outlier
- 2016 decline will be included in sample for 2018 forecast

RATE 1 ACTUAL & FORECAST COMPARISON

	Actual Normalized Average Use Per Customer	Board Approved Normalized Average Use Per Customer[1,3]	Variance Normalized Average Use Per Customer	% Variance Normalized Average Use Per Customer
	(m3)	m(3)	(2-3)	100*((2-3)/3)
2001	3,014	3,044	(30)	-1.0%
2002	2,980	2,970	10	0.3%
2003	2,877	2,892	(15)	-0.5%
2004	2,843	n/a	n/a	n/a
2005	2,890	2,953	(63)	-2.1%
2006	2,796	2,850	(54)	-1.9%
2007	2,726	2,687	39	1.5%
2008	2,636	2,647	(11)	-0.4%
2009	2,616	2,637	(21)	-0.8%
2010	2,579	2,622	(43)	-1.6%
2011	2,594	2,643	(49)	-1.9%
2012	2,529	2,510	18	0.7%
2013	2,547	2,568	(22)	-0.8%
2014	2,475	2,433	41	1.7%
2015	2,427	2,419	9	0.4%
2016	2,401	2,480	(79)	-3.2%

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Average Use Regression Models: Rate 6 General Service (Apt, Small Com & Small Ind)

- Revenue Class 48 (Commercial) in Central Region
  - Represents about 70% of customers, and close to 50% of volumes in Rate 6
- Log-Log Model specification
- Gas Price coefficient interpretation
  - Negative sign shows inverse relationship of demand to price
  - Magnitude shows low sensitivity or inelastic demand response to price change
- For all other revenue classes, if price variable is <u>not significant</u>, will exclude from model and assume no price impact on Rate 6 demand

Dependent Variable: LOG(Average Use_CEN48)		
Sample: 1985 2015		
Variable	Coefficient	t-Prob.
C	-0.97	0.41
LOG(Degree Day)	0.84	0.00
LOG(TIME)	-0.14	0.00
LOG(Vacancy Rate)	-0.07	0.00
LOG(ONT GDP)	0.35	0.00
LOG(Real Gas Price)	-0.04	0.16
R-squared	0.97	

ENBRIDGE

Witness: L. Stickles

Average Use Regression Models: Rate 6 – Accuracy results

- Average variance of 0.8% since 2001

RATE 6 ACTUAL & FORECAST COMPARISON

	Actual Normalized Average Use Per Customer	Board Approved Normalized Average Use Per Customer[1,3]	Variance Normalized Average Use Per Customer	% Variance Normalized Average Use Per Customer
	(m3)	m(3)	(2-3)	100*((2-3)/3)
2001	22,510	22,643	(133)	-0.6%
2002	22,097	22,125	(28)	-0.1%
2003	21,593	21,685	(92)	-0.4%
2004	21,472	n/a	n/a	n/a
2005	22,241	22,507	(266)	-1.2%
2006	22,272	21,999	273	1.2%
2007	22,783	21,010	1773	8.4%
2008	24,869	24,204	665	2.7%
2009	27,654	28,165	(512)	-1.8%
2010	29,106	27,949	1157	4.1%
2011	29,471	28,029	1442	5.1%
2012	28,941	30,122	(1182)	-3.9%
2013	29,203	29,878	(675)	-2.3%
2014	28,634	28,383	251	0.9%
2015	28,600	28,341	259	0.9%
2016	28,203	28,753	(550)	-1.9%

Contract Market Grassroots Forecast: Accuracy results

- By 2013, demand variability from recession and migration have stabilized
- Average variance of -0.6% since 2006, 0.9% since 2013

CONTRACT CUSTOMERS' TOTAL NORMALIZED VOLUME

	Actual Normalized Consumption ($10^6 m^3$)	Board-Approved Normalized Consumption ($10^6 m^3$)	% Variance Normalized Consumption (3/2)*100
2006	4,119.1	4,387.9	-6.1%
2007	3,739.8	4,134.3	-9.5%
2008	3,099.6	3,355.2	-7.6%
2009	2,191.4	2,316.6	-5.4%
2010	2,191.5	2,008.6	9.1%
2011	2,081.8	2,022.9	2.9%
2012	2,072.6	1,943.4	6.6%
2013	2,022.7	1,945.5	4.0%
2014	1,923.6	1,967.0	-2.2%
2015	1,913.5	1,916.2	-0.1%
2016	1,935.1	1,899.8	1.9%

Proposed 2018 Forecast Methodology

General Service Customers:

- Step #1:

  Regress historical average use (including 2016) against driver variables to estimate price elasticity of demand.

- Step #2:

  Include Cap and Trade obligation costs as part of Rate 1 and Rate 6 gas rates for 2018.

- Step #3:

  Calculate the 2018 average use forecast using estimated coefficient (Step 1) and combined impact of all elements of gas price (Step 2).

Contract Market Customers:

- Include Cap and Trade considerations as part of grassroots communication with contract customers
- Determine participation status (mandatory or voluntary) based on declaration form
- Forecast demand and abatement activity associated with Cap and Trade compliance as estimated by customer

Measuring the Impact for Revenue Classes 20 & 48: *sample calculations*

Rate 1 Typical Customer

- Based on Revenue Class 20 Central region (*slide 5 regression*)
- Estimated Gas price coefficient = **-0.03%** ↓
  - A 1% price increase results in a 0.03% decrease in average use volume.
- Assuming a **10% increase** in Total Gas Price w/ Cap and Trade obligation costs,
- Estimated demand impact = 10% x (-0.03%) = **-0.3%** ↓

Rate 6 Typical Customer

- Based on Revenue Class 48 Central region (*slide 7 regression*)
- Estimated Gas price coefficient = **-0.038%** ↓
  - A 1% price increase results in a 0.038% decrease in average use volume.
- Assuming a **10% increase** in Total Gas Price w/ Cap and Trade obligation costs,
- Estimated demand impact = 10% x (-0.038%) = **-0.38%** ↓

- **For a typical Residential customer consuming 2,400 m^3, Cap and Trade costs result in an estimated incremental 7 m^3 decrease in volumetric demand.**
- **For a typical Small Commercial customer consuming 22,600 m^3, Cap and Trade costs result in an estimated incremental 86 m^3 decrease in volumetric demand.**

Forecast Considerations Beyond 2018

Other Findings

- Limited publicly-available elasticity estimates specifically on carbon price
- Inelastic demand is a consistent feature
- "Learning curve" and "experience curve" effects results in variability of elasticity impact over time
- Expectation that elasticity increases in the long-run when technology and costs are not fixed

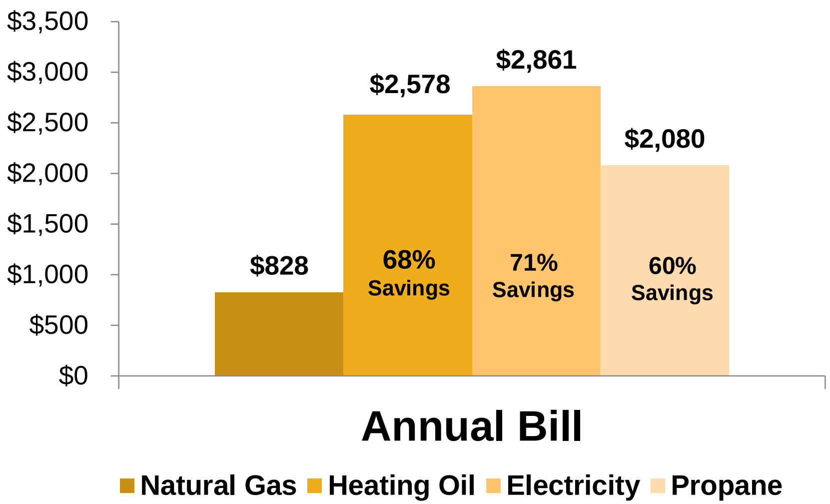
WCI Jurisdictional Impacts

- California Energy Commission's Energy Demand Forecast (CEDU) do not include carbon pricing in their inputs; more certainty post 2020
- Gaz Métro & Gazifère do not include Cap and Trade price impacts in their demand forecasts

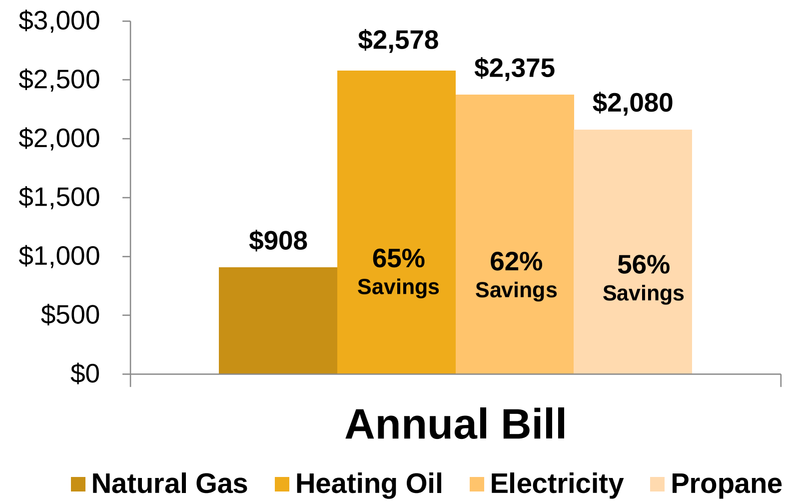
Witness: L. Stickles

Forecast Considerations Beyond 2018

No Cap and Trade Costs



With Cap and Trade + Electricity Reduction



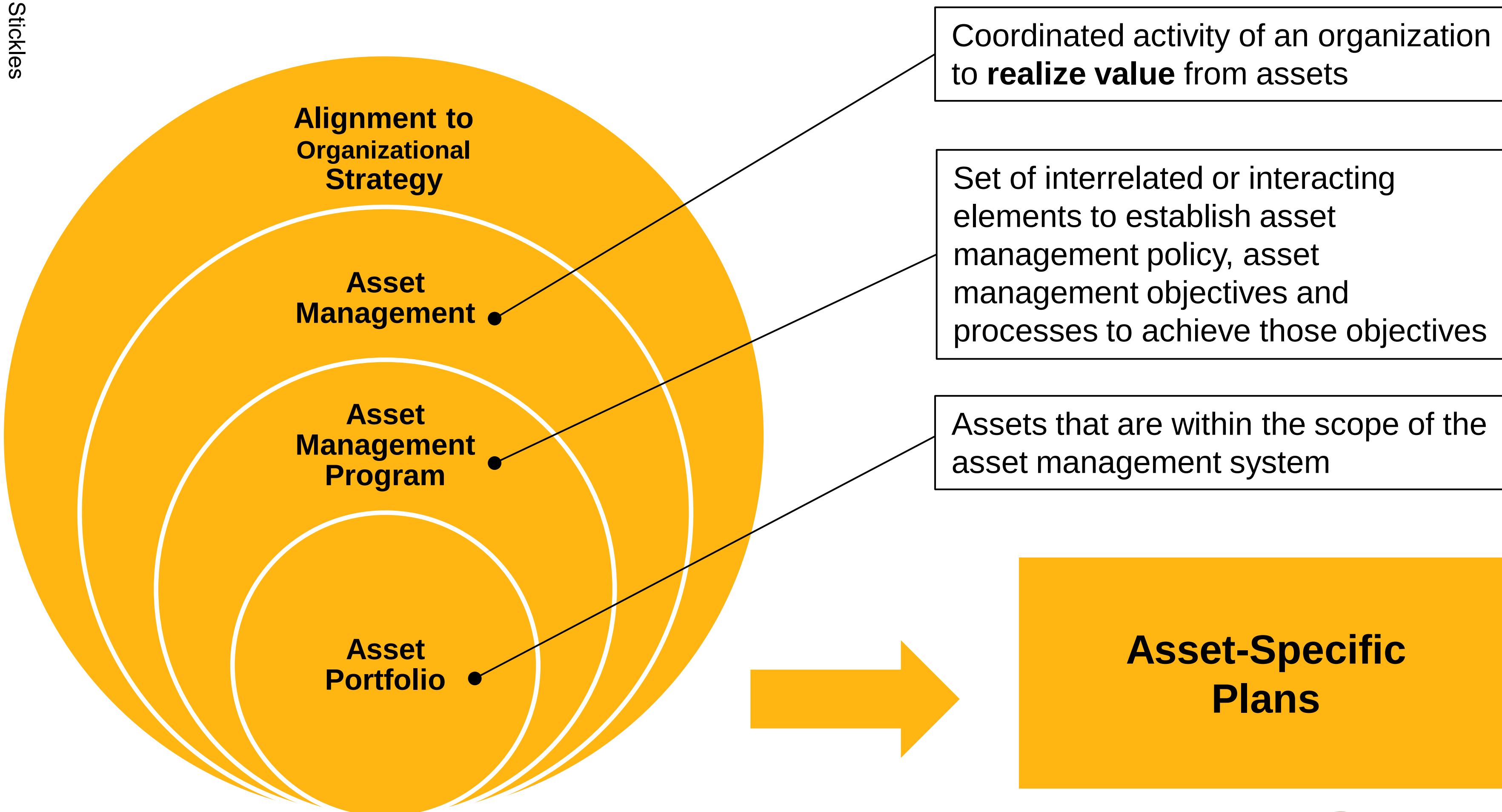
* *Cap and Trade costs layered only on natural gas prices (April 2017 QRAM).*

Asset Management

Hilary Thompson
Erik Naczynski

Witness: L. Stickles

Asset Management at EGD



Witness: L. Stickles

Asset Management at EGD

ALL COMPANY ASSETS

GAS-CARRYING ASSETS

Pipe
Stations
Storage
Customer Assets
Customer Growth*

NON GAS-CARRYING ASSETS

Real Estate Services
Fleet & Equipment
Technology Information Services
Business Development

*The Customer Growth Asset Class manages the acquisition and installation of assets to support the addition of new customers. Once in service, these assets are managed by Pipe, Stations, or Customer Assets as applicable.

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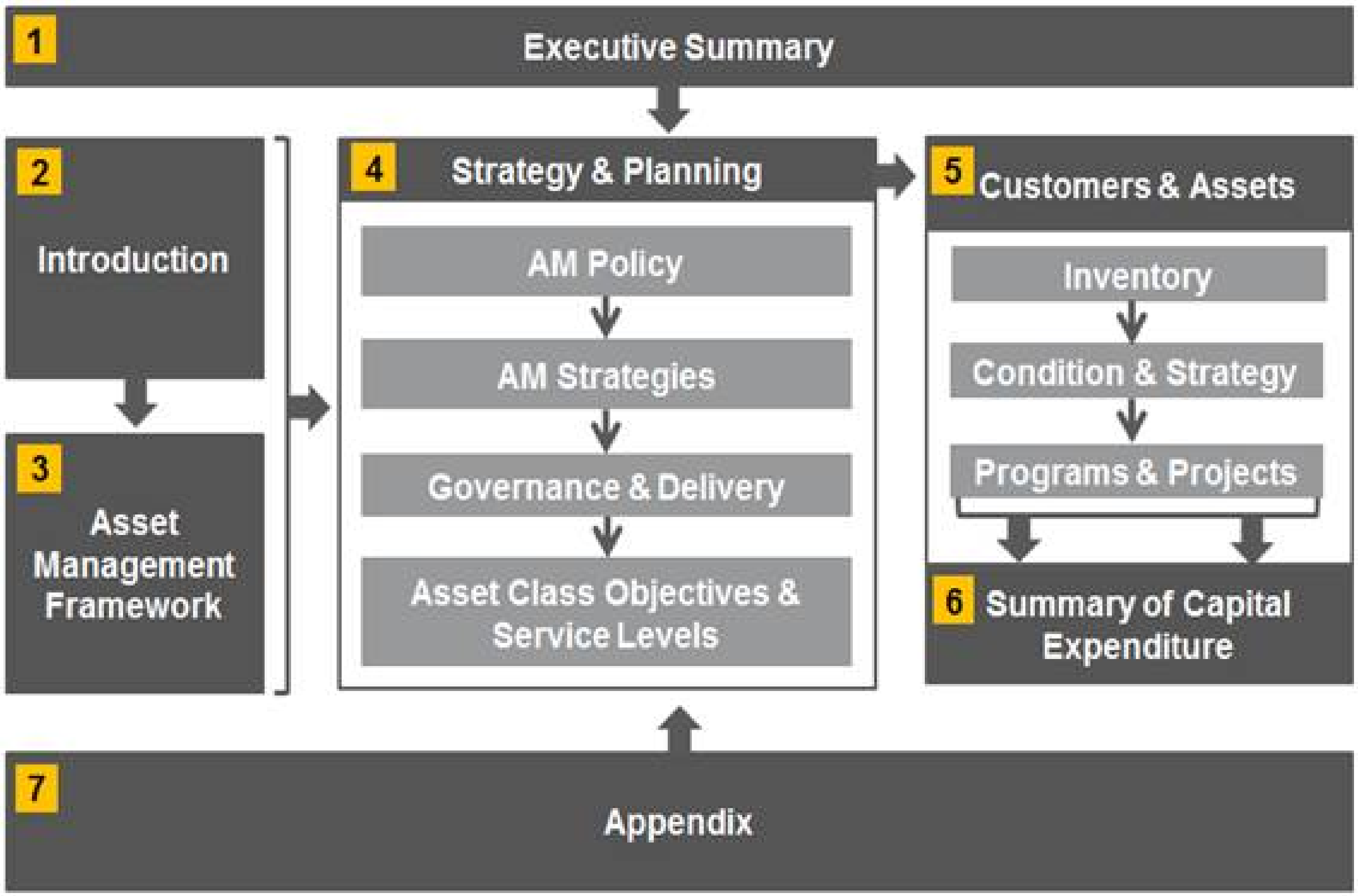
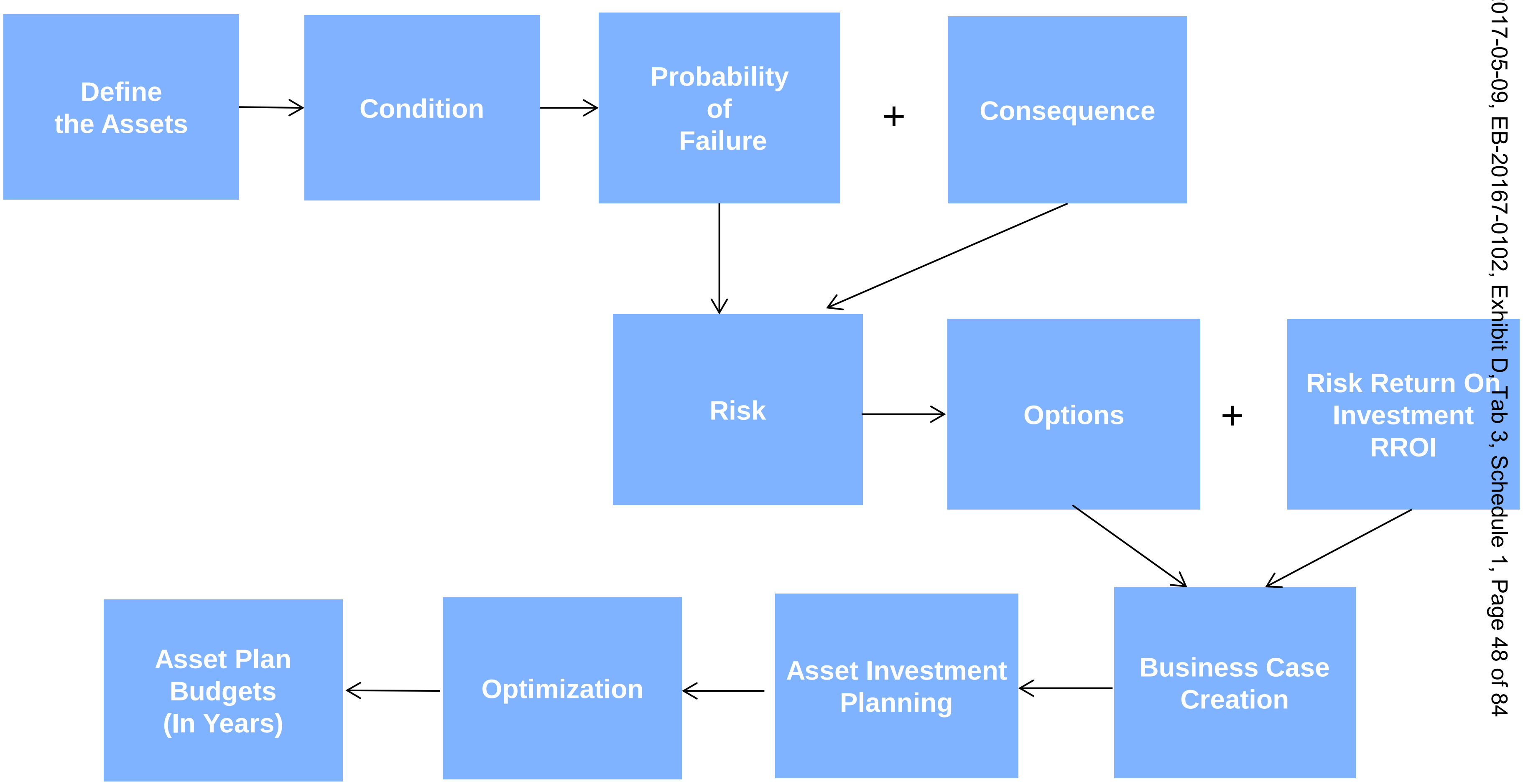
Asset Management at EGD: Asset Plan Structure



Witness: L. Stickles

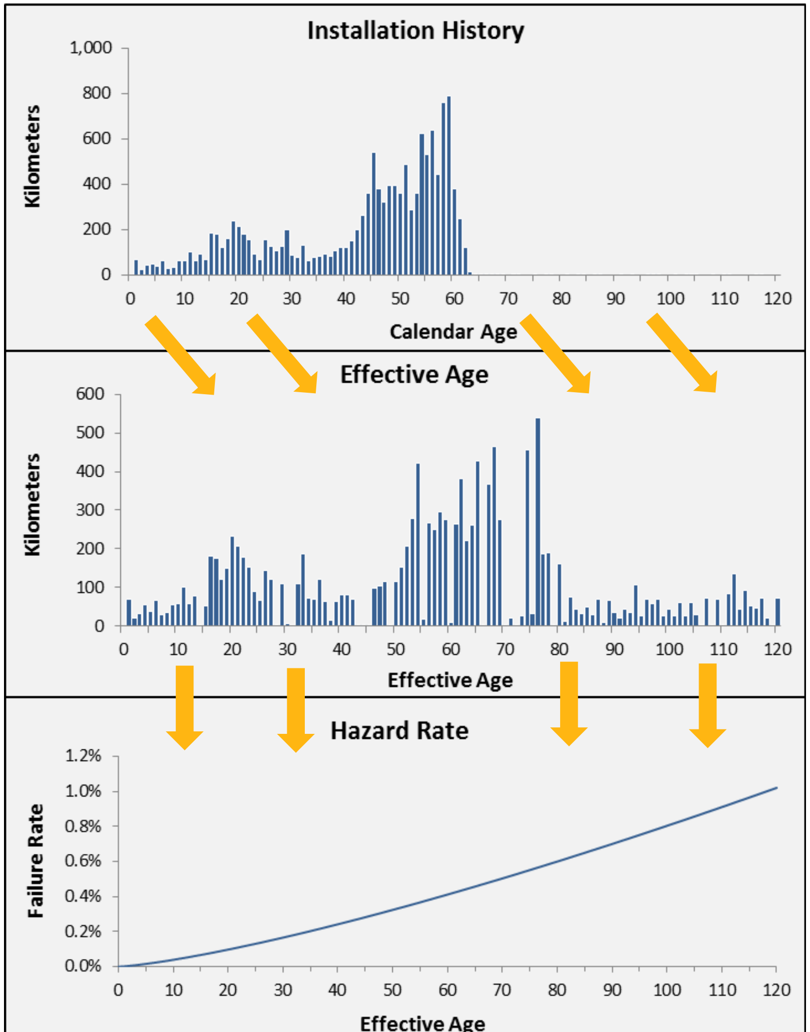
Understanding the Process



Witness: L. Stickles

Understanding the Process

Developing Probability of Failure (POF) Curves



Distribution of assets based on calendar age

Distribution of assets based on effective age (multipliers and condition assessment applied)

Effective age is then applied to the failure curve to determine POF for each asset

Witness: L. Stickles

Understanding the Process

Probability of Failure X **Consequence** = **Risk**

COF

Consequence of Failure

Population and Building Data → COF

Model Structure → COF

Emergency Repair Costs → COF

Outcome Definition and Probability → COF

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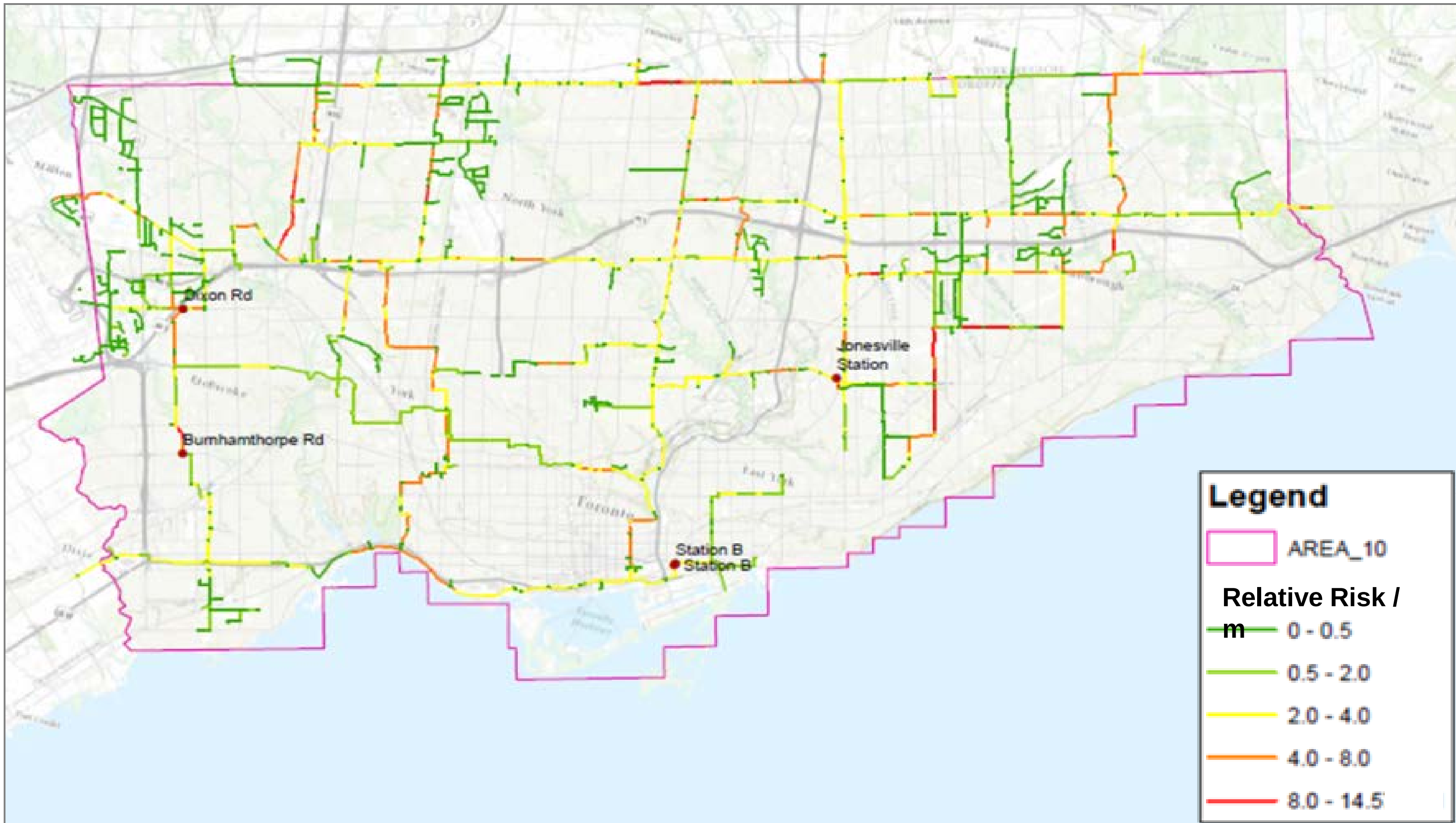
Risk

Understanding the Process

Risk



Gas Distribution System = 6.3M Dynamic Segments

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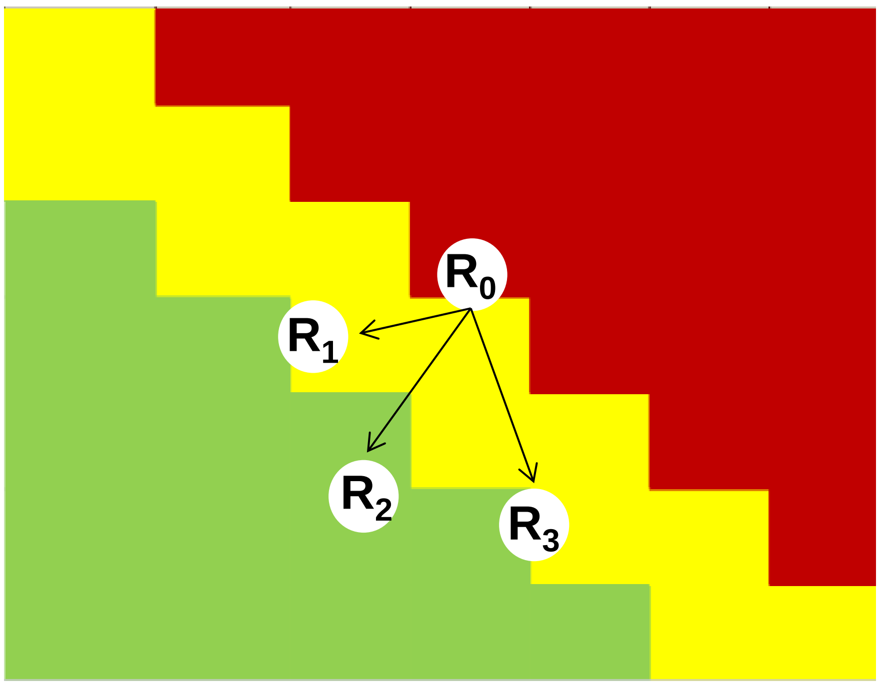
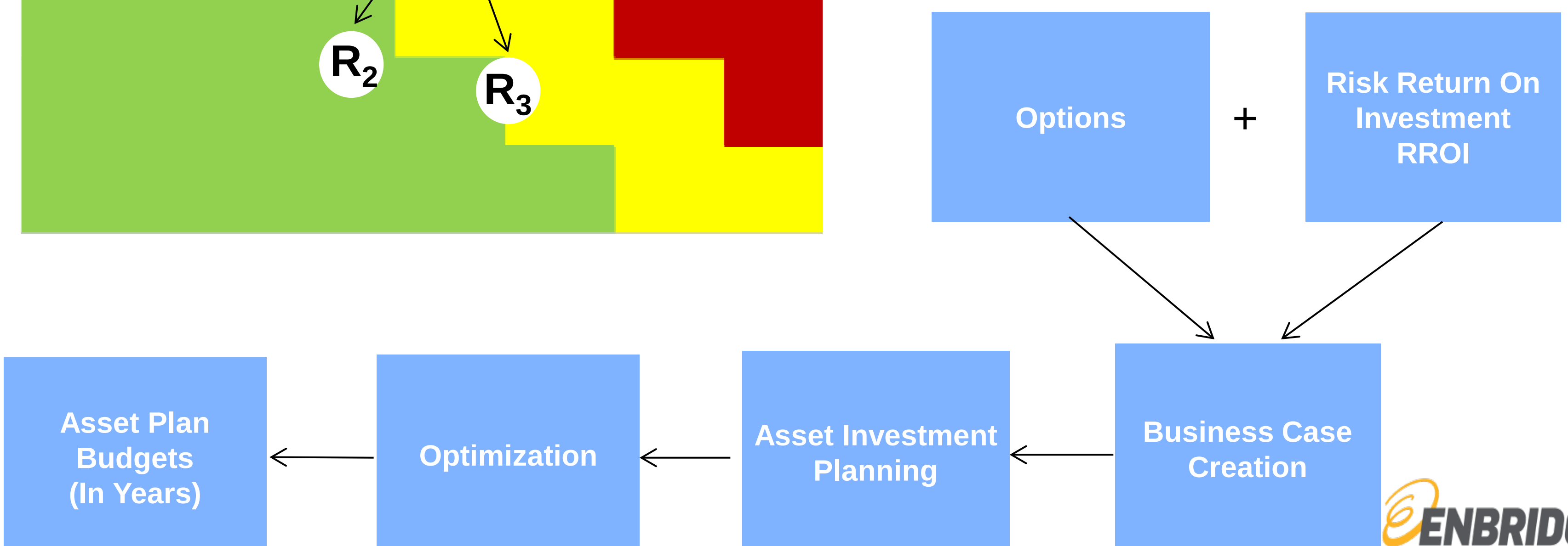
Understanding the Process



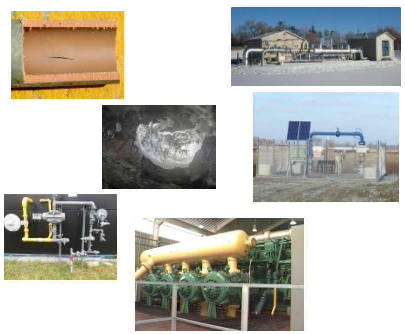
$$\text{RROI} = \frac{Risk\ Reduction}{Total\ Net\ Capital\ Investment}$$



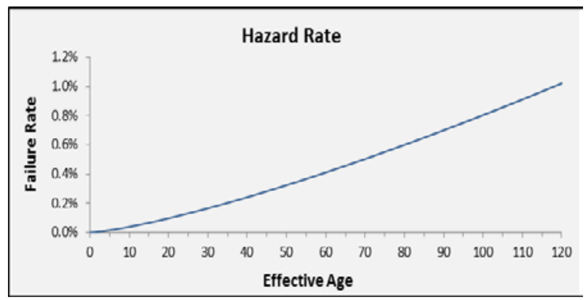
Connecting the Dots

Realize value from assets through defendable and repeatable decisions that balance risk, cost, and operational performance

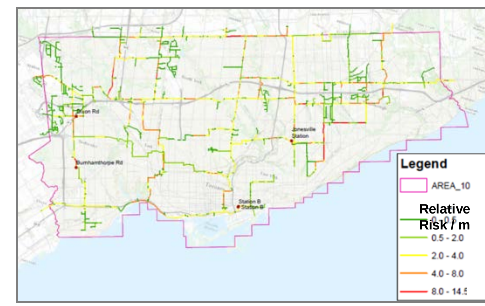
Understand our Assets



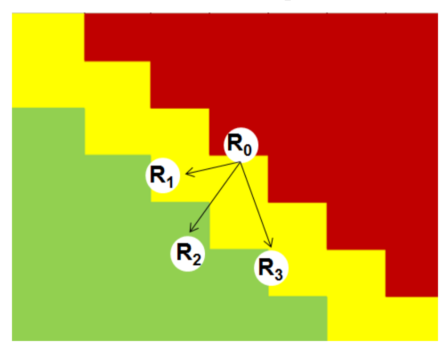
Understand Condition



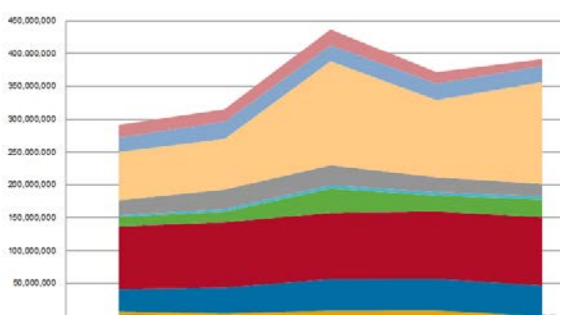
Understand Risk



Evaluate Options



Manage Portfolio



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Witness: L. Stickles

System Integrity and Reliability

Commodity Carrying Assets

Hilary Thompson
Deirdre Broude

Witness: L. Stickles

System Integrity & Reliability

System Integrity & Reliability for commodity carrying assets consists of those programs, projects and activities focused on:

- Maintaining the entire natural gas storage, transmission and distribution pressurized system at or above adopted standards for continued safe and effective operation (System Integrity);
- Ensuring the dependable delivery of natural gas to Enbridge’s customers and end-users (Reliability);

System Integrity & Reliability

Efforts have been focused on:

- Gaining a better understanding of the health and condition of assets as it pertains to risk and risk reduction
- Developing risk based assessment methodologies
- Designing appropriate risk reduction strategies for each asset (reduce risk to lowest practical level)
- Developing an asset management framework in order to make effective decisions in terms of prioritizing capital spend with the outcomes being spending the right money on the right asset at the right time.
- Re-prioritizing capital to address high risk and low performing assets

SIR, Reinforcements & Relocations and Storage Overall Variance

$ Thousands

ASSET CATEGORY	Evidence	2014/15 ACT	2014/15 IRM	2016 ACT	2016 IRM
Mains	B2-5-2	58,346	48,682	35,833	22,099
Services	B2-5-3	45,405	46,149	22,651	41,227
Stations	B2-5-4	36,512	50,432	26,319	24,517
Meters/Records	B2-5-5	67,135	68,458	26,350	35,810
Reinforcements	B2-3-1	8,310	28,352	7,879	8,743
Relocations	B2-4-1	5,721	28,622	13,844	12,603
Storage	B2-6-1	35,276	32,976	15,323	8,910
Total		**256,706**	**303,671**	**148,199**	**153,909**

Note: Totals above related to SIR exclude amounts related to Direct Resource Costs and Envision

- Mains: Capital dollars were re-allocated across the portfolio through risk-based assessments and portfolio prioritization. Incremental capital spent on mains replacement and assessment of high risk assets ($13M in 2016)
- Services: Capital was re-allocated to higher risk leaking / poorly performing assets rather than the anticipated proactive programs that were designed to stay ahead of the failure curve ($16M)
- Stations: Capacity related projects have been deferred ($6.2M)
- Records: program phased and risk prioritized
- Storage: remediation of degrading compressor foundations ($3M)

Gas Supply

Connecting to Supply Markets

Kerry Lakatos-Hayward
Andrew Welburn

Importance of transportation for gas supply planning

Transportation services connect our franchise to natural gas supply across North America

- Less than 1% of natural gas supply requirements produced in Ontario
- Transportation pipelines connect our distribution system to existing and emerging sources of natural gas supply
- Transportation service attributes are a critical part of operating our distribution system in a safe, reliable, and cost effective manner
- Transportation pipelines and related services are evolving rapidly creating opportunities to enhance gas supply plans

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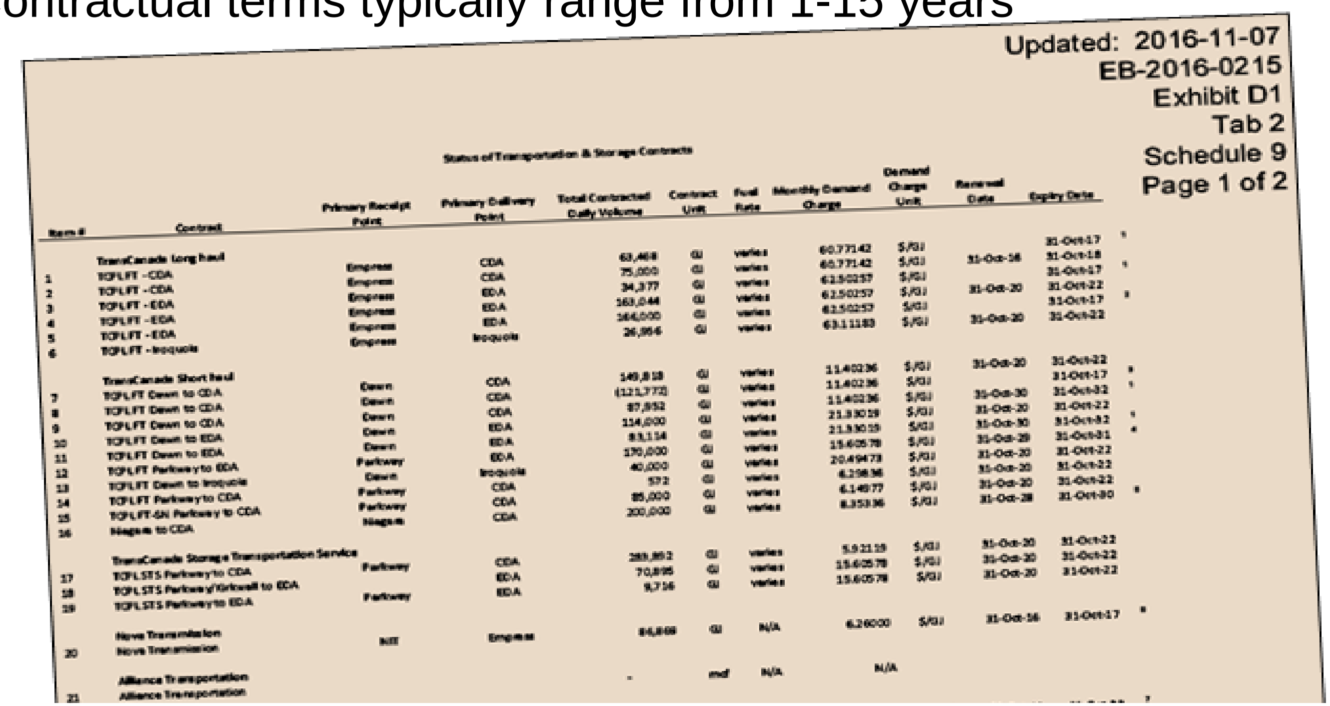
Witness: L. Stickles

Witness: L. Stickles

2017 Transportation Portfolio

The transportation portfolio and many of the service attributes are filed with the Board on an annual basis

- Transportation portfolio is filed as part of the annual rate application
- Developed to provide reliable, flexible, diverse and cost effective access to natural gas supply
- Contracts typically executed 2-3 years prior to commencement
- Contractual terms typically range from 1-15 years



Updated: 2016-11-07
EB-2016-0215
Exhibit D1
Tab 2
Schedule 9
Page 1 of 2

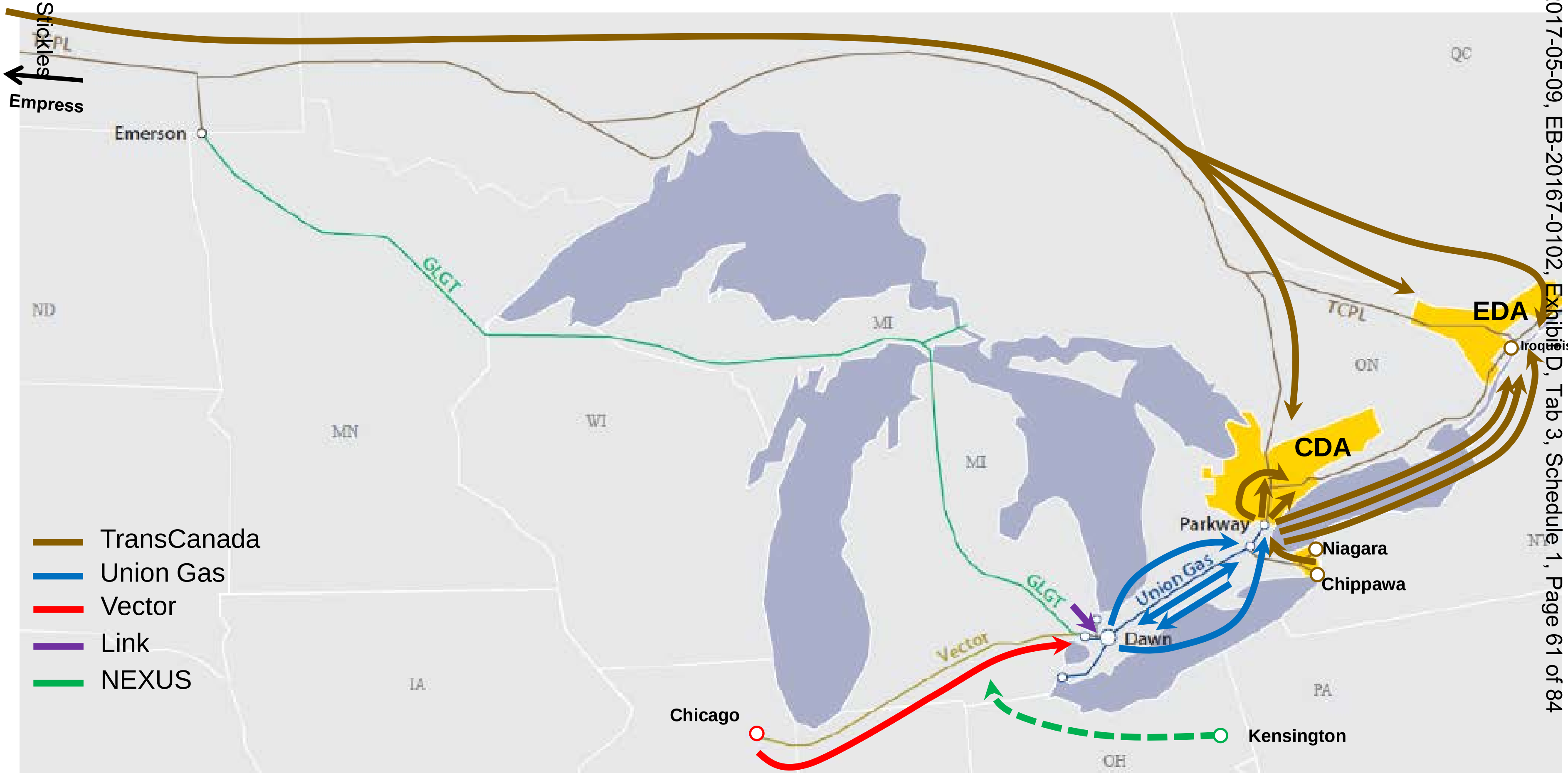
Status of Transportation & Storage Contracts

Item #	Contract	Primary Receipt Point	Primary Delivery Point	Total Contracted Daily Volume	Contract Unit	Fuel Rate	Monthly Demand Charge	Demand Charge Unit	Renewal Date	Expiry Date
	TransCanada Long haul									
1	TCPL FT - CDA	Empress	CDA	63,468	GJ	varies	60.77142	$/GJ		31-Oct-17
2	TCPL FT - CDA	Empress	CDA	75,000	GJ	varies	60.77142	$/GJ	31-Oct-16	31-Oct-18
3	TCPL FT - EDA	Empress	EDA	34,377	GJ	varies	62.50257	$/GJ		31-Oct-17
4	TCPL FT - EDA	Empress	EDA	163,044	GJ	varies	62.50257	$/GJ	31-Oct-20	31-Oct-22
5	TCPL FT - EDA	Empress	EDA	164,000	GJ	varies	62.50257	$/GJ		31-Oct-17
6	TCPL FT - Iroquois	Empress	Iroquois	26,956	GJ	varies	63.11183	$/GJ	31-Oct-20	31-Oct-22
	TransCanada Short haul									
7	TCPL FT Dawn to CDA	Dawn	CDA	149,818	GJ	varies	11.40236	$/GJ	31-Oct-20	31-Oct-22
8	TCPL FT Dawn to CDA	Dawn	CDA	(121,772)	GJ	varies	11.40236	$/GJ		31-Oct-17
9	TCPL FT Dawn to CDA	Dawn	CDA	87,952	GJ	varies	11.40236	$/GJ	31-Oct-30	31-Oct-32
10	TCPL FT Dawn to EDA	Dawn	EDA	114,000	GJ	varies	21.33019	$/GJ	31-Oct-20	31-Oct-22
11	TCPL FT Dawn to EDA	Dawn	EDA	83,114	GJ	varies	21.33019	$/GJ	31-Oct-30	31-Oct-32
12	TCPL FT Parkway to EDA	Parkway	EDA	170,000	GJ	varies	15.60578	$/GJ	31-Oct-29	31-Oct-31
13	TCPL FT Dawn to Iroquois	Dawn	Iroquois	40,000	GJ	varies	20.49473	$/GJ	31-Oct-20	31-Oct-22
14	TCPL FT Parkway to CDA	Parkway	CDA	572	GJ	varies	6.29836	$/GJ	31-Oct-20	31-Oct-22
15	TCPL FT-SN Parkway to CDA	Parkway	CDA	85,000	GJ	varies	6.14977	$/GJ	31-Oct-20	31-Oct-22
16	Niagara to CDA	Niagara	CDA	200,000	GJ	varies	8.35336	$/GJ	31-Oct-28	31-Oct-30
	TransCanada Storage Transportation Service									
17	TCPL STS Parkway to CDA	Parkway	CDA	283,892	GJ	varies	5.92119	$/GJ	31-Oct-20	31-Oct-22
18	TCPL STS Parkway/Kirkwall to EDA		EDA	70,895	GJ	varies	15.60578	$/GJ	31-Oct-20	31-Oct-22
19	TCPL STS Parkway to EDA	Parkway	EDA	9,716	GJ	varies	15.60578	$/GJ	31-Oct-20	31-Oct-22
	Nova Transmission									
20	Nova Transmission	NIT	Empress	84,868	GJ	N/A	6.26000	$/GJ	31-Oct-16	31-Oct-17
	Alliance Transportation									
21	Alliance Transportation			-	mcf	N/A	N/A			

![ENBRIDGE]

2017 Transportation Portfolio

Reliable, flexible, diverse and cost effective access to natural gas supply



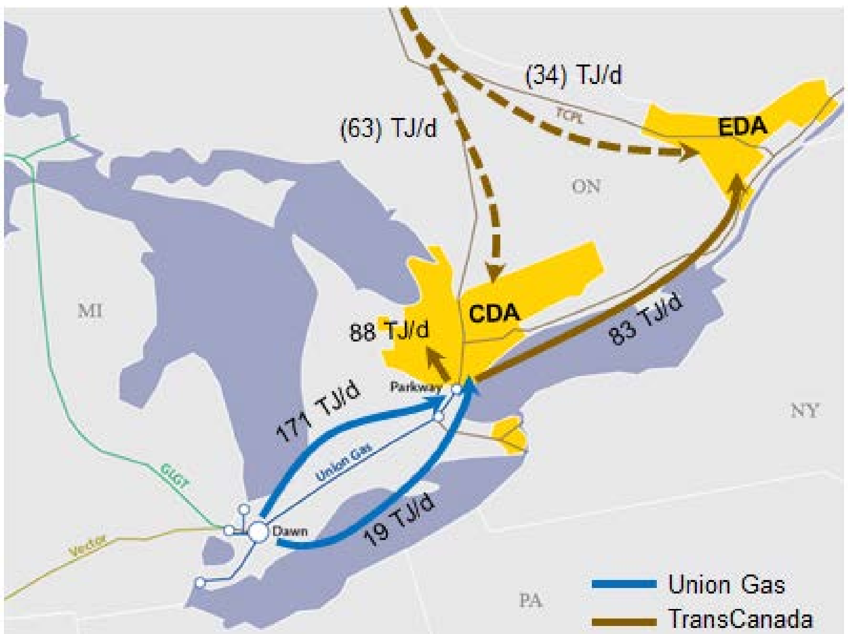
Witness: L. Stickles

Witness: L. Stickles

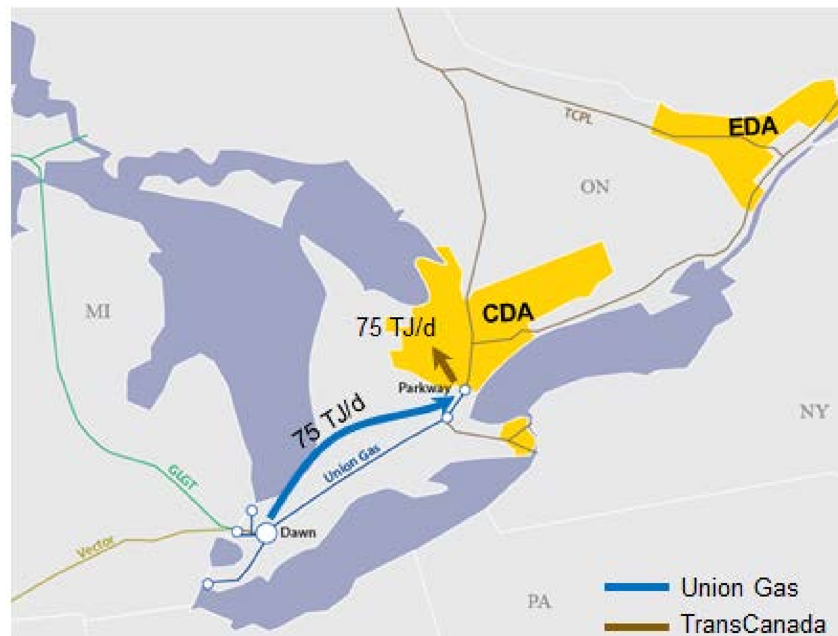
Upcoming Transportation Services

Supports growth in customer demand and facilitates the new Dawn Transportation Service

– 2017 New Capacity Open Season
- Growth in customer demand
- New Dawn Transportation Service
- Underpinned by Vaughan Mainline Project and Dawn-Parkway Expansions



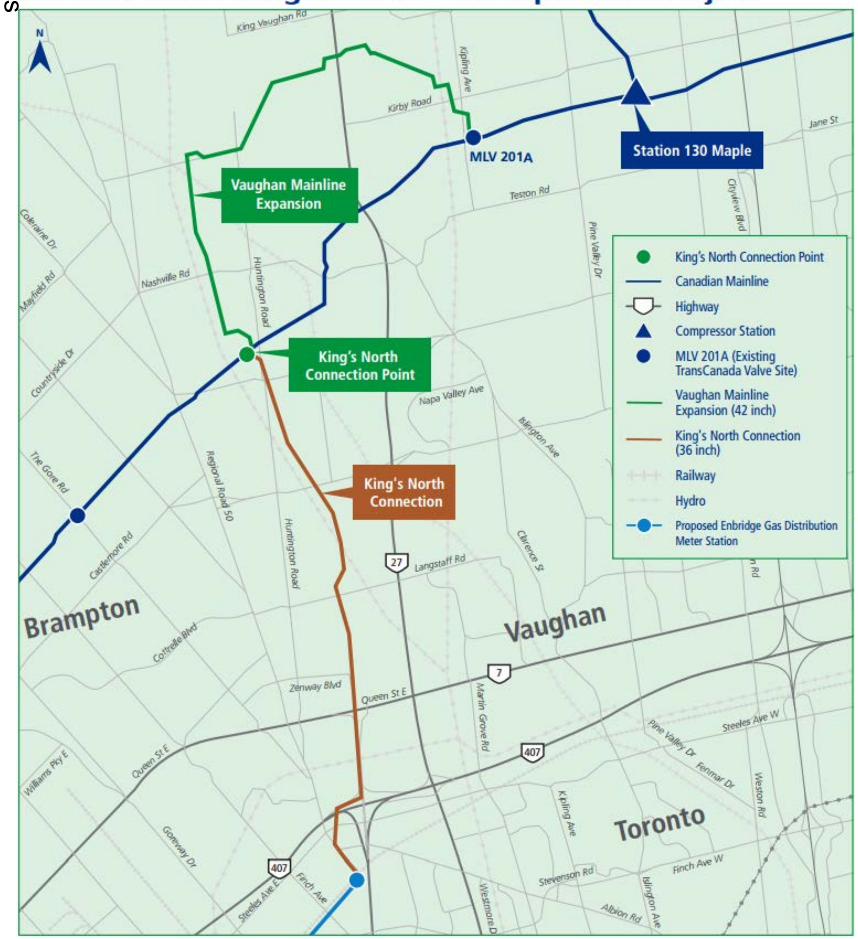
– 2019 New Capacity Open Season
- Growth in customer demand
- Maintain historical levels of peaking and delivered services
- Underpinned by new compression facilities



2017 Vaughan Mainline and Dawn-Parkway Expansions

Both projects have received regulatory approval and construction is on currently schedule

TransCanada's Vaughan Mainline Expansion Project



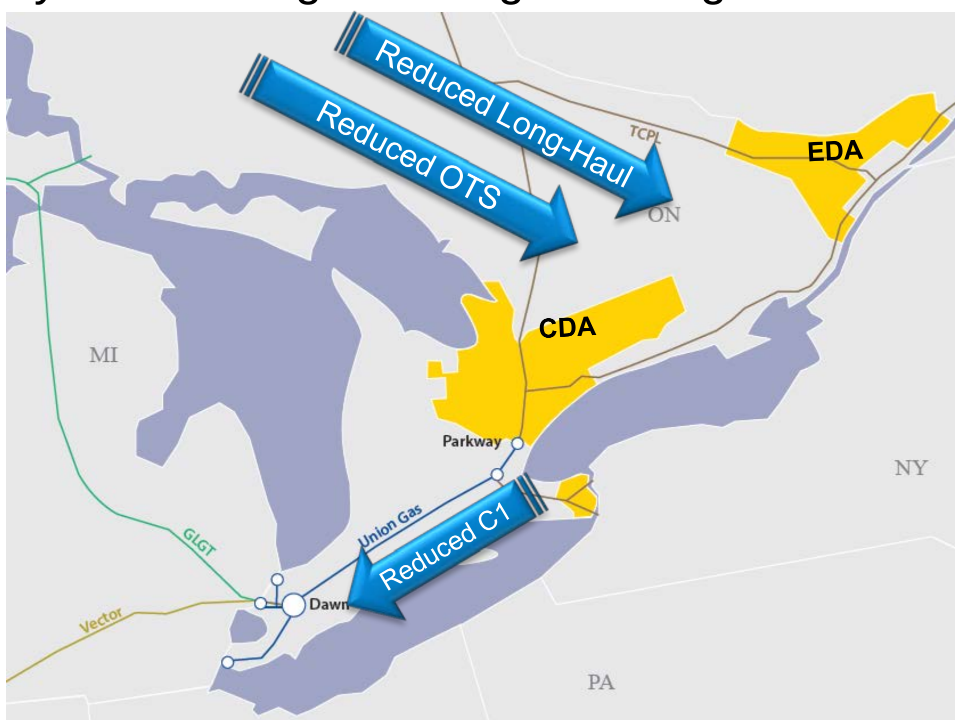
– Union Gas expansions on the Dawn-Parkway system include:
- Bright Compressor
- Lobo Compressor
- Dawn Compressor

Witness: L. Stickles

Elimination of Transportation Services

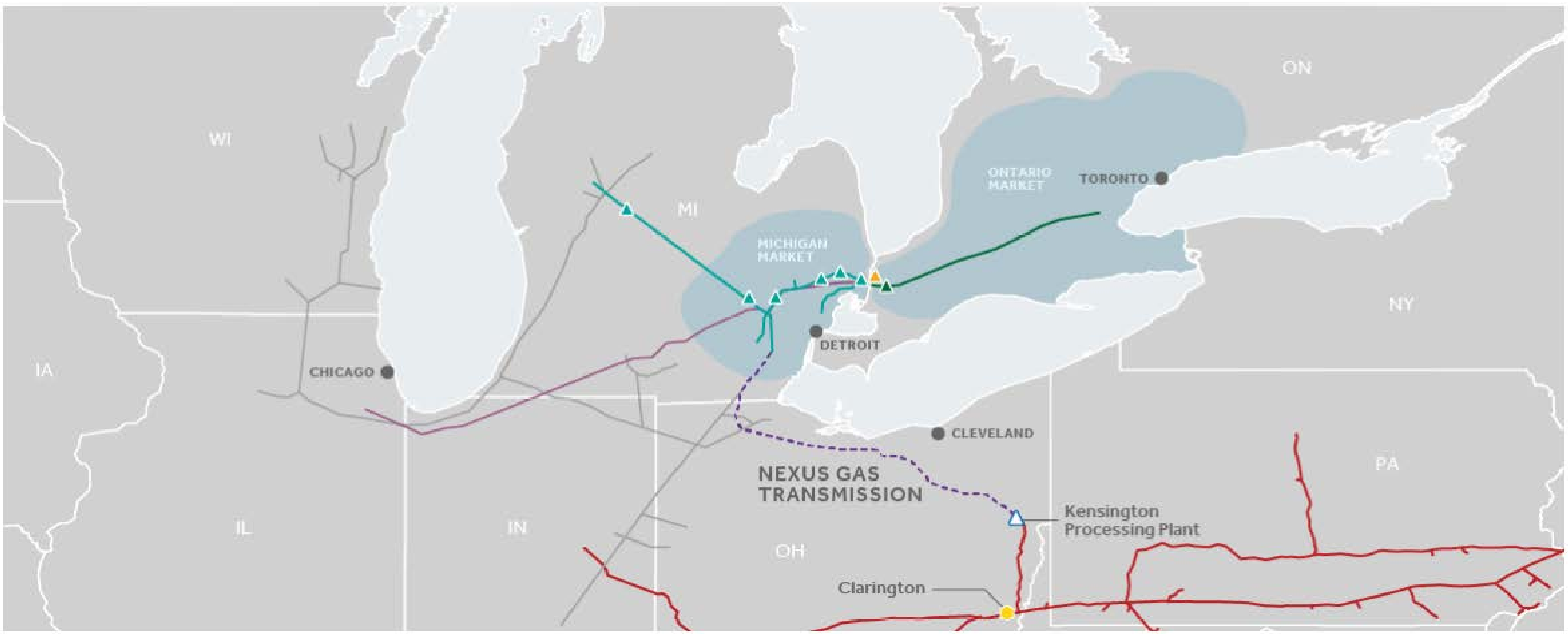
Driven by a reduction in long-haul transportation and the new Dawn Transportation Service

- Elimination of C1 service contracted on the Union Gas transportation system
  - Reduction in long-haul firm transportation on the TransCanada Mainline to the CDA and EDA
  - Reduction in Ontario Transportation Service (OTS) deliveries to the CDA and EDA from direct purchase customers
- Remaining westerly transportation requirements on the Union Gas transportation system managed through existing M12X contract



NEXUS Pipeline

Precedent Agreement executed for 110,000 Dth per day with a proposed in-service date of November 1, 2017



NEXUS Pipeline Path · Market Area · Texas Eastern Transmission · Dawn to Parkway Transmission Pipeline · DTE Gas Pipeline · Vector Pipeline · ANR Pipeline
DTE Natural Gas Storage · Union Gas Natural Gas Storage · Enbridge Tecumseh Natural Gas Storage · Natural Gas Processing Plant · Station · City

PROJECT STATUS	EVALUATION	SIGNED AGREEMENTS	REGULATORY REVIEW	REGULATORY APPROVAL	UNDER CONSTRUCTION	IN-SERVICE

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Witness: L. Stickles

Witness: L. Stickles

Potential Changes to Existing Mainline Services

– Energy East and Eastern Mainline Projects
  - Potential impacts on transportation capacity on the TransCanada Mainline and related tolls have been addressed through a settlement agreement
  - National Energy Board appointed a new panel on January 9, 2017
  - The new panel voided all decisions made by the previous panel

– Sale and Purchase of Dawn Extension Pipeline
  - Potential impact on Mainline tolls
  - TransCanada selling Mainline facilities at Dawn to Great Lakes Pipeline Canada Ltd.
  - Application filed in March 2017 and current under review by the National Energy Board

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Potential Changes to Existing Mainline Services

TransCanada's commitments under the Mainline Settlement Agreement

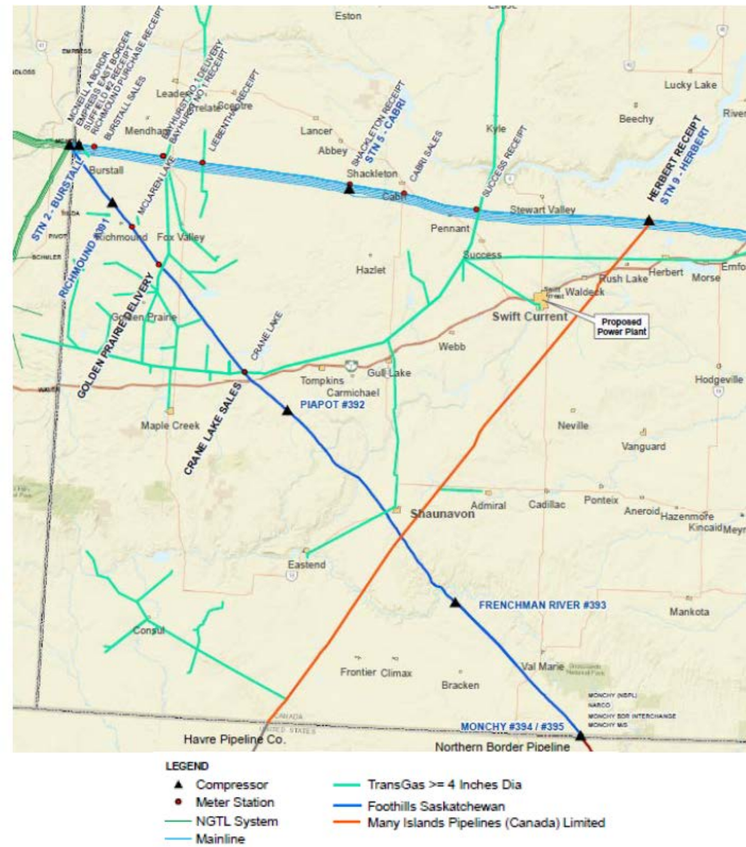
- 2018 TransCanada Mainline toll review
  - Review of revenue requirements, billing determinants, and miscellaneous revenue which may impact Mainline tolls
  - Anticipated to be filed later this year
- Segmented Tolling post 2020
  - Migration from consolidated tolling methodology to a new segmented tolling methodology
  - Potential impacts on transportation service attributes and tolls
  - Anticipated to be filed next year

Witness: L. Stickles

Proposed New Services on the Mainline

New services incorporate negotiated tolls and reduced service attributes

– Herbert and Dawn Long Term Fixed price ("LTFP") Services
  - Potential to establish a new approach to contracting for firm services on the TransCanada Mainline
  - Herbert LTFP application filed with the Board in January 2017 and currently being reviewed
  - Dawn LTFP Open Season concluded in March 2017 with 1.5 PJ/d of interest at $0.77/GJ
  - Dawn LTFP application to be filed in April 2017



Herbert LTFP Service

Dawn LTFP Service

Witness: L. Stickles

Ontario Energy Board Activities

Framework for the Assessment of Distributor Gas Supply Plans

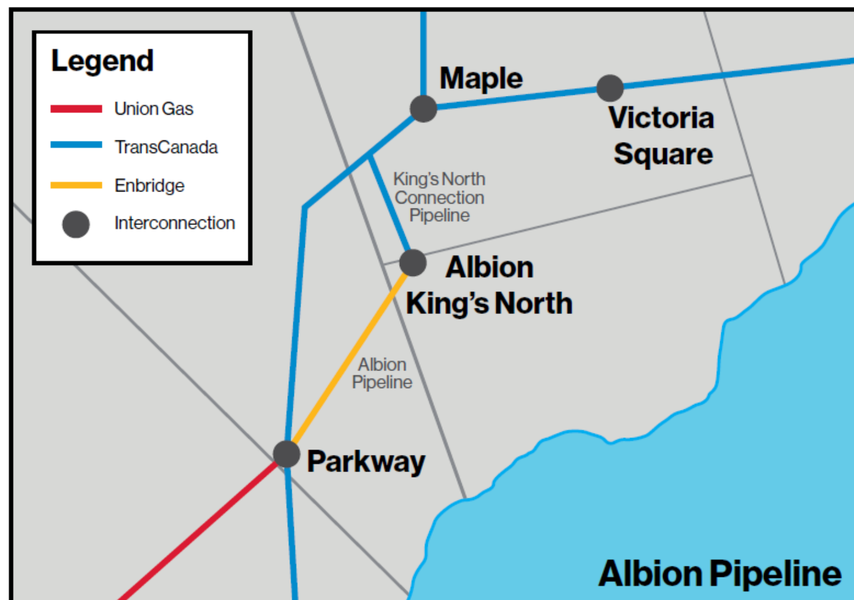
- Initiated in March 2017 based on Board Staff recommendations from the Distributor Gas Supply Planning Consultation
- Objective is to inject greater transparency, accountability, and measurement into the review of the gas supply planning process
- Draft Framework to be completed by the Board by fall 2017 and process provided in due course

Rate 332 Firm Transportation

- Open season expected in Q3 of 2017
- Consultation to provide interruptible service
  - Stakeholder consultation targeted for spring 2018
  - Outcomes to be reported to the Board in fall 2018

2017 Rate Application Commitment

- ICF International report on incremental storage filed with the Board on March 31st



WAMS

Will Akkermans

Witness: L. Stickles

Background

– Work and Asset Management Solution (WAMS) is a fundamental business tool and foundational to providing safe and reliable service to our utility customers.

– WAMS replaced existing obsolete technology that supported approximately one million work requests every year and stored asset records associated with servicing over two million customers.

– Existing Technology was problematic because it was based on an operating system that was no longer supported by the software vendor after 2015. Over 1,800 people use the related data, processes and technologies.

– WAMS went live in October, 2016 and since go-live, we have had positive users experiences:

- 306,284 work orders processed
- 179,952 invoices processed

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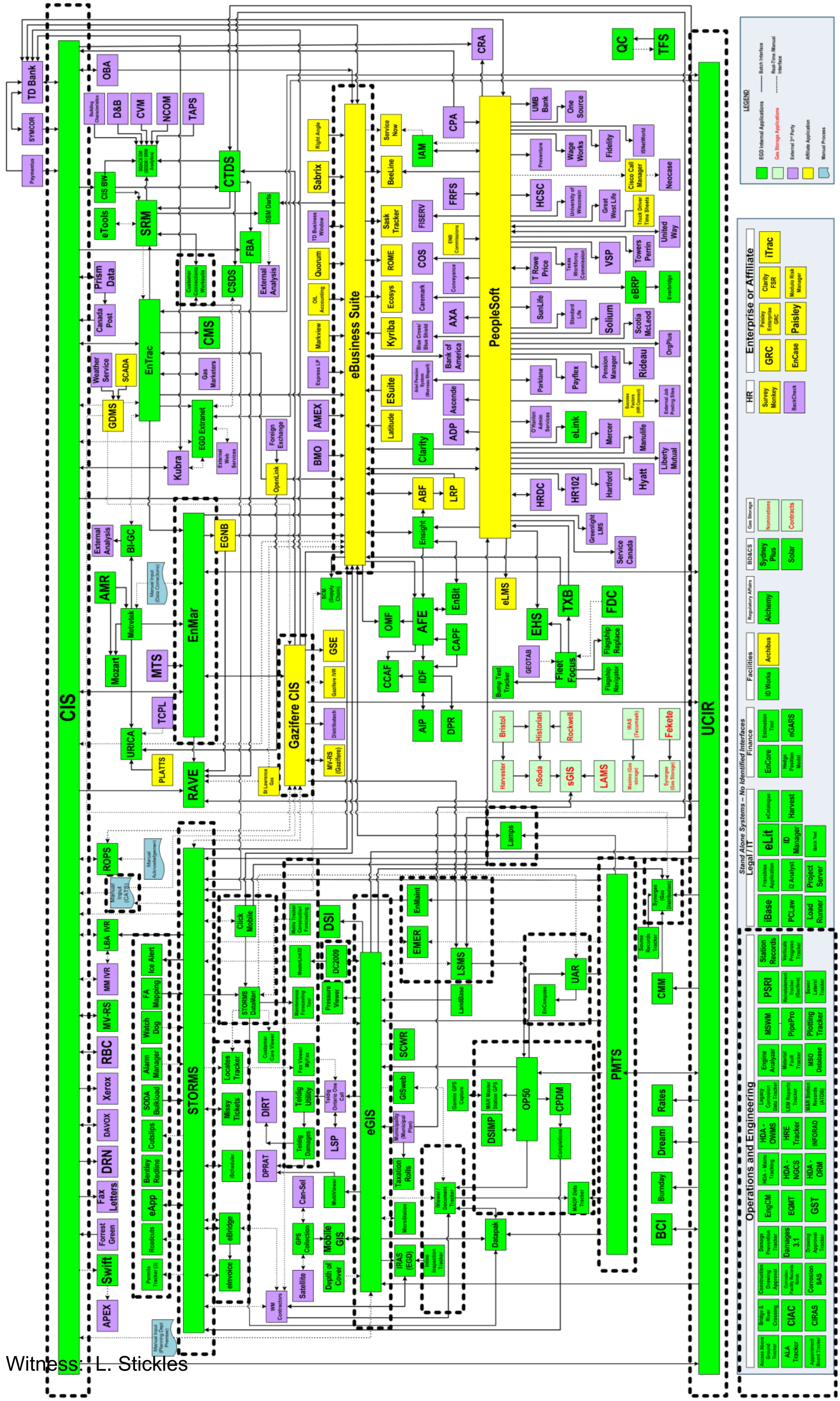
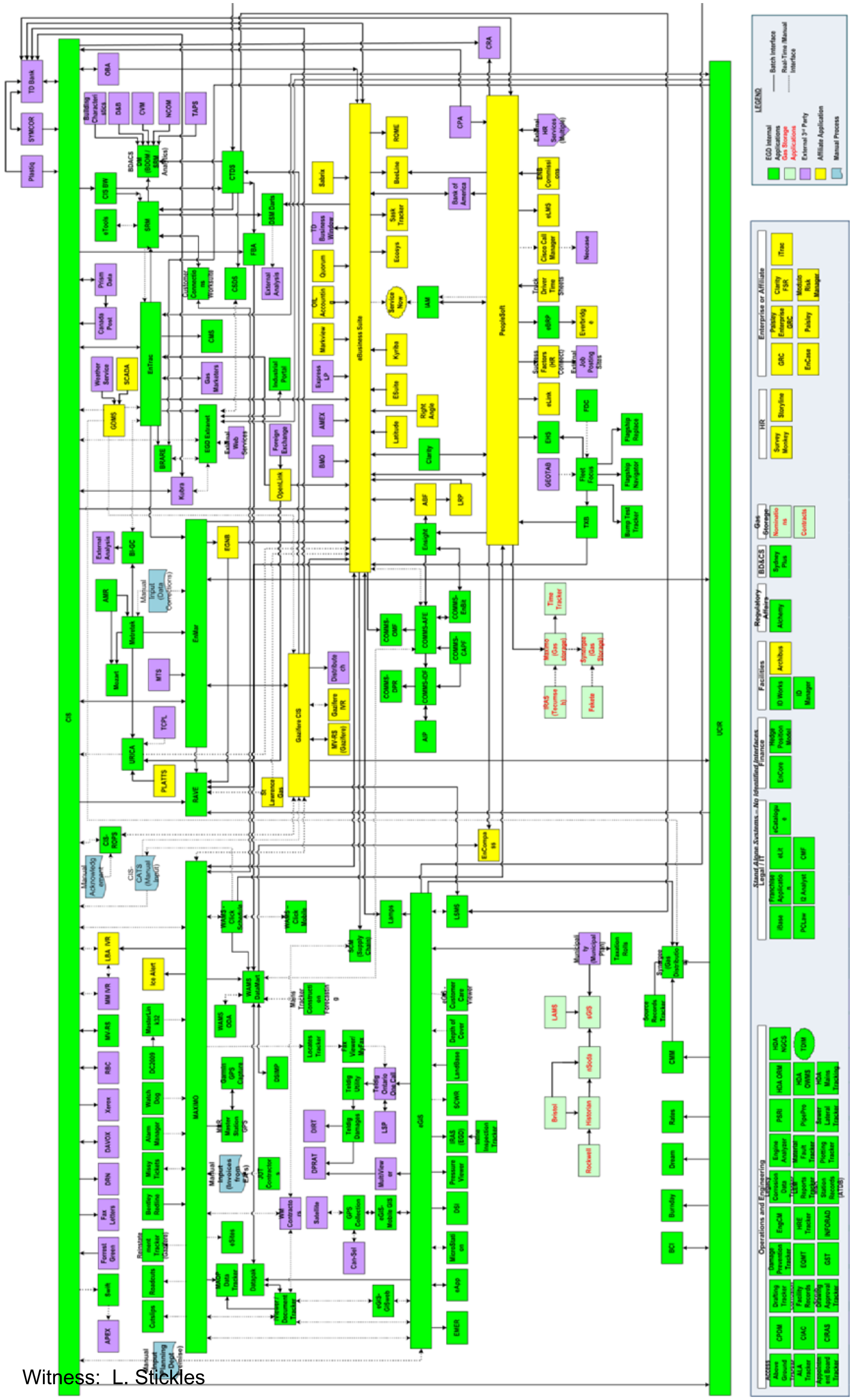
Enbridge Gas Distribution Application Landscape (Pre – WAMS)



Witness: L. Stickles

Enbridge Gas Distribution Application Landscape (Post – WAMS)



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Witness: L. Stickles

WAMS Implementation spend

– At the end of 2016, Project implementation actual cost was $90.1M and spend was over by $20.4M compared to IR budget of $69.7M. Major drivers for the overage are:

- Longer duration of solution design.
- Increased solution testing scope to ensure quality and minimize operational disruption at Go-Live.
- Training and change management of 1,800+ users took longer than expected.
- Additional Go-live readiness runs and checks.

Examples of benefits being realized

- Technology obsolescence risk mitigated
- Increased percentage of automated invoicing
- Improved governance with AFE process
- Better tracking of restorations
- Improved insight to progressing work
- Post go-live solution review underway

Witness: L. Stickles

Community Expansion

Steve McGill

Witness: L. Stickles

EB-2016-0004 Decision

Major Points:

1. **No ratepayer subsidies.**
2. **Project specific standalone rates or rate surcharges will be allowed.**
3. **Exemptions from the E.B.O. 188 guidelines will not be necessary.**
4. **Municipal tax relief (the "ITE") will not be mandatory but voluntary.**
5. **OEB will hear competing proposals for municipal franchises and Certificates of Public Convenience & Necessity in regard to natural gas community expansion projects.**
6. **The utility would bear the risk for a 10-year period if the customers additions forecast did not attach to the system, or if costs are greater than anticipated.**

Community Expansion

Ontario Ministry of Infrastructure Grant Program

- On January 30, 2017 The Ontario Ministry of Infrastructure announced its new Natural Gas Grant Program.
- $100 million is to be provided to support the expansion of gas service to rural and Northern Ontario and First Nations communities.
- The Company has been advised that the Natural Gas Grant Program will begin accepting applications in spring 2017.
- It is expected that the Natural Gas Grant Program will be coordinated with community expansion applications to be heard by the Board.
- The Ministry of Infrastructure has advised the Company that it is in the process of developing its grant application process and project ranking criteria.
- Enbridge expects to bring three community expansion Leave to Construct ("LTC") applications before the Board for its consideration by the end of 2017.

Witness: L. Stickles

Community Expansion

Communities Under Consideration

- Enbridge has revised its list of communities under consideration for system expansion since the conclusion of the EB-2106-0004 proceeding.
- In total 43 communities are under consideration representing approximately 21,000 potential customers.
- Based on the Company’s current assessment of these communities it is expected that up to twelve projects could proceed that could bring natural gas to over 10,000 potential customer over the next eight years.
- These projects will all include a request to the Board to approve the application of a System Expansion Surcharge (“SES”) as described in the Company’s EB-2016-0004 community expansion proposal.

Witness: L. Stickles

Community Expansion

Fenelon Falls Leave to Construct Application

- The LTC application for the community of Fenelon Falls is on track; targeting June 2017 submission to the OEB.
- The Fenelon Falls LTC application will include a request for the Board's approval of a SES under Section 36 of the OEB Act that will be applicable to all customers attached to the Company's Fenelon Fall gas distribution network.
- The LTC will be coordinated and make reference to an application to be made by the Company to the Ministry of Infrastructure for Natural Gas Grant Program
  - Assumed grant funding in an amount equal to the value of a contribution in aid of construction that will be required to achieve a project Profitability Index of 1.0.
- Duty to consult review request submitted to the Ministry of Energy March 13th.
- Construction cost estimates are being finalized.
- Construction drawings, geotechnical and topographical surveys are underway.
- In-town and reinforcement pre-engineering work is underway.

Other Growth Projects

Renewable Natural Gas, Power to Gas, Natural Gas Vehicles, Geothermal

Renewable Natural Gas

- Business Model complete.
- Proposal to be made to the Board later this year.

Power to Gas

- Manufacture of hydrogen utilizing electricity and water.
- Project is in conjunction with the IESO.
- Pilot project is being constructed.
- Target commissioning in June 2017.

Natural Gas Vehicles

- Focus has moved to heavy vehicles (long haul trucks and return to base fleets)
- Preliminary work underway on a NGV refueling station for trucking in the Niagara area with support of NRcan.

Geothermal

- Development of a geothermal business model is in progress.
- Discussions have taken place with MoECC, MOE and OEB Staff along with geothermal industry participants concerning the EGD geothermal concepts.

Witness: L. Stickles

Closing Remarks

Andrew Mandyam
Kevin Culbert

Appendix

2016 IT capital spend variance; spend under by $8.9M

Major drivers:

– **IT Infrastructure:**

- **Consolidation of IT Infrastructure within Enbridge Inc (IT Shared Services):** The capital spend for IT Infrastructure, which includes Network Services, Data Centre Operations and IT Risk Management, is now contained within IT Shared Services (as per ARC exemption filing for IT Shared Services with OEB) and services are provided to EGD and other business units on a standard, consistent and cost effective basis. This has resulted in a spend reduction of $3.4 million.

– **Enhancement/Upgrade Projects:**

- **Delayed EnTRAC Enhancement :** Reduction in capital spend of $2M. WAMS impacted systems such as CIS application were under freeze condition to complete WAMS. EnTRAC integrates to the CIS application, hence EnTRAC was delayed and the new timing of this spend is 2018.

- **CIS Software Upgrade:** A major upgrade is performed every 3-4 years. The last major upgrade performed was in 2015 and hence IR forecast spend of $3M was not incurred in 2016. The new timing of this spend is 2018/2019.

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Witness: L. Stickles

2016 RRR FILINGS – SERVICE QUALITY INDICATORS

1. Please find the Service Quality Indicator results in the tables below.

G.2.1.9.A - TELEPHONE ANSWERING PERFORMANCE

G.2.1.9.A.1 - Call Answering Service Level (CASL)
Measure Calculations: CASL = Number of calls reaching a distributor's general inquiry number answered within 30 seconds divided by the number of calls received by a distributor's general inquiry number.
OEB Approved Standard: Yearly performance shall be 75% with minimum monthly standard of 40%.

Month	Number of Calls Reaching a Distributor’s General Inquiry Number Answered Within 30 Seconds (1)	Number of Calls Received by a Distributor’s General Inquiry Number (2)	Call Answer Service Level (%) (3=1/2*100)
Jan.	165,491	203,658	81.3%
Feb.	161,138	199,378	80.8%
Mar.	156,110	195,927	79.7%
Apr.	197,588	244,301	80.9%
May	199,349	236,146	84.4%
Jun.	191,058	229,375	83.3%
Jul.	179,066	212,679	84.2%
Aug.	186,594	230,654	80.9%
Sept.	184,449	225,787	81.7%
Oct.	206,220	250,942	82.2%
Nov.	197,666	238,207	83.0%
Dec.	162,454	187,924	86.4%
TOTAL	2,187,183	2,654,978	82.4%

Witnesses: D. Brault
D. McIlwraith

G.2.1.9.A.2 - Abandon Rate (AR)
Measure Calculations: AR = Number of calls abandoned while waiting for a live agent divided by a total number of calls requesting to speak to a live agent.
OEB Approved Standard: Performance shall not exceed 10% on a yearly basis.

Month	Number of Calls Abandoned While Waiting for a Live Agent (1)	Total Number of Calls Requesting to Speak to a Live Agent (2)	Abandon Rate (%) (3=1/2*100)
Jan.	2,949	127,125	2.3%
Feb.	3,266	126,402	2.6%
Mar.	3,368	122,687	2.7%
Apr.	2,699	156985	1.7%
May	2,006	150938	1.3%
Jun.	2,351	148478	1.6%
Jul.	2,305	135469	1.7%
Aug.	2,701	150898	1.8%
Sept.	2,951	148140	2.0%
Oct.	2,495	164445	1.5%
Nov.	2,096	154658	1.4%
Dec.	1,547	114729	1.3%
TOTAL	30,734	1,700,954	1.8%

Witnesses: D. Brault
D. McIlwraith

G.2.1.9.B - BILL PERFORMANCE

Measure Calculations: The utility is required to have a verifiable Quality Assurance Program ("QAP") in place. Manual checks must be done to validate billing data when meter reads fall outside criteria (as set by the QAP) for excessively high or low usage.

OEB Approved Standard: No specific metric is attached to this requirement.

Month	Total Number of Billings	Total Number of Manual Checks Done as per QAP	Total Number of Manual Checks Done When Meter Reads Show Excessively High Usage Vs. QAP Criteria	Total Number of Manual Checks Done When Meter Reads Show Excessively Low Usage Vs. QAP Criteria
	(1)	(2)	(3)**	(5)**
January	2,171,212	32,179	11,692	
February	2,052,626	31,235	14,086	
March	2,144,287	33,155	18,787	
April	2,173,451	28,534	15,714	
May	2,163,908	42,428	17,770	
June	2,452,404	35,856	23,307	
July	2,166,835	58,051	23,423	
August	2,237,008	43,276	26,316	
September	2,193,915	42,537	22,572	
October	2,308,165	38,652	19,942	
November	2,281,767	36,883	16,796	
December	2,157,863	30,540	13,908	
Total	26,503,441	453,326	224,313	

**volume in Column 3 includes both high & low checks

Witnesses: D. Brault
D. McIlwraith

Brief Explanation for Excessively High Usage (In 100 Words or less) (4)	

1. Bills that exceed our parameters are manually verified or adjusted before mailing to the customer.
2. The meter might have been read incorrectly (e.g. backwards or digits like and 8 or 6 may have been visually misread).
3. An actual read could be higher following a number of estimates.
4. The historical usage on the account might that suggest that the customer's usage increases at a particular times each year. (eg. Pool heaters)
5. The customer has installed additional and/or upgraded gas appliances.

Brief Explanation for Excessively Low Usage (in 100 Words or less) (6)	

1. Bills that are below our parameters are manually verified or adjusted before mailing to the customer.
2. The meter might have been read incorrectly e.g. backwards or digits like and 8 or 6 may have been visually misread.
3. An actual read could be lower following a number of estimates.
4. The historical usage on the account might that suggest that the customer's usage is reduced or stops altogether for certain periods each year.
5. The customer has removed or discontinued use of gas appliances.

G.2.1.9.C - METER READING PERFORMANCE

G.2.1.9.C.1 - Meter Reading Performance Measurement (MRPM)

Measure Calculations: MRPM = Number of meters with no read for 4 consecutive months or more divided by the total number of active meters to be read.

OEB Approved Standard: Measurement shall not exceed 0.5% on a yearly basis.

Month	Number of Meters with No Read for 4 Consecutive Months or More (1)	Total Number of Active Meters to be Read (2)	Meter Performance Measurement (%) (3=1/2*100)
Jan	8,999	2,134,870	0.4%
Feb	9,822	2,136,912	0.5%
Mar	10,952	2,138,336	0.5%
Apr	9,089	2,140,077	0.4%
May	7,682	2,142,454	0.4%
Jun	7,170	2,144,549	0.3%
Jul	6,974	2,146,642	0.3%
Aug	8,735	2,149,241	0.4%
Sep	8,739	2,152,137	0.4%
Oct	8,542	2,153,881	0.4%
Nov	8,432	2,157,306	0.4%
Dec	9,914	2,160,017	0.5%
Total	105,050	25,756,422	0.4%

Witnesses: D. Brault
D. McIlwraith

G.2.1.9.D - SERVICE APPOINTMENTS RESPONSE TIME

G.2.1.9.D.1 - Appointments Met Within the Designated Time Period (AMWDTP)

Measure Calculations: AMWDTP = Number of appointments met within the 4 hour time on the scheduled date divided by the total number of appointments scheduled in the reporting month.

OEB Approved Standard: Minimum Performance Standard shall be 85% average over a year.

Month	Number of Appointments Met Within the 4-Hour Time on the Scheduled Date (1)	Total Number of Appointments Scheduled in the Reporting Month (2)	Appointments Met Within the Designated Time Period (%) (3=1/2*100)
Jan	3,403	3,553	95.8%
Feb	2,830	2,962	95.5%
Mar	2,925	3,016	97.0%
Apr	3,088	3,209	96.2%
May	3,544	3,702	95.7%
Jun	4,211	4,406	95.6%
Jul	3,541	3,688	96.0%
Aug	3,682	3,852	95.6%
Sep	4,067	4,401	92.4%
Oct	3,786	4,094	92.5%
Nov	5,020	5,277	95.1%
Dec	3,246	3,560	91.2%
Total	43,343	45,720	94.8%

Witnesses: D. Brault
D. McIlwraith

G.2.1.9.D.2 - Time to Reschedule a Missed Appointment (TRMA)
Measure Calculations: TRMA = this measurement tracks the time taken by the utility to contact the consumer to offer to reschedule a missed appointment. This includes appointments for meter-related customer requests or other customer requested work such as installations, meter reads, and reconnections appointments not due to non-payment. At minimum the distributor must contact the customer to reschedule the work within 2 hours of the end of the original appointment.
OEB Approved Standard: Minimum Performance Standard shall be 100% of affected customers will receive a call from the utility offering to reschedule work within 2 hours of the end of the original appointment time.

Month	Total Number of Customers Appointments Missed (1)	Total Number of Customers Who Did Receive a Call Offering to Reschedule Within 2 Hours of the End of the Original Appointment Time Missed (2)	Brief Explanation of the Reasons Customers Did Not Receive a Call Within the Time Limit (In 50 Words) (3)	Percentage of Customers who Did Receive a Call Divided by the Total Number of Customer Appointments Missed (%) (4=2/1*100)
Jan	93	79	14 calls missed: 3 calls arrived later than 2 hours, 11 rescheduled after 2 hour limit without notifying customer	84.9%
Feb	81	72	9 calls missed: 9 rescheduled after 2 hour limit without notifying customer	88.9%
Mar	49	46	3 calls missed; 3 reschedule after 2 hour limit without notifying customer	93.9%
Apr	71	67	4 calls missed; 2 calls arrived later than 2 hours, 2 rescheduled after 2 hour limit without notifying customer	94.4%

Witnesses: D. Brault
D. McIlwraith

Month	Total Number of Customers Appointments Missed (1)	Total Number of Customers Who Did Receive a Call Offering to Reschedule Within 2 Hours of the End of the Original Appointment Time Missed (2)	Brief Explanation of the Reasons Customers Did Not Receive a Call Within the Time Limit (In 50 Words) (3)	Percentage of Customers who Did Receive a Call Divided by the Total Number of Customer Appointments Missed (%) (4=2/1*100)
May	89	84	5 calls missed: 5 rescheduled after 2 hour limit without notifying customer	94.4%
Jun	124	120	4 calls missed: 4 rescheduled after 2 hour limit without notifying customer	96.8%
Jul	88	85	3 calls missed: 3 rescheduled after 2 hour limit without notifying customer	96.6%
Aug	90	87	3 calls missed: 3 rescheduled after 2 hour limit without notifying customer	96.7%
Sep	145	136	9 calls missed: 2 calls arrived later than 2 hours, 7 rescheduled after 2 hour limit without notifying customer	93.8%
Oct	252	238	14 calls missed: 7 calls arrived later than 2 hours, 7 rescheduled after 2 hour limit without notifying customer	94.4%
Nov	200	189	11 calls missed: 7 calls arrived later than 2 hours, 4 rescheduled after 2 hour limit without notifying customer	94.5%
Dec	224	215	9 calls missed: 5 calls arrived later than 2 hours, 4 rescheduled after 2 hour limit without notifying customer	96.0%
Total	1,506	1,418	As noted above.	94.2%

Witnesses: D. Brault
D. McIlwraith

G.2.1.9.E - GAS EMERGENCY RESPONSE

G.2.1.9.E.1 - Percentage of Emergency Calls Responded Within One Hour (ECRWOH)

Measure Calculations: ECRWOH = Number of emergency calls responded to within 60 minutes divided by the total number of emergency calls received.

OEB Approved Standard: Measurement shall be that 90% of customers have received responses within 60 minutes of their call reaching a live person calculated on an annual basis.

Month	Number of Emergency Calls Responded to Within 60 Minutes (1)	Total Number of Emergency Calls Received (2)	Percentage of Emergency Calls Responded Within One Hour (%) (3=1/2*100)
Jan	5,235	5,443	96.2%
Feb	4,068	4,241	95.9%
Mar	3,628	3,721	97.5%
Apr	4,172	4,293	97.2%
May	4,167	4,342	96.0%
Jun	3,745	3,858	97.1%
Jul	3,442	3,524	97.7%
Aug	3,388	3,467	97.7%
Sep	3,706	3,866	95.9%
Oct	3,693	3,916	94.3%
Nov	5,149	5,370	95.9%
Dec	4,499	4,819	93.4%
Total	48,892	50,860	96.1%

Witnesses: D. Brault
D. McIlwraith

G.2.1.9.F - CUSTOMER COMPLAINT WRITTEN RESPONSE

G.2.1.9.F.1 - Number of Days to Provide a Written Response (NDPAWR)

Measure Calculations: NDPAWR = Number of complaints requiring a written response responded to within 10 days divided by the total number of complaints requiring a written response.

OEB Approved Standard: Measurement shall be that 80% of customers have received written responses in 10 days of the distributor receiving the complaint.

Month	Number of Complaints Requiring a Written Response Responded to Within 10 Days (1)	Total Number of Complaints Requiring a Written Response (2)	NDPAWR Percentage (%) (3=1/2*100)
Jan.	0	0	0%
Feb.	1	1	100%
Mar.	0	0	0%
Apr.	2	2	100%
May	0	0	0%
Jun.	4	4	100%
Jul.	1	1	100%
Aug.	5	5	100%
Sept.	16	18	88.9%
Oct.	12	12	100%
Nov.	0	0	0%
Dec.	1	1	100%
TOTAL	42	44	95.5%

Witnesses: D. Brault
D. McIlwraith

G.2.1.9.G - RECONNECTION RESPONSE TIME

G.2.1.9.G.1 - Number of Days to Reconnect A Customer (NDTRAC)

Measure Calculations: NDTRAC = Number of reconnections completed within 2 business days divided by the total number of reconnections completed.

OEB Approved Standard: Measurement shall be that 85% of customers are reconnected within 2 business days of bringing their accounts into good standing and will be tracked on a monthly basis.

Month	Number of Reconnections Completed Within 2 Business Days (1)	Total Number of Reconnections Completed (2)	Number of Days to Reconnect a Customer Percentage (%) (3=1/2*100)
Jan	952	1,065	89.4%
Feb	630	685	92.0%
Mar	537	583	92.1%
Apr	3,677	3,765	97.7%
May	5,684	5,872	96.8%
Jun	3,188	3,306	96.4%
Jul	1,482	1,580	93.8%
Aug	3,163	3,313	95.5%
Sep	2,438	2,585	94.3%
Oct	3,125	3,475	89.9%
Nov	3,181	3,593	88.5%
Dec	1,171	1,355	86.4%
Total	29,228	31,177	93.7%

Witnesses: D. Brault
D. McIlwraith

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.

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

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.

Witness: L. Uhyrek

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.

Witness: L. Uhyrek

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

Witness: L. Uhyrek

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.

Witness: L. Uhyrek

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.

	2016				2015			
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	**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

	Pension		OPEB	
Year ended December 31,	**2016**	2015	**2016**	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.

Witness: L. Uhyrek

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.

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

December 31, 2016

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated February 16, 2017 should be read in conjunction with the audited Consolidated Financial Statements and notes thereto of Enbridge Gas Distribution Inc. (the Company) as at and for the year ended December 31, 2016, which are prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). It should also be read in conjunction with the audited Consolidated Financial Statements and MD&A prepared for the year ended December 31, 2015. All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide the Company's shareholders and potential investors with information about the Company and its subsidiaries, including management's assessment of the Company's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as ''anticipate'', ''expect'', ''project'', ''estimate'', ''forecast'', ''plan'', ''intend'', ''target'', ''believe'', ''likely'' and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to: expected earnings/(loss); expected future cash flows; expected costs related to projects under construction; expected in-service dates for projects under construction; expected capital expenditures; and estimated future dividends.

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

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

NON-GAAP MEASURES

This MD&A contains references to adjusted earnings, which represent earnings attributable to the common shareholder adjusted for weather and gains or losses on the settlement of pre-issuance hedge contracts during the applicable period. This MD&A also contains references to gas distribution margin, which represents gas commodity and distribution revenue and transportation of gas for customer revenue less gas commodity and distribution costs. Management believes that the presentation of these measures provides useful information to investors and shareholders as it provides increased transparency and predictive value. Gas distribution margin and adjusted earnings are not measures that have standardized meanings prescribed by U.S. GAAP and are not considered U.S. GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers.

OVERVIEW

The Company is a rate-regulated natural gas distribution utility that has been in operation for more than 160 years. The Company serves over 2 million residential, commercial and industrial customers in its franchise areas of central and eastern Ontario, including the City of Toronto and surrounding areas of Peel, York and Durham regions, as well as the Niagara Peninsula, Ottawa, Brockville, Peterborough, Barrie and many other Ontario communities. In addition, the Company serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence). The Company is a wholly owned subsidiary of Enbridge Inc. (Enbridge).

The Company also owns and operates regulated and unregulated natural gas storage facilities in Ontario.

STRATEGY

The Company’s vision is to become North America’s clean energy utility of choice.

To achieve its vision, the Company has outlined the following strategic objectives:
- achieve and maintain top decile safety performance;
- deliver lower carbon energy to consumers;
- enhance customer, government and stakeholder relationships;
- sustain a healthy and productive work environment aligned with evolving energy markets;
- enhance governance, integrity and transparency in all business processes; and
- deliver shareholder value.

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

Operations safety and system integrity continues to be the Company’s number one priority and sets the foundation for the Company’s strategic plan. Core to this priority is the focus on system integrity, and environmental and safety programs, which charts the course for best-in-class practices.

PERFORMANCE OVERVIEW

Year ended December 31,	2016	2015	2014
(millions of Canadian dollars, except per share amounts)			
Earnings attributable to the common shareholder[1]	**228**	232	244
Cash flow data			
Cash provided by/(used in) operating activities	**642**	842	(430)
Cash used in investing activities	**(740)**	(864)	(620)
Cash provided by financing activities	**138**	41	1,034
Dividends			
Common share dividends declared	**237**	223	204
Dividends declared per common share	**1.36**	1.38	1.34
Preference share dividends declared	**2**	2	2
Dividends declared per preference share	**0.54**	0.56	0.60
Total revenues			
Gas commodity and distribution revenues	**2,437**	3,043	2,803
Transportation of gas for customers	**330**	344	305
Other revenue	**100**	97	92
Total revenues	**2,867**	3,484	3,200
Total assets	**10,294**	9,989	9,749
Total long-term liabilities	**5,223**	5,414	4,894

1 Earnings per share is not provided, since the issuer is an indirect wholly owned subsidiary of Enbridge Inc.

HIGHLIGHTS

Year ended December 31,	2016	2015	2014
Number of active customers[1] *(thousands)*	**2,158**	2,129	2,098
Heating degree days[2]			
Actual	**3,412**	3,710	4,044
Forecasted based on normal weather	**3,617**	3,536	3,517
Volumetric statistics *(millions of cubic metres)*			
Gas commodity sales	**7,245**	7,631	8,209
Transportation of gas for customers	**4,076**	4,327	4,462
Unbundled volumes[3]	**392**	406	382
Total volumes	**11,713**	12,364	13,053

1 Number of active customers is the number of natural gas consuming customers at the end of the year.
2 Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's distribution franchise area. It is calculated by accumulating, for the fiscal year, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A daily mean temperature of zero degrees Celsius on any day equals 18 heating degree days for that day. The figures given are those accumulated in the Greater Toronto Area (GTA).
3 Unbundled customers deliver their own natural gas into the Company's distribution system and manage their load balancing independent of the Company.

EARNINGS ATTRIBUTABLE TO THE COMMON SHAREHOLDER

Earnings attributable to the common shareholder were $228 million for the year ended December 31, 2016 compared with $232 million for the year ended December 31, 2015. The decrease primarily resulted from warmer weather. Additionally, the decrease resulted from higher depreciation expense from a higher overall asset base, higher interest expense from the issuance of medium-term notes (MTNs) and lower capitalized interest from lower capital spending on the GTA project, which are primarily recoverable in distribution rates. This was partially offset by higher distribution charges from growth in rate base, including customer growth, and lower employee related costs, excluding severance costs.

Earnings attributable to the common shareholder were $232 million for the year ended December 31, 2015 compared with $244 million for the year ended December 31, 2014. The decrease primarily resulted from warmer weather and higher employee severance costs. This was partially offset by higher distribution charges from growth in rate base, including customer growth.

ADJUSTED EARNINGS

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Earnings attributable to the common shareholder	**228**	232	244
Warmer/(colder) than normal weather (after-tax impact)	**13**	(11)	(36)
Loss on settlement of pre-issuance hedge contracts	**2**	3	-
Adjusted earnings[1]	**243**	224	208

1 For more information on the non-GAAP measure see page 1.

The effect of weather is measured by heating degree days and is calculated by accumulating, for the fiscal year, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A daily mean temperature of zero degrees Celsius on any day equals 18 heating degree days for that day. Heating degree days is a key measure used by the Company to isolate the impact of weather, a factor beyond the control of management. This measure enables a meaningful analysis of the operational performance of the Company over different periods.

Normal weather is the weather forecast by the Company in its distribution franchise area, using the forecasting methodology approved by the Ontario Energy Board (OEB). As approved within the Company's 2014 to 2018 customized incentive regulation (IR) proceeding, the heating degree day forecast for the GTA utilizes a combination of a 10-year moving average method and 20-year trend method.

Normal weather is a measure that is unique to the Company and does not have any standardized meaning. In addition, due to differing franchise areas, it is unlikely to be directly comparable to the impact of weather-normalized earnings that may be reported by other entities. Moreover, normal weather may not be comparable from year to year given that the forecasting models are updated annually to reflect the most recent weather data.

The gains or losses as a result of the settlement of pre-issuance hedge contracts represent the ineffective portion upon settlement. Adjusted earnings exclude the impacts of the settlement within earnings attributable to the common shareholder, in order to match the associated gains or losses with the related debt's interest costs. The gains or losses will be amortized back into adjusted earnings over the term of the related debt.

Adjusted earnings were $243 million for the year ended December 31, 2016 compared with $224 million for the year ended December 31, 2015. The increase primarily resulted from higher distribution charges from growth in rate base, including customer growth, and lower employee related costs, excluding severance costs. This was partially offset by higher depreciation expense from a higher overall asset base, higher interest expense from the issuance of MTNs and lower capitalized interest from lower capital spending on the GTA project, which are primarily recoverable in distribution rates.

Adjusted earnings were $224 million for the year ended December 31, 2015 compared with $208 million for the year ended December 31, 2014. The increase primarily resulted from higher distribution charges from growth in rate base, including customer growth, partially offset by higher employee severance costs.

REVENUES

Revenues for the year ended December 31, 2016 were $2,867 million compared with $3,484 million for the year ended December 31, 2015. The decrease in revenues was primarily due to lower natural gas prices, warmer weather and the settlement of regulatory balances. This was partially offset by higher distribution charges from growth in rate base, including customer growth.

Revenues for the year ended December 31, 2015 were $3,484 million compared with $3,200 million for the year ended December 31, 2014. The increase in revenues was primarily due to higher distribution charges from growth in rate base, including customer growth and an increase in Other revenue mainly due to higher demand side management incentive (DSMIDA) revenue. This was partially offset by warmer weather.

RECENT DEVELOPMENTS

2017 RATE APPLICATION
The Company's final rate order for the setting of rates for 2017 was approved by the OEB in December 2016. The 2017 rate application was filed in August 2016 in accordance with the Company's approved customized IR plan, and represents the fourth year of a five-year term.

In November 2016, as discussed in the *Cap and Trade* section below, the OEB approved an interim rate order allowing the Company to begin recovery of cap and trade compliance costs commencing January 1, 2017.

EQUITY INJECTION BY PARENT COMPANY
In November 2016, the Company's parent company subscribed for and was issued an additional 15,529,673 common shares for proceeds of $280 million, which supported the Company's growth initiatives and helped rebalance the Company's capital structure to be in alignment with the OEB deemed equity ratio of 36%.

TRANSPORTATION AGREEMENTS
In October 2016, the Company entered into a contract with TransCanada Pipelines Limited (TransCanada) to provide firm transportation service from Parkway to TransCanada's Mainline at Albion King's North. The pipeline, referred to as Albion Pipeline, was recently placed into service as a part of the Company's GTA project. The transportation contract has a 15-year term and was effective November 16, 2016, pursuant to the Company's OEB approved Rate 332 Tariff.

In May 2016, the Company entered into restructured transportation contracts with Vector Pipeline Limited Partnership and Vector Pipeline L.P. (Vector), related entities partially owned by an affiliated company under common control, that extend the term of the existing contracts to align Vector transportation capacity with the Company's 15-year upstream commitment on the proposed NEXUS Gas Transmission project. The new contracts were effective June 1, 2016.

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) initiative 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.

APPOINTMENT OF NEW PRESIDENT
Effective June 1, 2016, Ms. Cynthia Hansen was appointed as President of the Company. At the same time, Mr. Glenn Beaumont, the Company's previous President, was appointed as Executive Advisor, Gas Distribution & Power of Enbridge until his retirement on August 1, 2016.

CAP AND TRADE
In May 2016, the Government of Ontario passed legislation to establish a cap and trade program in the Province of Ontario. Under the legislation, the Company will be required to meet greenhouse gas compliance obligations by purchasing emission allowances for itself and most of its customers. In September 2016, the OEB issued its regulatory framework for the assessment of costs of natural gas utilities' cap and trade activities, addressing regulatory requirements for implementation of cap and trade. In November 2016, the Company filed its compliance plan with the OEB and received approval of an interim rate order for the recovery of cap and trade compliance costs through rates beginning January 1, 2017.

GTA PROJECT

The Company undertook the expansion of its natural gas distribution system in the GTA to meet the demands of growth and to continue the safe and reliable delivery of natural gas to current and future customers. The GTA project involved the construction of two new segments of pipeline, a 27-kilometre 42-inch diameter pipeline (Western segment) and a 23-kilometre 36-inch diameter pipeline (Eastern segment) as well as related facilities to upgrade the existing distribution system that delivers natural gas to several municipalities in the GTA. Both the Western and Eastern segments were placed into service in March 2016. The total project cost is estimated to be approximately $875 million, with expenditures as of December 31, 2016 of approximately $865 million.

2016 RATE APPLICATION

In December 2015, the OEB issued its decision and interim rate order in relation to the Company's 2016 rate application. In January 2016, the OEB also issued its multi-year demand side management (DSM) decision which allowed for an increase in 2016 costs resulting in a revenue deficiency when compared to the 2016 interim rate order. DSM costs are pass-through costs and do not have an impact on earnings. In May 2016, the OEB approved the final rate order, which was implemented on July 1, 2016, effective as of January 1, 2016. Included in the final rate order was a revenue adjustment rider of approximately $14 million for the recovery of the revenue deficiency related to the January 2016 through June 2016 time period. The Company's policy is to account for regulatory decisions in the period in which they are issued and therefore the impacts of the OEB's approval of the final rate order were reflected within the Company's second quarter results of 2016.

RESULTS OF OPERATIONS

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Gas commodity and distribution revenue	**2,437**	3,043	2,803
Transportation of gas for customers	**330**	344	305
Gas commodity and distribution costs	**(1,636)**	(2,322)	(2,046)
Gas distribution margin[1]	**1,131**	1,065	1,062
Other revenue	**100**	97	92
Operating and administrative expenses	**(534)**	(509)	(493)
Depreciation and amortization	**(322)**	(290)	(286)
Earnings sharing	**(3)**	(7)	(12)
Other income	**73**	70	66
Interest expense, net	**(206)**	(181)	(177)
Income taxes	**(9)**	(11)	(6)
Earnings	**230**	234	246
Earnings attributable to the common shareholder	**228**	232	244

1 For more information on this non-GAAP measure see page 1.

GAS DISTRIBUTION MARGIN

Gas distribution margin for the year ended December 31, 2016 increased by $66 million compared with the year ended December 31, 2015. The increase primarily resulted from higher distribution charges from growth in rate base, including customer growth and the settlement of regulatory balances. This was partially offset by warmer weather in 2016 compared with 2015.

The heating degree days reported in 2016 were 205 days warmer compared with forecast heating degree days. On a weather-normalized basis, gas distribution margin for the year ended December 31, 2016 would have been higher by $18 million (2015 - lower by $15 million). Weather, measured in heating degree days, was 3,412 heating degree days for the year ended December 31, 2016 compared with 3,710 heating degree days for the year ended December 31, 2015.

Gas distribution margin for the year ended December 31, 2015 increased by $3 million compared with the year ended December 31, 2014. The increase primarily resulted from higher distribution charges from growth in rate base, including customer growth. This was partially offset by warmer weather in 2015 compared with 2014 and the settlement of regulatory balances.

The heating degree days reported in 2015 were 174 days colder compared with forecast heating degree days. On a weather-normalized basis, gas distribution margin for the year ended December 31, 2015 would have been lower by $15 million (2014 - lower by $48 million). Weather, measured in heating degree days, was 3,710 heating degree days for the year ended December 31, 2015 compared with 4,044 heating degree days for the year ended December 31, 2014.

OTHER REVENUE
Other revenue for the year ended December 31, 2016 increased by $3 million compared with the year ended December 31, 2015. The increase primarily resulted from transportation revenues, due to the Rate 332 Tariff, as discussed in the *Transportation Agreements* section above.

Other revenue for the year ended December 31, 2015 increased by $5 million compared with the year ended December 31, 2014. The increase primarily resulted from higher DSMIDA revenue and higher pipeline and storage optimization sales.

OPERATING AND ADMINISTRATIVE
Operating and administrative expenses for the year ended December 31, 2016 increased by $25 million compared with the year ended December 31, 2015. The increase primarily resulted from higher DSM costs, as discussed in the *2016 Rate Application* section above and the settlement of regulatory balances. This was partially offset by lower employee related costs, excluding severance costs, due to workforce reductions in November 2015 and October 2016.

Operating and administrative expenses for the year ended December 31, 2015 increased by $16 million compared with the year ended December 31, 2014. The increase primarily resulted from higher employee severance costs, partially offset by the settlement of regulatory balances.

DEPRECIATION AND AMORTIZATION
Depreciation and amortization expense for the year ended December 31, 2016 increased by $32 million compared with the year ended December 31, 2015. The increase primarily resulted from a higher overall asset base, mainly due to the GTA project.

Depreciation and amortization expense for the year ended December 31, 2015 increased by $4 million compared with the year ended December 31, 2014. The increase primarily resulted from a higher overall asset base resulting from customer growth projects and improvements to the distribution system.

EARNINGS SHARING
Earnings sharing represents the estimated customer portion of regulated weather normalized earnings in excess of the approved return on equity threshold applicable to the Company. Earnings sharing is management's best estimate of the proportionate earnings sharing with reference to earnings for the full year. The earnings sharing will result in the return of revenue of $3 million to customers for the year ended December 31, 2016, subject to OEB approval, compared to $7 million for the same period in 2015. Earnings sharing was $12 million for the 2014 rate year.

OTHER INCOME
Other income for the year ended December 31, 2016 increased by $3 million compared with the year ended December 31, 2015. The increase primarily resulted from a non-taxable reimbursement of Part VI.1 tax from Enbridge and higher interest on cash balances, partially offset by a gain on sale of assets in 2015.

Other income for the year ended December 31, 2015 increased by $4 million compared with the year ended December 31, 2014. The increase primarily resulted from a gain on sale of assets.

INTEREST EXPENSE
Interest expense, net, for the year ended December 31, 2016 increased by $25 million compared with the year ended December 31, 2015. The increase primarily resulted from the issuance of MTNs in 2015 and 2016 and lower capitalized interest from lower capital spending on the GTA project.

Interest expense, net, for the year ended December 31, 2015 increased by $4 million compared with the year ended December 31, 2014. The increase primarily resulted from the issuance of MTNs in 2015, lower interest earned on regulatory deferrals and a loss on settlement of pre-issuance hedge contracts. This was partially offset by higher capitalized interest.

INCOME TAXES

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Earnings before income taxes	**239**	245	252
Income taxes	**9**	11	6
Effective tax rate (%)	**3.8**	4.5	2.4

The effective tax rate for the year ended December 31, 2016 was lower compared with the year ended December 31, 2015. The decrease primarily resulted from temporary differences related to regulatory property, plant and equipment and intangible assets, offset by an increase in Part VI.1 tax, net of Part I tax deduction, relative to lower pre-tax earnings.

The effective tax rate for the year ended December 31, 2015 was higher compared with the year ended December 31, 2014. The increase primarily resulted from lower postretirement benefit contributions compared to 2014 and temporary differences relating to regulatory property, plant and equipment and intangible assets, relative to lower pre-tax earnings.

RATE REGULATION

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

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.

IMPACT OF RATE REGULATION

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

ASC 980 – Regulated Operations, requires the disclosure of information to facilitate an understanding of the nature and economic effects of rate regulation, as well as additional information on how rate regulation has affected the Company's Consolidated Financial Statements. Detailed disclosure on rate regulation is included in Note 4 to the 2016 Consolidated Financial Statements.

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

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

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

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

To the extent that the Regulators' future actions are different from current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

LIQUIDITY AND CAPITAL RESOURCES

The Company expects to utilize cash from operations and the issuance of debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. 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 with a diversified group of banks and institutions. If necessary, additional liquidity is available through intercompany transactions with its ultimate parent company, Enbridge, and other related entities. 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.

In September 2016, following Enbridge's announcement that it had entered into a definitive merger agreement under which Enbridge and Spectra Energy Corp would combine in a stock-for-stock merger transaction, the Company's credit ratings were affirmed as follows: (i) DBRS Limited affirmed the Company's issuer rating and MTNs and unsecured debentures rating of "A", preference share rating of "Pfd-2 (low)" and commercial paper rating of "R-1 (low)" with stable outlook; and (ii) Standard & Poor's Rating Services affirmed the Company's corporate credit rating and unsecured debt rating of "BBB+", preference share rating of "P-2 (low)" and commercial paper rating of "A-1 (low)" with stable outlook.

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.

In July 2016, the Company extended the term out date of its $1 billion external credit facility to July 2017, with a maturity date in July 2018.

In August 2016, the Company issued $300 million of ten-year MTNs at an interest rate of 2.50%.

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.

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

December 31,	**2016**	2015
(millions of Canadian dollars)		
Cash and cash equivalents	**76**	36
Restricted cash	**58**	-
Accounts receivable and other	**655**	790
Due from affiliates	**16**	10
Gas inventories	**512**	547
Bank indebtedness	**(72)**	(27)
Short-term borrowings	**(351)**	(599)
Short-term borrowings from affiliates	**(34)**	(40)
Accounts payable and other	**(807)**	(870)
Due to affiliates	**(95)**	(87)
Current maturities of long-term debt	**(500)**	(2)
Working capital	**(542)**	(242)

Despite the negative working capital as at December 31, 2016, the Company has net available liquidity through access to funds from committed credit facilities and the issuance of MTNs in the Canadian public capital markets through the Company's current MTN shelf prospectus. At December 31, 2016, the net available liquidity totaled $661 million (2015 - $716 million).

The Company must adhere to covenants in its Trust Indenture. Under the terms of the Company's Trust Indenture, in order to continue to issue long-term debt, the Company's pro forma long-term debt interest coverage ratio must be at least two times for twelve consecutive calendar months of the previous 23 months. As at December 31, 2016, the Company was in compliance with all covenants.

OPERATING ACTIVITIES
Cash provided by operating activities was $642 million for the year ended December 31, 2016 compared with cash provided of $842 million in 2015. The decrease in cash provided by operating activities primarily resulted from higher recoveries of the PGVA balance during the previous year ended December 31, 2015

as a result of the significant purchased gas variance account (PGVA) balance that was accumulated during the first quarter of 2014, which was recovered from June 2014 to June 2016 based on the OEB decision issued in May 2014. This was partially offset by timing differences in the payment of trade payable balances and an increase in the amounts recovered from customers in 2016 related to the unabsorbed demand cost deferral amounts, which were higher due to unutilized capacity under the firm transportation contracts in 2015.

Cash provided by operating activities was $842 million for the year ended December 31, 2015 compared with cash used of $430 million in 2014. The increase in cash provided by operating activities primarily resulted from an increase in the amounts recovered from customers related to the PGVA.

INVESTING ACTIVITIES

Cash used in investing activities was $740 million for the year ended December 31, 2016 compared with cash used of $864 million in 2015. The decrease in cash used in investing activities was primarily due to lower comparative capital spend on the GTA Project. This was partially offset by higher capital spending on improvements to the distribution system and technology related projects.

Cash used for investing activities was $864 million for the year ended December 31, 2015 compared with $620 million in 2014. The increase in cash used was primarily due to higher comparative capital spend on the GTA Project, the Work and Asset Management Solution (WAMS) program, and improvements to the distribution system.

CAPITAL EXPENDITURES

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
System improvements and upgrades	**343**	751	371
System expansion	**147**	160	165
Computers and communication equipment	**63**	53	44
Unregulated storage	**1**	-	1
Other	**48**	59	56
Total capital expenditures	**602**	1,023	637

The Company's existing distribution network consists of approximately 38,500 kilometres of underground natural gas mains and services. To support continuing customer growth, expansion of the network on an ongoing basis is required in addition to capital improvements.

The Company expects to spend approximately $500 million in 2017 on capital projects and maintenance. Annual capital expenditures in recent years have averaged approximately $754 million.

Major 2017 capital projects include system expansion projects. The net planned liquidity, together with cash from operations and anticipated future access to capital markets, is expected to be sufficient to finance all currently approved capital projects and to provide flexibility for new investment opportunities.

FINANCING ACTIVITIES

Cash provided by financing activities was $138 million for the year ended December 31, 2016 compared with cash provided of $41 million in 2015. The increase in cash provided by financing activities primarily resulted from lower net repayments on short-term borrowings, including borrowings from affiliates, due to lower working capital needs and higher common shares issued. This was partially offset by lower net term note issuances.

Cash provided by financing activities was $41 million for the year ended December 31, 2015 compared with $1,034 million in 2014. The decrease in cash provided primarily resulted from higher net repayments on short-term borrowings. This was partially offset by higher net term note issuances and higher common shares issued.

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

PREFERENCE SHARES

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.

OUTSTANDING SHARE DATA[1]

	Number
Preference Shares, Group 3, Series D, Fixed/Floating Cumulative Redeemable Convertible	4,000,000
Common shares	185,606,347

1 Outstanding share data information is provided as at February 16, 2017.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

The following chart outlines significant changes in the Consolidated Statements of Financial Position between December 31, 2015 and December 31, 2016.

Consolidated Statements of Financial Position Category	**Increase/ (Decrease)**	**Explanation**
(millions of Canadian dollars)		
Restricted cash	58	Due to receipt of cash from the government of Ontario for the specific purpose of executing the GIF program.
Accounts receivable and other (including due from affiliates)	(129)	Primarily due to lower natural gas costs to be recovered from customers related to the PGVA within the next 12 months.
Property, plant and equipment, net	337	Primarily due to capital additions relating to distribution system improvements, the GTA Project and customer growth, partially offset by depreciation.
Short-term borrowings (including amounts from affiliates)	(254)	Primarily due to lower working capital needs and repayments of short-term borrowings using cash and cash equivalents generated from operations.
Long-term debt (including current portion)	300	Due to the issuance of MTNs during the year.
Common shares	280	Due to a common share issuance during the year.

CONTINGENCIES AND COMMITMENTS

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

FORMER MANUFACTURED COAL GAS PLANT SITES

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages 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.

CONTRACTUAL OBLIGATIONS

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

	Total	Less than 1 year	1-2 years	3-5 years	After 5 years
(millions of Canadian dollars)					
Long-term debt[1]	3,989	500	9	575	2,905
Gas transportation and storage contracts[2]	4,369	1,143	1,080	960	1,186
Loans from affiliate company[1]	375	-	-	-	375
Customer care service contracts	171	56	115	-	-
Right-of-way commitments[3]	130	2	4	4	120
Capital commitments	59	15	30	14	-
Operating leases	2	2	-	-	-
Pension obligations[4]	34	34	-	-	-
Total contractual obligations	9,129	1,752	1,238	1,553	4,586

1 *Excludes interest, discounts and premiums. Changes to the planned funding requirements dependent on the terms of any debt re-financing agreements.*
2 *Includes the transportation agreement for long-term transportation capacity that was signed in May 2016.*
3 *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 60 years for the purposes of calculating the amount of future minimum commitments beyond 2021.*
4 *Assumes only required payments will be made into the pension plans. Contributions are made in accordance with the actuarial valuations as of December 31, 2013. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.*

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.

QUARTERLY FINANCIAL INFORMATION[1]

	2016				2015			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
(millions of Canadian dollars)								
Revenues	**811**	**342**	**594**	**1,120**	769	372	609	1,734
Earnings attributable to the common shareholder[2]	**61**	**4**	**49**	**114**	41	12	48	131
Warmer/(colder) than normal weather (after-tax impact)	**7**	**-**	**(7)**	**13**	16	-	6	(33)
Loss on settlement of pre-issuance hedge contracts	**-**	**2**	**-**	**-**	-	3	-	-

1 Quarterly financial information has been extracted from financial statements prepared in accordance with U.S. GAAP.
2 Earnings per share is not provided, since the Company is an indirect wholly owned subsidiary of Enbridge.

Revenues include amounts billed to customers for natural gas, which vary with fluctuations in natural gas prices. Higher natural gas prices would increase revenues, but would not similarly impact earnings, given that the cost of natural gas flows through to customers.

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

Earnings for a given quarter in two successive years may vary significantly primarily due to potentially varying weather patterns. Specifically, periods of colder than normal weather would typically result in higher earnings compared to periods of warmer than normal weather. As a result, a meaningful comparison can only be achieved after adjusting earnings for the impact of weather.

FOURTH QUARTER 2016 HIGHLIGHTS

Earnings attributable to the common shareholder were $61 million for the three months ended December 31, 2016 compared with $41 million for the same period in 2015. The increase primarily resulted from higher distribution charges from growth in rate base, including customer growth, colder weather and lower employee related costs, excluding severance costs. This was partially offset by higher depreciation expense from a higher overall asset base and lower capitalized interest from lower capital spending on the GTA project, which are primarily recoverable in distribution rates.

Earnings attributable to the common shareholder were $41 million for the three months ended December 31, 2015 compared with $72 million for the same period in 2014. The decrease primarily resulted from warmer weather during the fourth quarter of 2015 compared to 2014, higher employee severance costs, higher income taxes resulting from the timing of lower postretirement benefit contributions, and higher operating and administrative costs resulting from the timing of costs incurred on the demand side management program.

RELATED PARTY TRANSACTIONS

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

IPL System Inc. The Company has invested in Class D, non-voting redeemable, retractable preference shares of IPL System Inc., an affiliated company under common control. At December 31, 2016, the investment of $825 million in these shares resulted in a weighted average dividend yield of 7.60%. For the year ended December 31, 2016, dividends received amounted to $63 million (2015 - $63 million) with an outstanding receivable balance of $5 million at December 31, 2016 (2015 - $5 million).

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

Witness: L. Uhyrek

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) with an outstanding payable balance of $2 million at December 31, 2016 (2015 - $2 million).

Enbridge (U.S.) Inc., an affiliated company under common control, advanced St. Lawrence $34 million (2015 - $40 million) at the LIBOR rate plus 1.1%, payable on demand.

Enbridge Inc., the ultimate parent company, provides treasury and other management services and charges the Company amounts designed to recover the costs of providing such services. Charges incurred for the year ended December 31, 2016 were $49 million (2015 - $50 million) with an outstanding payable balance of nil at December 31, 2016 (2015 - $4 million).

Enbridge Inc. transferred a non-taxable reimbursement to the Company related to an agreement for the transfer of Part IV.1 tax and the associated Part 1 tax deduction. The reimbursement received for the year ended December 31, 2016 was $5 million (2015 - nil) with an outstanding receivable balance of $5 million at December 31, 2016 (2015 - nil).

Tidal Energy Marketing Inc., an affiliated company under common control, sells natural gas to the Company at prevailing market prices and under normal trade terms. Total charges for the year ended December 31, 2016 were $17 million (2015 - $23 million) with an outstanding payable balance of $4 million at December 31, 2016 (2015 - nil).

Tidal Energy Marketing Inc., an affiliated company under common control, obtains optimization services from the Company. Total revenues for the year ended December 31, 2016 were $8 million (2015 - $8 million) with an outstanding receivable balance of nil at December 31, 2016 (2015 - nil).

Tidal Energy Marketing (U.S.) LLC, an affiliated company under common control, sells natural gas to the Company at prevailing market prices and under normal trade terms. Total charges for the year ended December 31, 2016 were $26 million (2015 - $24 million) with an outstanding payable balance of $8 million at December 31, 2016 (2015 - $4 million).

Aux Sable Canada LP, a related entity partially owned by an affiliated company under common control, sells natural gas to the Company at prevailing market prices under normal trade terms. Total charges for the year ended December 31, 2016 were $16 million (2015 - $62 million) with an outstanding payable of nil at December 31, 2016 (2015 - $2 million).

Gazifère Inc., an affiliated company under common control, obtains gas procurement and transportation services from the Company. These services are pursuant to a contract negotiated between the two companies and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie. Total revenues for the year ended December 31, 2016 were $30 million (2015 - $40 million) with an outstanding receivable of $5 million at December 31, 2016 (2015 - $3 million).

Vector Pipeline Limited Partnership (U.S.), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2016 were $20 million (2015 - $28 million) with an outstanding payable of $2 million at December 31, 2016 (2015 - $1 million).

Vector Pipeline Limited Partnership (Canadian), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2016 were $1 million (2015 - $2 million) with an outstanding payable of nil at December 31, 2016 (2015 - nil).

Alliance Pipeline Limited Partnership (Canadian), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2016 were $2 million (2015 - $28 million) with an outstanding payable of nil at December 31, 2016 (2015 - $2 million).

Alliance Pipeline Limited Partnership (U.S.), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2016 were $4 million (2015 - $22 million) with an outstanding payable of nil at December 31, 2016 (2015 - $2 million).

Niagara Gas Transmission Limited, an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2016 were $2 million (2015 - $2 million) with an outstanding payable of nil at December 31, 2016 (2015 - nil).

2193914 Canada Limited, an affiliated company under common control, provides natural gas transportation services to the Company. Total charges to the year ended December 31, 2016 were $2 million (2015 - $1 million) with an outstanding payable balance of nil at December 31, 2016 (2015 - nil).

Other Transactions
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. At December 31, 2016, the Company had an outstanding payable of $6 million to Enbridge Pipelines Inc. (2015 - nil) and an outstanding payable of $13 million to Enbridge Employee Services Inc. (2015 - $13 million).

RISK FACTORS AND FINANCIAL INSTRUMENTS

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

REGULATORY RISK
The Company's operations are regulated and are subject to regulatory risk. The Company retains dedicated professional staff and maintains strong relationships with customers, intervenors and regulators to help minimize regulatory risk. The strong regulatory relationship continued in 2016 as the Company's 2017 rate application was approved by the OEB through settlement agreements rather than litigation. Under the customized IR decision, the Company does not file a request with the OEB to set its annual return on equity (ROE). The OEB sets through its formulaic process the allowed ROE that the Company is permitted to charge in rates, in addition to various other cost projections in relation to the utility's operations. The OEB approved ROE is based on the OEB's cost of capital guidelines as applicable to the Company. The Company is also permitted by the OEB to recover costs considered within the scope of various deferral and variance accounts in relation to items for which costs cannot be accurately forecast. To the extent that costs fall outside of those approved by the OEB within rates and permitted within the scope of approved deferral and variance accounts, the Company is at risk.

The Company does not profit from the sale of natural gas nor is it at risk for the difference between the actual cost of natural gas purchased and the price approved by the Regulators (including risk management costs for St. Lawrence). This difference is deferred as a receivable from or payable to customers until the Regulators approve its refund or collection. The Company, excluding St. Lawrence, has a quarterly rate adjustment mechanism in place that allows for the quarterly adjustment of rates to reflect changes in natural gas prices, and for the establishment of rate riders required to refund or collect gas cost variances. Adjustments are subject to OEB approval. St. Lawrence monitors its gas cost variance balance, and its potential impact on customers, and can request interim rate relief that will allow it to recover or refund the natural gas cost differential.

VOLUME RISKS

Since customers are billed on both a fixed charge and on a volumetric basis, the Company's ability to collect its total revenue depends in large part on achieving the forecast distribution volume established in the rate-making process. Volume forecasts are reviewed and approved by the OEB annually.

Variations in volumetric consumption depend on four key variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers.

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

Factor	Incremental change	Approximate incremental impact
Weather	18 heating degree days	0.8 billion cubic feet
Volume	1 billion cubic feet	$1.7 million (after-tax)

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

Distribution volume may also be impacted by increased adoption of energy efficient technologies, including more efficient building construction. In addition, conservation efforts by customers can further contribute to the decline in annual average consumption.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 80% (2015 - 80%) of total distribution volume. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions are important to all market sectors as continued expansion adds to the total consumption of natural gas.

There may be circumstances where the Company attains its total forecast distribution volume, but revenues are different from forecast as a result of other variables such as the mix between the residential, commercial and industrial sectors.

The Company remains at risk for the actual versus forecast large volume contract commercial and industrial volumes; however, general service volume risk is mitigated for both ratepayers and the Company through the average use true-up variance account. This variance account records the difference between forecast and actual weather normalized general service average uses, and trues up for the difference, through either a collection or repayment to customers.

MARKET RISK

The Company's earnings, cash flows and other comprehensive income (OCI) are subject to movements in natural gas prices, emission allowance 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.

Emission Allowance Price Risk
Emission allowance price risk is the risk of gain or loss due to changes in the market price of emission allowances that the Company is required to purchase for itself and most of its customers to meet greenhouse gas compliance obligations. Similar to the gas supply procurement framework, the OEB's framework for emission allowance procurement allows recovery of fluctuations in emission allowance prices in customer rates.

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 United States dollars (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.

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.

LIQUIDITY RISK
Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments 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 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.

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

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.

The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties to settle these instruments at the reporting date. The fair value of cash and cash equivalents, bank indebtedness, and short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximates their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates, natural gas prices and time value.

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), which approximates its cost and redemption value. At December 31, 2016, the Company's long-term debt had a carrying value of $3,983 million (2015 - $3,683 million) and a fair value of $4,585 million (2015 - $4,159 million).

Additional information about the Company's risk management and financial instruments is included in Note 17 of the 2016 Consolidated Financial Statements.

GENERAL BUSINESS RISKS
Service Interruption
The Company's ability to deliver natural gas to its customers on demand is dependent on adequate supply being transported on third party transmission pipelines to its franchise and a strong distribution system. While the Company has received reliable service from its upstream service providers, a large supply or pipeline disruption on a very cold day has the potential to cause service interruption. The Company procures supply and transport from third party suppliers and pipelines to meet design winter conditions as approved by its regulator and diversifies its procurement to the extent possible, reducing the potential for supply disruption. Network analysis, interruptible customers and the curtailment process enable the Company to manage gas supply deliveries to customers when required. The GTA Project is a key mitigation as the project provides significant diversification of gas supply to the Company's distribution network and will further reduce the likelihood of a service interruption incident. Additional mitigations to any service interruption to the distribution system are discussed in the Operating Risk section below.

Operating Risk
The Company's network, including storage assets, are exposed to operational risks such as accidental damage to mains and service lines, corrosion in mains and service lines, malfunction of compression, regulation and measurement equipment and other issues that can lead to unplanned natural gas escapes and outages. Leaks are an inherent risk of operations. Surveillance, maintenance and repair programs as well as the phased replacement of targeted pipes and facilities significantly reduces the exposure. In 2012, the Company completed its cast iron replacement and bare steel main replacement programs.

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

The Company has extensive programs to manage pipeline and storage well integrity, which include a comprehensive damage prevention program along with leak surveys, corrosion surveys and the use of in-line inspection tools for high stress pipelines. Maintenance and inspection programs are directed to the areas of greatest benefit and pipe and facilities are replaced or repaired as the need is identified. The Company conducts periodic planned emergency response exercises and training. The Company also maintains comprehensive insurance coverage for significant events and has a security program designed to reduce security-related risks. While the Company considers the level of insurance to be adequate, it may not be sufficient to cover all potential losses.

The Company participates in the comprehensive insurance program which is maintained by Enbridge for its subsidiaries and affiliates. The insurance program includes coverage for commercial general liability that is considered customary for its industry and includes coverage for sudden and accidental pollution incidents. In the unlikely event that multiple insurable incidents exceeding the program coverage limits are experienced by Enbridge subsidiaries or affiliates within the same insurance period, the total insurance coverage will be allocated on an equitable basis.

Environmental, Health and Safety Risk
The Company's workers, operations, facilities are subject to municipal, provincial and federal legislation which regulate the protection of the environment and the health and safety of workers. For the environment, this includes the regulation of discharges to air, land and water; the management and disposal of solid and hazardous waste; and the assessment of contaminated sites.

The operation of our gas distribution system and gas facilities comes with risk of incidents, malfunctions or other unplanned events that could result in spills or emissions to the environment that exceed permitted levels. These events could result in injuries to workers or the public, fines, penalties or other sanctions and/or property damage. The Company could also incur liability in the future for environmental contamination associated with past and present activities and properties.

The gas distribution system must maintain a number of environmental and other permits from various governmental authorities to operate. As a result, these facilities and the distribution network are subject to periodic inspection. Failure to maintain regulatory compliance could result in operational interruptions, fines, penalties, and/or orders for additional pollution control technology or environmental remediation, etc. As environmental requirements and regulations become more stringent, the cost to maintain compliance and the time required to obtain approvals has consistently increased.

In early 2015, Ontario announced its intention to develop a cap and trade carbon system that will be linked with Quebec and California. In December 2015, the Ontario greenhouse gas (GHG) reporting regulation was amended to include additional sources, including emissions resulting from the distribution of natural gas and equipment used for natural gas transmission, distribution and storage. Ontario released its cap and trade regulation and subsequently released a draft offset regulation with comments due at December 30, 2016. Implementation of cap and trade took place starting January 1, 2017. Under the cap and trade regulation, the Company will be required to purchase emission allowances for most of its customers' use of natural gas as well as for emissions from its own operations. This process is complex and requires ongoing monitoring of the carbon market and related climate change and carbon policies not only in Ontario but also in other jurisdictions especially those with whom the Government of Ontario aims to link – namely California and Quebec. Environmental non-compliance or significant costs to maintain compliance could have an impact on the demand for the Company's product, affecting operating results and profitability. The OEB approved an interim rate order for the recovery of cap and trade compliance costs through rates beginning January 1, 2017.

In 2016, the Company was required to report 2015 GHG emissions to the Ontario Ministry of Environmental and Climate Change from combustion sources only in Ontario, and all reported data was verified by a third party. There were no issues identified for the 2015 reporting year. The Company monitors developments and attends stakeholder consultations in Ontario.

The Company utilizes a carbon data management system to help with the data capture and mandatory and voluntary reporting needs of the Company. The Company continues to publicly report its GHG emissions and will continue to develop internal procedures to identify operationally related GHG reductions.

Public, Worker and Contractor Safety
The Company's distribution system is operated in close proximity to populated areas and a major incident could result in injury to members of the public. A public safety incident could result in reputational damage to the Company, material repair costs or increased costs of operating and insuring the Company's assets. In addition, given the natural hazards inherent in the Company's operations, its workers and contractors are subject to personal safety risks.

Safety and operational reliability are the most important priorities at the Company. The Company's mitigation efforts to reduce the likelihood and severity of a public safety incident are executed primarily through its integrated management system, asset management system and emergency response preparedness. The Company also actively engages stakeholders through public safety awareness activities to ensure the public is aware of potential hazards and understands the appropriate actions to take in the event of an emergency. The Company also actively engages first responders through education programs that endeavour to equip first responders with the skills and tools to safely and effectively respond to a potential incident.

Finally, the Company believes in a safety culture where safety incidents are not tolerated by employees and contractors and has established a target of zero incidents. For employees, safety objectives have been incorporated across all levels of the Company and are included as part of an employee's compensation measures. Contractors are chosen following a rigorous selection process that includes a strict adherence to the Company's safety culture.

Public Opinion
Public opinion or reputation risk is the risk of negative impacts on the Company's business, operations or financial condition resulting from changes in the Company's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Company operates as well as their opposition to development projects. Potential impacts of a negative public opinion may include loss of business, delays in project execution, legal action, increased regulatory oversight or delays in regulatory approval and higher costs.

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

- having health, safety and environment management systems in place, as well as policies, programs and practices for conducting safe and environmentally sound operations with an emphasis on the prevention of any incidents;
- having formal risk management policies, procedures and systems in place to identify, assess and treat risks to the Company;
- operating to the highest ethical standards, with integrity, honesty and transparency, and maintaining positive relationships with customers, investors, employees, partners, regulators and other stakeholders;
- building awareness and understanding of the role energy and the Company play in people's lives in order to shape public perception of the Company;
- having strong corporate governance practices, including a Statement on Business Conduct, which requires all employees to certify their compliance with the Company policy on an annual basis, and whistleblower procedures, which allow employees to report suspected ethical concerns on a confidential and anonymous basis; and
- pursuing socially responsible operations as a longer-term corporate strategy (implemented through the Company's Corporate Social Responsibility Policy, Climate Policy and Indigenous Peoples Policy)

The actions noted above are the key mitigation action against negative public opinion; however, the public opinion risk cannot be mitigated solely by the Company's individual actions. The Company actively works with other stakeholders in the industry to collaborate and work closely with government and Indigenous Peoples communities to enhance the public opinion of the Company, as well as the industry in which it operates. Unless otherwise specifically stated, none of the policies or initiatives described above are incorporated by reference herein.

Information Technology Security or Systems Incident
The Company's infrastructure, applications and data continue to become more integrated, creating an increased risk that failure in one system could lead to a failure of another system. There is also increasing industry-wide cyber-attacking activity targeting industrial control systems and intellectual property. A successful cyber-attack could lead to unavailability, disruption or loss of key functionalities within the Company's industrial control systems which could impact pipeline operations and potentially result in an environmental or public safety incident. A successful cyber-attack could also lead to a large scale data breach resulting in unauthorized disclosure, corruption or loss of sensitive company or customer information which could have lasting reputational impacts to the Company and could impact its ability to work with various stakeholders.

The Company has implemented a comprehensive security strategy that includes a security policy and standards framework, defined governance and oversight, layered access controls, continuous monitoring, infrastructure and network security, threat detection and incident response through a security operations centre. The Company's security strategy also includes continuing to improve overall intelligence levels related to cyber threat by partnering with a number of external law enforcement agencies and other organizations within its industry.

Transformation Projects
Transformation projects risk is the risk that a large change management initiative carried out by the Company will fail to fully deliver anticipated results because of a failure by the Company to fully address risks associated with change delivery and implementation. This could result in negative financial, operational and reputational impacts to the Company. In 2016, Enbridge launched the Building Our Energy Future initiative, an enterprise-wide transformation program that is intended to drive out focused improvements across the enterprise to ensure an effective and efficient organization that will better support the execution of key strategies, such as the Enbridge and Spectra Energy Corp integration. To mitigate its transformation projects risk associated with the Building Our Energy Future initiative, Enbridge established the Results Delivery Office to manage the integrated plan and roadmap of initiatives, execute the transformation process, provide coaching and support to impacted teams in the areas of results delivery, tracking progress and identification of new risks and establishment of appropriate mitigation steps to address those risks.

CRITICAL ACCOUNTING ESTIMATES

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

DEPRECIATION
Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2016 of $7,418 million (2015 - $7,081 million), or 72% of total assets (2015 - 71%), is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

These depreciation rates are reviewed through periodic depreciation studies conducted by an external consulting firm that makes an objective assessment of the useful lives of the Company's property, plant and equipment. The depreciation rates used by the Company are subject to approval by the OEB for rate setting purposes, which may not always reflect the recommendations of the latest depreciation study. The last such study was completed in 2013. The external consulting firm also provides a framework for the Company's calculation of the estimate of the net cumulative amount collected from customers for future site removal and restoration of property, plant and equipment.

REGULATORY ASSETS AND LIABILITIES
The Regulators exercise statutory authority over matters such as construction, rates and rate-making, and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities. Also, the Company records regulatory assets and liabilities to recognize the economic effects of the actions of the Regulators. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. On refund or recovery of this difference, no earnings impact is recorded. Effectively, the Consolidated Statement of Earnings captures only the approved costs and the related revenue rather than the actual costs and related revenue. As of December 31, 2016, the Company's regulatory assets totaled $634 million (2015 - $742 million) and regulatory liabilities totaled $720 million (2015 - $806 million). To the extent that the Regulators' future actions differ from the Company's current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

POSTRETIREMENT BENEFITS
The Company maintains pension plans, which provide non-contributory defined benefit and/or defined contribution pension benefits to the majority of its employees and OPEB to eligible retirees.

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

The actual return on plan assets was $13 million higher than the expected return on plan assets for the year ended December 31, 2016 (2015 - $14 million lower) as disclosed in Note 19 to the 2016 Consolidated Financial Statements. The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

Assuming no discretionary funding is made into the pension plans, contributions in 2017 will be $34 million.

The following sensitivity analysis identifies the impact on the December 31, 2016 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions.

	Pension Benefits		OPEB	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Decrease in discount rate	86	6	9	-
Decrease in expected return on assets	-	5	n/a	n/a
Decrease in rate of salary increase	(14)	(3)	-	-

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

Note 23 of the 2016 Consolidated Financial Statements.

REGULATORY GOVERNANCE

Undertakings

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

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

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

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

Affiliate Relationships Code

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

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

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

CHANGES IN ACCOUNTING POLICIES

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.