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January 23, 2014

VIA RESS, EMAIL and COURIER

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

Re: EB-2012-0459 - Enbridge Gas Distribution Inc. ("Enbridge")
2014 – 2018 Rate Application
Undertakings - Technical Conference

Please find attached the responses to undertakings given to Enbridge during the course of the Technical Conference which took place January 17, 18, and 20.

Please note that, as indicated at the Conference, some responses require more time to prepare than allowed for by Procedural Order #4. Enbridge will file the remainder of the undertaking responses as soon as possible.

Yours truly,

(original signed)

Lorraine Chiasson
Regulatory Coordinator

Attach.

cc: Mr. F. Cass, Aird & Berlis
EB-2012-0459 Intervenors

UNDERTAKING TCU1.9

UNDERTAKING

Technical Conference TR 1, page 49

EGDI to provide a more fulsome response to SEC technical conference question SEC – 46 (Treatment of incremental Community Expansion costs)

RESPONSE

School Energy Coalition Technical Conference Question #46

Ref: I.B18.EGDI.SEC.84

Please confirm that the Applicant proposes that the Board treat incremental Community Expansion costs, as set forth in the Applicant's future application, as a Y factor.

Enbridge Provides the following response:

As previously discussed, the Company has not fully developed its Community Expansion proposal. Enbridge expects to provide details within a future application. Examples of requests for approval that could be included in the future application are:

- A request for "Y" factor treatment of the related costs
- Establishment of a community expansion deferral account
- Changes to the Contribution and Connection Policies
- Relief from specific aspects of EBO 188
- Establishment of a rate rider
- Cost sharing arrangements

As set out at Exhibit B1, Tab 3, Schedule 1, access to natural gas service would provide significant benefits to home and business owners in these un-serviced communities. The Company would like to ensure that its Community Expansion proposal can be fully developed and can take into account information that is still being collected. Once the application is filed, it can be assessed by the Board and all Stakeholders, based on its merits.

Witnesses: D. McIlwraith
N. Ryckman

UNDERTAKING TCU1.10

UNDERTAKING

Technical Conference, TR 91

Concentric to confirm whether it looked at the Union Gas data set used by PEG to analyze the performance of the two gas utilities for the past period.

RESPONSE

The source of the benchmarking data used by Concentric for Union Gas is EB-2010-0039, 2009 Earnings Sharing & Disposition of Deferral Account and Other Balances, Exhibit A, Tab 2, Appendix A, Schedules 6, 10, 13, and 18, filed April 22, 2010. Because Concentric's original benchmarking study was conducted prior to Union providing data to PEG, Concentric requested benchmarking data directly from Union. In response to our request Union provided the referenced 2009 Earnings Sharing data (which covered the period 2008 to 2009).

Concentric examined the PEG report that compared Union and EGD, but Concentric did not request, or examine the data provided to PEG by Union because Concentric considers a two company comparison too narrow for TFP analysis, which requires a broader sample to determine industry productivity with a reasonable degree of confidence.

Witness: J. Coyne - Concentric Energy Advisors Inc.

UNDERTAKING TCU1.12

UNDERTAKING

TR Technical Conference, page 139

EGDI to provide average SQR results from the previous IR term as a comparative figure to 2013 numbers.

RESPONSE

Tables 1 and 2 on the following page present the 2008 to 2012 data for the proposed performance benchmarking and Service Quality Requirements ("SQR") metrics as stated at Exhibit A2, Tab 11, Schedule 2. As it takes time to compile, validate and conduct analytics on a complete year of the latest actual data for the various operational metrics, 2013 results are not yet available.

Table 1 shows that the Company's Operational and Customer related metrics have been progressing in the right direction when comparing the corresponding results between the last year and the first year of the previous IR term.

Table 2 demonstrates that the Company has been improving overall SQR results through the previous IR term, when comparing the corresponding results between the last year and the first year of the previous IR term. There were only two metrics that did not improve due to the implementation of the new Customer Information System in late 2009 and its enhancement, which was implemented in January 2012.

Witnesses: R. Fischer
S. Kancharla

Table 1
Performance Benchmarking Metrics

Metrics	Col. 1 2008	Col. 2 2009	Col. 3 2010	Col. 4 2011	Col. 5 2012	Col. 6 Average
Customer Experience: Customer Satisfaction Index	64%	63%	61%	64%	68%	64%
Damage Prevention: Number of Excavation Damages per 1,000 Locates	5.5	5.1	4.8	3.3	3.1	4.4
Leak Management: Service Leaks Repaired per Mile of Service	0.302	0.225	0.372	0.519	0.816	0.447
Leak Management: Total Number of Grade 1 (A) leaks eliminated or repaired during the year	35	36	117	51	566	161
Operational Effectiveness: All outages per 1,000 Customers	5.43	4.96	5.34	5.39	5.33	5.29
Employees Health and Safety: Total Reportable Injury Frequency Rate	3.36	3.04	2.68	1.74	2.01	2.57

Table 2
Service Quality Requirements Metrics

Metrics	Col. 1 2008	Col. 2 2009	Col. 3 2010	Col. 4 2011	Col. 5 2012
Call Answering Service Level	77.80%	74.10%	65.30%	75.20%	78.40%
Number of Calls Abandon Rate	3.70%	7.00%	11.60%	4.10%	2.40%
Meter Reading Performance	0.70%	0.47%	0.66%	0.70%	0.46%
Appointments Met within the Designated Time Period	92.60%	96.30%	94.70%	95.30%	93.30%
Time to Reschedule Missed Appointments	62.80%	97.60%	95.20%	92.80%	93.80%
Emergency Calls Responded within One Hour	94.20%	96.20%	94.20%	95.20%	96.90%
Number of Days to provide a Written Response	100.00%	89.00%	N/A[1]	N/A[1]	83.14%
Number of Days to Reconnect a Customer	97.10%	94.30%	93.90%	93.80%	94.10%

Note:

1. Information was not available for the 2010 and 2011 reporting periods due to a new Customer Information System which was implemented in late 2009 and its further enhancement in January 2012.

Witnesses: R. Fischer
S. Kancharla

UNDERTAKING TCU1.14

UNDERTAKING

Technical Conference TR 1, page 155

EGDI to calculate whether, if the average ROE is 124.5 basis points above allowed ROE during the IRM term, then the effect of the SEIM is for the ratepayers to give back all or more than all of the earnings sharing that they received.

RESPONSE

As stated at Exhibit A2, Tab 11, Schedule 3, the purpose of the SEIM is to include stronger incentives for the Company to implement long-term sustainable efficiencies which survive beyond the IR term and to encourage productivity investments in the later years of the IR term. These sustainable efficiencies will benefit ratepayers in terms of delivering safe and reliable energy to customers at rates lower than they would otherwise be beyond the IR term. ROE is only used as an input to calculate the potential SEIM reward. The SEIM reward will not be available to the Company unless it can meet the productivity and quality of service criteria as detailed on page 7 at Exhibit A2, Tab 11, Schedule 3.

As illustrated in the tables below, the potential SEIM reward approximates the ratepayer ESM amounts assuming actual average ROE is 124.5 bp above allowed ROE for very specific assumptions, however, different inputs/assumptions (i.e., rate base growth, fluctuations in actual ROE's over the term that still equate to an average overage of 124.5 bp, etc.) can result in very different results (i.e., SEIM amounts greater than or less than ESM amounts paid).

Witnesses: S. Kancharla
R. Small

Illustration of ESM and SEIM Calculations assuming average actual versus allowed ROE of 124.5 basis points

($ Millions)

ESM Calculations

	2014	2015	2016	2017	2018	Total
Rate Base	5,000.0	5,000.0	5,000.0	5,000.0	5,000.0	
Equity 36%	1,800.0	1,800.0	1,800.0	1,800.0	1,800.0	
Allowed ROE	10.00%	10.00%	10.00%	10.00%	10.00%	
Actual ROE	11.245%	11.245%	11.245%	11.245%	11.245%	
Net overearnings after 100bp deadband	4.4	4.4	4.4	4.4	4.4	
Gross overearnings (tax rate 26.5%)	6.0	6.0	6.0	6.0	6.0	
ESM amounts returned to ratepayers	3.0	3.0	3.0	3.0	3.0	**15.0**

SEIM Calculation

2014 - 2018 average actual ROE	11.245%	
2014 - 2018 average allowed ROE	10.000%	
Variance	1.245%	
ROE premium (Variance * 50% * 50%)	0.311%	(which is less than 0.5%)
2019 rate base	5,000.0	
2019 equity component of rate base	1,800.0	
Annual SEIM reward before gross-up for taxes	5.6	
Annual grossed-up SEIM reward	7.6	
Total SEIM reward (2 X Annual Reward)	**15.2**	

Witnesses: S. Kancharla
R. Small

UNDERTAKING TCU1.15

UNDERTAKING

Technical Conference TR 1, page 163

Enbridge to recalculate 2017 and 2018 O&M costs using the “simple method” of escalation instead of the “compound method”.

RESPONSE

As Filed

	($ Millions)
2016 Budgeted Other O&M	274.8
2013 Approved Other O&M	251.3
Change	23.5
Divided by 3 years	/ 3
Divided by the 2013 Approved base	/ 251.3
Average % increase	3.12%
2017 Budgeted O&M = (1.0312 * 2016 Budgeted Other O&M of $274.8)	283.4
2018 Budgeted O&M = (1.0312 * 2017 Budgeted Other O&M of $283.4)	292.2

2017 & 2018 Other O&M using the Simple Method

2016 Budgeted Other O&M	274.8
2013 Approved Other O&M	251.3
Change	23.5
Divided by 3 years	/ 3
Average Change $	7.8
2017 Budgeted O&M = ($7.8 + 2016 Budgeted Other O&M of $274.8)	282.6
2018 Budgeted O&M = ($7.8 + 2017 Budgeted Other O&M of $283.4)	290.5

Witnesses: S. Kancharla
R. Small

UNDERTAKING TCU1.16

UNDERTAKING

TR Technical Conference, page 164

With reference to deferral and variance accounts proposed for relocation projects and replacement mains for 2017 and 2018, EGDI to confirm that in both cases it's not mathematically possible to give money back to the ratepayers.

RESPONSE

The Company has performed the revenue requirement calculations for relocation mains and replacement mains forecast expenditures ($12.6M/annually relocations and $5.1M/annually replacement) and confirms that in both categories there is no level of underspend that will result in an amount being returned to ratepayers, through the Relocation Mains Variance Account or Replacement Mains Variance Account, in either 2017 or 2018. The revenue requirement forecast does not exceed $1.5M in either category in 2017, or cumulatively in either category in 2018.

Witness: R. Small

UNDERTAKING TCU2.2

UNDERTAKING

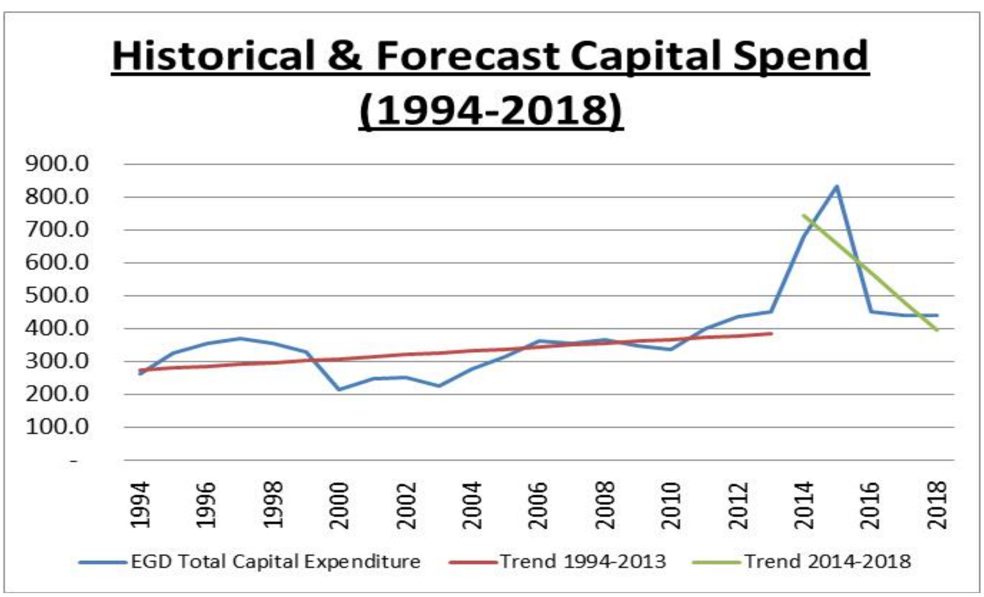
Technical Conference TR 2, page 18

EGDI to provide a table showing its three main challenges in the coming years (capital spending challenges, operating expenses and productivity challenges) and how they differ from the three groups of comparators identified by SEC (Union Gas, large Ontario LDCs and Enbridge's circumstances in 2007).

RESPONSE

Compared to Enbridge's circumstances in 2007, the current challenges are as follows:

Capital spending challenges:
This is the most significant issue facing Enbridge. Undertaking TCU2.15 provides historical and forecast capital spend. It is evident that the capital needs have increased and are lumpier in nature. This is largely driven by safety and integrity projects, major projects, customer growth, and relocation requirements. Aging infrastructure and increased focus on safety and reliability compared to 2007 levels have increased the system integrity spend. New requirements include projects like GTA reinforcement, Ottawa reinforcement, and WAMS. Recent changes to legislation further add pressure on capital expenses.



Witnesses: S. Kancharla
R. Fischer
J. Coyne - Concentric

Operating expense challenges:
The response to Board Staff Interrogatory #50 found at Exhibit I.B17.EGDI.STAFF.50 provides the historical and budget operating expenses for the period 2007 to 2018 in five main categories. The tables below show the expenses and growth rates for those five categories. The response to Board Staff Interrogatory #68 found at Exhibit I.B17.EGDI.SEC.68 provides details of the “Other O&M” category for the period 2007 to 2016. In the table, Lines 1 and 6 show the increasing employee related expenses and Outside services over the period under review. This is due to the increased amount of work and cost escalations to maintain a safe and reliable network and provide an accepted level of customer experience. Similar to capital, changes to legislation add pressure on operating expenses.

Enbridge Gas Distribution
Summary of Operating and Maintenance Expense by Category
From 2007 Actuals to 2018 Budget

Line No.	Categories ($ Millions)	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Board Approved 2013	Budget 2014	Budget 2015	Budget 2016	Budget 2017	Budget 2018
1.	Customer Care/CIS Service Charges	$ 84.4	$ 82.5	$ 87.5	$ 87.5	$ 79.2	$ 85.8	$ 89.4	$ 92.6	$ 96.5	$ 100.4	$ 104.4	$ 108.5
2.	Demand Side Management ("DSM")	$ 22.0	$ 23.1	$ 24.3	$ 25.5	$ 26.7	$ 28.1	$ 31.6	$ 32.2	$ 32.8	$ 33.5	$ 34.2	$ 34.9
4.	Pension and OPEB Costs	$ 4.3	$ 4.7	$ 5.9	$ 7.2	$ 6.5	$ 24.3	$ 42.8	$ 37.2	$ 33.8	$ 30.9	$ 28.5	$ 26.2
3.	Regulatory Cost Allocation Methodology("RCAM")	$ 18.1	$ 19.1	$ 21.2	$ 24.3	$ 26.7	$ 31.6	$ 32.1	$ 35.3	$ 34.0	$ 33.8	$ 34.8	$ 35.9
5.	Other O&M	$ 193.2	$ 194.0	$ 198.2	$ 202.2	$ 221.4	$ 224.0	$ 219.2	$ 228.0	$ 231.5	$ 241.0	$ 248.5	$ 256.3
6.	Total Net Utility O&M Expense	$ 322.0	$ 323.4	$ 337.0	$ 346.7	$ 360.5	$ 393.8	$ 415.1	$ 425.3	$ 428.5	$ 439.5	$ 450.5	$ 461.8

Line No.	Categories ($ Millions)	2008 vs. 2007	2009 vs. 2008	2010 vs. 2009	2011 vs. 2010	2012 vs. 2011	2013 vs. 2012	2014 vs. 2013	2015 vs. 2014	2016 vs. 2015	2017 vs. 2016	2018 vs. 2017
1.	Customer Care/CIS Service Charges	-2.3%	6.1%	0.0%	-9.5%	8.3%	4.2%	3.6%	4.2%	4.0%	4.0%	3.9%
2.	Demand Side Management ("DSM")	5.0%	5.2%	4.9%	4.7%	5.2%	12.5%	1.9%	1.9%	2.1%	2.1%	2.0%
4.	Pension and OPEB Costs	9.3%	25.5%	22.0%	-9.7%	273.8%	76.1%	-13.1%	-9.1%	-8.6%	-7.7%	-8.2%
3.	Regulatory Cost Allocation Methodology("RCAM")	5.5%	11.0%	14.6%	9.9%	18.4%	1.6%	10.0%	-3.7%	-0.6%	3.1%	3.0%
5.	Other O&M	0.4%	2.2%	2.0%	9.5%	1.2%	-2.1%	4.0%	1.5%	4.1%	3.1%	3.1%
6.	Total Net Utility O&M Expense	0.4%	4.2%	2.9%	4.0%	9.2%	5.4%	2.5%	0.8%	2.6%	2.5%	2.5%

Productivity challenges:
In the forecast operating expenses, productivity is embedded. There are cost pressures and these are detailed in the response to Board Staff Interrogatory #19 found at Exhibit I.A2.EGDI.STAFF.19. The organization needs to find efficiencies to absorb these cost pressures. Concentric’s study and analysis shows that EGD has maintained total productivity performance and related to O&M productivity, EGD has outpaced the industry. In the response to SEC Interrogatory #16 found at Exhibit I.A1.EGDI.SEC.16, Concentric observes that incremental productivity gains become more challenging as companies become more efficient. From 2007, this is the second generation of incentive regulation for EGD and the opportunity to find further efficiencies diminishes.

Witnesses: S. Kancharla
R. Fischer
J. Coyne - Concentric

Considering the unique circumstances of individual companies, Enbridge is unable to comment on the challenges faced by Union Gas and Large Ontario electric LDCs.

The response to SEC Interrogatory #6 found at Exhibit I.A1.EGDI.SEC.6 provides some high level differences between Union Gas and Enbridge. Any challenges from legislation for gas utilities will be common for Union Gas and Enbridge, but even here the applicability of these changes could be different due to differences in each utility's circumstances.

Hydro One has recently filed a Custom IR application under EB-2013-0416. In the summary Hydro One discusses its capital challenges as follows:

> Hydro One Distribution has determined that a custom application is most appropriate, given its proposed significant and necessary multi-year investments with relatively certain timing and levels of associated expenditures. This approach has been customized to fit Hydro One Distribution's specific circumstances to ensure that Hydro One Distribution is capable of effectively addressing the large capital expenditure requirements needed to manage its aging infrastructure and plan for future expansion and modernization of the distribution system. This is required to provide a safe, reliable and secure supply of electricity.[i]

From EGD's perspective, this is very similar to EGD's reason for proposing the Customized IR plan.

[i] EB-2013-0416, Exhibit A, Tab 4, Schedule 1, page 1

Witnesses: S. Kancharla
R. Fischer
J. Coyne - Concentric

UNDERTAKING TCU2.3

UNDERTAKING

Technical Conference TR 2, page 20

To provide a table showing O&M budget up to 2018 (reference Exhibit A2, Tab 1, Schedule 1, Paragraph 64)

RESPONSE

Please see Table 1 on following page.

Witness: S. Kancharla

Table 1
Enbridge Gas Distribution
Summary of Operating and Maintenance Expense by Category
From 2013 Board Approved to 2018 Budget

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
Line No.	Categories ($ Millions)	Board Approved 2013	Budget 2014	Budget 2015	Budget 2016	Budget 2017	Budget 2018	2014 vs. 2013	2015 vs. 2014	2016 vs. 2015	2017 vs. 2016	2018 vs. 2017
1.	Customer Care/CIS Service Charges	$89.4	$92.6	$96.5	$100.4	$104.4	$108.5	$3.2	$3.9	$3.9	$4.0	$4.1
2.	Demand Side Management ("DSM") (1)	31.6	32.2	32.8	33.5	34.2	34.9	0.6	0.6	0.7	0.7	0.7
3.	Pension and OPEB Costs	42.8	37.2	33.8	30.9	28.5	26.2	(5.6)	(3.5)	(2.9)	(2.4)	(2.3)
4.	Regulatory Cost Allocation Methodology("RCAM")	32.1	35.3	34.0	33.8	34.8	35.9	3.2	(1.3)	(0.2)	1.1	1.1
5.	Other O&M	219.2	228.0	231.5	241.0	248.5	256.3	8.8	3.5	9.5	7.5	7.7
6.	Total Net Utility O&M Expense	$415.1	$425.3	$428.5	$439.5	$450.5	$461.8	$10.2	$3.2	$11.0	$11.0	$11.3

(1) 2013 DSM reflects the final Board approved amount of $31.6M

UNDERTAKING TCU2.6

UNDERTAKING

Technical Conference TR 2, page 52

Enbridge to provide all presentations that Concentric gave to EGD management.

RESPONSE

Please see the attached presentation to the Executive Management Team dated February 11, 2011. Please note for clarification, at the outset of this project Concentric anticipated conducting a simple corroborating econometric analysis to directly measure the relationship between inflation and utility cost. As our study progressed, the Company concluded that the TFP and PFP work was more complete and a robust econometric model would be subject to the limitations as specified in Board Staff Interrogatory Response found at Exhibit I.A1.EGDI.STAFF.17. For clarity, Concentric did not anticipate utilizing an econometric analysis to establish share weights for the TFP analysis or for benchmarking.

Witnesses: R. Fischer
J. Coyne - Concentric Energy Advisors Inc.

CONCENTRIC ENERGY ADVISORS

IR Plan Analysis Overview

Prepared for:

ENBRIDGE

February 11, 2011

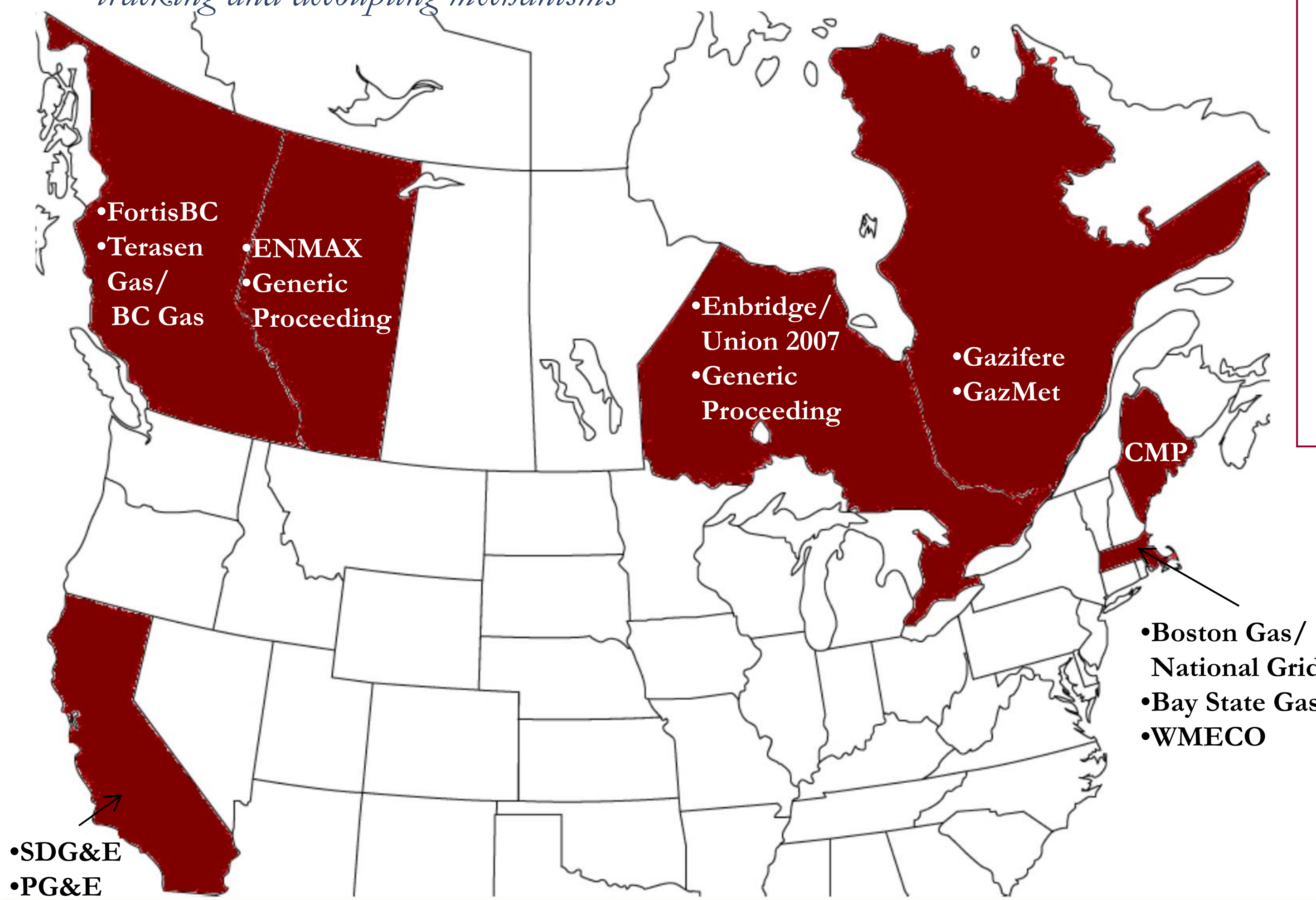
Client Confidential

Agenda

- Productivity Concepts
- Productivity Study Methods
- Concentric Methodology
- Range of X-Factor Estimates
- Path Forward

Productivity Concepts

IR Plans are common for natural gas and electric utilities in Canada, and while they were more prevalent in the United States in the 1990's, many US states have shifted their focus to periodic rate cases, cost tracking and decoupling mechanisms



Concentric has reviewed the Elenchus report, as well as many individual IR Plans, with a specific focus on productivity factor studies, including methodologies employed, results generated, and ultimate X-Factor decisions.

Productivity Concepts

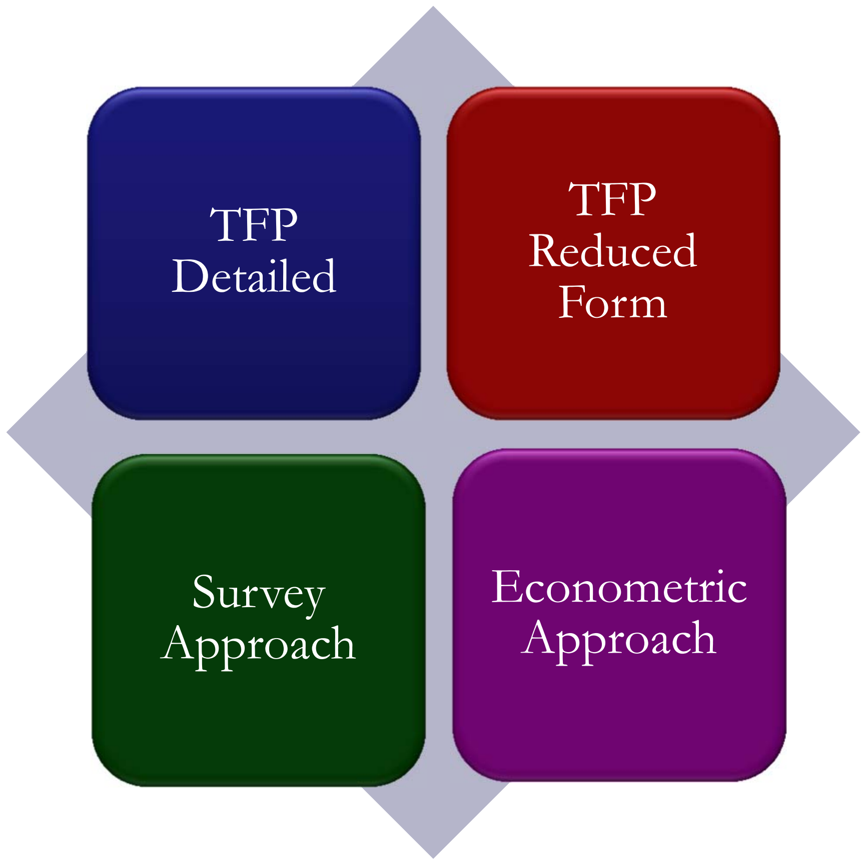
Adjustment Factor
1 + (I – X)

There are many complicating factors when developing an X-Factor:

- The X-Factor can be a fixed subtraction from the Inflation Factor, or it can be a multiplier that as a result changes with the Inflation Factor.
- If the Inflation Factor is an index related to industry-specific input costs, then the X-Factor should represent industry-specific productivity improvement, but if the Inflation Factor is a macroeconomic measure of output (e.g., GDIPI), then the X-Factor should represent:
  - The difference between the input costs of the economy as a whole and the industry (known as the Input Price Differential ("IPD")), and
  - the difference between productivity of the economy as a whole and the industry (known as the Productivity Differential ("PD")).
- The calculation of industry productivity depends on what "Other Identified Costs" are handled as separate Y-Factors or Z-Factors, as these other costs should be removed from the analysis.

Productivity Study Methods

Based on our research, we have identified four general approaches to determining industry productivity:



Productivity Study Methods – TFP Detailed

TFP Detailed

Description	• Full total factor productivity analysis that measures input costs and quantities and output costs and quantities for individual utilities over a period of time. • Often includes detailed analysis to determine input and output weights, capital quantities and prices, and labour quantities and prices.
Recent Examples	• Ontario Enbridge/Union 2007 (Pacific Economics Group) • Ontario Generic Proceeding (Pacific Economics Group) • California – San Diego Gas & Electric (Pacific Economics Group)
Benefits	• Accepted in multiple jurisdictions • Approach is founded in economic theory
Drawbacks	• Complicated methodology; issues and disputes among dueling experts are difficult for other participants in the proceeding to follow • Data intensive • Results are highly sensitive to many required assumptions (as demonstrated by 2007 OEB IR process) • Analysis often does not include key gas LDC cost drives (because data is not consistently available)

Productivity Study Methods – TFP Reduced Form

TFP Reduced Form

Description

- Total factor productivity analysis conducted at a higher level than a detailed study (e.g., no additional analysis to determine share amounts)

Recent Examples

- Alberta Generic Proceeding (NERA)
- Gazifere (Internal Witness)

Benefits

- Less data intensive than detailed TFP study
- Fewer assumptions required to fill missing data

Drawbacks

- Methodology is still complex, although less so than detailed TFP analysis
- Results sensitive to assumptions

Productivity Study Methods – Econometric Approach

Econometric Approach

Description	• Use econometric analysis to directly measure the relationship between inflation and utility costs
Recent Examples	• Massachusetts – WMECO (Concentric)
Benefits	• Analysis is more intuitive than detailed productivity study • Data is more readily available than for detailed productivity study
Drawbacks	• Although the econometric approach may produce reasonable analysis of O&M costs (including labour), applicability to capital costs is less established

Productivity Study Methods – Survey Approach

Survey Approach

Description

- Conduct a survey of productivity factors adopted in other jurisdictions
- Make any necessary adjustments to apply results from other jurisdictions to target utility

Recent Examples

- Alberta – ENMAX (London Economics)

Benefits

- Information is readily available
- Avoids detailed analysis, which is often difficult to present and support
- Provides results that are easy to understand and intuitively sensible

Drawbacks

- No other jurisdiction or utility is facing the exact same situation
- Requires assumptions regarding appropriate adjustments necessary to apply results to target utility
- Applicability of electric utility results to natural gas utilities
- Applicability of non-North American results to North American utilities
- Survey results are more readily challenged, and provide substantial room for interpretation by all parties

Concentric Methodology (Note: A Work In Progress)

At this point, Concentric plans to use a TFP Reduced Form approach to calculate industry productivity in support of Enbridge's next generation IR Plan.

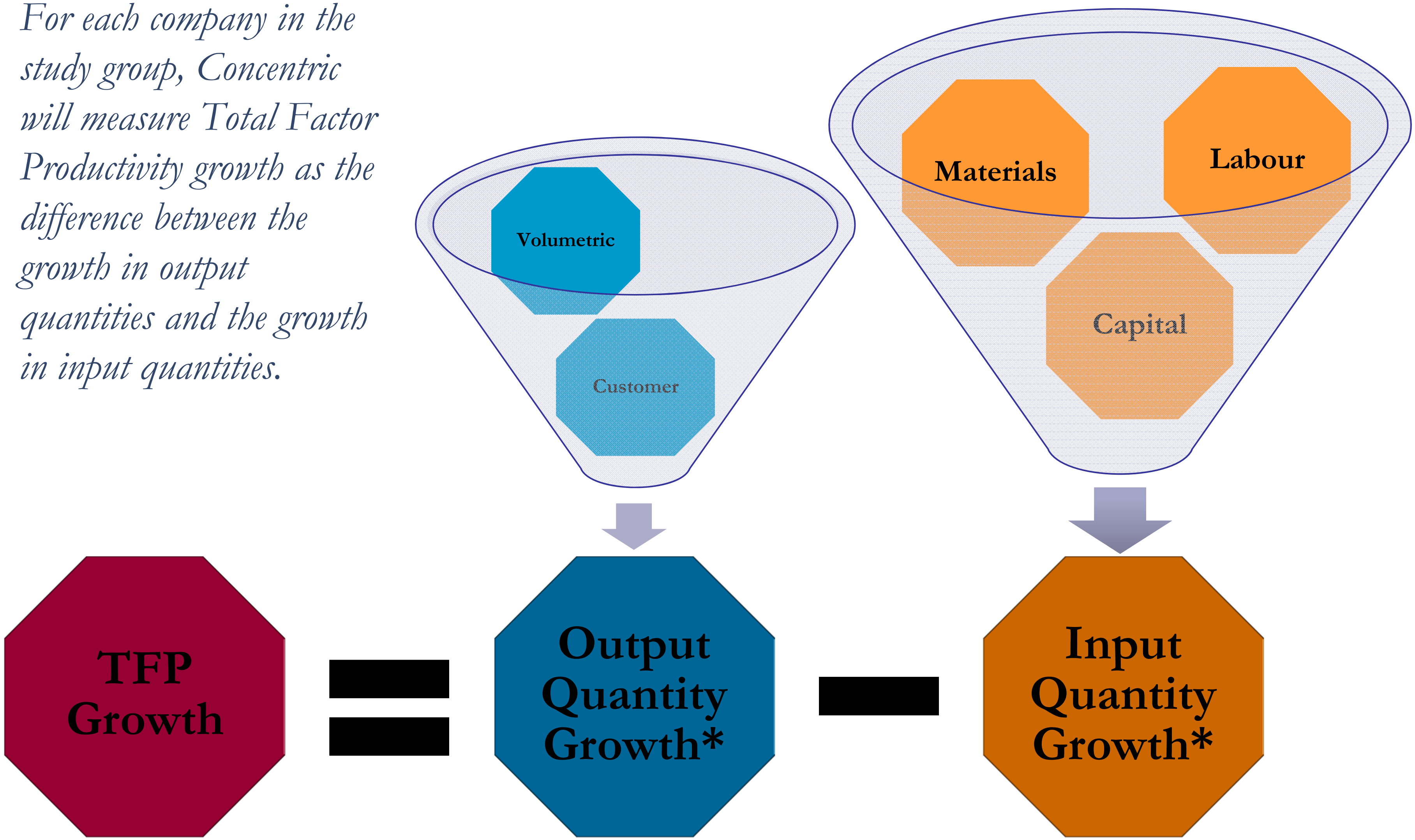
- We believe that the TFP Reduced Form is a good middle ground between the extremely detailed and difficult-to-follow TFP Detailed approach and the simplistic Survey Approach.
- While specific changes will be made, the Concentric approach will likely have a similar feel to the NERA approach used in Alberta and the Gazifere approach used in Quebec.
- We will also use econometric analysis and survey results to corroborate the TFP work.

Concentric will develop an appropriate study group to determine the industry productivity factor for Enbridge.

- Because detailed company-specific data is not available on a consistent basis for many Canadian natural gas utilities, the study group analysis will rely on US natural gas utilities.
  - Concentric believes that relying on natural gas utility data is more appropriate than relying on electric utility data.
  - Concentric also believes that relying on US data is more appropriate than relying on data from non-North American companies.
- Concentric will supplement our analysis with limited Canadian utility data to provide context.

Concentric Methodology

For each company in the study group, Concentric will measure Total Factor Productivity growth as the difference between the growth in output quantities and the growth in input quantities.



* Quantity = Cost/Price

Concentric Methodology – Output Quantity Growth

Output Quantity Growth

Output growth will be measured through a combination of weighted volumetric growth and customer growth by broad customer class (e.g., residential, commercial, industrial).

Volumetric Growth

- Growth in throughput
- Weather variations present complications
  - Annual weather normalization is an imperfect solution
  - Obtaining data to weather normalize on a monthly basis is difficult

Customer Growth

- Growth in customer count
- Less volatile than volumetric growth
- Can be weighted by
  - Revenue/customer
  - Volume/customer
- Also presents a weather normalization challenge
- Difficult to obtain distribution only revenues

Concentric Methodology – Input Quantity Growth: Labour & Materials

Labour Growth

Materials Growth

Growth in labour and materials are two components of Input Growth.

Labour Growth

- Growth in number of employees and labour costs for natural gas distribution business
  - How to handle shared services handled at the corporate level?
  - Include costs of outside services employed?
  - Include A&G salaries?

Materials Growth

- Growth in real distribution non-labour O&M
  - Need to determine appropriate index

Concentric Methodology – Input Quantity Growth: Capital

Capital Growth

Concentric will contrast two approaches to measuring capital growth: the accounting method and the physical plant method.

Accounting Method

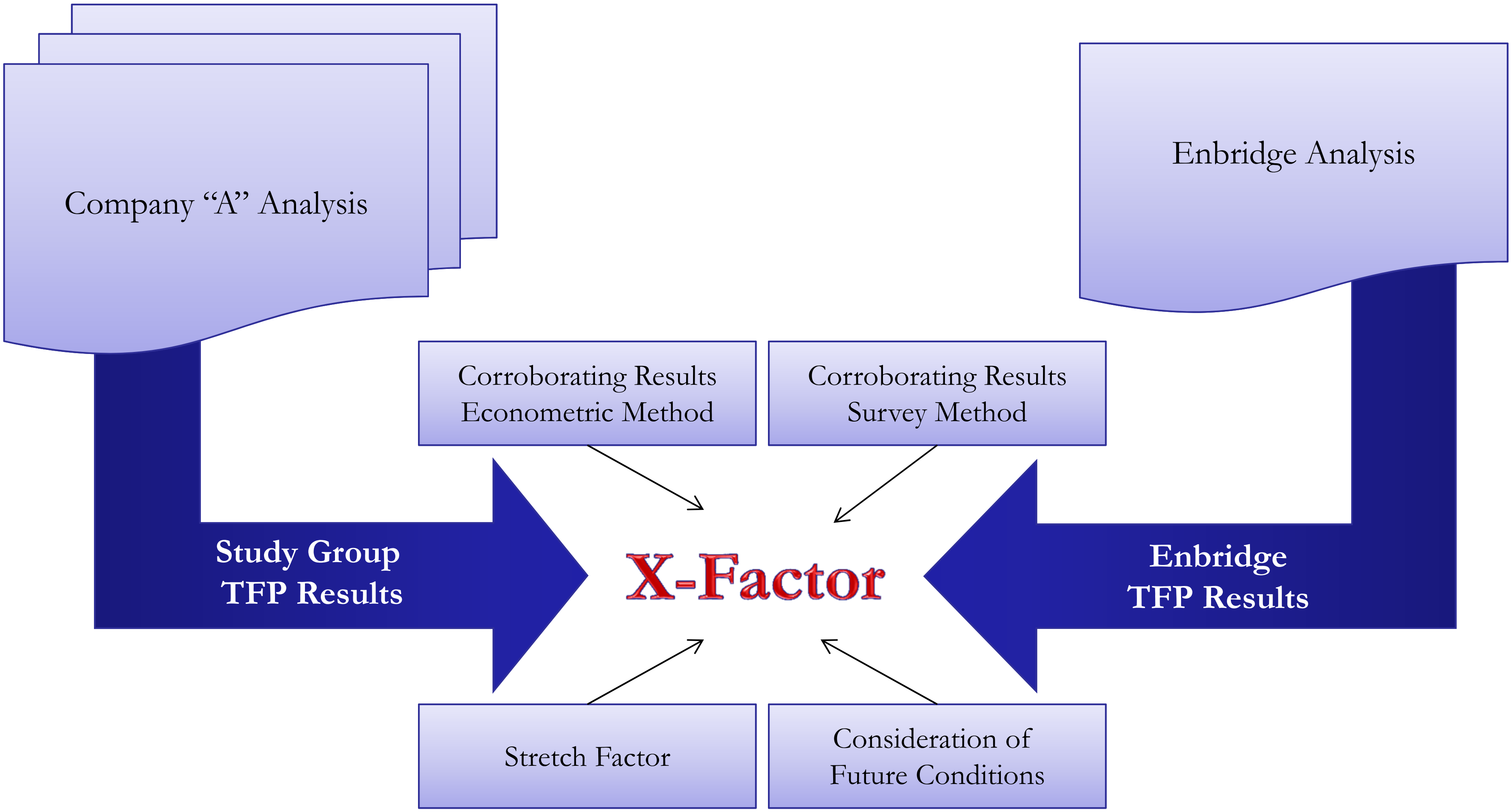
- Based on accounting data for each category, including:
  - Net book value
  - Additions
  - Retirements
  - Depreciation
  - Price escalators

Physical Plant Method

- Based on physical data such as:
  - Number of services
  - Miles of mains
  - Number of meters

Concentric Methodology

The Total Factor Productivity growth results for the study group will be compared with Enbridge's Total Factor Productivity growth, to produce the recommended X-Factor.



Range of X-Factor Estimates – Preliminary Guidance

A survey of current or recently effective IR / PBR plans indicates that

- Canadian X-Factors fall in the range of 1.3% to 1.8%; US X-Factors are between 0.41% and 1.0%
    - Canadian X-Factors are larger because of the form of typical Canadian IR plans (Revenue per customer caps) versus US IR plans (price caps)
- IR / PBR type rate plans seem to have fallen out of favor in the US, replaced by targeted approaches that more closely track the distribution company's O&M and / or Capital spending

Canadian X-Factors

	X-Factor	Stretch Factor	IR Period
Terasen Gas	66% of CPI[1]	Not explicit	2004 – 09[2]
FortisBC	1.5%	Not explicit	2007 – 11
ENMAX Power	1.2%	0.4%	2009 – 11
Ontario 3rd Gen Elec IRM	0.92% to 1.32%[3]	0.2% to 0.6%	2009 – 13
Enbridge	50% of GDP PI[1]	Not explicit	2008 – 12
Union	1.82%	Not explicit	2008 - 12
GazMet	0.3%	None	2007 - 12
Gazifere	0.3%	0.3%	2011 - 15

1 *Terasen: 2009 X-Factor; Enbridge: 2011 X-Factor*
2 *Discontinued IR*
3 *X-Factor within the range depends on company benchmarked performance*

US X-Factors

	X-Factor	Stretch Factor	IR Period
CMP	1.0%	Not explicit	2009 - 13
Boston Gas	0.41%	0.3%	2004 - 13[4]
Berkshire Gas	1.0%	1.0%	2004 - 12
Bay State Gas	0.51%	0.4%	2006 - 15[5]
Vermont Gas Systems	0.39%[6]	Not explicit	2006 - 11

4 *Discontinued IR in 2010*
5 *Discontinued IR in 2010*
6 *Applied to O&M; Budgeted capital spending is recovered through a separate mechanism*

Path Forward

- Complete U.S. and Canadian data sets
  - Determine if a subset of U.S. gas distributors should be used
  - Check data for consistency and any critical gaps
- Estimate reduced form TFP
  - Test results for reasonableness, and consistency with Enbridge experience
  - Review with EGD team
- Estimate econometric model(s)
  - Contrast with reduced form TFP, survey and Enbridge
- Determine preferred approach
  - Robustness of method and data
  - Applicability to Enbridge's experience
  - Consistency with Enbridge's objectives
  - Acceptability by regulator and stakeholders
- Draft Report

UNDERTAKING TCU2.7

UNDERTAKING

Technical Conference TR 2, page 56

Enbridge to provide a response to SEC Technical Conference question 11C (Exhibit TC 1.3)

RESPONSE

SEC Technical Conference Question 11

Ref: I.A1.EGDI.CCC.1, Attachment 2

With respect to the Concentric proposal:

a. P. 3. Please provide all information in the possession of Concentric relating to the current Application as of December 8, 2010 that allowed Concentric to commit in its proposal to “effectively support the Company’s proposal for its next generation Incentive Regulation Plan”.
b. P. 5. Please provide the Concentric presentation at the kickoff meeting.
c. P. 5. Please provide the Productivity Study Outline.
d. P. 6. Please provide the “early draft of the Study results” and “preliminary recommendations” referred to.
e. P. 7. Please provide the “company feedback” referred to in item 6.

Enbridge provides the following response:

Please see the attached Productivity Study Outline Draft dated January 31, 2011. Please also see the note included in the response to Undertaking No. TCU2.6.

Witness: J. Coyne - Concentric Energy Advisors Inc.

Enbridge Gas Distribution
2011 IR Proposal
Productivity Study Outline Draft

I. Introduction/ Scope of the Study

II. Review Productivity Concepts and Relevance to IR Proposal

A. Brief indication of relevant regulatory precedents North American jurisdictions

1. Canada: Ontario, Alberta, BC, Quebec
2. United States: California, Massachusetts, Maine

B. Discussion of EGD's productivity performance under the current IR plan

III. Productivity Study Methods

A. TFP – Detailed

1. Description of Approach – Full total factor productivity analysis that measures input costs and shares and output costs and shares for individual utilities over a period of time, often using detailed analysis to determine input and output weights, capital quantities and prices, labour quantities and prices
2. Recent Examples: Ontario Generic Proceeding (PEG); California SDG&E (PEG)
3. Benefits

a. Accepted in multiple jurisdictions
b. Approach is founded in economic theory

4. Drawbacks

a. Complicated methodology; issues and disputes among dueling experts are difficult for other participants in the proceeding to follow
b. Data intensive
c. Many assumptions required; results are highly sensitive to the assumptions
d. Analysis often does not include key gas LDC cost drivers (because data is not consistently available)
e. 2007 OEB IR process demonstrated that TFP results vary significantly as assumptions or estimates are revised or modified

B. TFP – Reduced Form

1. Description of Approach – Total factor productivity analysis conducted at a higher level than a detailed study (e.g., no additional analysis to determine share amounts)
2. Recent Examples: Alberta Generic Proceeding (NERA)
3. Benefits
   a. Less data intensive than detailed TFP study
   b. Fewer assumptions required to fill missing data
4. Drawbacks
   a. Methodology is still complex, although less so than detailed TFP analysis.
   b. Results are still sensitive to assumptions

C. Econometric Approach

1. Description of Approach – Use econometric analysis to directly measure the relationship between inflation and utility costs
2. Recent Examples: Massachusetts WMECO (Concentric)
3. Benefits
   a. Analysis is more intuitive than detailed productivity study
   b. Data is more readily available than for detailed productivity study
4. Drawbacks
   a. Although econometric approach may produce reasonable analysis of O&M costs, applicability to capital costs is less established

D. Survey Approach

1. Description of Approach
   a. Conduct a survey of productivity factors adopted in other jurisdictions
   b. Make any necessary adjustments to apply results from other jurisdictions to current situation
2. Examples: Alberta ENMAX (London Economics)
3. Benefits
   a. Information is readily available
   b. Avoids detailed analysis, which is often difficult to present and support

c. Provides a result that is easy to understand and intuitively sensible

4. Drawbacks

   a. No other jurisdiction is facing the exact same situation
   b. Requires assumptions regarding appropriate adjustments necessary to apply results to current situation
   c. Applicability of Electric Utility Results to Natural Gas Utilities
   d. Applicability of Non-North American Results to North America
   e. Survey results are more readily challenged, and provide substantial room for interpretation by all parties

IV. Concentric Methodology

A. Selected Methodology (or methodologies) and basis
B. Appropriate Study Group for EGD

   1. US Natural Gas LDCs
   2. Canadian LDCs as Context

C. Data Utilized

   1. Timeframe (minimum of 10 years)
   2. Sources:

      a. US companies: State LDC Filings (SNL), Uniform Statistical Reports (AGA)
      b. Canadian companies: Individual Company Filings

   3. Economy-wide cost inflation measures (e.g., Statistics Canada's Gross Domestic Product Implicit Price Index Final Domestic Demand, US GDP Implicit Price Deflator and Producer Price Index, etc.)
   4. Industry specific cost/inflation measures (e.g., Handy-Whitman Index)
   5. Data limitations and issues

D. Detailed Methodology Description
E. Preliminary Results
F. Adjustments

   1. Y factor Costs that should be excluded from the analysis because they are outside of EGD's control
   2. Events or circumstances that should be isolated broadly or for specific companies

V. Results and Interpretation

A. Estimated productivity factors for the study group
B. Comparison of results to other studies
C. Interpretation of the results and observed differences between EGD and comparators
D. US vs. Canadian company differences
E. Relation of the results over the historic time period to Enbridge's current and anticipated operating and commercial environment

VI. Recommendations and Findings

A. Base productivity factor
B. Appropriateness of a consumer dividend or "stretch" factor
C. Concentric's validation of Enbridge's analysis of their productivity during the currently effective IR
D. Concentric's validation of Enbridge's recommended next generation IR Plan

UNDERTAKING TCU2.8

UNDERTAKING

Technical Conference TR 2, page 57

Enbridge to provide attachment 1 to I.A1.EGDI.CCC.1 Attachment 3.

RESPONSE

See attached.

Witnesses: R. Fischer
J. Frayer - London Economics International

ATTACHMENT 1

Expert Instructions

Enbridge is a gas transmission, distribution, storage and retail business operating in Ontario with a large and lumpy capital expenditure profile predominantly reflecting asset replacement and new investment needs.

Enbridge's rates are regulated by the Ontario Energy Board ("**OEB**") under an incentive regulation framework commonly referred to as "I-X" using a revenue cap/customer approach. Very simply, under this framework, prices or revenues per customer are permitted to increase by an inflation rate ("I") less a component ("X") which is designed to reflect and encourage improvements in efficiency/productivity.

The OEB has recently completed a cost of service rebasing for Enbridge for 2013 and Enbridge is now finalizing a submission to the OEB for its next Incentive Regulation Plan. The previous Plan was for a five-year period (2008-2012). Enbridge is anticipating pre-filing testimony in March 2013. The current submission is being prepared in the context of the:

- OEB's legislated obligations to:
    - protect the interests of consumers with respect to prices and the reliability and quality of gas service;
    - facilitate rational expansion of transmission and distribution systems and rational development and safe operation of gas storage; and
    - facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas;
- OEB's Uniform System of Accounts;
- OEB's preference for a comprehensive incentive rate regulation framework which covers operating and capital expenditure. This is reflected most recently in the approach the OEB has set out for electricity local distribution companies in the *Renewed Regulatory Framework for Electricity* and previously in the move to incentive regulation for gas utilities;[1]
- safety and technical standard requirements; and
- Fair Return Standard ("FRS") principle which must be applied ay all regulators. A fair return should not be modified due to the impact upon customers.

In this context, Enbridge is seeking to understand the implications for its business of the treatment of capital under incentive regulation and other forms of regulation, such as cost-of service. Enbridge is concerned that stakeholders do not understand the challenges posed by its capital investment profile, including strong growth in capital expenditures and depreciation, on maintaining a viable commercial business and would like to be able to demonstrate to stakeholders the realities of these challenges and the negative impacts on its business.

Enbridge requires work within 4-6 weeks so that it can include the analysis with its Incentive Rate Regulation Plan submission to the OEB. Enbridge has also requested that the analysis is conceptual and independent, supported with case study analysis and economic principles, but also tied to specific Enbridge's circumstances (for example, high growth residential customer base and capital needs for meeting increasingly more stringent compliance requirements and the aging asset base).

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[1] See OEB *National Gas Regulation in Ontario: A Renewed Policy Framework* (March 2005) and *Staff Discussion Paper: On an Incentive Regulation Framework for Natural Gas Utilities* (January 2007)

UNDERTAKING TCU2.10

UNDERTAKING

Technical Conference TR 2, page 68

EGDI to advise what adjustments were made to calculate the EGDI customized IR revenue requirement (excluding depreciation and SRC) in the table at page 2 of Exhibit I.A1.EGDI.SEC.5.

RESPONSE

The EGDI customized IR Allowed Revenues, excluding the impacts of the proposed Site Restoration Cost changes, shown in the first row of the table at page 2 of SEC's Interrogatory #5 filed at Exhibit I.A1.EGDI.SEC.5, were derived by making the following adjustments to the As Filed Allowed Revenues:

1. Depreciation rates were reverted to 2013 Approved, from those proposed in this proceeding as part of Site Restoration Cost proposal and the adoption of the Constant Dollar Net Salvage approach,
2. Adjustments to accumulated depreciation, to reflect amounts to be returned to ratepayers via the proposed Rider D (designed to reduce the site restoration cost reserve amount currently included in accumulated depreciation to the level required under the Constant Dollar Net Salvage approach), were removed, and
3. Budgeted tax deductions, equivalent to the annual amounts to be returned via Rider D, were removed.

The adjustments mentioned above resulted in changes to Rate Base (accumulated depreciation), Utility Income (depreciation and income tax expenses), and Capital Structure (due to a different Rate Base value), and ultimately the annual revenue sufficiency/deficiency amounts. Please note, potential impacts to the Company's financing plan (timing and level of debt issuances) were not able to be considered in the response to SEC's Interrogatory #5 at Exhibit I.A1.EGDI.SEC.5.

If one compares the following schedules, to those included in the pre-filed evidence, it will illustrate all the above mentioned changes.

Witnesses: K. Culbert
R. Small

UTILITY RATE BASE
2014 FISCAL YEAR

Line No.		Col. 1 2014 Fiscal Year Excl. CIS & Customer Care	Col. 2 2014 Fiscal Year CIS & Customer Care	Col. 3 Total 2014 Fiscal Year
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	6,977.0	127.1	7,104.1
2.	Accumulated depreciation	(2,950.3)	(69.3)	(3,019.6)
3.	Net property, plant, and equipment	4,026.7	57.8	4,084.5
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.3	-	1.3
5.	Materials and supplies	32.8	-	32.8
6.	Mortgages receivable	0.1	-	0.1
7.	Customer security deposits	(65.7)	-	(65.7)
8.	Prepaid expenses	0.9	-	0.9
9.	Gas in storage	279.9	-	279.9
10.	Working cash allowance	43.2	-	43.2
11.	Total Working Capital	292.5	-	292.5
12.	Utility Rate Base	4,319.2	57.8	4,377.0

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 FISCAL YEAR

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2014	Col. 7 Regulatory Adjustments (Note 1)	Col. 8 Utility Balance Dec.2014	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-	-	-
2.	Land and gas storage rights (451.00)	(23.2)	(0.5)	-	-	-	(23.6)	-	(23.6)	(23.4)
3.	Structures and improvements (452.00)	(5.8)	(0.4)	-	-	-	(6.2)	0.1	(6.1)	(5.9)
4.	Wells (453.00)	(17.2)	(0.8)	-	0.5	-	(17.5)	-	(17.5)	(17.3)
5.	Well equipment (454.00)	(5.6)	(0.5)	-	-	-	(6.2)	-	(6.2)	(5.9)
6.	Field Lines (455.00)	(24.2)	(0.9)	-	0.1	-	(25.1)	-	(25.1)	(24.7)
7.	Compressor equipment (456.00)	(35.8)	(2.7)	-	-	-	(38.5)	0.2	(38.3)	(37.0)
8.	Measuring and regulating equipment (457.00)	(5.8)	(0.4)	-	-	-	(6.2)	-	(6.2)	(6.0)
9.	Total	(117.5)	(6.3)	-	0.5	-	(123.2)	0.3	(123.0)	(120.1)

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

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 FISCAL YEAR

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2014	Col. 7 Regulatory Adjustment (Note 1)	Col. 8 Utility Balance Dec.2014	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(1.9)	(0.1)	-	-	-	(2.0)	-	(2.0)	(2.0)
2.	Structures and improvements (472.00)	(13.6)	(7.8)	-	0.5	0.3	(20.6)	0.2	(20.4)	(16.9)
3.	Services, house reg & meter install. (473/474)	(1,037.8)	(69.2)	-	21.9	13.5	(1,071.6)	-	(1,071.6)	(1,055.7)
4.	NGV station compressors (476)	(1.9)	(0.2)	-	0.1	-	(1.9)	-	(1.9)	(1.9)
5.	Meters (478)	(130.4)	(38.6)	-	13.0	-	(156.0)	-	(156.0)	(143.1)
6.	Mains (475)	(1,231.6)	(96.5)	-	3.9	2.4	(1,321.9)	1.7	(1,320.2)	(1,274.9)
7.	Measuring and regulating equip. (477)	(192.0)	(8.6)	-	2.0	-	(198.6)	0.5	(198.1)	(194.8)
8.	Total	(2,609.2)	(220.9)	-	41.3	16.2	(2,772.6)	2.3	(2,770.3)	(2,689.2)

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

UTILITY INCOME
2014 FISCAL YEAR

Line No.		Col. 1 Utility Income Excl. CIS & Customer Care ($Millions)	Col. 2 CIS & Customer Care ($Millions)	Col. 3 Total Utility Income ($Millions)
1.	Gas sales	2,161.7	91.8	2,253.5
2.	Transportation of gas	224.4	18.4	242.8
3.	Transmission, compression and storage revenue	1.8	-	1.8
4.	Other operating revenue	40.5	-	40.5
5.	Interest and property rental	-	-	-
6.	Other income	0.1	-	0.1
7.	Total operating revenue	2,428.5	110.2	2,538.7
8.	Gas costs	1,455.9	-	1,455.9
9.	Operation and maintenance	332.7	92.6	425.3
10.	Depreciation and amortization expense	279.9	12.7	292.6
11.	Fixed financing costs	1.9	-	1.9
12.	Municipal and other taxes	41.2	-	41.2
13.	Interest and financing amortization expense	-	-	-
14.	Other interest expense	-	-	-
15.	Cost of service	2,111.6	105.3	2,216.9
16.	Utility income before income taxes	316.9	4.9	321.8
17.	Income tax expense	43.6	8.0	51.6
18.	Utility income	273.3	(3.1)	270.2

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2014 FISCAL YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	316.9	316.9	
	Add			
2.	Depreciation and amortization	279.9	279.9	
3.	Accrual based pension and OPEB costs	37.3	37.3	
4.	Other non-deductible items	1.4	1.4	
5.	Total Add Back	318.6	318.6	
6.	Sub-total	635.5	635.5	
	Deduct			
7.	Capital cost allowance	231.4	231.4	
8.	Items capitalized for regulatory purposes	45.9	45.9	
9.	Deduction for "grossed up" Part VI.1 tax	3.5	3.5	
10.	Amortization of share/debenture issue expense	3.9	3.9	
11.	Amortization of cumulative eligible capital	0.3	0.3	
12.	Amortization of C.D.E. and C.O.G.P.E	0.2	0.2	
13.	Site restoration cost adjustment	-	-	
14.	Cash based pension and OPEB costs	44.3	44.3	
15.	Total Deduction	329.5	329.5	
16.	Taxable income	306.0	306.0	
17.	Income tax rates	15.00%	11.50%	
18.	Provision	45.9	35.2	81.1
19.	Part VI.1 tax			1.2
20.	Total taxes excluding interest shield			82.3
	Tax shield on interest expense			
21.	Rate base	4,319.2		
22.	Return component of debt	3.38%		
23.	Interest expense	145.9		
24.	Combined tax rate	26.500%		
25.	Income tax credit			(38.7)
26.	Total utility income taxes			43.6

REVENUE SUFFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN
2014 FISCAL YEAR

		Col. 1	Col. 2	Col. 3	Col. 4
Line No.		Principal Excl. CC/CIS	Component	Cost Rate	Return Component
		($Millions)	%	%	%
1.	Long and Medium-Term Debt	2,596.9	60.12	5.57	3.349
2.	Short-Term Debt	67.4	1.56	1.78	0.028
3.		2,664.3	61.68		3.377
4.	Preference Shares	100.0	2.32	2.96	0.069
5.	Common Equity	1,554.9	36.00	9.27	3.337
6.		4,319.2	100.00		6.783
7.	Rate Base	($Millions)			4,319.2
8.	Utility Income	($Millions)			273.3
9.	Indicated Rate of Return				6.328
10.	Deficiency in Rate of Return				(0.455)
11.	Net Deficiency	($Millions)			(19.7)
12.	Gross Deficiency	($Millions)	(other than CC - CIS)		(26.7)
13.	Customer Care/CIS Deficiency	($Millions)	($114.1 vs $110.2)		(3.9)
14.	Total Gross Revenue Sufficiency	($Millions)			(30.6)
15.	Revenue at Existing Rates	($Millions)			2,498.0
16.	Allowed Revenue	($Millions)			2,528.6
17.	Gross Revenue Deficiency	($Millions)			(30.6)
	Common Equity				
18.	Allowed Rate of Return				9.270
19.	Earnings on Common Equity				8.006
20.	Deficiency in Common Equity Return				(1.264)

ALLOWED REVENUE
AND SUFFICIENCY
2014 FISCAL YEAR

Line No.		Col. 1 Reference	Col. 2 Exclusive of CC-CIS	Col. 3 CC-CIS	Col. 4 EGD Total
			($Millions)	($Millions)	($Millions)
	Cost of Capital				
1.	Rate base		4,319.2	57.8	4,377.0
2.	Required rate of return		6.78%	6.44%	6.77%
3.			292.8	3.7	296.5
	Cost of Service				
4.	Gas costs		1,455.9		1,455.9
5.	Operation and maintenance		332.7	92.6	425.3
6.	Depreciation and amortization		279.9	12.7	292.6
7.	Fixed financing costs		1.9	-	1.9
8.	Municipal and other taxes		41.2	-	41.2
9.			2,111.6	105.3	2,216.9
	Miscellaneous operating and non operating revenue				
10.	Other operating revenue		(40.5)	-	(40.5)
11.	Interest and property rental		0.0	-	-
12.	Other income		(0.1)	-	(0.1)
13.			(40.6)	-	(40.6)
	Income taxes on earnings				
14.	Excluding tax shield		82.3	8.7	91.0
15.	Tax shield provided by interest expense		(38.7)	(0.7)	(39.4)
16.			43.6	8.0	51.6
	Taxes on deficiency				
17.	Gross deficiency -w/out CC/CIS		(26.7)	-	(26.7)
18.	Net deficiency -w/out CC/CIS		(19.7)	-	(19.7)
19.			7.1	-	7.1
20.	Sub-total Allowed Revenue		2,414.5	117.0	2,531.5
21.	Customer Care Rate Smoothing Variance Account Adjustment		-	(2.9)	(2.9)
22.	**Allowed Revenue**		2,414.5	114.1	2,528.6
	Revenue at existing Rates				
23.	Gas sales		2,161.7	91.8	2,253.5
24.	Transportation service		224.4	18.4	242.8
25.	Transmission, compression and storage		1.8		1.8
26.	Rounding adjustment		(0.1)		(0.1)
27.	Total		2,387.8	110.2	2,498.0
28.	**Gross revenue deficiency**		(26.7)	(3.9)	(30.6)

UTILITY RATE BASE
2015 FORECAST YEAR

Line No.		Col. 1 2015 Forecast Year Excl. CIS & Customer Care	Col. 2 2015 Forecast Year CIS & Customer Care	Col. 3 Total 2015 Forecast Year
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	7,441.0	127.1	7,568.1
2.	Accumulated depreciation	(3,151.0)	(82.0)	(3,233.0)
3.	Net property, plant, and equipment	4,290.0	45.1	4,335.1
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.3	-	1.3
5.	Materials and supplies	33.7	-	33.7
6.	Mortgages receivable	0.1	-	0.1
7.	Customer security deposits	(65.1)	-	(65.1)
8.	Prepaid expenses	0.9	-	0.9
9.	Gas in storage	291.2	-	291.2
10.	Working cash allowance	50.0	-	50.0
11.	Total Working Capital	312.1	-	312.1
12.	Utility Rate Base	4,602.1	45.1	4,647.2

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2014	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2015	Col. 7 Regulatory Adjustments (Note 1)	Col. 8 Utility Balance Dec.2015	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-	-	-
2.	Land and gas storage rights (451.00)	(23.6)	(0.5)	-	-	-	(24.1)	-	(24.1)	(23.8)
3.	Structures and improvements (452.00)	(6.2)	(0.6)	-	-	-	(6.8)	0.1	(6.7)	(6.4)
4.	Wells (453.00)	(17.5)	(0.8)	-	-	-	(18.3)	-	(18.3)	(17.9)
5.	Well equipment (454.00)	(6.2)	(0.5)	-	-	-	(6.7)	-	(6.7)	(6.4)
6.	Field Lines (455.00)	(25.1)	(1.0)	-	-	-	(26.1)	-	(26.1)	(25.6)
7.	Compressor equipment (456.00)	(38.5)	(2.9)	-	-	-	(41.4)	0.2	(41.2)	(39.8)
8.	Measuring and regulating equipment (457.00)	(6.2)	(0.4)	-	-	-	(6.6)	-	(6.6)	(6.4)
9.	Total	(123.2)	(6.7)	-	-	-	(129.9)	0.3	(129.6)	(126.3)

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

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 FORECAST YEAR

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
Line No.		Opening Balance Dec.2014	Additions	Net Salvage Adjustment	Retirements	Costs Net of Proceeds	Closing Balance Dec.2015	Regulatory Adjustment (Note 1)	Utility Balance Dec.2015	Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(2.0)	(0.3)	-	-	-	(2.3)	-	(2.3)	(2.1)
2.	Structures and improvements (472.00)	(20.6)	(8.3)	-	1.9	0.8	(26.2)	0.2	(26.0)	(22.8)
3.	Services, house reg & meter install. (473/474)	(1,071.6)	(71.8)	-	22.3	13.4	(1,107.8)	-	(1,107.8)	(1,090.6)
4.	NGV station compressors (476)	(1.9)	(0.2)	-	0.1	-	(2.0)	-	(2.0)	(1.9)
5.	Meters (478)	(156.0)	(39.5)	-	13.0	-	(182.5)	-	(182.5)	(169.2)
6.	Mains (475)	(1,321.9)	(104.2)	-	4.0	2.4	(1,419.8)	1.7	(1,418.1)	(1,367.9)
7.	Measuring and regulating equip. (477)	(198.6)	(9.4)	-	2.0	-	(206.0)	0.5	(205.5)	(201.6)
8.	Total	(2,772.6)	(233.7)	-	43.2	16.6	(2,946.6)	2.4	(2,944.1)	(2,856.1)

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

UTILITY INCOME
2015 FORECAST YEAR

Line No.		Col. 1 Utility Income Excl. CIS & Customer Care ($Millions)	Col. 2 CIS & Customer Care ($Millions)	Col. 3 Total Utility Income ($Millions)
1.	Gas sales	2,312.5	91.8	2,404.3
2.	Transportation of gas	211.2	18.4	229.6
3.	Transmission, compression and storage revenue	1.8	-	1.8
4.	Other operating revenue	40.9	-	40.9
5.	Interest and property rental	-	-	-
6.	Other income	0.1	-	0.1
7.	Total operating revenue	2,566.5	110.2	2,676.7
8.	Gas costs	1,606.8	-	1,606.8
9.	Operation and maintenance	332.0	96.5	428.5
10.	Depreciation and amortization expense	295.6	12.7	308.3
11.	Fixed financing costs	1.9	-	1.9
12.	Municipal and other taxes	43.1	-	43.1
13.	Interest and financing amortization expense	-	-	-
14.	Other interest expense	-	-	-
15.	Cost of service	2,279.4	109.2	2,388.6
16.	Utility income before income taxes	287.1	1.0	288.1
17.	Income tax expense	23.5	7.7	31.2
18.	Utility income	263.6	(6.7)	256.9

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2015 FORECAST YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	287.1	287.1	
	Add			
2.	Depreciation and amortization	295.6	295.6	
3.	Accrual based pension and OPEB costs	33.8	33.8	
4.	Other non-deductible items	1.1	1.1	
5.	Total Add Back	330.5	330.5	
6.	Sub-total	617.6	617.6	
	Deduct			
7.	Capital cost allowance	279.5	279.5	
8.	Items capitalized for regulatory purposes	46.8	46.8	
9.	Deduction for "grossed up" Part VI.1 tax	4.2	4.2	
10.	Amortization of share/debenture issue expense	3.3	3.3	
11.	Amortization of cumulative eligible capital	5.0	5.0	
12.	Amortization of C.D.E. and C.O.G.P.E	0.4	0.4	
13.	Site Rest Costs adjustment	-	-	
14.	Cash based pension and OPEB costs	39.6	39.6	
15.	Total Deduction	378.8	378.8	
16.	Taxable income	238.8	238.8	
17.	Income tax rates	15.00%	11.50%	
18.	Provision	35.8	27.5	63.3
19.	Part VI.1 tax			1.4
20.	Total taxes excluding interest shield			64.7
	Tax shield on interest expense			
21.	Rate base	4,602.1		
22.	Return component of debt	3.38%		
23.	Interest expense	155.3		
24.	Combined tax rate	26.500%		
25.	Income tax credit			(41.2)
26.	Total utility income taxes			23.5

REVENUE DEFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN
2015 FORECAST YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long and Medium-Term Debt	2,918.4	63.41	5.39	3.418
2.	Short-Term Debt	(73.1)	(1.58)	2.75	(0.043)
3.		2,845.3	61.83		3.375
4.	Preference Shares	100.0	2.17	3.68	0.080
5.	Common Equity	1,656.8	36.00	9.72	3.499
6.		4,602.1	100.00		6.954
7.	Rate Base	($Millions)			4,602.1
8.	Utility Income	($Millions)			263.6
9.	Indicated Rate of Return				5.728
10.	Deficiency in Rate of Return				(1.226)
11.	Net Deficiency	($Millions)			(56.4)
12.	Gross Deficiency	($Millions)	(other than CC - CIS)		(76.8)
13.	Customer Care/CIS Deficiency	($Millions)	($118.7 vs $110.2)		(8.5)
14.	Total Gross Revenue Deficiency	($Millions)			(85.3)
15.	Revenue at Existing Rates	($Millions)			2,635.4
16.	Allowed Revenue	($Millions)			2,720.7
17.	Gross Revenue Deficiency	($Millions)			(85.3)
	Common Equity				
18.	Allowed Rate of Return				9.720
19.	Earnings on Common Equity				6.314
20.	Deficiency in Common Equity Return				(3.406)

ALLOWED REVENUE
AND DEFICIENCY
2015 FORECAST YEAR

Line No.		Col. 1 Reference	Col. 2 Exclusive of CC-CIS	Col. 3 CC-CIS	Col. 4 EGD Total
			($Millions)	($Millions)	($Millions)
	Cost of Capital				
1.	Rate base		4,602.1	45.1	4,647.2
2.	Required rate of return		6.95%	6.44%	6.94%
3.			319.8	2.9	322.7
	Cost of Service				
4.	Gas costs		1,606.8		1,606.8
5.	Operation and maintenance		332.0	96.5	428.5
6.	Depreciation and amortization		295.6	12.7	308.3
7.	Fixed financing costs		1.9	-	1.9
8.	Municipal and other taxes		43.1	-	43.1
9.			2,279.4	109.2	2,388.6
	Miscellaneous operating and non operating revenue				
10.	Other operating revenue		(40.9)	-	(40.9)
11.	Interest and property rental		0.0	-	-
12.	Other income		(0.1)	-	(0.1)
13.			(41.0)	-	(41.0)
	Income taxes on earnings				
14.	Excluding tax shield		64.7	8.3	73.0
15.	Tax shield provided by interest expense		(41.2)	(0.6)	(41.8)
16.			23.5	7.7	31.2
	Taxes on deficiency				
17.	Gross deficiency -w/out CC/CIS		(76.8)	-	(76.8)
18.	Net deficiency -w/out CC/CIS		(56.4)	-	(56.4)
19.			20.3	-	20.3
20.	Sub-total Allowed Revenue		2,602.0	119.8	2,721.8
21.	Customer Care Rate Smoothing Variance Account Adjustment		-	(1.1)	(1.1)
22.	**Allowed Revenue**		2,602.0	118.7	2,720.7
	Revenue at existing Rates				
23.	Gas sales		2,312.5	91.8	2,404.3
24.	Transportation service		211.2	18.4	229.6
25.	Transmission, compression and storage		1.8		1.8
26.	Rounding adjustment		(0.3)		(0.3)
27.	Total		2,525.2	110.2	2,635.4
28.	**Gross revenue deficiency**		(76.8)	(8.5)	(85.3)

UTILITY RATE BASE
2016 FORECAST YEAR

Line No.		Col. 1 2016 Forecast Year Excl. CIS & Customer Care	Col. 2 2016 Forecast Year CIS & Customer Care	Col. 3 Total 2016 Forecast Year
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	8,321.9	127.1	8,449.0
2.	Accumulated depreciation	(3,363.0)	(94.7)	(3,457.7)
3.	Net property, plant, and equipment	4,958.9	32.4	4,991.3
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6
6.	Mortgages receivable	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0
9.	Gas in storage	276.3	-	276.3
10.	Working cash allowance	40.1	-	40.1
11.	Total Working Capital	288.8	-	288.8
12.	Utility Rate Base	5,247.7	32.4	5,280.1

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

		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 Adjustments (Note 1)	Utility Balance Dec.2016	Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-	-	-
2.	Land and gas storage rights (451.00)	(24.1)	(0.5)	-	-	-	(24.6)	-	(24.6)	(24.3)
3.	Structures and improvements (452.00)	(6.8)	(0.7)	-	0.5	-	(7.0)	0.1	(6.9)	(6.8)
4.	Wells (453.00)	(18.3)	(0.9)	-	-	-	(19.2)	-	(19.2)	(18.8)
5.	Well equipment (454.00)	(6.7)	(0.5)	-	-	-	(7.2)	-	(7.2)	(7.0)
6.	Field Lines (455.00)	(26.1)	(1.0)	-	0.1	-	(27.0)	-	(27.0)	(26.5)
7.	Compressor equipment (456.00)	(41.4)	(2.9)	-	-	-	(44.3)	0.2	(44.1)	(42.6)
8.	Measuring and regulating equipment (457.00)	(6.6)	(0.4)	-	-	-	(7.0)	-	(7.0)	(6.8)
9.	Total	(129.9)	(7.0)	-	0.6	-	(136.3)	0.3	(136.0)	(132.8)

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

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

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 Adjustment (Note 1)	Col. 8 Utility Balance Dec.2016	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(2.3)	(1.1)	-	-	-	(3.4)	-	(3.4)	(2.8)
2.	Structures and improvements (472.00)	(26.2)	(8.5)	-	4.8	1.4	(28.5)	0.2	(28.3)	(25.9)
3.	Services, house reg & meter install. (473/474)	(1,107.8)	(74.8)	-	22.6	12.7	(1,147.3)	-	(1,147.3)	(1,128.4)
4.	NGV station compressors (476)	(2.0)	(0.2)	-	0.1	-	(2.0)	-	(2.0)	(2.0)
5.	Meters (478)	(182.5)	(40.6)	-	13.5	-	(209.7)	-	(209.7)	(196.0)
6.	Mains (475)	(1,419.8)	(122.2)	-	4.0	2.2	(1,535.7)	1.8	(1,533.9)	(1,475.7)
7.	Measuring and regulating equip. (477)	(206.0)	(11.3)	-	2.0	-	(215.3)	0.5	(214.7)	(210.1)
8.	Total	(2,946.6)	(258.7)	-	47.1	16.3	(3,141.9)	2.6	(3,139.3)	(3,040.8)

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

UTILITY INCOME
2016 FORECAST YEAR

Line No.		Col. 1 Utility Income Excl. CIS & Customer Care ($Millions)	Col. 2 CIS & Customer Care ($Millions)	Col. 3 Total Utility Income ($Millions)
1.	Gas sales	2,372.7	91.8	2,464.5
2.	Transportation of gas	198.7	18.4	217.1
3.	Transmission, compression and storage revenue	1.8	-	1.8
4.	Other operating revenue	41.2	-	41.2
5.	Interest and property rental	-	-	-
6.	Other income	0.1	-	0.1
7.	Total operating revenue	2,614.5	110.2	2,724.7
8.	Gas costs	1,632.5	-	1,632.5
9.	Operation and maintenance	339.1	100.4	439.5
10.	Depreciation and amortization expense	326.9	12.7	339.6
11.	Fixed financing costs	1.9	-	1.9
12.	Municipal and other taxes	45.5	-	45.5
13.	Interest and financing amortization expense	-	-	-
14.	Other interest expense	-	-	-
15.	Cost of service	2,345.9	113.1	2,459.0
16.	Utility income before income taxes	268.6	(2.9)	265.7
17.	Income tax expense	13.7	7.5	21.2
18.	Utility income	254.9	(10.4)	244.5

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2016 FORECAST YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	268.6	268.6	
	Add			
2.	Depreciation and amortization	326.9	326.9	
3.	Accrual based pension and OPEB costs	30.9	30.9	
4.	Other non-deductible items	1.0	1.0	
5.	Total Add Back	358.8	358.8	
6.	Sub-total	627.4	627.4	
	Deduct			
7.	Capital cost allowance	310.1	310.1	
8.	Items capitalized for regulatory purposes	46.6	46.6	
9.	Deduction for "grossed up" Part VI.1 tax	5.0	5.0	
10.	Amortization of share/debenture issue expense	3.8	3.8	
11.	Amortization of cumulative eligible capital	4.7	4.7	
12.	Amortization of C.D.E. and C.O.G.P.E	0.2	0.2	
13.	Site Rest Costs adjustment	-	-	
14.	Cash based pension and OPEB costs	35.7	35.7	
15.	Total Deduction	406.1	406.1	
16.	Taxable income	221.3	221.3	
17.	Income tax rates	15.00%	11.50%	
18.	Provision	33.2	25.4	58.6
19.	Part VI.1 tax			1.7
20.	Total taxes excluding interest shield			60.3
	Tax shield on interest expense			
21.	Rate base	5,247.7		
22.	Return component of debt	3.35%		
23.	Interest expense	175.9		
24.	Combined tax rate	26.500%		
25.	Income tax credit			(46.6)
26.	Total utility income taxes			13.7

REVENUE DEFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN
2016 FORECAST YEAR

		Col. 1	Col. 2	Col. 3	Col. 4
Line No.		Principal Excl. CC/CIS	Component	Cost Rate	Return Component
		($Millions)	%	%	%
1.	Long and Medium-Term Debt	3,367.0	64.16	5.33	3.420
2.	Short-Term Debt	(108.5)	(2.07)	3.35	(0.069)
3.		3,258.5	62.09		3.351
4.	Preference Shares	100.0	1.91	4.32	0.083
5.	Common Equity	1,889.2	36.00	10.12	3.643
6.		5,247.7	100.00		7.077
7.	Rate Base	($Millions)			5,247.7
8.	Utility Income	($Millions)			254.9
9.	Indicated Rate of Return				4.857
10.	Deficiency in Rate of Return				(2.220)
11.	Net Deficiency	($Millions)			(116.5)
12.	Gross Deficiency	($Millions)	(other than CC - CIS)		(158.5)
13.	Customer Care/CIS Deficiency	($Millions)	($123.5 vs $110.2)		(13.3)
14.	Total Gross Revenue Deficiency	($Millions)			(171.8)
15.	Revenue at Existing Rates	($Millions)			2,683.5
16.	Allowed Revenue	($Millions)			2,855.3
17.	Gross Revenue Deficiency	($Millions)			(171.8)
	Common Equity				
18.	Allowed Rate of Return				10.120
19.	Earnings on Common Equity				3.953
20.	Deficiency in Common Equity Return				(6.167)

ALLOWED REVENUE
AND DEFICIENCY
2016 FORECAST YEAR

Line No.		Col. 1 Reference	Col. 2 Exclusive of CC-CIS	Col. 3 CC-CIS	Col. 4 EGD Total
			($Millions)	($Millions)	($Millions)
	Cost of Capital				
1.	Rate base		5,247.7	32.4	5,280.1
2.	Required rate of return		7.08%	6.44%	7.08%
3.			371.5	2.1	373.6
	Cost of Service				
4.	Gas costs		1,632.5	-	1,632.5
5.	Operation and maintenance		339.1	100.4	439.5
6.	Depreciation and amortization		326.9	12.7	339.6
7.	Fixed financing costs		1.9	-	1.9
8.	Municipal and other taxes		45.5	-	45.5
9.			2,345.9	113.1	2,459.0
	Miscellaneous operating and non operating revenue				
10.	Other operating revenue		(41.2)	-	(41.2)
11.	Interest and property rental		0.0	-	-
12.	Other income		(0.1)	-	(0.1)
13.			(41.3)	-	(41.3)
	Income taxes on earnings				
14.	Excluding tax shield		60.3	7.9	68.2
15.	Tax shield provided by interest expense		(46.6)	(0.4)	(47.0)
16.			13.7	7.5	21.2
	Taxes on deficiency				
17.	Gross deficiency -w/out CC/CIS		(158.5)	-	(158.5)
18.	Net deficiency -w/out CC/CIS		(116.5)	-	(116.5)
19.			42.0	-	42.0
20.	Sub-total Allowed Revenue		2,731.8	122.7	2,854.5
21.	Customer Care Rate Smoothing Variance Account Adjustment		-	0.8	0.8
22.	**Allowed Revenue**		2,731.8	123.5	2,855.3
	Revenue at existing Rates				
23.	Gas sales		2,372.7	91.8	2,464.5
24.	Transportation service		198.7	18.4	217.1
25.	Transmission, compression and storage		1.8	-	1.8
26.	Rounding adjustment		0.1	-	0.1
27.	Total		2,573.3	110.2	2,683.5
28.	**Gross revenue deficiency**		(158.5)	(13.3)	(171.8)

UTILITY RATE BASE
2017 FORECAST YEAR

Line No.		Col. 1 2017 Forecast Year Excl. CIS & Customer Care	Col. 2 2017 Forecast Year CIS & Customer Care	Col. 3 Total 2017 Forecast Year
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	8,686.6	127.1	8,813.7
2.	Accumulated depreciation	(3,594.6)	(107.4)	(3,702.0)
3.	Net property, plant, and equipment	5,092.0	19.7	5,111.7
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6
6.	Mortgages receivable	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0
9.	Gas in storage	276.3	-	276.3
10.	Working cash allowance	40.0	-	40.0
11.	Total Working Capital	288.7	-	288.7
12.	Utility Rate Base	5,380.7	19.7	5,400.4

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2017	Col. 7 Regulatory Adjustments (Note 1)	Col. 8 Utility Balance Dec.2017	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-	-	-
2.	Land and gas storage rights (451.00)	(24.6)	(0.5)	-	-	-	(25.0)	-	(25.0)	(24.8)
3.	Structures and improvements (452.00)	(7.0)	(0.8)	-	0.5	-	(7.3)	0.1	(7.2)	(7.1)
4.	Wells (453.00)	(19.2)	(1.0)	-	-	-	(20.2)	-	(20.2)	(19.7)
5.	Well equipment (454.00)	(7.2)	(0.5)	-	-	-	(7.8)	-	(7.8)	(7.5)
6.	Field Lines (455.00)	(27.0)	(1.0)	-	0.1	-	(27.9)	-	(27.9)	(27.5)
7.	Compressor equipment (456.00)	(44.3)	(2.9)	-	-	-	(47.2)	0.2	(47.0)	(45.5)
8.	Measuring and regulating equipment (457.00)	(7.0)	(0.4)	-	-	-	(7.5)	-	(7.5)	(7.3)
9.	Total	(136.3)	(7.2)	-	0.6	-	(142.9)	0.3	(142.6)	(139.3)

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

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2017	Col. 7 Regulatory Adjustment (Note 1)	Col. 8 Utility Balance Dec.2017	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(3.4)	(1.1)	-	-	-	(4.6)	-	(4.6)	(4.0)
2.	Structures and improvements (472.00)	(28.5)	(9.0)	-	0.4	0.3	(36.9)	0.2	(36.6)	(32.4)
3.	Services, house reg & meter install. (473/474)	(1,147.3)	(78.2)	-	22.6	12.7	(1,190.2)	-	(1,190.2)	(1,169.6)
4.	NGV station compressors (476)	(2.0)	(0.2)	-	0.1	-	(2.0)	-	(2.0)	(2.0)
5.	Meters (478)	(209.7)	(41.8)	-	13.5	-	(238.0)	-	(238.0)	(223.7)
6.	Mains (475)	(1,535.7)	(127.8)	-	4.0	2.2	(1,657.3)	1.9	(1,655.4)	(1,594.5)
7.	Measuring and regulating equip. (477)	(215.3)	(11.9)	-	2.0	-	(225.1)	0.5	(224.5)	(219.6)
8.	Total	(3,141.9)	(270.0)	-	42.7	15.2	(3,354.0)	2.7	(3,351.3)	(3,245.7)

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

UTILITY INCOME
2017 FORECAST YEAR

Line No.		Col. 1 Utility Income Excl. CIS & Customer Care ($Millions)	Col. 2 CIS & Customer Care ($Millions)	Col. 3 Total Utility Income ($Millions)
1.	Gas sales	2,388.5	91.8	2,480.3
2.	Transportation of gas	192.7	18.4	211.1
3.	Transmission, compression and storage revenue	1.8	-	1.8
4.	Other operating revenue	41.2	-	41.2
5.	Interest and property rental	-	-	-
6.	Other income	0.1	-	0.1
7.	Total operating revenue	2,624.3	110.2	2,734.5
8.	Gas costs	1,632.5	-	1,632.5
9.	Operation and maintenance	346.1	104.4	450.5
10.	Depreciation and amortization expense	338.2	12.7	350.9
11.	Fixed financing costs	1.9	-	1.9
12.	Municipal and other taxes	47.9	-	47.9
13.	Interest and financing amortization expense	-	-	-
14.	Other interest expense	-	-	-
15.	Cost of service	2,366.6	117.1	2,483.7
16.	Utility income before income taxes	257.7	(6.9)	250.8
17.	Income tax expense	17.8	7.3	25.1
18.	Utility income	239.9	(14.2)	225.7

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2017 FORECAST YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	257.7	257.7	
	Add			
2.	Depreciation and amortization	338.2	338.2	
3.	Accrual based pension and OPEB costs	28.5	28.5	
4.	Other non-deductible items	1.0	1.0	
5.	Total Add Back	367.7	367.7	
6.	Sub-total	625.4	625.4	
	Deduct			
7.	Capital cost allowance	293.2	293.2	
8.	Items capitalized for regulatory purposes	46.6	46.6	
9.	Deduction for "grossed up" Part VI.1 tax	5.6	5.6	
10.	Amortization of share/debenture issue expense	3.9	3.9	
11.	Amortization of cumulative eligible capital	4.3	4.3	
12.	Amortization of C.D.E. and C.O.G.P.E	0.1	0.1	
13.	Site Rest Costs adjustment	-	-	
14.	Cash based pension and OPEB costs	32.2	32.2	
15.	Total Deduction	385.9	385.9	
16.	Taxable income	239.5	239.5	
17.	Income tax rates	15.00%	11.50%	
18.	Provision	35.9	27.5	63.4
19.	Part VI.1 tax			1.9
20.	Total taxes excluding interest shield			65.3
	Tax shield on interest expense			
21.	Rate base	5,380.7		
22.	Return component of debt	3.33%		
23.	Interest expense	179.3		
24.	Combined tax rate	26.500%		
25.	Income tax credit			(47.5)
26.	Total utility income taxes			17.8

REVENUE DEFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN
2017 FORECAST YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long and Medium-Term Debt	3,515.5	65.34	5.31	3.470
2.	Short-Term Debt	(171.9)	(3.20)	4.30	(0.138)
3.		3,343.6	62.14		3.332
4.	Preference Shares	100.0	1.86	4.64	0.086
5.	Common Equity	1,937.1	36.00	10.17	3.661
6.		5,380.7	100.00		7.079
7.	Rate Base	($Millions)			5,380.7
8.	Utility Income	($Millions)			239.9
9.	Indicated Rate of Return				4.459
10.	Deficiency in Rate of Return				(2.620)
11.	Net Deficiency	($Millions)			(141.0)
12.	Gross Deficiency	($Millions)	(other than CC - CIS)		(191.8)
13.	Customer Care/CIS Deficiency	($Millions)	($128.6 vs $110.2)		(18.4)
14.	Total Gross Revenue Deficiency	($Millions)			(210.2)
15.	Revenue at Existing Rates	($Millions)			2,693.3
16.	Allowed Revenue	($Millions)			2,903.5
17.	Gross Revenue Deficiency	($Millions)			(210.2)
	Common Equity				
18.	Allowed Rate of Return				10.170
19.	Earnings on Common Equity				2.892
20.	Deficiency in Common Equity Return				(7.278)

ALLOWED REVENUE
AND DEFICIENCY
2017 FORECAST YEAR

Line No.		Col. 1 Reference	Col. 2 Exclusive of CC-CIS	Col. 3 CC-CIS	Col. 4 EGD Total
			($Millions)	($Millions)	($Millions)
	Cost of Capital				
1.	Rate base		5,380.7	19.7	5,400.4
2.	Required rate of return		7.08%	6.44%	7.08%
3.			381.0	1.3	382.3
	Cost of Service				
4.	Gas costs		1,632.5	-	1,632.5
5.	Operation and maintenance		346.1	104.4	450.5
6.	Depreciation and amortization		338.2	12.7	350.9
7.	Fixed financing costs		1.9	-	1.9
8.	Municipal and other taxes		47.9	-	47.9
9.			2,366.6	117.1	2,483.7
	Miscellaneous operating and non operating revenue				
10.	Other operating revenue		(41.2)	-	(41.2)
11.	Interest and property rental		0.0	-	-
12.	Other income		(0.1)	-	(0.1)
13.			(41.3)	-	(41.3)
	Income taxes on earnings				
14.	Excluding tax shield		65.3	7.5	72.8
15.	Tax shield provided by interest expense		(47.5)	(0.2)	(47.7)
16.			17.8	7.3	25.1
	Taxes on deficiency				
17.	Gross deficiency -w/out CC/CIS		(191.8)	-	(191.8)
18.	Net deficiency -w/out CC/CIS		(141.0)	-	(141.0)
19.			50.8	-	50.8
20.	Sub-total Allowed Revenue		2,774.9	125.7	2,900.6
21.	Customer Care Rate Smoothing Variance Account Adjustment		-	2.9	2.9
22.	**Allowed Revenue**		2,774.9	128.6	2,903.5
	Revenue at existing Rates				
23.	Gas sales		2,388.5	91.8	2,480.3
24.	Transportation service		192.7	18.4	211.1
25.	Transmission, compression and storage		1.8	-	1.8
26.	Rounding adjustment		0.1	-	0.1
27.	Total		2,583.1	110.2	2,693.3
28.	**Gross revenue deficiency**		(191.8)	(18.4)	(210.2)

UTILITY RATE BASE
2018 FORECAST YEAR

Line No.		Col. 1 2018 Forecast Year Excl. CIS & Customer Care	Col. 2 2018 Forecast Year CIS & Customer Care	Col. 3 Total 2018 Forecast Year
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	9,042.2	127.1	9,169.3
2.	Accumulated depreciation	(3,838.3)	(120.1)	(3,958.4)
3.	Net property, plant, and equipment	5,203.9	7.0	5,210.9
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6
6.	Mortgages receivable	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0
9.	Gas in storage	276.3	-	276.3
10.	Working cash allowance	39.9	-	39.9
11.	Total Working Capital	288.6	-	288.6
12.	Utility Rate Base	5,492.5	7.0	5,499.5

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
Line No.		Opening Balance Dec.2017	Additions	Net Salvage Adjustment	Retirements	Costs Net of Proceeds	Closing Balance Dec.2018	Regulatory Adjustments (Note 1)	Utility Balance Dec.2018	Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-	-	-
2.	Land and gas storage rights (451.00)	(25.0)	(0.5)	-	-	-	(25.5)	-	(25.5)	(25.3)
3.	Structures and improvements (452.00)	(7.3)	(0.9)	-	0.5	-	(7.7)	0.1	(7.6)	(7.4)
4.	Wells (453.00)	(20.2)	(1.0)	-	-	-	(21.2)	-	(21.2)	(20.7)
5.	Well equipment (454.00)	(7.8)	(0.5)	-	-	-	(8.3)	-	(8.3)	(8.0)
6.	Field Lines (455.00)	(27.9)	(1.0)	-	0.1	-	(28.9)	-	(28.9)	(28.4)
7.	Compressor equipment (456.00)	(47.2)	(2.9)	-	-	-	(50.1)	0.2	(49.9)	(48.4)
8.	Measuring and regulating equipment (457.00)	(7.5)	(0.4)	-	-	-	(7.9)	-	(7.9)	(7.7)
9.	Total	(142.9)	(7.3)	-	0.6	-	(149.6)	0.3	(149.3)	(146.0)

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

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2018	Col. 7 Regulatory Adjustment (Note 1)	Col. 8 Utility Balance Dec.2018	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(4.6)	(1.1)	-	-	-	(5.7)	-	(5.7)	(5.1)
2.	Structures and improvements (472.00)	(36.9)	(9.5)	-	0.4	0.3	(45.7)	0.3	(45.5)	(41.0)
3.	Services, house reg & meter install. (473/474)	(1,190.2)	(81.6)	-	22.6	12.7	(1,236.5)	-	(1,236.5)	(1,214.1)
4.	NGV station compressors (476)	(2.0)	(0.2)	-	0.1	-	(2.1)	-	(2.1)	(2.0)
5.	Meters (478)	(238.0)	(43.1)	-	13.5	-	(267.5)	-	(267.5)	(252.7)
6.	Mains (475)	(1,657.3)	(133.2)	-	4.0	2.2	(1,784.3)	2.0	(1,782.3)	(1,718.6)
7.	Measuring and regulating equip. (477)	(225.1)	(12.5)	-	2.0	-	(235.6)	0.6	(235.0)	(229.7)
8.	Total	(3,354.0)	(281.1)	-	42.7	15.2	(3,577.3)	2.8	(3,574.5)	(3,463.3)

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

UTILITY INCOME
2018 FORECAST YEAR

Line No.		Col. 1 Utility Income Excl. CIS & Customer Care ($Millions)	Col. 2 CIS & Customer Care ($Millions)	Col. 3 Total Utility Income ($Millions)
1.	Gas sales	2,404.4	91.8	2,496.2
2.	Transportation of gas	186.6	18.4	205.0
3.	Transmission, compression and storage revenue	1.8	-	1.8
4.	Other operating revenue	41.2	-	41.2
5.	Interest and property rental	-	-	-
6.	Other income	0.1	-	0.1
7.	Total operating revenue	2,634.1	110.2	2,744.3
8.	Gas costs	1,632.5	-	1,632.5
9.	Operation and maintenance	353.3	108.5	461.8
10.	Depreciation and amortization expense	348.5	12.7	361.2
11.	Fixed financing costs	1.9	-	1.9
12.	Municipal and other taxes	50.4	-	50.4
13.	Interest and financing amortization expense	-	-	-
14.	Other interest expense	-	-	-
15.	Cost of service	2,386.6	121.2	2,507.8
16.	Utility income before income taxes	247.5	(11.0)	236.5
17.	Income tax expense	16.2	7.1	23.3
18.	Utility income	231.3	(18.1)	213.2

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2018 FORECAST YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	247.5	247.5	
	Add			
2.	Depreciation and amortization	348.5	348.5	
3.	Accrual based pension and OPEB costs	26.2	26.2	
4.	Other non-deductible items	1.0	1.0	
5.	Total Add Back	375.7	375.7	
6.	Sub-total	623.2	623.2	
	Deduct			
7.	Capital cost allowance	293.8	293.8	
8.	Items capitalized for regulatory purposes	46.6	46.6	
9.	Deduction for "grossed up" Part VI.1 tax	5.6	5.6	
10.	Amortization of share/debenture issue expense	4.0	4.0	
11.	Amortization of cumulative eligible capital	4.0	4.0	
12.	Amortization of C.D.E. and C.O.G.P.E	0.1	0.1	
13.	Site Rest Costs adjustment	-	-	
14.	Cash based pension and OPEB costs	29.8	29.8	
15.	Total Deduction	383.9	383.9	
16.	Taxable income	239.3	239.3	
17.	Income tax rates	15.00%	11.50%	
18.	Provision	35.9	27.5	63.4
19.	Part VI.1 tax			1.9
20.	Total taxes excluding interest shield			65.3
	Tax shield on interest expense			
21.	Rate base	5,492.5		
22.	Return component of debt	3.37%		
23.	Interest expense	185.2		
24.	Combined tax rate	26.500%		
25.	Income tax credit			(49.1)
26.	Total utility income taxes			16.2

REVENUE DEFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN
2018 FORECAST YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long and Medium-Term Debt	3,614.9	65.82	5.36	3.528
2.	Short-Term Debt	(199.7)	(3.64)	4.30	(0.157)
3.		3,415.2	62.18		3.371
4.	Preference Shares	100.0	1.82	4.64	0.084
5.	Common Equity	1,977.3	36.00	10.27	3.697
6.		5,492.5	100.00		7.152
7.	Rate Base	($Millions)			5,492.5
8.	Utility Income	($Millions)			231.3
9.	Indicated Rate of Return				4.211
10.	Deficiency in Rate of Return				(2.941)
11.	Net Deficiency	($Millions)			(161.5)
12.	Gross Deficiency	($Millions)	(other than CC - CIS)		(219.8)
13.	Customer Care/CIS Deficiency	($Millions)	($133.8 vs $110.2)		(23.6)
14.	Total Gross Revenue Deficiency	($Millions)			(243.4)
15.	Revenue at Existing Rates	($Millions)			2,702.8
16.	Allowed Revenue	($Millions)			2,946.2
17.	Gross Revenue Deficiency	($Millions)			(243.4)
	Common Equity				
18.	Allowed Rate of Return				10.270
19.	Earnings on Common Equity				2.100
20.	Deficiency in Common Equity Return				(8.170)

ALLOWED REVENUE
AND DEFICIENCY
2018 FORECAST YEAR

Line No.		Col. 1 Reference	Col. 2 Exclusive of CC-CIS	Col. 3 CC-CIS	Col. 4 EGD Total
			($Millions)	($Millions)	($Millions)
	Cost of Capital				
1.	Rate base		5,492.5	7.0	5,499.5
2.	Required rate of return		7.15%	6.44%	7.15%
3.			392.7	0.5	393.2
	Cost of Service				
4.	Gas costs		1,632.5	-	1,632.5
5.	Operation and maintenance		353.3	108.5	461.8
6.	Depreciation and amortization		348.5	12.7	361.2
7.	Fixed financing costs		1.9	-	1.9
8.	Municipal and other taxes		50.4	-	50.4
9.			2,386.6	121.2	2,507.8
	Miscellaneous operating and non operating revenue				
10.	Other operating revenue		(41.2)	-	(41.2)
11.	Interest and property rental		0.0	-	-
12.	Other income		(0.1)	-	(0.1)
13.			(41.3)	-	(41.3)
	Income taxes on earnings				
14.	Excluding tax shield		65.3	7.2	72.5
15.	Tax shield provided by interest expense		(49.1)	(0.1)	(49.2)
16.			16.2	7.1	23.3
	Taxes on deficiency				
17.	Gross deficiency -w/out CC/CIS		(219.8)	-	(219.8)
18.	Net deficiency -w/out CC/CIS		(161.5)	-	(161.5)
19.			58.2	-	58.2
20.	Sub-total Allowed Revenue		2,812.4	128.8	2,941.2
21.	Customer Care Rate Smoothing Variance Account Adjustment		-	5.0	5.0
22.	**Allowed Revenue**		2,812.4	133.8	2,946.2
	Revenue at existing Rates				
23.	Gas sales		2,404.4	91.8	2,496.2
24.	Transportation service		186.6	18.4	205.0
25.	Transmission, compression and storage		1.8	-	1.8
26.	Rounding adjustment		(0.2)	-	(0.2)
27.	Total		2,592.6	110.2	2,702.8
28.	**Gross revenue deficiency**		(219.8)	(23.6)	(243.4)

UNDERTAKING TCU2.11

UNDERTAKING

Technical Conference TR 2, page 70

EGDI to respond to SEC Technical Conference Question No. 18 (Exhibit TC 1.3)

RESPONSE

SEC Technical Conference Question 18

Ref: I.A1.EGDI.SEC.7

Please provide the data underlying the two graphs.

Enbridge provides the following response:

Please refer to Undertaking TCU2.15.

Witness: S. Kancharla

UNDERTAKING TCU2.12

UNDERTAKING

Technical Conference TR 2, page 86

EGDI to provide Capital Finance Plan produced by Enbridge Inc. for EGDI, if such a document exists.

RESPONSE

EGD Financing Plan		2013	2014	2015	2016	2017	2018
1: Planned Issuances (not for GTA)							
Debt Timing		Oct-13	Sep-14	Jun-15	Sep-16	Nov-17	Jan-18
Equity Timing		Jul-13	Jan-14	Jun-15	Sep-16	Jan-17	Jan-18
Debt		400	430	130	162	250	65
Equity		150	100	-	50	50	60
Planned Issuances (for GTA)							
Debt Timing				Oct-15			
Equity Timing				Oct-15			
Debt to issue @ in-service				420			
Equity to issue @ in-service				150			
Cumulative GTA spend		**23**	**216**	**564**	**-**	**-**	**-**
Total Planned Issuances (YE Balance)							
Debt		400	430	550	162	250	65
Equity		150	100	150	50	50	60
Total		**550**	**530**	**700**	**212**	**300**	**125**
Regulatory							
Rate Base (incl. CC/CIS)		**4,162**	**4,423**	**4,774**	**5,512**	**5,737**	**5,906**
Common Equity	36%	1,498	1,592	1,719	1,984	2,065	2,126
Preference Shares	100	100	100	100	100	100	100
Debt		2,564	2,731	2,955	3,428	3,571	3,680
% Debt		61.6%	61.7%	61.9%	62.2%	62.3%	62.3%
% Equity		36.0%	36.0%	36.0%	36.0%	36.0%	36.0%
Debt-LT (AoA)		2,463	2,655	2,968	3,407	3,545	3,634
Remove CIS		(37)	(37)	(29)	(21)	(20)	(7)
Remove Unamortized Finance Cos		(21)	(21)	(21)	(19)	-	-
Debt-LT (net)		2,405	2,598	2,918	3,367	3,525	3,627
Debt-ST avg balance		158	133	38	60	46	53
TOTAL Debt		2,564	2,731	2,955	3,428	3,571	3,680

Witness: S. Kancharla

UNDERTAKING TCU2.13

UNDERTAKING

Technical Conference TR 2, page 106

EGDI to confirm that there will be no annual update to the working capital lead-lag study.

RESPONSE

The Company proposes to update the lead-lag study as follows:

Lag Day	Update Frequency
Revenue Lag	Updated Annually
Gas Cost Lag	Updated Annually
Capital Lag	Not Updated
O&M Lag	Not Updated

This approach is consistent with the approach used during EGD's first Incentive Regulation period (2008 to 2012). The Capital and O&M lag days are kept fixed during the Incentive Regulation period, however the Revenue and Gas Cost lag days are updated annually to better represent impacts on carrying cost of gas-in-inventory and HST for working cash.

Witnesses: K. Culbert
R. Small

UNDERTAKING TCU2.14

UNDERTAKING

Technical Conference TR 2, page 109

EGDI to respond to Energy Probe's Technical Conference Question 1(c) (Exhibit TC 2.2).

RESPONSE

Please see the tables below. The cumulative difference in Revenue Requirement is reduced from the $342 million in SEC Interrogatory #5, found at Exhibit I.A1.EGDI.SEC.5 to $290 million assuming return on equity, cost of debt, cost of preferred shares, and capital structure are set to levels approved by the Board for 2013.

Witnesses: R. Fischer
R. Small

Allowed Revenue (net of Gas Cost)						
$ Millions	**2013 Board Approved**	**2014**	**2015**	**2016**	**2017**	**2018**
Customized IR (Excluding Depreciation & SRC, assuming 2013 capital structure for 2014-2018) (Refer to Table 2)	1,021	1,072	1,103	1,201	1,248	1,285
Approximation of Union Model (Refer to Table 1)	1,021	1,031	1,046	1,107	1,117	1,126
Difference (Implied Deficiency)	-	(41)	(57)	(94)	(131)	(159)
Cumulative Difference		(41)	(98)	(150)	(224)	(290)

Table 1

Distributed Revenues - Approximation of Union Model (Exclusive of SRC impact)

Allowed Revenue - IR ($M)	**Rebase 2013**	**Second Generation IR - Approximation of Union Model** 2014	2015	2016	2017	2018
	ADR					
Escalation factor		1.7%	1.7%	1.7%	1.7%	1.7%
Productivity		-1.0%	-1.0%	-1.0%	-1.0%	-1.0%
Total Escalation factor		0.7%	0.7%	0.7%	0.7%	0.7%
Revenue Requirement - COS	**817**					
Allowed Revenue - IR with escalation		**822**	**828**	**834**	**839**	**845**
Y factor						
Carrying cost for Gas in Storage	20	20	20	21	21	21
Pension cost	43	37	34	31	30	28
DSM	31	32	33	33	34	35
Y factor for Customer Care	110	114	119	124	129	134
Y factor for GTA&Ottawa	-	5	12	64	64	64
	204	209	218	273	277	281
Total Allowed Revenues -IR	**1,021**	**1,031**	**1,046**	**1,107**	**1,117**	**1,126**

Witnesses: R. Fischer
R. Small

Table 2

ALLOWED REVENUE AND DEFICIENCIES (INCL. CIS/CC)
ASSUMING PROPOSED SITE RESTORATION COST CHANGES ARE REMOVED
AND ASSUMING 2013 CAPITAL STRUCTURE RATIOS AND RATES ARE MAINTAINED
2014 - 2018 FISCAL YEARS

Line No.		Col. 1 2014 EGD Total	Col. 2 2015 EGD Total	Col. 3 2016 EGD Total	Col. 4 2017 EGD Total	Col. 5 2018 EGD Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Cost of Capital					
1.	Rate base	4,377	4,647	5,280	5,400	5,500
2.	Required rate of return	6.80%	6.81%	6.81%	6.81%	6.81%
3.		298	316	360	368	375
	Cost of Service					
4.	Gas costs	1,456	1,607	1,633	1,633	1,633
5.	Operation and maintenance	425	429	440	451	462
6.	Depreciation and amortization	293	308	340	351	361
7.	Fixed financing costs	2	2	2	2	2
8.	Municipal and other taxes	41	43	46	48	50
9.		2,217	2,389	2,459	2,484	2,508
	Miscellaneous operating and non operating revenue					
10.	Other operating revenue	(41)	(41)	(41)	(41)	(41)
11.	Other income	(0)	(0)	(0)	(0)	(0)
12.		(41)	(41)	(41)	(41)	(41)
	Income taxes on earnings					
13.	Excluding tax shield	91	73	68	73	73
14.	Tax shield provided by interest expens	(41)	(44)	(49)	(50)	(51)
15.		50	30	19	22	21
	Taxes on deficiency					
16.	Gross deficiency	(26)	(65)	(136)	(169)	(191)
17.	Net deficiency	(19)	(48)	(100)	(124)	(141)
18.		7	17	36	45	51
19.	Sub-total Allowed Revenue	2,531	2,711	2,832	2,877	2,913
20.	Customer Care Rate Smoothing Var. Adj	(3)	(1)	1	3	5
21.	**Allowed Revenue**	2,528	2,710	2,833	2,880	2,918
	Revenue at existing Rates					
22.	Gas sales	2,254	2,404	2,465	2,480	2,496
23.	Transportation service	243	230	217	211	205
24.	Transmission, compression and storage	2	2	2	2	2
25.	Rounding adjustment	(0)	-	(0)	-	(0)
26.	Total	2,498	2,636	2,683	2,693	2,703
27.	**Gross revenue deficiency**	(30)	(74)	(150)	(187)	(215)
28.	**Allowed Revenue (net of Gas cost)**	1,072	1,103	1,201	1,248	1,285

Witnesses: R. Fischer
R. Small

UNDERTAKING TCU2.15

UNDERTAKING

Technical Conference TR 2, page 109

EGDI to respond to Energy Probe's Technical Conference Question 2 (Exhibit TC 2.2).

RESPONSE

Energy Probe Technical Conference Question #2

Ref: I.A1.EGDI.SEC.7

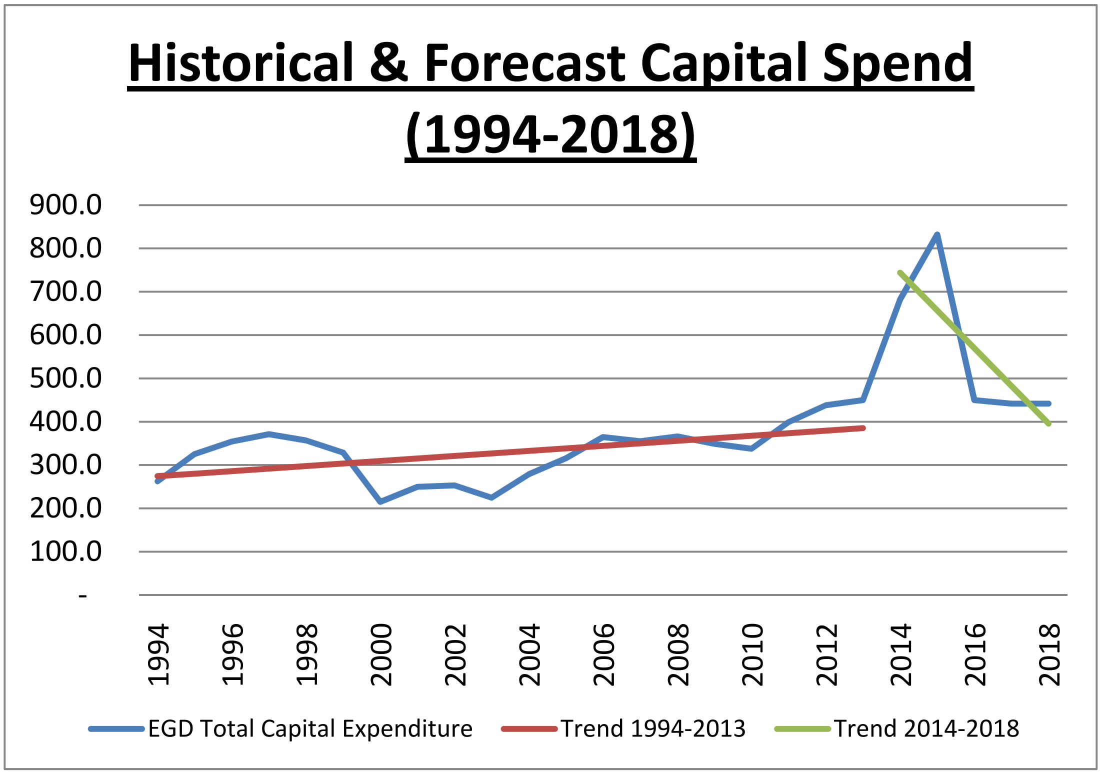
a) Please provide the graphs on pages 1 and 2 of the response that extends the graphs to include the forecast through 2018.

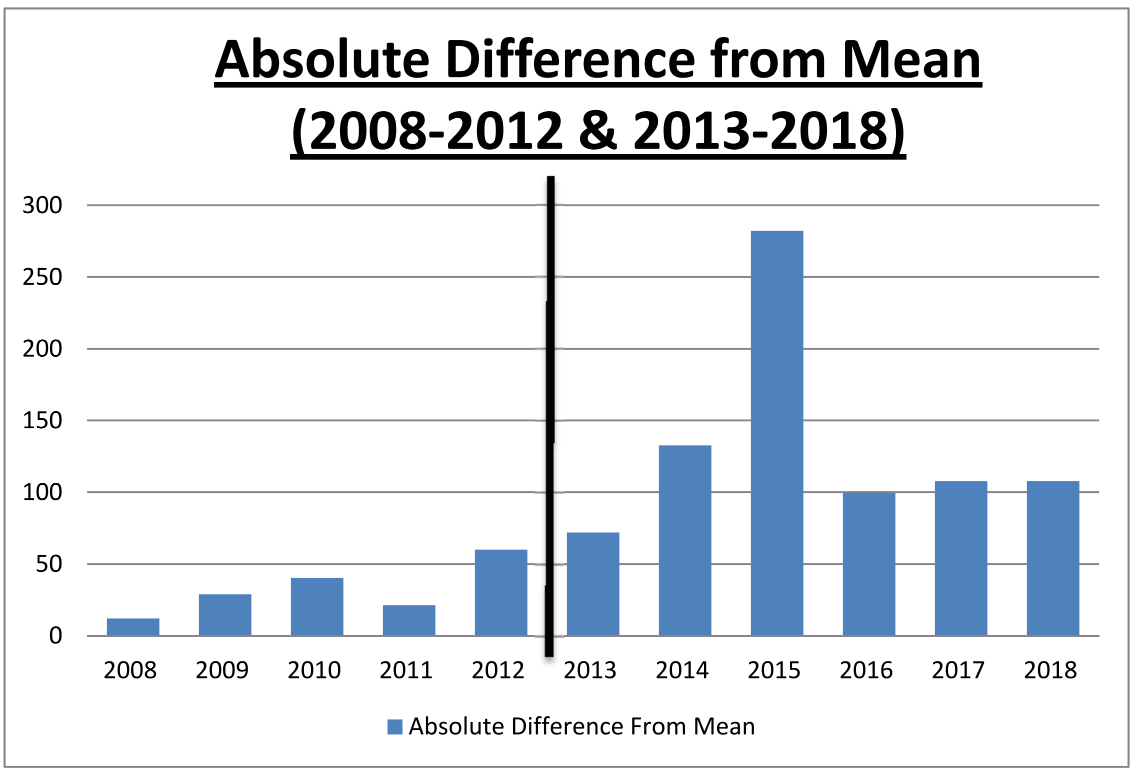
b) Please provide the graphs on pages 1 and 2 of the response that extends the graphs to include the forecast through 2018 but excludes the capital expenditures related to the Ottawa and GTA reinforcement projects.

Enbridge provides the following response:

a) The graphs on the following pages present the referenced graphs including the data extended out to 2018. Note that there was a slight error in the original graphs, which inadvertently double counted the data for some years. This has been corrected in the graphs provided.

Witnesses: R. Fischer
S. Kancharla





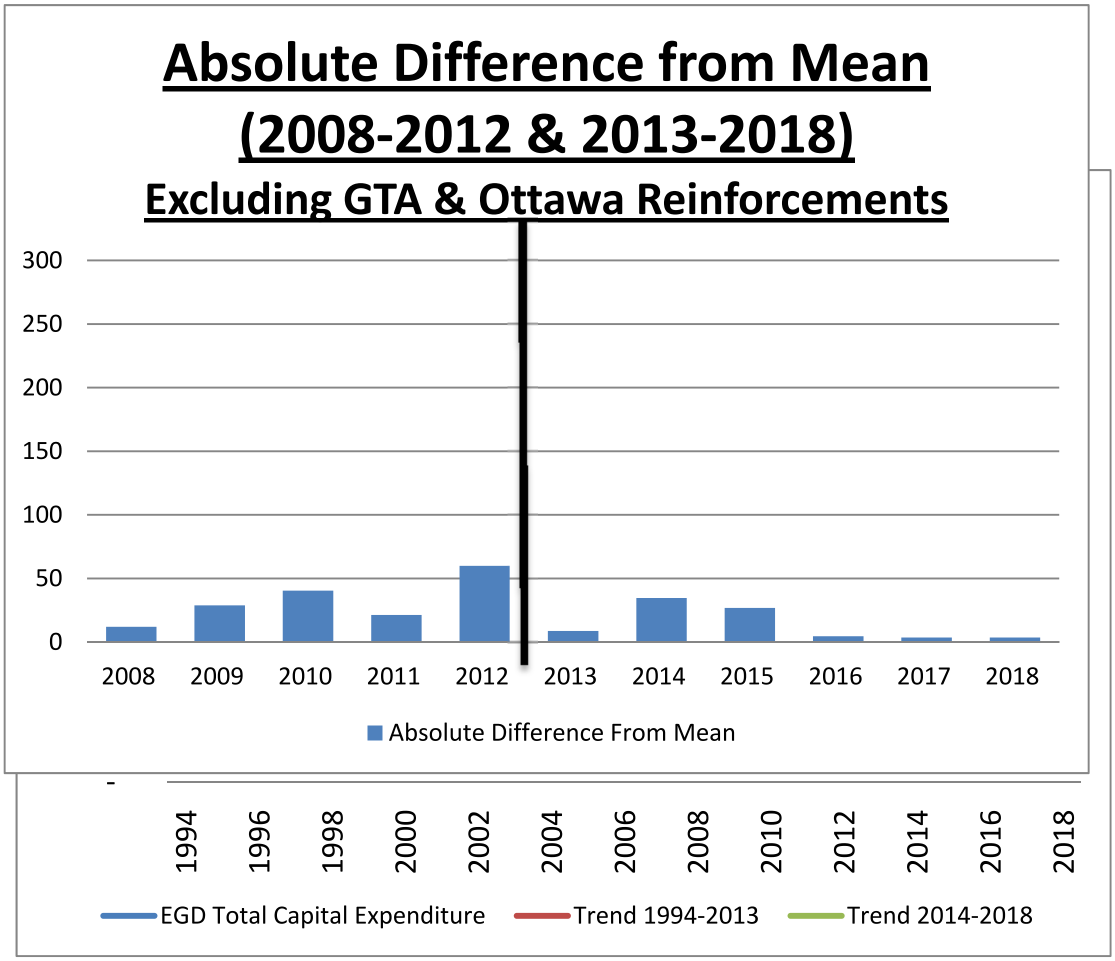
Witnesses: R. Fischer
S. Kancharla

In addition, in the Undertaking TCU2.11, EGD agreed to provide the data underlying the graphs presented here. The table below shows the data for each of the total Capital, Trend line Capital (for the periods 1994 to 2013 and 2014 to 2018, respectively) and the Absolute Difference from the Mean (for the periods 1994 to 2013 and 2014 to 2018, respectively).

	Total Capital	Trendline Capital (1994-2013)	Trendline Capital (2014-2018)	Absolute Difference from Mean (1994-2013)	Absolute Difference from Mean (1994-2013)
1994	$ 262.20	$ 274.31			
1995	$ 325.40	$ 280.14			
1996	$ 354.30	$ 285.97			
1997	$ 371.20	$ 291.80			
1998	$ 357.00	$ 297.64			
1999	$ 328.60	$ 303.47			
2000	$ 215.20	$ 309.30			
2001	$ 249.80	$ 315.14			
2002	$ 252.90	$ 320.97			
2003	$ 224.80	$ 326.80			
2004	$ 278.40	$ 332.64			
2005	$ 315.50	$ 338.47			
2006	$ 364.50	$ 344.30			
2007	$ 354.90	$ 350.14			
2008	$ 366.00	$ 355.97		$ 11.96	
2009	$ 349.10	$ 361.80		$ 28.86	
2010	$ 337.60	$ 367.64		$ 40.36	
2011	$ 399.20	$ 373.47		$ 21.24	
2012	$ 437.90	$ 379.30		$ 59.94	
2013	$ 449.90	$ 385.13		$ 71.94	
2014	$ 682.30		$ 743.80		$ 132.63
2015	$ 832.00		$ 656.71		$ 282.33
2016	$ 450.00		$ 569.62		$ 99.67
2017	$ 441.90		$ 482.53		$ 107.77
2018	$ 441.90		$ 395.44		$ 107.77

b) The graphs below present the referenced graphs including the data extended out to 2018, and excluding data for the GTA & Ottawa Reinforcement projects.

Witnesses: R. Fischer
S. Kancharla



Witnesses: R. Fischer
S. Kancharla

UNDERTAKING TCU2.16

UNDERTAKING

Technical Conference TR 2, page 109

EGDI to respond to Energy Probe’s Technical Conference Question 3 (Exhibit TC 2.2).

RESPONSE

Energy Probe Technical Conference Question #3

Ref: I.A1.EGDI.SEC.17

The response indicates that Concentric did prepare an analysis, which is summarized in Figure 30 of Exhibit A2, Tab 9, Schedule 1, p. 61, that demonstrates that an I-X formula would not provide adequate recovery of EGDI's planned capital-related costs during the 2014-2016 period.

Please provide the same analysis, extended to 2018 based on the updated evidence of EGDI. Please also assume y-factor treatment for the GTA and Ottawa reinforcement capital expenditures.

Enbridge provides the following response:

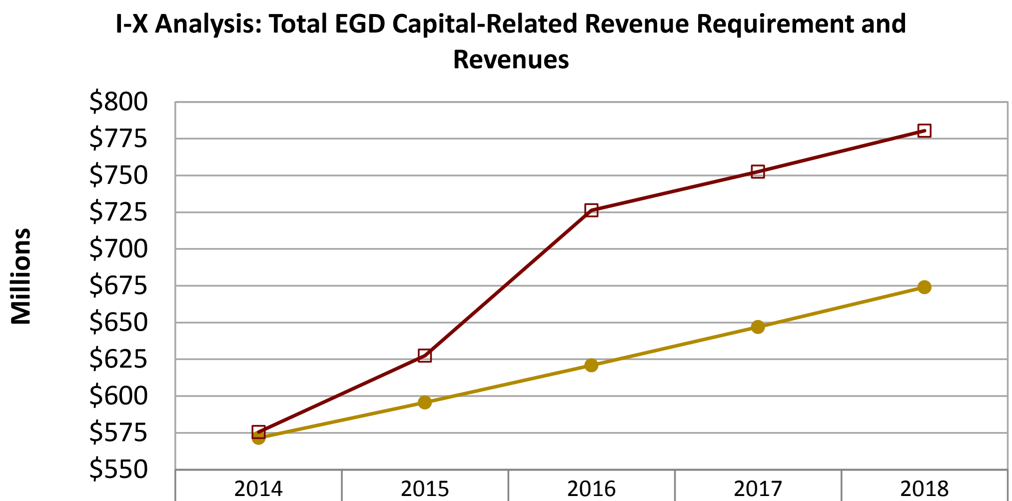
Analysis of I-X formula:
Concentric’s analysis that demonstrates that an I-X formula would not provide adequate recovery of EGDI's planned capital-related costs during the five year IR period, 2014 to 2018, is provided in Figures TCU2.16 A and TCU2.16 B on the following page.

Witness: J. Coyne - Concentric Energy Advisors Inc.

Figure TCU2.16 A: Revenues based on I-X rate adjustments

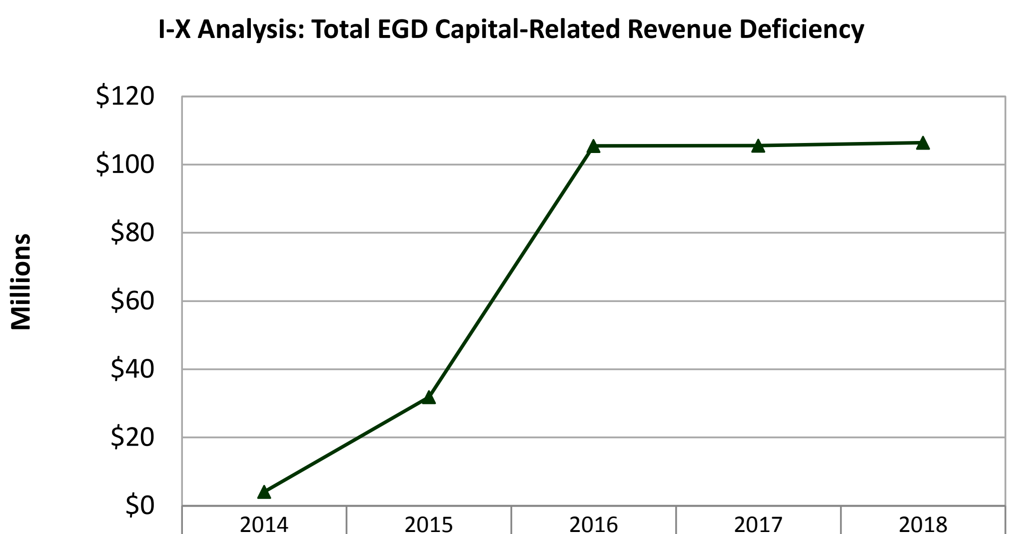
		2014	2015	2016	2017	2018
1	**Revenue Requirement**					
2	Average of Monthly Avgs Plant	$6,977,000,000	$7,441,000,000	$8,321,900,000	$8,698,400,000	$9,054,000,000
3	Depreciation Rate	3.58%	3.55%	3.50%	3.41%	3.37%
4	Depreciation Expense	$(250,100,000)	$(263,900,000)	$(291,200,000)	$(296,400,000)	$(305,000,000)
5	Average of Monthly Avgs Rate Base	$4,081,300,000	$4,440,400,000	$5,203,200,000	$5,437,200,000	$5,619,500,000
6	ROR^{Pretax}	7.98%	8.19%	8.36%	8.39%	8.46%
7	Return: ROR^{Pretax} x RB	$325,500,000	$363,600,000	$435,200,000	$456,200,000	$475,400,000
8	Revenue Requirement: Return + DeprExp	$575,600,000	$627,500,000	$726,400,000	$752,600,000	$780,400,000
9	**Revenues**					
10	Rebasing Return	$311,300,000	$311,300,000	$311,300,000	$311,300,000	$311,300,000
11	Rebasing Depreciation Expense	$237,300,000	$237,300,000	$237,300,000	$237,300,000	$237,300,000
12	P (Percent increase in Rates)	2.45%	2.45%	2.45%	2.45%	2.45%
13	G (Percent increase in Customers)	1.69%	1.73%	1.75%	1.72%	1.69%
14	(1 + P) x (1 + G)	1.04173	1.08571	1.13171	1.17932	1.22858
15						
16	$Revenues_{Plant\text{-}related}$ = [Rebasing Return + Depreciation] x (1+P) x (1+G)	$571,500,000	$595,600,000	$620,900,000	$647,000,000	$674,000,000
17						
18	Deficiency (Surplus) in Revenues	$4,100,000	$ 31,900,000	$105,500,000	$105,600,000	$106,400,000

Figure TCU2.16 B: Revenues, Revenue Requirement, and Revenue Deficiency



	2014	2015	2016	2017	2018
Revenues	$571,500,000	$595,600,000	$620,900,000	$647,000,000	$674,000,000
Rev Req	$575,600,000	$627,500,000	$726,400,000	$752,600,000	$780,400,000

Assumptions:
I-X Rate adjustments: with Y Factor recovery of GTA Ottawa Additions to Plant



	2014	2015	2016	2017	2018
Deficiency	$4,100,000	$31,900,000	$105,500,000	$105,600,000	$106,400,000

Assumptions:
I-X Rate adjustments: with Y Factor recovery of GTA Ottawa Additions to Plant

It is Concentric's assessment that Figures TCU2.16 A and TCU2.16 B demonstrate that an I-X escalation formula does not provide adequate recovery of capital-related costs during the 2014 to 2018 period. The cumulative five year capital-related revenue deficiency is $353.5 million.

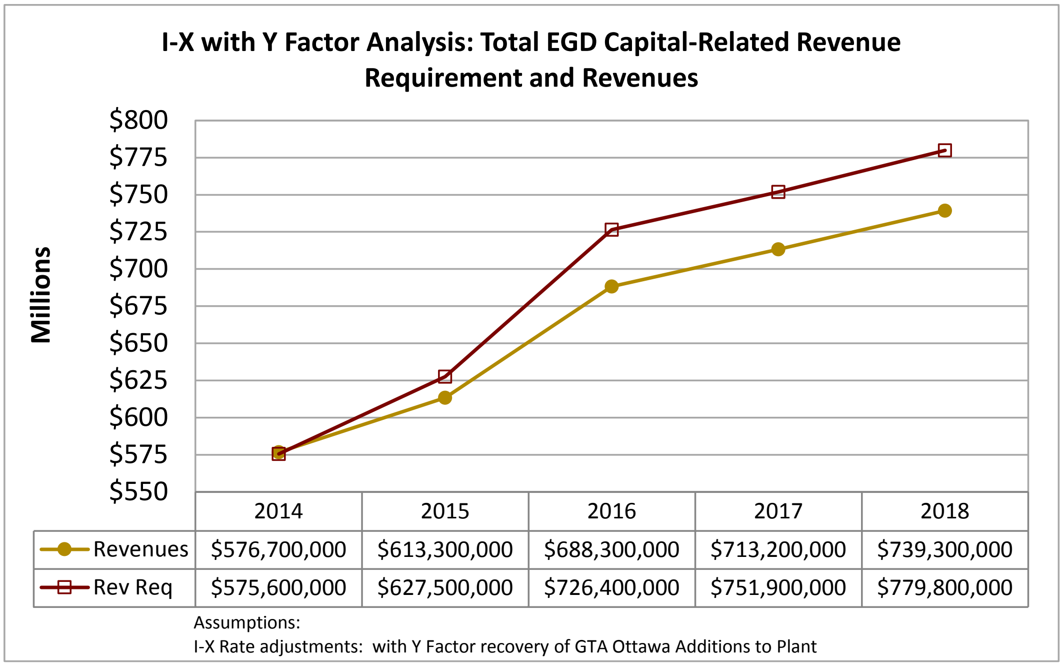
Witness: J. Coyne - Concentric Energy Advisors Inc.

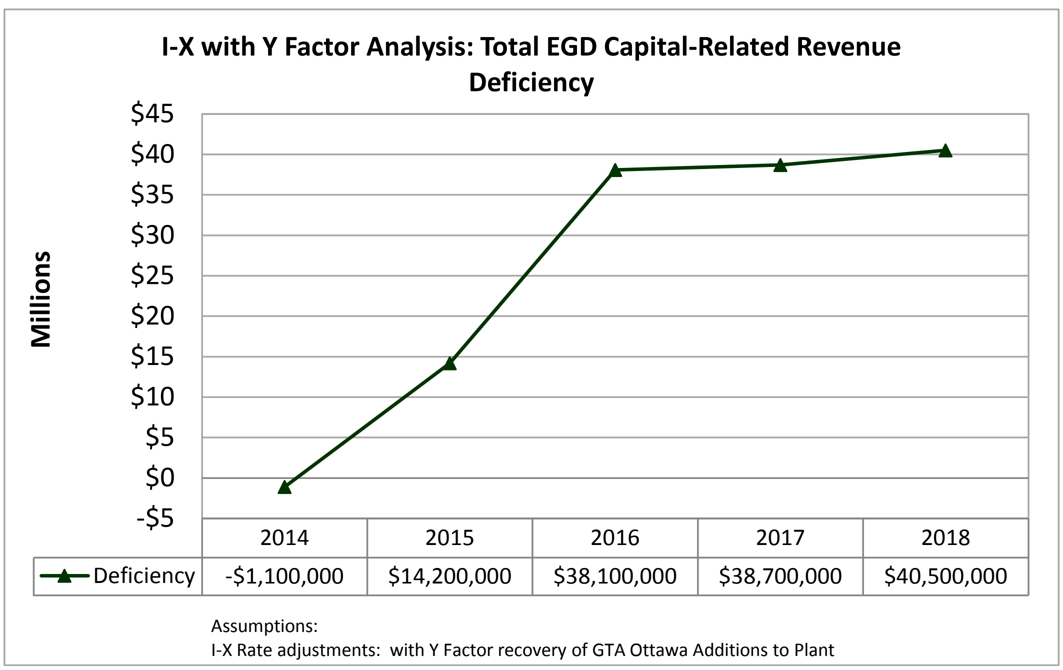
Analysis of I-X formula with y-factor:
Concentric's analysis that demonstrates that an I-X formula with Y-factor treatment for the GTA and Ottawa reinforcement capital expenditures would not provide adequate recovery of EGDI's planned capital-related costs during the 2014 to 2018 period is provided in Figures TCU2.16 C and TCU2.16 D, below.

Figure TCU2.16 C: Revenues based on I-X plus Special Project Capital Tracker

		2014	2015	2016	2017	2018
1	**Revenue Requirement**					
2	Average of Monthly Avgs Plant	$6,977,000,000	$7,441,000,000	$8,321,900,000	$8,698,400,000	$9,054,000,000
3	Depreciation Rate	3.58%	3.55%	3.50%	3.40%	3.36%
4	Depreciation Expense	$(250,100,000)	$(263,900,000)	$(291,200,000)	$(295,700,000)	$(304,400,000)
5	Average of Monthly Avgs Rate Base	$4,081,300,000	$4,440,400,000	$5,203,200,000	$5,437,200,000	$5,619,500,000
6	ROR^{Pretax}	7.98%	8.19%	8.36%	8.39%	8.46%
7	Return: ROR^{Pretax} x RB	$325,500,000	$363,600,000	$435,200,000	$456,200,000	$475,400,000
8	Revenue Requirement: Return + DeprExp	$575,600,000	$627,500,000	$726,400,000	$751,900,000	$779,800,000
9	**Revenues**					
10	Rebasing Return	$311,300,000	$311,300,000	$311,300,000	$311,300,000	$311,300,000
11	Rebasing Depreciation Expense	$237,300,000	$237,300,000	$237,300,000	$237,300,000	$237,300,000
12	P (Percent increase in Rates)	2.45%	2.45%	2.45%	2.45%	2.45%
13	G (Percent increase in Customers)	1.69%	1.73%	1.75%	1.72%	1.69%
14	(1 + P) x (1 + G)	1.04173	1.08571	1.13171	1.17932	1.22858
15	I-X RevenuesPlant-related = [Rebasing Return + Depreciation] x (1+P) x (1+G)	$571,500,000	$595,600,000	$620,900,000	$647,000,000	$674,000,000
16	GTA, Ottawa Plant	$ 48,900,000	$172,100,000	$631,900,000	$631,900,000	$631,900,000
17	Depreciation Rate	2.66%	2.21%	2.47%	2.47%	2.47%
18	GTA, Ottawa Depreciation Expense	$ (1,300,000)	$ (3,800,000)	$(15,600,000)	$(15,600,000)	$(15,600,000)
19	GTA, Ottawa Rate Base	$ 48,400,000	$169,900,000	$619,100,000	$603,500,000	$587,800,000
20	RORPretax	7.98%	8.19%	8.36%	8.39%	8.46%
21	GTA, Ottawa Return: ROR^{Pretax} x RB	$3,900,000	$ 13,900,000	$ 51,800,000	$ 50,600,000	$ 49,700,000
22	GTA, Ottawa Revenue Requirement	$5,200,000	$ 17,700,000	$ 67,400,000	$ 66,200,000	$ 65,300,000
23	Total Revenues (I-X plus Y Factor)	$576,700,000	$613,300,000	$688,300,000	$713,200,000	$739,300,000
24						
25	Revenue Deficiency (with I-X and Y Factor)	$ (1,100,000)	$ 14,200,000	$ 38,100,000	$ 38,700,000	$ 40,500,000

Figure TCU2.16 D: Revenues, Revenue Requirement, and Revenue Deficiency





It is Concentric's assessment that Figures TCU2.16 C and TCU2.16 D demonstrate that an I-X escalation formula combined with Y Factor Recovery of the GTA and Ottawa projects does not provide adequate recovery of capital-related costs during the 2014 to 2018 period. The cumulative five year revenue deficiency is $130.4 million.

Witness: J. Coyne - Concentric Energy Advisors Inc.

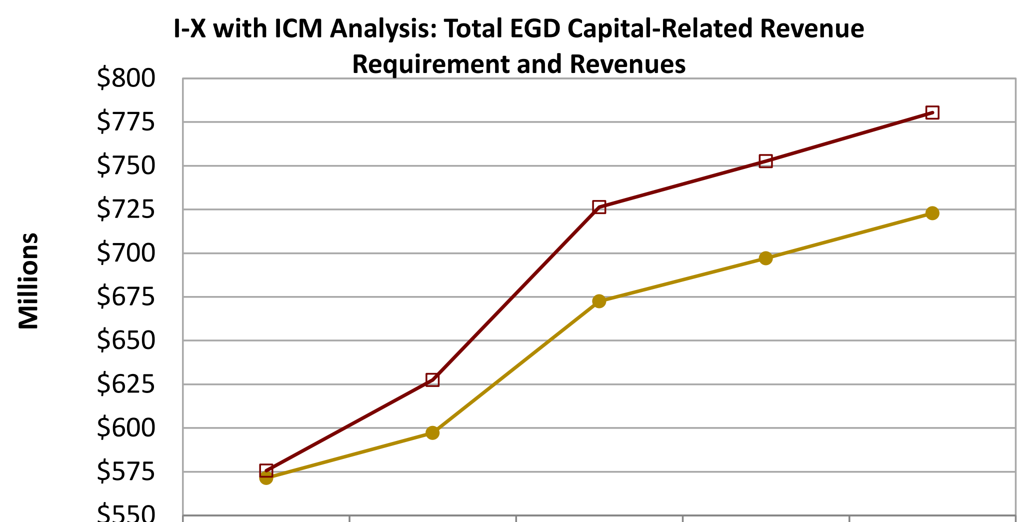
Analysis of I-X formula with ICM:

Concentric's analysis that demonstrates that an I-X formula combined with an ICM-type mechanism would not provide adequate recovery of EGDI's planned capital-related costs during the 2014 to 2018 period is provided in Figures TCU2.16 E and TCU2.16 F, provided on the following pages.

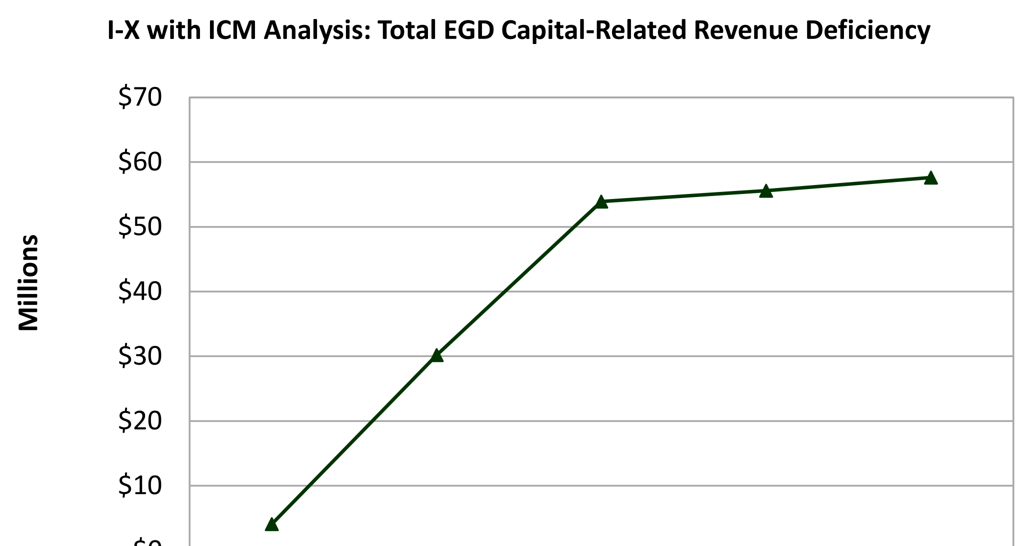
Figure TCU2.16 E: Revenues based on I-X and General Purpose (Electric ICM) Capital tracker rate adjustments

		2014	2015	2016	2017	2018
1	**Revenue Requirement**					
2	Average of Monthly Avgs Plant	$6,977,000,000	$7,441,000,000	$8,321,900,000	$8,698,400,000	$9,054,000,000
3	Depreciation Rate	3.58%	3.55%	3.50%	3.41%	3.37%
4	Depreciation Expense	$(250,100,000)	$(263,900,000)	$(291,200,000)	$(296,400,000)	$(305,000,000)
5	Average of Monthly Avgs Rate Base	$4,081,300,000	$4,440,400,000	$5,203,200,000	$5,437,200,000	$5,619,500,000
6	ROR^{Pretax}	7.98%	8.19%	8.36%	8.39%	8.46%
7	Return: ROR^{Pretax} x RB	$325,500,000	$363,600,000	$435,200,000	$456,200,000	$475,400,000
8	Revenue Requirement: Return + DeprExp	$575,600,000	$627,500,000	$726,400,000	$752,600,000	$780,400,000
9	**Revenues**					
10	Rebasing Return	$311,300,000	$311,300,000	$311,300,000	$311,300,000	$311,300,000
11	Rebasing Depreciation Expense	$237,300,000	$237,300,000	$237,300,000	$237,300,000	$237,300,000
12	P (Percent increase in Rates)	2.45%	2.45%	2.45%	2.45%	2.45%
13	G (Percent increase in Customers)	1.69%	1.73%	1.75%	1.72%	1.69%
14	(1 + P) x (1 + G)	1.04173	1.08571	1.13171	1.17932	1.22858
15	I-X $Revenues_{Plant\text{-}related}$ = [Rebasing Return + Depreciation] x (1+P) x (1+G)	$571,500,000	$595,600,000	$620,900,000	$647,000,000	$674,000,000
16						
17	**THRESHOLD CALCULATION**					
	Threshold = 1.2 x $DeprExp_{rebasing}$ + $RateBase_{rebasing}$ x (P + G + PxG)					
18	(G + P + P x G)	4.173%	4.222%	4.237%	4.207%	4.177%
19	$RateBase_{rebasing}$ x (G + P + GxP)	$162,300,000	$164,200,000	$164,800,000	$163,600,000	$162,500,000
20	Threshold (1.2) x $DeprExp_{rebasing}$	$284,800,000	$284,800,000	$284,800,000	$284,800,000	$284,800,000
21	Threshold	$447,100,000	$449,000,000	$449,600,000	$448,400,000	$447,300,000
22						
23	Plant Additions	$218,400,000	$463,900,000	$880,900,000	$364,700,000	$355,600,000
24	Plant Additions above Threshold	$-	$14,900,000	$431,300,000	$-	$-
25	Total Plant Above Threshold	$-	$14,900,000	$446,200,000	$446,200,000	$446,200,000
26	Depreciation	$-	$500,000	$15,600,000	$15,200,000	$15,000,000
27	Accumulated Depreciation	$-	$500,000	$16,100,000	$31,300,000	$46,300,000
28	Rate Base above Threshold	$-	$14,400,000	$430,100,000	$414,900,000	$399,900,000
29	ICM Revenues	$-	$1,700,000	$51,600,000	$50,000,000	$48,800,000
30						
31	Total Revenues	$571,500,000	$597,300,000	$672,500,000	$697,000,000	$722,800,000
32	Deficiency (Surplus) in Revenues	$4,100,000	$30,200,000	$53,900,000	$55,600,000	$57,600,000

Figure TCU2.16 F: Revenues, Revenue Requirement, and Revenue Deficiency



	2014	2015	2016	2017	2018
Revenues	$571,500,000	$597,300,000	$672,500,000	$697,000,000	$722,800,000
Rev Req	$575,600,000	$627,500,000	$726,400,000	$752,600,000	$780,400,000



	2014	2015	2016	2017	2018
Deficiency	$4,100,000	$30,200,000	$53,900,000	$55,600,000	$57,600,000

It is Concentric's assessment that Figures TCU2.16 E and TCU2.16 F demonstrate that an I-X escalation formula combined with an ICM-type mechanism does not provide adequate recovery of capital-related costs during the 2014 to 2018 period. The cumulative five year revenue deficiency is $201.4 million.

UNDERTAKING TCU2.17

UNDERTAKING

Technical Conference TR 2, pages 112-113 and 132

LEI to provide references with respect to intentional over-forecasting

RESPONSE

LEI has not come across any actual enforcement proceedings or official reports that demonstrate intentional manipulation of forecasts by utilities to game the regime in the UK or Australia energy sector. However, Enbridge has found a number of examples that discuss the variances between the allowed capital expenditure ("capex") or operating expenditure ("opex") and actual capex or opex. Below are the five (5) reference documents:

- **Document 1**: Office of Gas and Electricity Markets ("Ofgem"). *Electricity Distribution Price Control Review – Second Consultation – Data and Cost Commentary Appendix*. December 2003. ("Ofgem December 2003 report"). Available online at https://www.ofgem.gov.uk/ofgem-publications/46386/5495-dataandcostcommentaryappendix18dec03.pdf

- **Document 2**: Ofgem. Electricity Distribution Price Control Review Final Proposals. November 2004. ("Ofgem November 2004 report"). Available online at https://www.ofgem.gov.uk/ofgem-publications/46251/8944-26504.pdf

- **Document 3**: Ofgem. *Gas Distribution Price Control Review Final Proposals Document – Supplementary Appendices. December 3, 2007*. ("Ofgem December 2007 report"). Available online at https://www.ofgem.gov.uk/ofgem-publications/48551/gdpcr-final-proposals-appendix-rev.pdf

- **Document 4**: Essential Services Commission. *Electricity Distribution Price Review 2006-10 Final Decision Volume 1 Statement of Purpose and Reasons.* October 2006. ("ESC report"). Available online at: http://www.royalcommission.vic.gov.au/getdoc/d09c58ae-4770-4cae-9435-586148b53398/PAL.019.001.0636

- **Document 5**: Australia Energy Regulator. *Capital Expenditure Incentive Guideline for Electricity Network Service Providers.* November 2013. ("AER report"). Available online at:

http://www.aer.gov.au/sites/default/files/1.%20AER%20explanatory%20statement%20-%20capital%20expenditure%20incentive%20guideline%20-%20November%202013.DOCX.

UK Experience

The Ofgem report of December 2003 (Document 1) shows that there are years in the regulatory period (2000 to 2003) where actual capex and opex exceeded forecasted capex and opex and vice versa in the gas distribution sector.[1,2] However, nowhere in this report did the Ofgem state that the gas distribution utilities intentionally manipulated their submissions to Ofgem and over-forecast their capex and/or opex in order to game the ratemaking process.

As Enbridge mentioned during the technical conference, the difference in the forecasted capex (or opex) and actual capex (or opex) can be attributed to various factors.[3] As shown in the attached Ofgem 2003 report,[4] the variance between the forecasted capex/opex "allowances" and actual capex/opex could be explained by numerous factors such as the following:[5]

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[1] *See* pages 11, 30, 54, 66, and 72 for examples of actual capex and opex exceeding forecasted capex and opex and pages 5, 11, 17, 24, 36, 41, 47, 54, 60, 66, 72, 78, and 85 for examples of forecasted capex and opex exceeding actual capex (*Electricity Distribution Price Control Review – Second Consultation – Data and Cost Commentary Appendix*. December 2003.)

[2] There is no similar report for the gas utilities and for the same time period (pre-implementation of the sliding scale mechanism) that is currently available electronically off the Ofgem website. This is because (i) Gas Distribution Price Control Review only started in 2002 (previous to that, the gas distribution sector was incorporated with the gas transmission price control) and (ii) Ofgem only posts information of the current regulatory period (RIIO 2013-2021) and previous regulatory period (Gas Distribution Price Control Review 2008-2013).

[3] Ontario Energy Board. EB 2012-0459 Technical Conference Transcript on January 17, 2014. Lines 9-11, Page 113.

[4] We selected this Ofgem report since Dr. Kauffman hinted in his PEG report that gaming was observed during this time (before the sliding scale mechanism was established in the electricity sector) and that the sliding scale mechanism was "motivated by Ofgem's view that the distributors have incentives to inflate their forecast capex during the next price control period but then "underspend" once an allowed capex is used to set the value of X." (PEG. *Enbridge Gas Distribution's Customized Incentive Regulation Proposal – Assessment and Recommendations*. October 2013. P. 52).

[5] Please note that this is not an exhaustive list. Please refer to the Ofgem December 2003 report for the list of all the factors that contributed to the differences observed between the utilities' forecasted costs and actual costs.

- efficiency gains (due to any of the following: operational and process improvements, procurement and outsourcing savings, overhead reductions, automation, synergies arising from a merger, company reorganization which removed management layers and reduced staff, and development of asset management policies and practices);
- restatement of asset lives which affected depreciation expenses;[6]
- lower than forecast load growth;[7]
- redesigning or adoption of alternative design options;[8] and
- changes in national metering recertification policies.[9]

In addition, in the Electricity Distribution Price Control Review Final Proposals of November 2004 (Document 2), Ofgem expressed concern about the potential for gaming by utilities and discussed the sliding scale mechanism as a tool to offset the incentive for gaming.[10] However, Ofgem did not go so far as to state that it had knowledge that intentional gaming occurred.

Furthermore, pages 69 to 76 of the Ofgem December 2007 Report (Document 3)[11] show that from 2002 to 2007, gas utilities' actual capital spending exceeded the allowances by at least 30%. This information indicates that UK gas utilities did not deliberately over-forecast their costs under the building blocks approach even before the sliding scale mechanism was implemented in the gas sector on April 2008.[12]

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[6] Ofgem. *Electricity Distribution Price Control Review – Second Consultation – Data and Cost Commentary Appendix*. December 2003. P.18.

[7] Ofgem (December 2003). pages 21 and 63.

[8] Ofgem (December 2003). pages 27 and 33.

[9] Ofgem (December 2003). pages 45 and 58.

[10] Ofgem. *Electricity Distribution Price Control Review Final Proposals*. November 2004. P. 85.

[11] Based on LEI's research, there is no single report on the Ofgem website that provides a comparison of the actual and allowed capex for gas utilities during the most recent regulatory period (e.g., the 2008-2013 gas distribution price control review).

[12] Ofgem. *Regulating Energy Networks for the Future: RPI-X@20 – History of Energy Network Regulation*. February 27, 2009. P. 75.

Australia Experience

The Essential Service Commission ("ESC") was the regulator of utilities in the state of Victoria prior to 2009. ESC's report from October 2006 (Document 4) specifically on page 255 shows that there were years in the first and second generation of incentive ratemaking when actual capex was lower than forecasted capex.[13] But there were also years when actual capex was higher than forecasted capex.[14] The variances between forecast and actual are not unexpected, and may be due to a variety of factors as acknowledged by ESC:

> The fact that capital expenditure has been lower than forecast may be due to a combination of factors:
>
> - efficiency gains achieved over the period;
> - the deferral of capital expenditure projects between regulatory periods;
> - changes in external drivers of expenditure, for example lower than anticipated peak demand...[15]

It is notable that the concerns of Australian Energy Regulator ("AER") currently are not related to over-forecasting of total expenditures under the building blocks approach (and there is no Information Quality Incentive or sliding scale mechanism in Australia's building block regime). The AER is more concerned with actual capex exceeding forecast levels (which is referred to as "allowances") and has clarified in its recent report entitled *Better Regulation – Capital Expenditure Incentive Guideline for Electricity Network Service Providers* (Document 5) that it will have the ability to assess actual spending to determine whether it was efficient during the rate reviews.[16] Enbridge's understanding is that the Ontario Energy Board has similar authority to review the prudence of capital spending during an IR term at rebasing, in the context of setting the new rate base that reflects capital spending during the IR term.

[13] Such as in 1996, 1997, and 2001 to 2005.

[14] Such as 1998 to 2000.

[15] ESC. *Electricity Distribution Price Review 2006-10 Final Decision Volume 1 Statement of Purpose and Reasons. October 2005*. P. 255.

[16] Australian Energy Regulator. *Capital Expenditure Incentive Guideline for Electricity Network Service Providers.* November 2013. P. 10.

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Technical Conference TR 2, page 149

EGDI to provide a Chart showing proposed capital expenditures by categories for each of the five years and showing the amounts subject to proposed Deferral/Variance Accounts.

RESPONSE

The following chart identifies 2014 to 2018 budgeted capital expenditures that are subject to deferral/variance accounts.

Budgeted Capital Expenditures Subject to Deferral Account Treatment
($ Millions)

Deferral/Variance Account Name	Capital Category	2014	2015	2016	2017	2018
Greater Toronto Area Project Variance Account	Leave to Construct	197.1	359.7	-	-	-
Relocation Mains Variance Account	System Improvements & Upgrades	-	-	-	12.6	12.6
Replacement Mains Variance Account	System Improvements & Upgrades	-	-	-	5.1	5.1
		197.1	359.7	-	17.7	17.7

Witnesses: S. Kancharla
R. Small

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Technical Conference TR 2, page 154

EGDI to provide budget letter for the period in question, or note where it is cited in the evidence filed.

RESPONSE

Please see attached.

Witness: S. Kancharla

ENBRIDGE

Enbridge Gas Distribution Inc.
Raymond Lei
Manager, Budgets & Business Support
500 Consumers Road
North York, ON, M2J 1P8
Tel 416 495 3927
Fax 416 495 6451
Raymond.lei@enbridge.com

Memo

Date: March 12, 2013

To: Distribution List

From: Raymond Lei

Re: **EGD Budget Assumptions and Guidelines for 2014 to 2016**

The purpose of this document is to set out guidelines to be used in preparation of EGD's ("the Company") **three-year budgets** for 2014 to 2016, which will be filed for the 2014 rates application.

1. General Budget Approach

The budget will be established by converging the top-down expectations and the bottom-up inputs. Departments are required to develop the grass-roots budget based on the business needs that are aligned with the Company's strategic objectives. In the meantime, it is essential for departments to identify opportunities or plans to achieve productivity gains in the three year term as the savings to the budget.

If the business plans to incorporate new initiatives in the budget, the budget owner is required to justify the cost with the business rationale. The budget should be built up from the economic and business drivers.

In principle, the budget should be developed on the basis that the funds required are adequate to sustain the business, prudent and reasonable in terms of cost increases, and defendable from the business's perspective. The final budget is subject to review and approval by the Executive Management Team ("EMT").

Table 1: Specific Budget Approach

Budget Item	Approach		Data Profile
O&M	Incremental	Changes from 2013 Settlement Agreement	Annual
FTEs			Annual
Capital Expenditures	Zero-based	Multi-year capital projection	Monthly
Other Revenue/Municipal taxes	Zero-based	revenue/tax forecast	Annual

2. Timeline

Table 2: Key Activities and Corresponding Dates

Activity	Date
Budget Letter and budget templates are issued to departments	March 12
Departments develop and review the three-year budgets	March 12-31
Departments provide the budgets to the Budgets group	April 1
EMT reviews and approves Capex and O&M budgets	April 5
Three-year budgeted financial statements are completed	April 19
Capital evidence is completed	April 15
O&M and all other evidence is completed	April 22
File Application	May 31

3. Economic Inputs

Customer additions and inflation rates are principal inputs for most budget items. Please apply these two economic factors if applicable.

Table 3: Key Economic Inputs

Economic Inputs	2014	2015	2016
Customer Additions	36,647	38,489	39,645
Inflation Rates (GDP IPI FDD)*	1.39%	1.64%	1.72%

**The latest forecast reflects actual data to Q4 2012*

4. O&M and FTE Budget

The top down expectation will be that the overall budget increases for each department will be at or less than the applicable inflation level inclusive of labour costs and all other costs. Each department will be asked to find cost savings and efficiencies that would result in budget increase less than the level of inflation.

When there are new initiatives and new hires which will have cost implications for other departments, please ensure that the incremental costs or savings are included in each department's budget.

The template to develop the O&M and FTE budgets will be provided to the departments.

1) Merit Increases

Table 4: Merit Increases

Economic Inputs	2014	2015	2016
Non-Union Employee (effective on Apr 1)	3.0%	3.0%	3.0%
Union Employee (effective on Jan 1)	2.5%	2.5%	2.5%

2) Vacancy Credits

Please apply **2.25%** of gross salary as vacancy credits to the departmental labour budget. Vacancy credits reflect potential savings from the staff lag and staff reduction as the Company's endeavor to achieve productivity gains.

3) FTE's

Departments should use the actual FTE's as of Feb 28, 2013 confirmed by HR as the starting point to project the FTE levels for three years. The following format in Table 5 will be used to file the FTE budget.

Table 5: Format for Regulatory Filing

Salary Band	2013	2014	2015	2016
Management (G9/10 and above)				
Supervisory (G1-G8)				
Union				
Vacancies				
Total FTE				

Table 6: FTE Buildup Template

Department Name: ABC (Example)	Mgmt	Supervisory	Union	Total
2014 FTEs – Active Employees	**5**	**10**	**3**	**18**
+ Vacancy - Replacement Hires	0	0	1	1
+ Vacancy - New Hires	0	1	0	1
+ Return to work*	1	0	0	1
- Staff reduction	0	-1	0	-1
2014 Total FTEs	**6**	**10**	**4**	**20**

maternity, disability, secondment, etc.

4) Incremental Costs to Add a New FTE

For every new FTE that is hired, the Company will incur incremental costs over and above the employee's salary, training, and travel, etc. Department should develop the associated costs in relation to hiring a new FTE.

Departments are responsible for developing the FTE forecast and budgeting department-related O&M. If there is an interrelationship in cost between departments, please ensure that the associated costs are properly accounted for by various departments. Please refer to Table 7 for the budget accountability.

Table 7: Increment Costs Per A New FTE

Cost Item	Cost per FTE	Budget Owner	Structure
Salaries and Wages	Base pay	Hiring Dept.	Decentralized
Training, travel, etc.	Job requirements	Hiring Dept.	Decentralized
STIP (based on salary band)	% of Salary	HR	Centralized
Benefit, pension, EI,CPP & EHT	41% of Salary	HR	Centralized
IT hardware and software (capital)	$2,600	IT	Centralized
IT maintenance cost (O&M)	$1,300	IT	Centralized
Facilities	$7,500	Facilities	Centralized

5) Budget Analysis

Please provide the driver-based budget analysis year to year. Please use the following template to conduct the budget analysis.

Table 8: Driver-Based Budget Analysis

Example	
2013 Budget	**$100**
1). Merit increases	3
2). New FTEs	2
3). Productivity - vacancy credits	-1
4). Inflationary pressures	1
5). New initiatives	5
6). Incremental cost from customer adds	0
7). Cost to maintain new capital assets	2
8). Other	1
2014 Budget	**$113**

5. Budget Contact in Finance

Table 9: Budget Contact in Finance

Subject Matter	Contact	Phone
Departmental O&M, FTEs, capital, and other revenues	Tunde Adesipo John Briggs Arvind Dhoot Lorraine Kennedy Michelle Tian Brad Pilon Andy Grbic	416-495-5186 416-495-5898 416-495-5979 416-495-6119 416-495-5377 519-862-6001 613-748-6792
Other revenue consolidation, Financial statements	Sandee Qian	416-753-7475
Capital consolidation	Linda Au	416-495-5245
O&M consolidation	Danny Ko/ Mina Torriano	416-758-7982 416-495-5968
FTE consolidation	Mary Lee	416-495-5145
Budget guidelines and process	Raymond Lei	416-495-3927

6. Strategic Alignment

The budget needs to be consistent with the strategic direction.

1) Safety
2) Employee
3) Productivity
4) Financial Performance
5) Customer Satisfaction and Corporate Reputation

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Technical Conference TR 3, page 2

EGDI to provide responses to outstanding SEC questions.

RESPONSE

Please see responses that follow.

SEC Technical Conference Question 26

Ref: I.A9.EGDI.SEC.43

Please confirm that the impact on Allowed Revenues over 2014 to 2018 of changing the financing mix is an increase of approximately $79 million, representing an average distribution rate increase of approximately 1.4%.

Enbridge provides the following response:

The Company confirms that forecast Allowed Revenues over the 2014 to 2018 time period would decline by approximately $79M if it were able to maintain its 2013 Board Approved capital structure component ratios and cost rates, thereby maintaining a required rate of return equivalent to 2013 Board Approved. As indicated in the response to SEC Interrogatory #43 found at Exhibit I.A9.EGDI.SEC.43, it would not be practical to assume that the Company would be able to issue debt or preferred shares at the rates, or in the increments required to maintain a constant overall required rate of return.

The Company further confirms the corresponding impact on distribution revenues of approximately 1.4% per year.

SEC Technical Conference Question 31

Ref: I.A12.EGDI.SEC.58

Please provide a detailed calculation of the impact on revenue requirement and Allowed Revenue, for each year from 2014 through 2018, resulting from the $292.8 million overcollection being refunded to ratepayers over time, rather than at the beginning of 2014.

Enbridge provides the following response:

The table on the following page provides a detailed breakdown of the 2014 through 2018 Allowed Revenues that would result if $259.8M, of the $292.8M excess site restoration cost reserve identified as a result of the proposed adoption of the Constant Dollar Net Salvage approach, currently included within utility accumulated depreciation, was refunded to ratepayers at the beginning of 2014. The Company cannot accurately calculate the impact of returning the full $292.8M upfront, because the difference of $33M is designed to be returned to ratepayers over the 2014 to 2018 period as part of the proposed lower depreciation rates that result from the Net Salvage Study supporting the adoption of the Constant Dollar Net Salvage approach. Depreciation rates that exclude the $33M are not available.

The results shown in the table on the following page were derived by making the following adjustments to the As Filed Allowed Revenues:

1. Monthly adjustments to accumulated depreciation, totaling $68.1M in 2014, $63.1M in 2015, $58.1M in 2016, $53.1M in 2017, and $17.4M in 2018, to reflect amounts to be returned to ratepayers via the proposed Rider D, were removed and replaced with one adjustment of $259.8M in January 2014,
2. Annual tax deductions, equivalent to the annual amounts to be returned via Rider D identified above, were removed and replaced with a $259.8M deduction in 2014.

The adjustments mentioned above resulted in changes to Rate Base (accumulated depreciation), Utility Income (income tax expenses), and Capital Structure (due to a different Rate Base values), and ultimately the annual revenue sufficiency/deficiency amounts. Please note, potential impacts to the Company’s financing plan (timing and level of debt issuances) were not able to be considered in this response.

Witnesses: Enbridge Witness Panels

ALLOWED REVENUE AND DEFICIENCIES (INCL. CIS/CC)
ASSUMING $259.8 MILLION IN SITE RESTORATION COSTS ARE RETURNED IN JANUARY 2014
2014 - 2018 FISCAL YEARS

Line No.		Col. 1 2014 EGD Total	Col. 2 2015 EGD Total	Col. 3 2016 EGD Total	Col. 4 2017 EGD Total	Col. 5 2018 EGD Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Cost of Capital					
1.	Rate base	4,640.7	4,952.5	5,619.1	5,776.0	5,913.4
2.	Required rate of return	6.65%	6.85%	7.00%	7.04%	7.10%
3.		308.5	339.1	393.2	406.5	419.9
	Cost of Service					
4.	Gas costs	1,455.9	1,606.8	1,632.5	1,632.5	1,632.5
5.	Operation and maintenance	425.3	428.5	439.5	450.5	461.8
6.	Depreciation and amortization	262.8	276.6	303.9	313.4	322.1
7.	Fixed financing costs	1.9	1.9	1.9	1.9	1.9
8.	Municipal and other taxes	41.2	43.1	45.5	47.9	50.4
9.		2,187.1	2,356.9	2,423.3	2,446.2	2,468.7
	Miscellaneous operating and non operating revenue					
10.	Other operating revenue	(40.5)	(40.9)	(41.2)	(41.2)	(41.2)
11.	Other income	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
12.		(40.6)	(41.0)	(41.3)	(41.3)	(41.3)
	Income taxes on earnings					
13.	Excluding tax shield	22.1	73.0	68.2	72.8	72.5
14.	Tax shield provided by interest expense	(40.1)	(43.2)	(48.9)	(50.4)	(52.2)
15.		(18.0)	29.8	19.3	22.4	20.3
	Taxes on deficiency					
16.	Gross sufficiency / (deficiency)	92.4	(53.5)	(133.9)	(169.9)	(198.7)
17.	Net sufficiency / (deficiency)	67.9	(39.3)	(98.4)	(124.9)	(146.1)
18.		(24.5)	14.2	35.5	45.0	52.7
19.	Sub-total Allowed Revenue	2,412.5	2,699.0	2,830.0	2,878.8	2,920.3
20.	Customer Care Rate Smoothing Var. Adj.	(2.9)	(1.1)	0.8	2.9	5.0
21.	**Allowed Revenue**	2,409.6	2,697.9	2,830.8	2,881.7	2,925.3
	Revenue at existing Rates					
22.	Gas sales	2,253.5	2,404.3	2,464.5	2,480.3	2,496.2
23.	Transportation service	242.8	229.6	217.1	211.1	205.0
24.	Transmission, compression and storage	1.8	1.8	1.8	1.8	1.8
25.	Rounding adjustment	-	0.2	0.2	0.2	(0.1)
26.	Total	2,498.1	2,635.9	2,683.6	2,693.4	2,702.9
27.	**Gross revenue sufficiency / (deficiency)**	88.5	(62.0)	(147.2)	(188.3)	(222.4)

SEC Technical Conference Question 32

Ref: I.A12.EGDI.SEC.59

Please explain why the drawdown of the $292.8 million should not include interest at the weighted average cost of capital, in the same manner as the PP&E account for electricity distributors and others moving to IFRS.

Enbridge provides the following response:

As discussed at the Technical Conference (January 17, 2014, TR2, p. 95), the Company does not believe it is appropriate to calculate interest on the drawdown of the $292.8M in site restoration cost reserve over-funding, because the excess reserve has served to reduce the Company's rate base, and therefore the required return on rate base, or cost of capital. Going forward, any portion of the over-funding which has not been returned to ratepayers will continue to reduce rate base and the required return on rate base. The Company's proposal is to return $33M, of the $292.8M, through lower depreciation rates over the 2014 through 2018 time period, while the residual $259.8M will be returned through the proposed Rider D. Rider D will be designed to return, on a monthly basis, $68.1M in 2014, $63.1M in 2015, $58.1M in 2016, $53.1M in 2017, and $17.4M in 2018. Each month, over the 2014 through 2018 time period, the Company will make an adjustment to decrease utility accumulated depreciation in an amount equivalent to the amount designed to be returned through Rider D.

SEC Technical Conference Question 34

Ref: I.A16.EGDI.EP.11

Please confirm that, absent the constant dollar salvage changes, the cumulative deficiency being proposed by the Applicant for 2014 to 2018 is $741.3 million. Please confirm that the average distribution rate increase for the five year period would be 29.3%, for an average annual increase of about 5.3% per year for five years.

Enbridge provides the following response:

The Company confirms that absent the impacts of the proposed Site Restoration Cost adjustments, resulting from the proposed adoption of the Constant Dollar Net Salvage approach, the cumulative deficiency for 2014 through 2018 would become approximately $741.3M based on the residual components of the proposed Customized Incentive Regulation plan, as detailed in Energy Probe Interrogatory #11 found at Exhibit I.A16.EGDI.EP.11. It should be noted however, in responding to that interrogatory, the potential impacts to the Company's financing plan (timing and level of debt issuances) were not able to be considered.

Witnesses: Enbridge Witness Panels

The Company confirms the corresponding impact on distribution revenues of approximately 29% for the five year period and an average annual impact of approximately 5.3%.

Further, the associated average rate increases for residential customers are provided in the response to Energy Probe Interrogatory #11 found at Exhibit I.A16.EGDI.EP.11.

SEC Technical Conference Question 35

Ref: I.A16.EGDI.SEC.64

Please confirm that, absent the constant dollar salvage changes and the declining pension costs, the cumulative deficiency being proposed by the Applicant for 2014 to 2018 is $798.8 million. Please confirm that the average distribution rate increase for the five year period would be 31.7%, for an average annual increase of about 5.7% per year for five years.

Enbridge provides the following response:

The Company confirms that if the impacts of the proposed Site Restoration Cost adjustments, resulting from the proposed adoption of the Constant Dollar Net Salvage approach were removed, and pension and OPEB costs were held at the Approved 2013 level of $42.8M, the cumulative deficiency for 2014 through 2018 would become approximately $798.8M based on the residual components of the proposed Customized Incentive Regulation plan, as detailed in response to SEC Interrogatory #64 found at Exhibit I.A16.EGDI.SEC.64. It should be noted however, in responding to that interrogatory, the potential impacts to the Company's financing plan (timing and level of debt issuances) were not able to be considered.

The Company confirms the corresponding impact on distribution revenues of approximately 30% for the five year period and an average annual impact of approximately 5.7%.

SEC Technical Conference Question 36

Ref: I.B17.EGDI.Staff.50

Please provide the Applicant's best available information on the disaggregated information for 2002 to 2006, with the sources referenced.

Enbridge provides the following response:

The complete disaggregated information for 2002 to 2006 is not available as the historical data prior to 2007 is not kept in our financial system. However, Enbridge did trace the discrete items of DSM and RCAM from the historical documents and compiled the following table on the best effort basis.

Enbridge Gas Distribution
Summary of Operating and Maintenance Expense by Category
From 2002 Actuals to 2006 Actuals

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
Line No.	Categories ($ Millions)	Actual 2002	Actual 2003	Actual 2004	Actual 2005	Actual 2006
1.	Demand Side Management ("DSM")	10.9	11.5	13.6	15.3	18.9
2.	Regulatory Cost Allocation Methodology("RCAM")	11.6	21.8	22.2	13.5	17.2
3.	All Other O&M	224.0	249.6	260.1	266.7	275.4
4.	Total Net Utility O&M Expense	$246.4	$282.8	$295.9	$295.5	$311.5

SEC Technical Conference Question 38

Ref: I.B17.EGDI.SEC.67

Please explain why grass-roots budgets are not retained. Please detail any efforts made to find copies of the grass-roots budgets for past years. Please explain how, if the budget process is essentially unchanged from IRM to COS, the Applicant responds to the Board’s IRM regulatory model by implementing productivity and efficiency improvements.

Enbridge provides the following response:

The convergence of the grass-roots budget and the top down targets leads to the final version of O&M budgets which are retained in the Company’s budget system. The Company doesn’t preserve the interim iterations of the O&M budgets in the system.

Although the budget process essentially remains unchanged from IRM to COS, the greater emphasis is placed on the embedded productivity to contain the overall increases within the inflation factor.

Witnesses: Enbridge Witness Panels

SEC Technical Conference Question 39

Ref: I.B17.EGDI.SEC.69

Please explain why the aging workforce issue should be considered a priority by the Board if the Applicant has neither formal plans nor empirical studies to deal with the issue.

Enbridge provides the following response:

The Company is not requesting that the Board specifically consider the aging workforce a priority issue. Rather it is highlighting an important issue that the Company is managing. While no formal plans exist Enbridge is dealing with the aging workfoce issue through various methods. Enbridge has an annual practice of reviewing all employees over the age of 55 and determining where potential risks exist due to critical skills and knowledge that may potentially be exiting the organization due to upcoming retirements. Individual leaders then prepare plans to replace or transition this knowledge and skill as appropriate. One example of dealing with the aging workforce issue is the creation of the Leadership Development program. Through the exercise indicated above, it was determined that a number of leaders are eligible to retire and therefore the need to build the leadership competency was highlighted. Plans are in place today to build this competency and ensure Enbridge maintains strong leadership which will result in a productive and efficient workforce.

SEC Technical Conference Question 40

Ref: I.B17.EGDI.SEC.70

Please provide a more complete response to the question.

Please confirm that the shareholder, as well as the Applicant and the ratepayers, benefits from the LTIP. Please explain why the shareholder does not contribute any part of the cost of the LTIP. Pease provide any studies, reports, memoranda, or similar documents dealing in whole or in part with the appropriate sharing of the cost of LTIP.

Enbridge provides the following response:

Total employee compensation, of which the LTIP program is a component, allows the Company to attract and retain employees with the necessary skills to ensure the business operates in an efficient and effective manner. The shareholder benefits no more nor less than it does with any other part of the compensation package which serves to create motivated and engaged employees, or for that matter any other dollar spent in the efficient and effective operation of the utility. Therefore LTIP is an operating expense, recoverable from ratepayers, as is salary and wages, and benefits.

SEC Technical Conference Question 41

Ref: I.B17.EGDI.SEC.71

Please reconcile the budget for the business case for the new leadership development program provided with Attachment 2, page 9 and 10.

Enbridge provides the following response:

The presentation attached to SEC Interrogatory #71 found at Exhibit I.B17.EGDI.SEC.71 was the original budget estimate submitted for approval for all of Enbridge, including EGDI. EGDI has approximately 22% of the total employee population therefore will incur 22% of the total cost indicated on page 9, resulting in the budget of $695,000.

Page 10 of the presentation refers to broader employee education programs across all of Enbridge, and not specific to the leadership development program.

SEC Technical Conference Question 42

Ref: I.B17.EGDI.SEC.73

Please explain why the nine year increase in Salaries and Wages of 45.3% is reasonable in context of the 520% increase in the RCAM component of compensation, much of which is stock-based compensation of EGD employees.

Enbridge provides the following response:

There is not a direct correlation between changes in salary and the RCAM component of compensation. The table on the following page shows Total Salaries, FTE's, Average Salary per FTE, and the annual percentage increase in average salary for 2007 through 2016. The average annual salary increase over the nine year period is 2.75%. Salary adjustments are required to ensure Enbridge remains competitive in the market in which the Company competes for talent.

In regards to the RCAM component of compensation, this is based on the number of employees eligible to receive stock-based compensation and the share prices which are a reflection of company performance.

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Average
Total Salaries ($000)	135,549	138,276	137,140	145,216	155,399	168,280	183,846	188,678	192,304	196,943	
FTE's	2,070	1,943	1,884	1,947	2,084	2,399	2,388	2,377	2,364	2,361	
Average Salaries	$65,482	$71,166	$72,792	$74,584	$74,568	$75,428	$76,987	$79,377	$81,347	$83,415	
Total Average Salary % Increase		9%	2%	2%	0%	1%	2%	3%	2%	3%	2.75%

SEC Technical Conference Question 43

Ref: I.B17.EGDI.SEC.75

Please advise whether, in the Applicant's opinion, counsel who participated in the confidential RCAM meetings are restricted in their ability to cross-examine Enbridge witnesses, including MNP, in the hearing of this matter. If so, please advise whether, in the Applicant's opinion, counsel that does not rely on any confidential notes of, or materials from, those meetings would have the same restrictions.

Enbridge provides the following response:

The RCAM consultative has been held on the basis that it was to be treated as if it were a settlement conference. Accordingly the rights of counsel are subject to the same limitations on the use of materials and discussions as those which apply to a settlement conference.

SEC Technical Conference Question 45

Ref: I.B18.EGDI.Staff.55

Please confirm that the Applicant does not plan to proceed with any discretionary projects within the 2014 to 2018 period. Please provide a list of all discretionary projects completed in the last five years. Please provide the definition used by the

Applicant to define “discretionary projects”. Please identify which, if any, of the projects listed on page 2 of the response are discretionary.

Enbridge provides the following response:

The goal of the capital budget process was to deliver capital expenditures within the Capital Budget that are limited to the lowest prudent level. Given that the capital requirements identified for 2014 and 2016 at the start of the process (Review 1) were greater than the Board approved capital for 2013 and the actual capital requirement for 2012, the Company recognized that only expenditures considered necessary would take priority. The iterative review process identified and removed projects and projects costs from the capital plan to arrive at the final Capital Budget (Review 6). As noted in paragraph (b) of Board Staff Interrogatory #55 found at Exhibit I.B18.EGDI.STAFF.55, there is a reasonable likelihood that some of the variable cost will be required during the CIR period. This additional cost pressure will require even further assessments of the planned capital expenditures for priorities.

Attempting to separate all capital projects into either a discretionary or non-discretionary category is an over simplification of the budget review process used to arrive at a prudent capital plan. In addition to the fundamental understanding of the expenditure requirement, the criteria applied throughout the process are given in Exhibit B2, Tab 1, Schedule 1, pages 22 to 25.

Given that the Company does not typically define projects as discretionary or non-discretionary, there is no list of discretionary projects completed over the last five years. Projects were completed based on prioritized need within budget parameters.

SEC Technical Conference Question 47

Ref: I.B18.EGDI.SEC.89

Please confirm that there is no cost-benefit analysis or business case for WAMS.

Enbridge provides the following response:

Confirmed. As outlined in Exhibit B2, Tab 8, Schedule 2, the primary driver for the WAMS Program is the future technology and security risk that will become unacceptable with the loss of vendor support after 2015 to the operating system of Windows Server 2003 that underpins the Existing Technology. The Existing Technology is ten years old and is a core system that supports the Company’s daily operations such as emergency response, construction, maintenance and service activities. In the response to SEC Interrogatory #104 found at Exhibit I.B18.SEC.104, more detail is provided on how the Company's day-to-day operations would be significantly impacted by any long term unplanned outage. With the unacceptable technology and security risk in the future, as well as the significant business impact as a result of any unplanned long term outage, the only prudent decision is the Replacement Option.

SEC Technical Conference Question 48

Ref: I.B18.EGDI.SEC.91

Please provide a method of cross-referencing the categories in Table 1 to the categories or line items in I.B18.EGDI.SEC.86, p. 2. Please explain the 9.9% increase in DLC from Review 1 to Review 6.

Enbridge provides the following response:

The table provided in response to SEC Interrogatory #86 found at Exhibit I.B18.EGDI.SEC.86, page 2 contains an error and should be replaced with the corrected Table 1 below. This corrected table shows a decrease of 9% in 2014 to 2016 DLC from Review 1 to Review 6.

Table 1
SUMMARY COMPARISON OF CHANGES FINAL REVIEW 6 VS. BASELINE REVIEW 1
($K)

	Review 1- Jan 18th				Review 6 - Final Capital				Changes Review 6 vs. Review 1			
CAPITAL BUSINESS AREA	**F2014**	**F2015**	**F2016**	**Sum 14-16**	**F2014**	**F2015**	**F2016**	**Sum 14-16**	**F2014**	**F2015**	**F2016**	**Sum 14-16**
1. CUSTOMER GROWTH	99,638	107,190	114,744	321,571	91,156	97,495	102,340	290,991	(8,482)	(9,695)	(12,403)	(30,580)
2. REINFORCEMENT	7,242	16,375	2,918	26,535	10,894	16,958	8,744	36,595	3,652	583	5,825	10,060
3. RELOCATIONS	15,336	15,786	16,203	47,325	15,236	13,386	12,603	41,225	(100)	(2,400)	(3,600)	(6,100)
4. SYSTEM INTEGRITY RELIABILITY	154,438	187,046	184,351	525,835	132,833	135,127	141,104	409,063	(21,605)	(51,919)	(43,247)	(116,772)
5. STORAGE	22,231	14,816	14,785	51,832	19,168	13,808	8,910	41,886	(3,063)	(1,008)	(5,875)	(9,946)
6. GENERAL PLANT	28,052	29,601	27,483	85,136	27,095	25,614	20,986	73,695	(957)	(3,987)	(6,497)	(11,441)
7. INFORMATION TECHNOLOGY	24,300	26,200	27,200	77,700	29,300	27,200	27,500	84,000	5,000	1,000	300	6,300
8. DEPARTMENTAL LABOUR COSTS	81,067	80,501	83,247	244,815	74,843	73,348	75,552	223,744	(6,223)	(7,153)	(7,695)	(21,071)
9. ADMINISTRATIVE AND GENERAL	36,523	37,072	37,664	111,259	35,500	36,440	37,140	109,080	(1,023)	(632)	(524)	(2,179)
9. INTEREST DURING CONSTRUCTION (CORE UTILTITY)	7,435	8,981	9,825	26,241	7,800	7,251	6,999	22,050	365	(1,730)	(2,826)	(4,191)
	476,262	**523,568**	**518,419**	**1,518,249**	**443,825**	**446,627**	**441,877**	**1,332,329**	**(32,437)**	**(76,941)**	**(76,542)**	**(185,920)**

Table 2 below provides a method of mapping the categories in Table 1 of SEC Interrogatory #91 found at Exhibit I.B18.EGDI.SEC.91 to the categories in SEC Interrogatory #86 found at Exhibit I.B18.EGDI.SEC.86. Note that the category values in the table in SEC Interrogatory #86 found at Exhibit I.B18.EGDI.SEC.86 include allocated amounts for Departmental Labour Costs, Administrative and General, and Interest During Construction, whereas Table 1 of SEC Interrogatory #91 found at Exhibit I.B18.EGDI.SEC.91 includes the allocation of these amounts to separate line items.

Witnesses: Enbridge Witness Panels

Table 2

Item No.	**I.B18.EGDI.SEC.86 Budget Categories**		**I.B18.EGDI.SEC.91 Budget Categories (Table 1)**
A.	Customer Related		
1.1.1	Sales Mains		
1.1.2	Services		
1.1.3	Meters and Regulation		
1.1.4	Customer Related Distribution Plant		Line Item 1
1.1.5	NGV Rental Equipment		Line Item 6
1.1	TOTAL CUSTOMER RELATED CAPITAL		
B.	System Improvements and Upgrades		
1.2.1	Mains	- Relocations	Line Item 3
1.2.2		- Replacement	Line Item 4
1.2.3		- Reinforcement	Line Item 2
1.2.4	Total Improvement Mains		
1.2.5	Services - Relays		Line Item 4
1.2.6	Regulators - Refits		Line Item 4
1.2.7	Measurement and Regulation		Line Item 4
1.2.8	Meters		Line Item 4
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES		
C.	General and Other Plant		
1.3.1	Land, Structures and Improvements		Line Item 6
1.3.2	Office Furniture and Equipment		Line Item 6
1.3.3	Transp/Heavy Work/NGV Compressor Equipment		Line Item 6
1.3.4	Tools and Work Equipment		Line Item 6
1.3.5	Computers and Communication Equipment		Line Item 7
1.3	TOTAL GENERAL AND OTHER PLANT		
D.	Underground Storage Plant		Line Item 5
E.	SUBTOTAL "CORE" CAPITAL EXPENDITURES		
F.	Work and Asset Management System (WAMS)		Not included
G.	SUBTOTAL CAPITAL EXPENDITURES		
H.	Leave to Construct		
1.7.1	Ottawa Reinforcement		Not included
1.7.2	GTA Reinforcement		Not included
1.7	TOTAL LEAVE TO CONSTRUCT		
I.	TOTAL CAPITAL EXPENDITURES		

SEC Technical Conference Question 49

[Ref: I.B18.EGDI.SEC.95

Please explain why the totals in Reviews 4 through 6 are all higher than the totals in Review 3.

Enbridge provides the following response:

The profile of total capital across the six review stages illustrates the evolution of the Company's thinking as it developed the Customized IR model. In particular, the decision to categorize firm and variable capital costs separately occurred at Review 3, hence what appears to be a sudden drop in forecasted (firm) capital in Review 3. What occurred through the analysis conducted in Review 4 and 5 was the alignment of all capital owners to a common usage of the Firm and Variable categories. Following that discussion, the changes seen from Review 6 to Review 5 reflected the final identification of the project costs that were deemed necessary.

SEC Technical Conference Question 50

Ref: I.B18.EGDI.SEC.96

Please provide a list of FTE increases that were denied.

Enbridge provides the following response:

Enbridge does not have a list of denied FTE increases. The process employed to determine the capital forecast assumed no new FTE's through the forecast period, and department managers across the organization were asked to prepare forecasts under that assumption. This is consistent with the O&M commitment to hold labour cost growth to the rate of inflation, as outlined in the O&M evidence at Exhibit D1, Tab 3, Schedule 1, paragraph 19, effectively limiting the opportunity for adding new FTE's.

The capital budgeting process Enbridge employed for this application reviewed aggregate Department Labour Costs with all capital owners to ascertain if the proposed capital projects could be delivered with the budgeted staffing levels. It is not Enbridge's practice to retain a listing of FTE requests that are denied. Typically, individual departmental staffing plans are reviewed by department managers as part of their accountability and requests that meet a business need and are approved by their managers are then processed.

SEC Technical Conference Question 51

Ref: I.B18.EGDI.SEC.97

Please confirm for which years, if any, rates will include costs for both Envision and WAMS. Please include any years after 2018. Please advise when the Envision costs will no longer be providing current value to ratepayers. Please confirm that the total Allowed Revenue applicable to the Envision/WAMS function is proposed to be:

a. 2014 - $15.3 million
b. 2015 - $7.3 million
c. 2016 - $23.0 million
d. 2017 - $33.5 million
e. 2018 - $35.2 million

Enbridge provides the following response:

Enbridge can confirm that the numbers above are the sum of proposed Allowed Revenue for the 2 separate items, Envision and WAMS from the response to SEC Interrogatory #97 found at Exhibit I.B18.EGDI.SEC.97. Envision is a service provided to Enbridge that enables installation of mains and services. The costs of those mains and services are depreciated over approximately 25 years in line with the Company's depreciation rates outlined in Exhibit D2, Tab 1, Schedule 2. WAMS will be an Enbridge IT asset that is proposed to be depreciated over a 10 year period.

SEC Technical Conference Question 52

Ref: I.B18.EGDI.SEC.100

Please confirm that, of the problems listed, many of them were repeats because the problem was not fixed after the first instance. Please confirm that more than thirty of the listed problems were the fact that a printer had not been turned on before a function was run.

Enbridge provides the following response:

It is common practice to record all incidents from the low priority to critical priority nature and regardless of business impact. These incidents are used to conduct root cause analysis and manage resolution with the system stakeholders.

Table 1 on the following page is a categorization and breakdown of the 255 incidents that occurred between January 2010 and November 2013. Each category has a most common root cause, description, and business impact. Where there are multiple incidents (5+) in a category, an explanation has been provided in the comments column to explain what has been done to mitigate or eliminate the repeat occurrences of the issue.

As can be seen from the descriptive table on the following pages, it is not possible to repair a problem when it first occurs in a manner that will prevent a similar type of problem or issue arising again in future. Often it is necessary to individually repair each problem with a data patch. Due to the amount of data that is supplied by vendors and external systems, it is common to have problems or issues with incoming data. These data issues may require the sending system to resend or a manual correction of the data.

The issue dealing with the printer issue is addressed in the highlighted row in the table below. The printer is located with an external vendor and any issue with the network or the printer would result in time sensitive customer notification letters not being delivered.

Table 1: EnTRAC Incident Breakdown January 2010 - November 2013

Category	Count	Most Common Root Cause	Description	Impact Level	Business Impact	Comments
ABC Fees Engine	2	Bad data in database	Engine that generates vendor administration and pool charges	Critical	The business impact is the inability to accurately calculate and generate charges to the Vendor	
Actual Consumption Materialized view refresh	1	Data error	Refreshes a materialized view with data from database tables	Medium	The business impact is the unavailability of consumption data for the MDV Engine which leads to the inability of correctly calculating the MDV.	
AltraTo EnTRAC Delivery	33	Mismatches of data from inbound delivery file and EnTRAC application data	Inbound interface that loads files containing gas deliveries	Critical	The business impact is that critical delivery data will not be available to calculate critical non-compliance charges	This incident is repeated due to the inaccuracies of data received from Enbridge Delivery system. This issue requires the support team to contact the sending system to correct and resend the file.
BGA report engine	3	Code defect could not handle certain scenarios	Engine that calculates and generates Banked Gas Account information for vendor pools	Critical	The business impact to the Vendors is they will not be able to aware of their current (positive or negative) status of gas volumes and to perform gas load balancing of the pools	

Category	Count	Most Common Root Cause	Description	Impact Level	Business Impact	Comments
CCL2	22	Code defects, bad data in database	Engine that generates customer move transactions and setups contract data for new account	High	The business impact is that Vendors will not know their customers have moved to a new location and the billing system would not have most up to date contract data for these customers. Customer invoices will have incorrect charges to current owner.	This incident is repeated due to the inaccuracies of data received from vendors and new code defects identified in EnTRAC. These issues have to be individually fixed with data patches.
Charge Uploader	11	Incorrect data and input by users, code deployment problem	Engine that uploads vendor charges into the database These charges are manually created by EnTRAC user	Critical	The business impact is the uploading of the manually generated charges by Direct Purchase group will not be processed and therefore will not be billed to the Vendor/Customer.	This incident is repeated due to issues with manually generated data by users. These issues have to be individually fixed with data patches.
Check P2P Errors	2	Configuration error	Job that generates daily reports of failed inbound/outbound vendor transaction files	Low	The business impact is low as this is a technical support validation check to ensure that the failed inbound/outbound transactions are communicated to our business partners. They in turn contact the vendors to re-submit their failed transaction	

Category	Count	Most Common Root Cause	Description	Impact Level	Business Impact	Comments
Compliance Manager Charges	1	Insufficient table space in the database	Engine that generates vendor/customer non-compliance charges	Critical	The business impact is a financial impact to both EGD and the Vendor(s) and LVC (Large Volume Customers). The non-compliance penalties will not be known and therefore not charged to the Vendor/Customer.	
Consumer Notification (Printer)	47	Print job to Xerox failed	Job that generates consumer notification letters and sends to printer	Low	The business impact is low as the Consumer Notification letters are queued and will be sent when the printer comes back on line.	This incident is repeated due to printer issues. This issue has been resolved with a system change implemented in Dec 2012.
Consumption Exception Processor	12	Permissions & code deployment issues	Job that reprocesses consumption records that are in exception status but have been subsequently manually reviewed by Business Partners	Medium	The impact is that the gas consumption in exception status will not be billed to the Customer.	This incident is repeated due to security access when deploying code.
Delivery Manager	2	Bad inbound data from upstream system	Engine that processes the daily pool gas deliveries	Critical	The business impact is that critical delivery data will not be available to calculate critical non-compliance charges	

Category	Count	Most Common Root Cause	Description	Impact Level	Business Impact	Comments
ENCHG	8	Files that did not come in or came in with incorrect file ownership	Job Changes permissions on inbound interface files	High	The business impact is that current information in EnTRAC is not up to date. The EnTRAC job stream will be delayed as required inbound information cannot be loaded into the database	This incident is repeated due to incoming files having incorrect access.
EnTRAC to P2P	1	Data format code defect	Job that moves outbound vendor transaction files from the EnTRAC database to the P2P database	Critical	The business impact is that the Vendors will not have responses to business transactions previously submitted.	
Hyperion Reports	4	Code deployment issues or server unavailability	End user reports that are generated from data within EnTRAC application	High	The business impact is that the Direct Purchase group will not have access to update to date report data. These reports contain volumetric & financial data.	
IRR	5	Engine could not handle a specific scenario or there was bad data	Engine that generates outbound transactions to vendors related to their customer gas volumes and charges	High	The business impact is that the Vendor will not be able to validate individual customer's gas volumes and charges.	This incident was repeated due to new requirements that the system was not designed to handle. These issues have to be individually fixed with data patches.
IRS	1	Control M Scheduler issue	Engine that generates the monthly dollar remittances to the vendors	Critical	The business impact is that Enbridge will not be able to validate and submit the correct remittances to the vendors.	

Category	Count	Most Common Root Cause	Description	Impact Level	Business Impact	Comments
IVA Processor	13	Deployment issues and bad data	Interface / engine that processes inbound vendor/customer adjustments	Critical	The business impact is the inability to submit and have customer bill adjustments applied.	This incident is repeated due to security access when deploying code and bad data.
MDV Engine	5	Bad data and database table availability issue	Engine that calculates the estimated mean daily gas volume of vendor pools prior to and during the pool term lifecycle	High	The business impact is that the vendor will not know the estimate/forecasted consumption volumes for their pools of customers. Inaccurate information could result in wrong charges applied to the Vendors.	This incident is repeated due to the bad duplicate data entered by the user. These issues have to be individually fixed with data patches.
P2P to EnTRAC	19	Inbound vendor transaction files that had not been decrypted before 8pm cut-off. Bad inbound vendor transaction data	Job that moves inbound vendor transaction files from the P2P database to the EnTRAC application	Critical	The business impact is that the Vendors will not have time sensitive business transactions processed (financial, contractual & customer account updates). This could have a financial impact.	This incident is repeated due to slow decryption of inbound transaction files. The performance of the decryption has been enhanced to eliminate the issue.
PCR Generation	7	Engine could not access materialized view due to refresh job running in parallel	Engine that generates a pool composition report that contains all customer accounts in a vendor pool	High	The business impact is that Vendors will not know the specific account information that contributes to their pool's estimated mean daily volume	This incident is repeated due to scheduling conflict with creating the materialized data views. This issue was resolved by changing job schedules.

Category	Count	Most Common Root Cause	Description	Impact Level	Business Impact	Comments
Processed STR Materialized View	1	Incorrect database permissions	Job that refreshes a Oracle materialized view with data of electronic business transactions	Medium	The inability to have accurate information required to generate Vendor pool termination requests	
SAP To EnTRAC	25	Invalid inbound data, configuration errors, slow database performance	Interface jobs that load files sent from CIS billing system to EnTRAC containing account, premise, work orders and other types of inbound data	Critical	The business impact is that important inbound data that is ultimately used to determine customer/vendor charges and to generate contractual information will not be available. EnTRAC will not be able to perform any data processing.	This incident is repeated due to issues with data from SAP primarily during the SAP stabilization period.
STR Validation	8	Bad data	Engine that validates inbound vendor transactions against specific business rules	Critical	The business impact is that submitted business transactions will not be validated against GDAR business rules, and/or processed resulting in responses not being generated and sent to Vendor. Also, not be compliant with GDAR (Gas Distribution Access Rules)	This incident is repeated due to bad data in EnTRAC. These issues have to be individually fixed with data patches.

Category	Count	Most Common Root Cause	Description	Impact Level	Business Impact	Comments
XML Request Processor	22	Bad date format or other bad data of inbound vendor transactions.	Engine that extracts and loads vendor transactions into EnTRAC database tables. Also generates outbound transactions to vendors in XML formatted files	Critical	The business impact is that EnTRAC will not be able to process any inbound transaction from Vendors.	This incident is repeated due to the bad data format received from vendors.
Grand Total	**255**					

Witnesses: Enbridge Witness Panels

UNDERTAKING TCU3.2

UNDERTAKING

Technical Conference TR 3, page 9

Enbridge to provide answers to questions in Exhibit No TC3.2

RESPONSE

Reponses to FRPO Technical Conference questions are as follows:

Preamble: Enbridge and ratepayer representatives worked quickly and dilgently to establish an agreement to allow Enbridge to acquire annual firm contracts to meet system reliability needs for the franchise. As was discussed in the month of October, this reliability firm capacity is in excess of the annualized needs of the utility resulting in a significant risk of UDC. When ratepayers asked that Enbridge utilize the approximately 18 PJ's on summer deliveries at Dawn, Enbridge explained that the 18PJ's of capacity has historically been used as a buffer for shareholder risk for UDC. Ratepayers are seeking assurance of equitable treatment through on-going reporting.

FRPO Technical Conference Question 1

1) For the months of November and December of 2013, please provide:
   a) the actual heating degree days (HDD) by area
   b) the total capacity used for base exchanges
   c) the total capacity that was optimized in other manners that did not result in a gas being delivered to the franchise or storage

Enbridge provides the following response:

a) Actual Degree Days

	Toronto	Niagara	Ottawa
November/13	467.3	436.0	554.0
December/13	685.4	631.5	846.8

b) During the months of November and December of 2013 the Company fully utilized its contracted long haul firm transportation capacity on TCPL. The utilization of these contracts in conjunction with other assets ie., storage enabled the Company to meet the demands of its customers. During the months of November and December opportunities did arise on certain days whereby the

Company was able to take advantage of the flexibility of all of its transportation contracts, both long haul and short haul contracts, and enter into arrangement with third parties and complete Base Exchanges while still meeting the demands of its customers.

Base Exchange – Gj's	
November	5,184,701
December	3,564,918

c) As mentioned in response b) above the Company utilized 100% of the its contracted capacity for the purpose of meeting customer demand and did not assign away or release any of the capacity to third parties.

Witnesses: J. Denomy
D. Small

FRPO Technical Conference Question 2

2) Using an October 31 maximum storage fill, please provide the amount of gas that would be forecasted to be purchased at Dawn in the summer for to meet the maximum target storage fill.

Enbridge provides the following response:

The 2014 volumetric forecast filed with the Board assumes that the Company will acquire approximately 18.3 PJ's of gas at Dawn during the April to October period to ensure storage is full at the end of the injection cycle. The 2014 forecasted monthly purchases are provided below.

Dawn Purchases	PJ's
January	-
February	-
March	-
April	2.1
May	2.3
June	1.7
July	3.1
August	3.1
September	3.4
October	2.4
November	-
December	-
	18.3

Witnesses: J. Denomy
D. Small

FRPO Technical Conference Question 3

3) Please provide EGD's total storage space available for 2014?

Enbridge provides the following response:

Inclusive of the storage capacity contracted with third parties the Company has included in its 2014 forecast filed with the Board a total available capacity of 120.5 TJ's.

FRPO Technical Conference Question 3

4) What is the expected total storage space for 2015?

Enbridge provides the following response:

The Company is currently forecasting no change in its storage capacity in 2015.

FRPO Technical Conference Question 5

5) Please provide the targeted in PJ's and % storage fill at month end included in Enbridge's gas supply plan that was approved in the summer prior to the decision to acquire FT instead of STFT.

Enbridge provides the following response:

The Company prepares a gas cost forecast that includes month-end storage balances based upon a design day forecast. Throughout the winter months the month-end forecasted storage balances also take into consideration the need to maintain maximum deliverability from storage as long as possible which will also assist in meeting design day conditions.

On a budgeted basis the Company plans to withdraw the maximum amount of gas from storage during the withdrawal cycle which for planning purposes will continue into the month of April. Therefore, the balance at the end of March may not be the minimum storage balance for planning purposes.

Similarly, when the Company is injecting gas into storage throughout the summer months it will plan for the possibility for injections being required in the first part of

November. Therefore, the balance of gas in storage at the end of October may not equal the total storage capacity.

The 2014 forecast storage balances are provided below:

`	PJ's	% of Total Capacity
January 1/2014	90.9	0.75
January 31/14	57.1	0.47
February 28/14	28.4	0.24
March 31/14	7.3	0.06
April 30/14	8.8	0.07
May 31/14	23.9	0.20
June 30/14	43.6	0.36
July 31/14	66.9	0.56
August 31/14	90.4	0.75
September 30/14	111.4	0.92
October 31/14	120.3	1.00
November 30/14	114.0	0.95
December 31/14	93.9	0.78

FRPO Technical Conference Question 6

6) Using actual volumes up to the end of December and forecast volumes for 2014, with the contracted delivered volumes and no mitigation nor Dawn purchases, what is projected storage balance at month end for the month of 2014 until the end of October.

Enbridge provides the following response:

The Company does not have an updated forecast for 2014 at this time however, what the Company can provide is that because of the colder than budgeted weather in December 2013 the opening gas in storage balance for 2014 was less than budget. This lower than budget storage balance coupled with the colder weather experienced to date in January 2014 will result in the Company fully utilizing 100% of its' contracted long haul capacity in the month of January thereby avoiding the previously forecast UDC in January of approximately $13.3 million. The Company would also like to add that it plans to meet the end of March storage targets identified in its gas supply plan. This will be accommodated by adjusting its purchases throughout January to March including the utilization of its contracted long haul capacity in conjunction with changes in demand over the winter period. Similarly the Company plans to manage its injections throughout the summer to meet its end of October storage targets.

REF: EXHIBIT N, Tab 1, Schedule 1, page 20

FRPO Technical Conference Question 7

7) Please explain why there is no UDC forecasted for December?

Enbridge provides the following response:

The 2014 forecast assumes 100% utilization of the long haul capacity in December 2014.

Witnesses: J. Denomy
D. Small

FRPO Technical Conference Question 8

8) Please provide the correlation factor between a change of 1 HDD and the corresponding change in consumption expected for each of the Regions.

Enbridge provides the following response:

The table below provides an estimate of the impact of one heating degree day on demand for each of the three weather zones in the Enbridge franchise area. This estimate was calculated utilizing average use per degree day for the 2012/2013 winter. Enbridge has provided these estimates in an effort to be responsive and to assist FRPO in its inquiries. As this estimate is based on a winter period for a particular heating season the use per degree day calculations measure an average impact and will not be representative of the impact of one degree day during, for example, periods of high demand such as peak or near-peak conditions or during the summer period. Please note that the Central Weather Zone and the Niagara Weather Zone comprise the Enbridge CDA.

GJ per Heating Degree Day		
Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone
54,826	10,316	4,924

FRPO Technical Conference Question 9

9) Please provide the monthly volumes to be purchased in 2014 as delivered services (i.e., not through previously contracted transport).

a) If gas is being purchased in Ontario in January of 2014without transport, please indicate where it is being purchased and why.

Enbridge provides the following response:

As previously mentioned the Company expects to fully utilize its contracted long haul capacity in the month of January 2014. The Company has also called on its Peaking Service contracts for gas to be delivered directly to the franchise area and requested curtailment from its interruptible customers because of the colder than normal weather.

Witnesses: J. Denomy
D. Small

The Company has also purchased additional gas at Dawn to supplement storage withdrawals in order to satisfy demand.

The 2014 budgeted forecast of Dawn purchases can be found in response to question #2 above.

Witnesses: J. Denomy
D. Small

UNDERTAKING TCU3.3

UNDERTAKING

Technical Conference TR 3, page 13

EGDI to clarify whether the GTA Variance Account will be cleared/addressed during the IR term, or instead not until the end of the IR term.

RESPONSE

The Greater Toronto Area Project Variance Account ("GTAPVA") will be cleared/addressed after each of the fiscal 2015 through 2018 years. The project is forecast to be in service in late 2015, and therefore the Company's forecast of Allowed Revenues for each of 2015 through 2018 includes GTA project impacts. At the end of each of those years, any variance between the project's forecast Allowed Revenue incorporated into that year's rates, and the eventual actual Allowed Revenue, will be recorded in that year's GTAPVA. After each fiscal year, the Company will file an application setting out its proposal for the clearance of amounts recorded in the prior year's Board Approved deferral and variance accounts.

Witness: R. Small

UNDERTAKING TCU3.4

UNDERTAKING

Technical Conference TR 3, pages 18 and 21

(PART A): EGDI to provide exhibit references to show the lumpiness of EGDI's capital spending requirements during the IR term.

(PART B): EGDI to identify references to existing interrogatories and exhibits that lay out both the firm and variable amounts of capital spending, and to sum up the firm and variable amounts.

RESPONSE

PART A:

The largest drivers of "lumpiness" in Enbridge's capital requirements over the forecast period are the GTA and Ottawa reinforcement projects, and the WAMS project. Of the core capital, however, there are additional drivers of lumpiness, which are outlined in Exhibit B2, Tab 1, Schedule 1, paragraphs 75 to 89. In particular, the variability caused by system integrity and reliability programs, as well as externally initiated projects like relocations are key drivers. Exhibit I.A1.EGDI.SEC.11 Attachment 1, "Continuity of Draft Capital Budget Details from Review 1 to Review 6" provides some detailed examples to illustrate some of these drivers.

There are several line items in the table that demonstrate how the Company went about its capital review. Lumpiness was largely stripped out of the spending requirements, as a result of certain costs being deemed variable costs. The significant line items are:

Line Item	Potential Lumpiness	Subject to Variance Acct 2017 / 2018
AMP Fitting Replacement	If the replacement program in evidence does not sufficiently address the Company's need to get in front of the failure curve, the program may need to ramped up	N
ILI for Pipelines over 20% SMYS	Newly inspected pipelines may require immediate pressure reduction and / or replacement	Y

Witnesses: J. Sanders
P. Squires

Low Pressure Delivery Meter Set Program	Currently a study. Should a program be warranted, it may be costly.	N
Plastic Mains (incl Services) Study	Currently a study. Study may result in the need for immediate pressure reduction and/or replacement	Y
Relays	Failing components may necessitate accelerated relays	N
Sombra Tecumseh Redundancy	The need for a minimum 30% redundancy through Sombra has been identified for Enbridge gas storage which may need to be accelerated based on future operating profiles	N
Verification of MAOP	Newly researched pipelines may require immediate pressure reduction and/or replacement	Y
Horizontal Well Replacement Program	This program will be dependent on future well testing, abandonments and landowner negotiations which may accelerate the need for the horizontal well program.	N

PART B:

The following exhibit documents both the firm and variable costs forecast by the Company for the forecast period 2014 to 2016:

Exhibit B2, Tab 1, Schedule 1, page 34, Table 8 summarizes the firm and variable budget amounts forecast by the Company for each review stage, for each year in the forecast period 2014 to 2016. These amounts are summed in the table below:

Firm and Variable Costs 2014 to 2016 ($ millions) (Review 6 only)				
	2014	2015	2016	Sum 2014 to 2016
Firm	443,817	446,626	441,877	1,332,328
Variable	25,142	63,031	75,937	164,110
Firm Plus Variable	468,959	509,657	517,814	1,496,438

Witnesses: J. Sanders
P. Squires

The following exhibits offer additional views on the firm and variable costs over the forecast period:

- Exhibit B2, Tab 1, Schedule 1, Table 7 (p. 29) – list of System Integrity and Reliability related firm and variable costs

- Exhibit I.B18.EGDI.SEC.93, page 3, Table 2 – listing of Variable or Uncertain Projects/Programs Excluded from the Final Capital

- Exhibit I.B18.EGDI.STAFF.62, page 3, Table 1 – Capital Expenditures: Firm and Variable by Probability. Also lays out and sums the firm and variable amounts of capital spending.

Witnesses: J. Sanders
P. Squires

UNDERTAKING TCU3.5

UNDERTAKING

Technical Conference TR 3, pages 24 and 30

A. Enbridge to provide a table (or graph) of capital expenditures, 2000-2018 showing:

(a) capital expenditures as percentage of depreciation costs;

(b) capital expenditures on a per-customer basis;

B. Enbridge to then provide a similar table of capital expenditures, 2000 to 2018, after removing expenditures related to municipal relocations and the GTA project.

C. Enbridge to provide a list of the agencies that could trigger relocations of Enbridge plant, and the cost-sharing arrangements that apply to each agency.

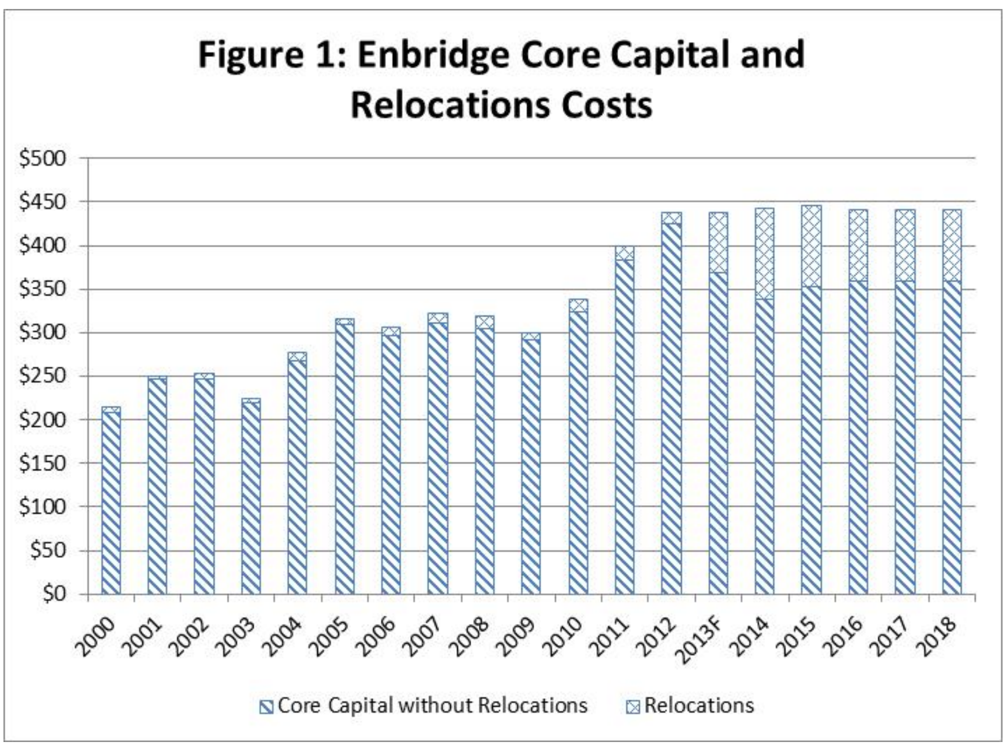
RESPONSE

For Part A (a) see Table 3 and Figure 3, Part A (b) see Table 2 and Figure 2 on the following pages.

For Part B please see Table 1 and Figure 1 on the following page.

Witnesses: P. Squires
T. Teed-Martin

Table 1: Enbridge Core Capital and Relocations			
	Core Capital ($ millions)	Core Capital without Relocations ($ millions)	Relocations Costs ($ millions)
2000	$215	$209	$6
2001	$250	$246	$3
2002	$253	$248	$5
2003	$225	$220	$5
2004	$278	$267	$11
2005	$316	$309	$7
2006	$306	$296	$10
2007	$323	$311	$11
2008	$320	$305	$15
2009	$300	$292	$8
2010	$338	$325	$13
2011	$399	$384	$16
2012	$438	$425	$13
2013F	$439	$369	$69
2014	$444	$338	$106
2015	$447	$352	$94
2016	$442	$359	$83
2017	$442	$359	$83
2018	$442	$359	$83



Witnesses: P. Squires
T. Teed-Martin

Table 2: Enbridge Core Capital and Relocations per Customer Addition						
	Core Capital ($ millions)	Core Capital without Relocations ($ millions)	Relocations Costs ($ millions)	Customer Adds	Core Cap w/o reloc. Per cust add	Relocations costs per cust add
2000	$215	$209	$6	53,676	$3,901	$108
2001	$250	$246	$3	53,688	$4,589	$63
2002	$253	$248	$5	54,649	$4,531	$97
2003	$225	$220	$5	60,473	$3,643	$74
2004	$278	$267	$11	56,485	$4,734	$195
2005	$316	$309	$7	50,697	$6,095	$128
2006	$306	$296	$10	47,622	$6,220	$206
2007	$323	$311	$11	42,920	$7,253	$261
2008	$320	$305	$15	41,052	$7,425	$361
2009	$300	$292	$8	32,089	$9,112	$249
2010	$338	$325	$13	36,902	$8,799	$358
2011	$399	$384	$16	35,657	$10,761	$435
2012	$438	$425	$13	35,971	$11,812	$361
2013F	$439	$369	$69	34,996	$10,553	$1,980
2014	$444	$338	$106	36,647	$9,229	$2,882
2015	$447	$352	$94	38,489	$9,156	$2,447
2016	$442	$359	$83	39,645	$9,065	$2,081
2017	$442	$359	$83	39,645	$9,065	$2,081
2018	$442	$359	$83	39,645	$9,065	$2,081

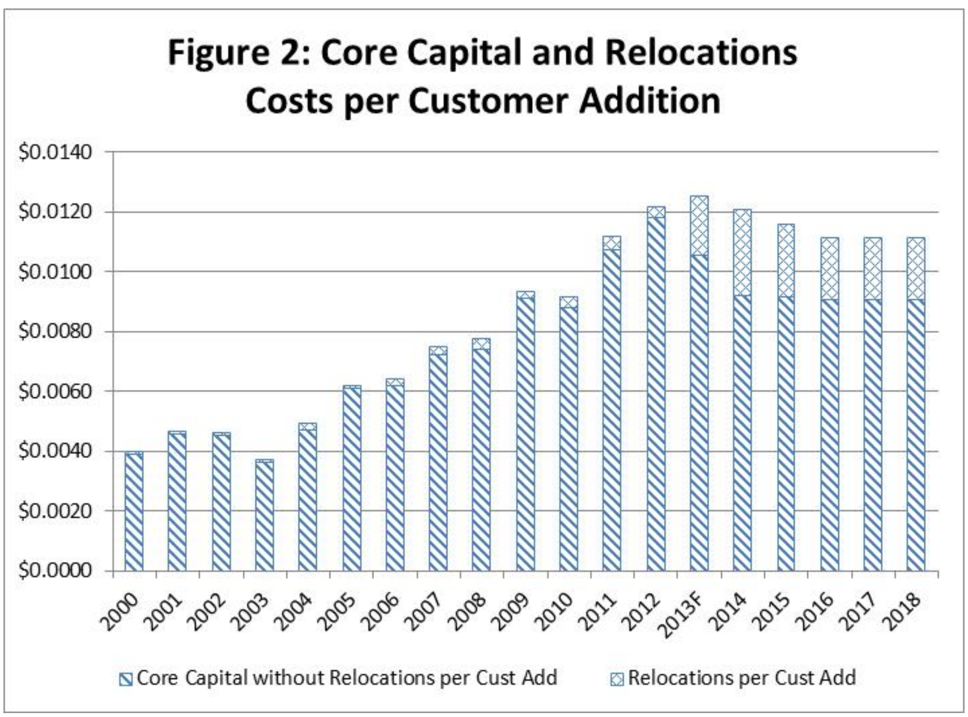
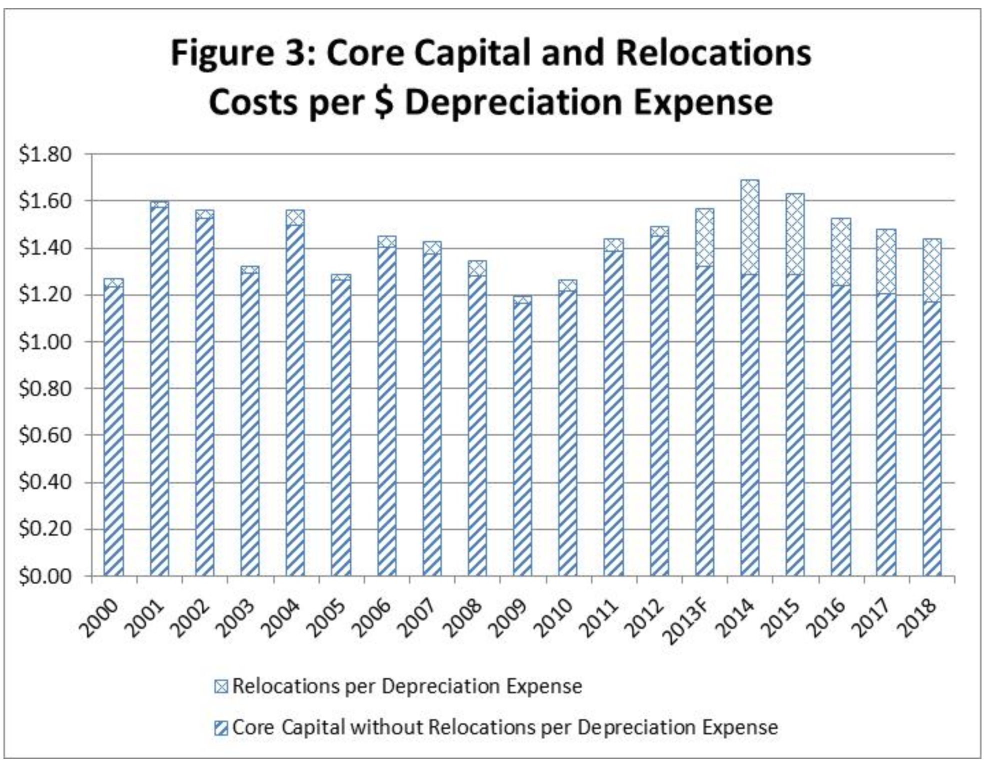


Table 3: Enbridge Core Capital and Relocations per $ Depreciation Expense						
	Core Capital ($ millions)	Core Capital without Relocations ($ millions)	Relocations Costs ($ millions)	Depreciation ($ millions)	Core Cap w/o reloc. Per $ Depreciation	Relocations costs per $ Depreciation
2000	$215	$209	$6	$170	$1.23	$0.034
2001	$250	$246	$3	$156	$1.58	$0.022
2002	$253	$248	$5	$162	$1.53	$0.033
2003	$225	$220	$5	$170	$1.30	$0.026
2004	$278	$267	$11	$178	$1.50	$0.062
2005	$316	$309	$7	$245	$1.26	$0.027
2006	$306	$296	$10	$210	$1.41	$0.047
2007	$323	$311	$11	$226	$1.38	$0.050
2008	$320	$305	$15	$237	$1.29	$0.062
2009	$300	$292	$8	$251	$1.16	$0.032
2010	$338	$325	$13	$267	$1.22	$0.049
2011	$399	$384	$16	$277	$1.39	$0.056
2012	$438	$425	$13	$293	$1.45	$0.044
2013F	$439	$369	$69	$279	$1.32	$0.248
2014	$444	$338	$106	$262	$1.29	$0.403
2015	$447	$352	$94	$274	$1.29	$0.344
2016	$442	$359	$83	$289	$1.24	$0.285
2017	$442	$359	$83	$299	$1.20	$0.276
2018	$442	$359	$83	$307	$1.17	$0.269



Witnesses: P. Squires
T. Teed-Martin

Part C:
Enbridge deals with well over 200 different municipalities and agencies which fall into one of the four cost sharing arrangements described below.

- Public Service Works on Highways Act– 50% labour and labour saving devices
- Franchise – 35%/65%
- 100% re-billable – third party pays 100% of costs
- Non re-billable – Enbridge Gas Distribution Inc. pays 100% of costs

Public Service Works on Highways Act (“PSWHA”) – used in the absence of a franchise agreement or encroachment permit. The Act spells out that the road authority is responsible for 50% of labour and labour saving devices and the utility is responsible for the remainder of all costs. Labour is all costs paid to all workmen up to and including the foreman including wages, travelling time, food, lodging, and transportation to carry out the work. A labour saving device is anything during construction that by exception will cause an increase to labour costs such as a back-hoe.

Franchise Agreement – The model franchise agreement which is used in most municipalities follows a cost sharing mechanism for road improvements instituted by the municipality within the right of way (R.O.W.). All costs are tallied and shared on a 35% municipality and 65% EGD basis.

100% re-billable - If a third party (other than a municipality) is requesting the relocation within the R.O.W., they will pay 100% of the costs.

Non-rebillable – A non-rebillable relocation will occur in instances where, whether due to change in ownership or improper initial installation, EGD plant is discovered to be on private property or it has been discovered that EGD has installed gas main in a location other than that agreed to in the municipal application. A non-rebillable relocation may also occur where EGD has agreed to relocate in the event of future need, through the terms laid out in an encroachment permit, with the agency holding the private ROW.

Witnesses: P. Squires
T. Teed-Martin

UNDERTAKING TCU3.6

UNDERTAKING

Technical Conference TR 3, page 33

(Ref: I.B17.EGDI.FRPO 13) EGDI to make best efforts to advise of the cost consequences of the hypothetical scenario where the costs of LUF gas and base pressure gas are allocated to the regulated and unregulated storage businesses based on their relative percentages of storage space.

RESPONSE

There have been no incremental costs for base gas as a result of the unregulated storage operations. All incremental LUF cost for the unregulated operations are included in the costs allocated to the unregulated operations. The non-utility storage business has been creating a reserve of gas through its unregulated customers, and any cost consequences for that reserve will follow our consistent approach to other cost consequences and allocations related to this business.

Base gas is treated like all other storage assets. If at some point through our analysis of operations it is determined that there is a change in base gas requirements then a similar approach will be used for the allocation any base gas incremental cost.

Witnesses: K. Culbert
J. Denomy
D. Small

UNDERTAKING TCU3.7

UNDERTAKING

Technical Conference TR 3, page 33

(Ref: I.B17.EGDI.FRPO 15) EGDI to make best efforts to advise about the timing of the completion of the study re. migration of gas from the A1 structure, and to advise of how, if there was a determination of migration, any cost consequences would be managed by EGDI.

RESPONSE

The recent study of Enbridge gas storage reservoir and gas inventories has been completed. That study is based, in part, on operational data that has been gathered up to the end of the 2010/2011 storage cycle. Verification of some data is underway.

With the recent installation of new measurement equipment, completed in 2013, and the completion of reservoir models, Enbridge will continue to gather additional operating data over the next several years. In addition, Enbridge in its efforts to better understand its storage pools and gas inventory has been and is in the process of drilling observation wells into identified A1 areas near some of the pools. The drilling of these wells will, first, confirm the existence and extent of those zones and, secondly, will allow the Company to monitor gas pressures in them to see indications of increased gas migration. The overall data gathered through the injection and withdrawal cycles will then be assessed annually to ensure that a conclusion can be drawn and any required next steps can be determined.

At this time Enbridge does not believe there are any specific issues or discrepancies related to the A1 interaction with the working storage volumes and therefore no cost consequences.

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Witness: D. Dalpe

UNDERTAKING TCU3.8

UNDERTAKING

Technical Conference TR 3, page 45

EGDI to identify number of forecast new contract customers by rate class for 2014.

RESPONSE

There are two new contract customers that were not included in the 2014 budget at the time of filing; one is a Rate 100 customer and the other is on Rate 145.

Witness: M. Suarez

UNDERTAKING TCU3.9

UNDERTAKING

Technical Conference TR 3, page 46

EGDI confirm whether, since the time of the filing of this application, it has been in discussions with any new contract customers for 2014 and the respective volumes.

RESPONSE

The Company confirms that it is involved in a number of ongoing discussions with potential customers at this time. The nature of the discussions is quite fluid as there remains much uncertainty around the probability of projects proceeding, whether customers will sign up for Rate 6 or contract rates, when projects will be completed, or what annual volumes would be required.

Witness: M. Suarez

UNDERTAKING TCU3.10

UNDERTAKING

Technical Conference TR 3, page 50

EGDI to confirm whether the customer in EB-2012-0382, Exhibit A, Tab 3, Schedule 2, page 1 of 1 (Durham York Energy Centre), is explicitly included in EGDI's 2014 volumetric forecast.

RESPONSE

Confirmed. The Durham York Energy Center is included in the 2014 forecast and the volumes are captured under Rate 6.

Witness: M. Suarez

UNDERTAKING TCU3.11

UNDERTAKING

Technical Conference TR 3, page 51

EGDI to provide updated version of economic assumptions in Exhibit C2, Tab 1, Schedule 1.

RESPONSE

Please see the updated economic assumptions as reflected in the Q4 2013 Economic Outlook on pages 2 and 3 of this response.

Witness: M. Suarez

KEY ECONOMIC ASSUMPTIONS*

ECONOMIC OUTLOOK: CANADA & U.S.

CALENDAR YEAR	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F
REAL GDP (% CHANGE)									
CANADA	1.0	-3.1	3.2	2.4	1.8	1.7	2.4	2.5	2.4
U.S.	-0.3	-2.8	2.5	1.8	2.8	1.6	2.7	3.3	2.9
CANADA REAL EXPORTS (% CHANGE)	-4.4	-13.0	6.0	4.7	1.7	1.5	4.5	4.5	4.0
CANADA REAL IMPORTS (% CHANGE)	0.8	-12.3	13.5	6.4	3.4	1.3	3.1	3.0	2.6
CANADA HOUSING STARTS (000's)	211.1	149.1	189.9	194.0	214.8	183.0	178.7	182.5	191.8
CANADA UNEMPLOYMENT RATE (%)	6.1	8.3	8.0	7.6	7.4	7.1	6.9	6.4	6.1
CANADA EMPLOYMENT GROWTH (% CHANGE)	1.7	-1.6	1.4	1.6	1.3	1.2	1.3	1.7	1.4
CONSUMER PRICES (% CHANGE)									
CANADA	2.4	0.3	1.8	2.9	1.6	1.1	1.8	2.1	2.1
U.S.	3.8	-0.4	1.7	3.1	2.1	1.6	2.0	2.4	2.4

ECONOMIC OUTLOOK: ONTARIO

CALENDAR YEAR	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F
REAL GDP (% CHANGE)	-0.2	-3.5	3.2	1.8	1.5	1.4	2.3	2.8	2.6
REAL MANUFACTURING OUTPUT (% CHANGE)	-8.9	-15.7	6.5	2.4	2.4	-1.3	2.6	3.2	2.8
HOUSING STARTS (000's)	75.1	50.4	60.4	67.8	76.8	59.1	56.8	60.6	69.5
UNEMPLOYMENT RATE (%)	6.5	9.0	8.6	7.8	7.9	7.6	7.4	6.8	6.2
EMPLOYMENT GROWTH (% CHANGE)	1.5	-2.4	1.6	1.8	0.8	1.3	1.4	1.8	1.7
CONSUMER PRICES (% CHANGE)	2.3	0.4	2.4	3.1	1.4	1.2	1.7	1.9	2.0
RETAIL SALES (% CHANGE)	4.0	-2.2	5.4	3.6	1.6	1.7	3.6	4.0	3.9
WAGE RATE ** (% CHANGE)	1.4	0.1	1.8	2.7	2.3	1.4	2.5	2.8	2.9
REAL RESIDENTIAL NATURAL GAS PRICE (% CHANGE)	1.5	-17.8	-13.2	-11.5	-10.2	5.1	11.6	1.5	1.4
REAL COMMERCIAL NATURAL GAS PRICE (% CHANGE)	1.6	-19.8	-14.5	-12.8	-12.1	6.7	14.2	2.0	1.9

* The forecasts have been updated to reflect the Q4 2013 Economic Outlook.
** The wage rate indicator has been modified to reflect wages and salaries per employee as Statistics Canada has discontinued the original series. The forecast is sourced from a single provider, hence is not a consensus.

ECONOMIC OUTLOOK: REGIONS

Economic Outlook

REGIONS

CALENDAR YEAR	2008	2009	2010	2011	2012	2013	2014F	2015F	2016F
FRANCHISE HOUSING STARTS (000's)	51.1	32.7	38.6	47.9	55.4	38.4	36.8	39.4	45.3
GTA									
HOUSING STARTS (000's)	42.7	25.8	30.6	40.5	48.0	30.8	30.5	32.6	37.3
SINGLES	12.2	8.4	11.8	12.1	11.8	10.5	11.1	11.5	12.9
MULTIPLES	30.5	17.4	18.8	28.5	36.2	20.3	19.4	21.1	24.4
CONSUMER PRICES (% CHANGE)	2.4	0.5	2.5	3.0	1.6	1.3	1.9	1.9	1.9
EMPLOYMENT GROWTH (% CHANGE)	1.8	-1.7	2.1	2.1	0.8	3.4	2.6	2.4	2.4
COMMERCIAL VACANCY RATE (%)	5.4	6.9	7.9	7.0	6.8	7.1	7.1	7.1	7.1
INDUSTRIAL VACANCY RATE (%)	5.9	7.0	6.5	6.1	6.1	6.2	6.2	6.2	6.2
VINTAGE METRO REGION CENTRAL WEATHER ZONE (% CHANGE)	-0.9	-0.9	-1.1	-1.0	-1.0	-1.0	-1.0	-0.9	-0.9
VINTAGE WESTERN REGION CENTRAL WEATHER ZONE (% CHANGE)	-2.1	-2.1	-3.3	-2.9	-2.8	-2.7	-2.7	-2.7	-2.6
VINTAGE CENTRAL REGION CENTRAL WEATHER ZONE (% CHANGE)	-2.7	-2.7	-2.9	-2.0	-1.8	-1.7	-1.7	-1.7	-1.6
VINTAGE NORTHERN REGION CENTRAL WEATHER ZONE (% CHANGE)	-3.1	-3.1	-5.0	-3.8	-3.6	-3.5	-3.5	-3.4	-3.4
CENTRAL HEATING DEGREE DAYS**	2919	2922	2659	2856	2388	2879	2679	2679	2679
EASTERN									
HOUSING STARTS (000's)	7.2	6.0	6.6	6.0	6.2	6.4	5.2	5.6	6.6
SINGLES	3.1	2.6	2.4	2.2	1.7	1.8	2.1	2.2	2.6
MULTIPLES	4.1	3.4	4.2	3.8	4.5	4.6	3.1	3.4	4.0
CONSUMER PRICES (% CHANGE)	2.2	0.6	2.5	3.0	1.4	1.1	2.1	2.1	2.1
EMPLOYMENT GROWTH (% CHANGE)	4.0	-1.4	1.3	0.1	2.5	-0.8	2.2	1.8	1.8
VINTAGE EASTERN WEATHER ZONE (% CHANGE)	-3.1	-3.1	-2.0	-2.6	-2.6	-2.6	-2.6	-2.6	-2.5
EASTERN HEATING DEGREE DAYS **	3458	3526	3092	3261	3160	3501	3275	3275	3275
NIAGARA									
HOUSING STARTS (000's)	1.3	1.0	1.3	1.3	1.2	1.2	1.1	1.1	1.3
SINGLES	0.8	0.7	0.9	0.7	0.7	0.7	0.7	0.7	0.8
MULTIPLES	0.5	0.3	0.4	0.6	0.5	0.5	0.4	0.4	0.5
EMPLOYMENT GROWTH (% CHANGE)	2.9	-6.0	1.8	2.5	2.7	-3.7	1.3	1.1	1.1
VINTAGE NIAGARA WEATHER ZONE (% CHANGE)	-1.1	-1.1	-0.3	-0.9	-0.8	-0.8	-0.8	-0.7	-0.7
NIAGARA HEATING DEGREE DAYS **	2761	2821	2650	2737	2318	2795	2667	2667	2667

* The forecasts have been updated to reflect the Q4 2013 Economic Outlook.
**Balance Point Heating Degree Days are adjusted for billing cycles. The 2014 Degree Day forecasts for all weather zones represent the Company's proposed Degree Day methodologies for 2014-2016 (EB-2012-0459 Exhibit C, Tab 2, Schedule 1). Degree Day forecasts for 2015 and 2016 will be updated.

UNDERTAKING TCU3.12

UNDERTAKING

Technical Conference TR 3, page 53

With reference to Exhibit I.B17.EGDI.FRPO 3, EGDI to identify cost savings generated from new technologies which add efficiency to engineering analysis, and to advise whether those cost savings are in forecasted costs moving forward.

RESPONSE

As outlined in the response to FRPO Interrogatory #3 found at Exhibit I.B17.EGDI.FRPO.3; “The use of these technologies was not intended for cost savings purposes and may actually increase the short term costs associated with the mitigation program as more defects or features are found”, and as reinforced in the transcript for Day 3 of the Technical Conference, held on January 20, 2014, page 53, Lines 11 to 15. There are no cost savings in either O&M or Capital included in the forecasts moving forward.

Witnesses: D. Lapp
L. Lawler
P. Squires

UNDERTAKING TCU3.13

UNDERTAKING

Technical Conference TR 3, page 54

(Ref. Exhibit I.B17.EGDI.FRPO.10) In relation to the third paragraph of the response, which describes the assignment of a new Vice President role accountable for the GTA project, and the creation of a Senior Vice President of Operations role, EGDI to advise as to:

(a) what percentage allocation of the salaries for these would go to capital and to O&M;

(b) what is the quantitative impact of the new positions on the capital and O&M budgets.

RESPONSE

(a) 100% of the salaries referenced in FRPO Interrogatory #10, found at Exhibit I.B17.EGDI.FRPO.10 are O&M expenses.

(b) The 2 new roles referenced result in an increase of 1.8% or $51,717.85 to the O&M budget. There was no impact to FTE's as the new responsibilities were added to existing roles.

Witness: S. Trozzi

UNDERTAKING TCU3.14

UNDERTAKING

Technical Conference TR 3, page 56

With reference to Exhibit I.B17.EGDI.CCC.21, EGDI to add columns 4 and 5 and put in the amounts consistent with 2017 and 2018.

RESPONSE

With respect to the 2017 and 2018 O&M Budget, Customer Care/CIS Service Charges are based on the CC/CIS Settlement Agreement updated with customer numbers; DSM is escalated by 2% inflation rate; Pension and OPEB costs are as per Mercer's reports; and RCAM and Other O&M is inflated by 3.12% based on 2013-2016 average growth rate.

Please refer to the following table for the O&M budgets excluding productivity savings:

Line No.	Categories ($ Millions)	Col. 1 Budget 2014	Col. 2 Budget 2015	Col. 3 Budget 2016	Col 4 Budget 2017	Col 5 Budget 2018
1.	Customer Care/CIS Service Charges	$92.6	$96.5	$100.4	$104.4	$108.5
2.	Demand Side Management ("DSM")	32.2	32.8	33.5	34.2	34.9
3.	Pension and OPEB Costs	37.2	33.8	30.9	28.5	26.2
4.	Regulatory Cost Allocation Methodology("RCAM")	35.3	34.0	33.8	34.8	35.9
5.	Other O&M (Excluding Productivity Savings)	252.1	261.6	276.6	287.8	299.5
6.	Total Net Utility O&M Expense	$449.4	$458.6	$475.1	$489.8	$505.0

The budgeted savings for each year to be included within Line 5 are:

2014: $24.1 million
2015: $30.1 million
2016: $35.6 million
2017: $39.3 million
2018: $43.3 million

Witness: S. Kancharla

UNDERTAKING TCU3.15

UNDERTAKING

Technical Conference TR 3, page 59

With reference to Energy Probe Technical Conference Question 11(a) (Exhibit TC2.2), EGDI to explain the $8.3 million increase in Allowed Revenue resulting from an increase in Rate 1 average use of $27m^3$ and a decrease in Rate 6 average use of $34m^3$.

RESPONSE

a) The increase in Rate 1 average use of $27m^3$ and a decrease in Rate 6 average use of $34m^3$ will result in net volume increase of $45.9\ 10^6m^3$. The higher volume will incur higher gas cost charges of approximately $8.3M. As shown in Exhibit F3, Tab 1, Schedule 1, gas cost is one of the components of the allowed revenues.

The return component on the rate base as a result of the volume change is not included in the calculation since the gas in storage may or may not change due to incremental volume change and the impact is considered immaterial.

b) The revenues at existing rates will increase by approximately $10.8M, therefore the 2014 revenue sufficiency will increase $2.5M resulting from an increase in Rate 1 average use of $27m^3$ and a decrease in Rate 6 average use of $34m^3$.

Witnesses: S. Kancharla
M. Suarez

UNDERTAKING TCU3.16

UNDERTAKING

Technical Conference TR 3, page 66

EGDI to make best efforts to respond to Board Staff questions on site restoration costs, net salvage percentages and asset retirement obligation.

RESPONSE

Please see the following responses:

Preamble

Ref: I.E40.EGDI.STAFF.94

Issue E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

In answer to **Staff's IR#94,** Enbridge stated that the SRC is a fund and that it is considered to be over-funded by an estimated amount of $292 million as of December 31, 2010. The fund will require a significant level of funding over the remaining life of the assets currently in service and that approximately $3 billion of funds will be required for the eventual removal and retirement of the $5.9 billion of assets in service.

In answer to **SEC's IR#120** [I.E39.EGDI.SEC.120], Enbridge stated that the SRC is not a fund. It is disclosed as a liability in EGD's financial statements. For regulatory accounting and rate-making, the liability is grouped with accumulated depreciation.

Technical Conference Question #1

From a regulatory perspective, could Enbridge please clarify which response is correct, and describe what the implications are for this application?

Enbridge provides the following response:

From a regulatory perspective, the response to SEC Interrogatory #120 found at Exhibit I.E39.EGDI.SEC.120 is correct. The amounts collected in tolls related to SRC funding is included in the Company's accumulated depreciation account. The amounts related to the SRC requirements are not separately held or administered in any type of segregated account in any manner different from the amounts included in tolls related to depreciation expense.

However, for financial reporting purposes, an annual calculation is made to determine the amount of SRC funding included in the Company's accumulated depreciation account. The amounts collected related to SRC funding are required to be disclosed separately from the accumulated depreciation account on the Company's financial statements. It is this estimated amount that is referred to in response to the Board Staff Interrogatory #94 found at Exhibit I.E40.EGDI.STAFF.94.

Preamble

Ref: I.E40.EGDI.STAFF.84 & .88

Issue E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

The depreciation rates which included the SRC recovery were approved by the Board in several cases since at least 1959 as stated by Enbridge in reply to **Staff IR#84.**

Accumulated depreciation is not a deferral account; and Staff's understanding is that normally, there would be no true-up on accumulated depreciation.

Technical Conference Question #2

What is the regulatory support for the refund proposal?

Enbridge provides the following response:

It has been the historic practice of Enbridge Gas Distribution (as well as other OEB regulated utilities) to determine depreciation rates on a "Remaining Life" basis. In this procedure the deprecation rate is determined by dividing the actual net book value of an account over the estimated remaining life the account as at the depreciation study date. In this manner, any differences in the required versus actual amounts of accumulated depreciation are dealt with over the remaining life of each account. In essence, with the use of the remaining life basis, the accumulated depreciation true-ups (truing up the difference between the required and actual amounts of accumulated depreciation) are, and have historically been, embedded in the remaining life calculations. In this manner, toll-payers can be assured that over the life of the assets, only the service value of the assets (original cost as adjusted for actual net salvage) is recovered from the toll-payers – nothing more, nothing less. As such, calculation of depreciation rates using the remaining life basis is the most commonly used practice throughout Canadian and North American regulatory jurisdictions.

As discussed in the Net Salvage Study report prepared by Gannett Fleming, starting at Page III-4, (Exhibit D2, Tab 1, Schedule 1), the change in method for determination of the net salvage requirement is considered to be a fundamental change in policy, which requires a more accelerated adjustment to the accumulated depreciation account.
In the view of Gannett Fleming the implementation of the CDNS Approach as recommended in the Gannett Fleming Net Salvage Study report, best meets the combined needs of the Enbridge financial reporting, long standing regulatory precedent for dealing with changes in estimates, and intergenerational fairness to current and future toll payers.

Technical Conference Question #3

Have similar refunds of accumulated depreciation been made in this or other jurisdictions?

Enbridge provides the following response:

As indicated in the response to Technical Conference Question #2, virtually all depreciation rates calculated throughout North America using the Remaining Life Basis have an embedded amount of accumulated depreciation true-up within the depreciation rates. Mr. Kennedy (Gannett Fleming) is also aware of two specific circumstances where a large accumulated depreciation surplus has been refunded to toll-payers in an accelerated fashion.

- In an EMMAX Power Corporation filing before the Alberta Utilities Commission in 2007, a refund of accumulated depreciation surplus was made over a 7 year period as part of a negotiated settlement.
- A 2009 Florida Power and Light Proceeding the Florida Public Utilities Commission ordered an accelerated refunded of the accumulated depreciation surplus over the rate application test period.

Mr. Kennedy also notes that the issue of truing up accumulated depreciation variances has been a topic of debate in a number of other recent U.S. proceedings. While Mr. Kennedy was not directly involved in the proceedings, it is noted that these proceedings have resulted in a variety of Regulatory Orders that have resulted in accelerated true-ups of the accumulated depreciation variances.

Witnesses: R. Small
B. Yuzwa
L. Kennedy - Gannett Fleming

Technical Conference Question #4

Why does Enbridge believe that there should be a true-up on accumulated depreciation for the SRC?

Enbridge provides the following response:

A long accepted regulatory compact has dictated that a regulated utility should be provided with a reasonable opportunity to recover the service value of assets consumed while the asset is in utility service. As such it is important that over the estimated life of an asset (or group of assets) that the service value of the assets – nothing more or nothing less – should be recovered from the toll-payer. The only way in which this regulatory compact can be adhered to is to ensure that the depreciation rate calculations can deal with any variances between the required and actual accumulated depreciation balances. As the SRC is a critical component of the overall depreciation expense (and accumulated depreciation balances) any variances between the actual and required levels of SRC need to be trued-up.

As indicated in response to Technical Conference Question #2, in the circumstances of Enbridge and other OEB regulated utilities, this true-up has been embedded in the remaining life depreciation rate calculations. However, in the specific circumstances of this proceeding it is noted that a significant level of the variance between the required and actual accumulated depreciation balances is caused by the change in Company policy to determine the net salvage requirements using the CDNS method. Therefore an accelerated true-up of the imbalance caused by the change in accounting policy is reasonable.

Technical Conference Question #5

Does the proposed refund not create intergenerational inequity, whether it is $300 million or $900 million, given that Enbridge has been collecting SRC in depreciation rates since at least 1959? Please discuss with reference to the assumed threshold at which inequity begins.

Enbridge provides the following response:

Variances between required and actual accumulated depreciation balances can be caused by a number of factors, including:

- Changes in the estimated average serive life
- Changes in the estimated net salvage percentage requirement

Witnesses: R. Small
B. Yuzwa
L. Kennedy - Gannett Fleming

- Variances in the actual costs of retirement from the amounts anticipated in the depreciation rate calculations
- Actual retirement of assets either prior to or a an age beyond the estimated average service life indications
- Changes in the use of the asset
- Changes in accounting policy (such as the change to the CDNS method)

Each of the above causes result in an accumulated depreciation variance. It is generally considered by Depreciation Professionals that when the actual booked accumulated depreciation balance is within +/- 5% of the calculated required accumulated depreciation balance, that the accumulated depreciation account is in balance. However, when the booked accumulated depreciation balance is not within the +/- 5% threshold, corrective action should be taken. The corrective action is usually embedded in the calculation of the depreciation rate through the use of the remaining life method. However the specific booking of a true-up amount is also commonly used.

The overall goal of truing up the accumulated depreciation account is to (1) minimize any generational inequities; and (2) to provide reasonable assurance that the service value of the assets is recovered over the life of the asset (or group of assets) being depreciated. In the circumstances of this proceeding, the proposed refund caused by the change in method of determination of the required net salvage percentages will minimize any generation inequity after the conclusion of the five year refund period. Gannett Fleming notes that through completion of periodic depreciation studies which include the review of the depreciation parameters and include the recalculation of depreciation rates, the potential for generational inequities will be minimized.

Preamble

Ref: I.E40.EGDI.STAFF.96 & .97

Staff asked a question about the future benefits of a return on a higher rate base. Enbridge replied with a table showing ROE but not the return on rate base which would include the debt component as well.

Technical Conference Question #6

Could Enbridge please update the tables to show the projected incremental return on rate base?

Witnesses: R. Small
B. Yuzwa
L. Kennedy - Gannett Fleming

Enbridge provides the following response:

The tables provided in response to Board Staff Interrogatory Responses #96 and 96 found at Exhibits I.E40.EGDI.STAFF.96 and 97 have been updated below to show the incremental cost of capital, or required return on rate base, that results from the proposed site restoration cost changes. The Company notes that it does not view the entire incremental cost of capital as a benefit. In the Company's view, the benefit would be limited to the incremental return on equity component of the incremental cost of capital, as was presented in the original interrogatory responses.

Line No.	($ Millions)	Col. 1 2014 EGD Total	Col. 2 2015 EGD Total	Col. 3 2016 EGD Total	Col. 4 2017 EGD Total	Col. 5 2018 EGD Total
	As Filed					
1.	Rate base	4,431.6	4,797.6	5,524.4	5,736.6	5,906.1
2.	Required rate of return as filed	6.74%	6.90%	7.02%	7.04%	7.11%
3.	Cost of capital as filed	298.9	330.8	387.6	403.8	419.9
	Excluding SRC Adjustment Impacts as per I.A16.EGDI.EP11					
4.	Rate base excluding the impact of SRC adj.	4,377.0	4,647.2	5,280.1	5,400.4	5,499.5
5.	Required rate of return excluding the impact of SRC adj.	6.77%	6.94%	7.08%	7.08%	7.15%
6.	Cost of capital excluding the impact of SRC adj.	296.5	322.7	373.6	382.3	393.2
7.	Incremental cost of capital due to SRC adj. proposal	2.4	8.1	14.0	21.5	26.7

	Incremental Cost of Capital ($Millions)	Ratepayers' Credit ($Millions)
2014	2.4	74.7
2015	8.1	69.7
2016	14.0	64.7
2017	21.5	59.7
2018	26.7	24.0
Total	72.7	292.8

Witnesses: R. Small
B. Yuzwa
L. Kennedy - Gannett Fleming

UNDERTAKING TCU3.17

UNDERTAKING

Technical Conference TR 3, page 68

EGDI to respond to Board Staff questions on Pension and OPEB Costs, Exhibit No. TC3.4

RESPONSE

Please see the following responses.

BOARD STAFF WRITTEN QUESTION #1

Ref: Pension & OPEB Costs

Please provide updated actuarial valuations (one for financial reporting purposes – accrual basis and one for funding purposes as reported to FSCO) at December 31, 2013 with new actuarial assumptions and actual experience. The valuations should include a revised discount rate since government bond yields have increased almost 100 basis points over the past year and higher asset returns given the strong equity markets over the past year.

Please update the 2014 to 2018 pension and OPEB costs in EGD's evidence reflecting the updated actuarial valuation.

RESPONSE

The actuarial valuation for funding purposes and actuarial valuation for financial reporting purposes at December 31, 2013 are expected to be completed by April 2014 and the end of January 2014, respectively, and therefore are not available at this time.

Enbridge Gas Distribution Inc. ("EGD") does not plan to update the 2014 to 2018 pension and OPEB costs, as EGD has requested continuance of the Post Retirement True-Up ("PTUVA") from 2014 to 2018 to capture any difference between the amount included within Allowed Revenue and the actual costs determined by Mercer (Canada) Limited. Further, the pension and OPEB costs for 2015 to 2018 will be updated within the Rate Adjustment proceedings for each of those years, to minimize the impact within the PTUVA for those years.

Witnesses: J. Shem
R. Small
B. Yuzwa

BOARD STAFF WRITTEN QUESTION #2

Ref: Pension & OPEB Costs

Provide a rough estimate of 2014 pension costs, using management's assumptions, if employees contribute 50% towards the cost.

RESPONSE

If employees contributed to the pension plan, the estimated reduction in EGD's pension costs would be roughly $9.3 million.

This estimate is provided for information purposes only. EGD will not be introducing employee contributions as it would negatively impact our total compensation philosophy of positioning ourselves at the 50th percentile of the market in which EGD competes for talent. In order to maintain EGD's market competitiveness and philosophy, other components of the total compensation package would need to increase resulting in no change to EGD's overall compensation costs. In addition, the administration to support two different pension plans would increase resulting in additional costs to Enbridge.

BOARD STAFF WRITTEN QUESTION #3

Ref: Pension & OPEB Costs

As per Exhibit A2, Tab 1, Schedule 1, Page 5, updated December 11, 2013, EGD plans to update the approved Allowed Revenue amounts for the years 2015 through 2018 to include recent forecasts of amounts related to Pension and OPEB.

Please explain why EGD is requesting continuance of the 2013 PTUVA from 2014 to 2018, instead of just for 2014, in light of the fact that pension and OPEB costs will be updated every year from 2015 through 2018.

RESPONSE

EGD's proposal is to update the Allowed Revenue amounts for 2015 to 2018, in the annual rate applications to include the most recent forecast for pension and OPEB costs into rates. Each year the PTUVA will then be used to record the variance between the actual pension and OPEB costs and the forecast included in rates, to ensure ratepayers only pay actual costs. This adheres to the settlement of issues D1 in the EB-2011-0354 proceeding.

Witnesses: J. Shem
R. Small
B. Yuzwa

BOARD STAFF WRITTEN QUESTION #4

Ref: Pension & OPEB Costs

Board Staff has prepared the following Table 1 from EGD’s 2005-2012 audited financial statements and data from EB-2011-0354 and current proceedings.

Table 1

Enbridge Gas Distribution Inc.
Pension & OPEB Costs 2005-2014

($ millions)	2005 CGAAP	2006 CGAAP	2007 CGAAP *	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 CGAAP	2011 US GAAP	2012 US GAAP	2013 USGAAP Actual	2013 USGAAP Board Approved	Reference	2014 USGAAP Budget	Reference
	As per audited financial statements													
Defined Benefit Pension Net Periodic Benefit Cost	- 21.4	- 21.7	- 21.9	- 26.8	- 7.5	- 6.0	- 5.0	21.0	40.0		37.3	EB-2011-0354	30.0	D1-16-1-1
Defined Contribution Pension Net Periodic Benefit Cost	-	-	-	1.3	1.2	2.0	1.0	1.0	1.0		-	Settlement	-	
OPEB Net Periodic Benefit Cost	9.0	10.9	11.2	11.1	9.9	9.0	9.0	6.0	6.0		5.5	Agreement	5.9	D1-16-1-1
Total	- 12.4	- 10.8	- 10.7	- 14.4	3.6	5.0	5.0	28.0	47.0		42.8		35.9	
													37.2	→ D1-3-1
											Unaccounted for Difference		1.3	

* 2007 financial year restated in 2008 audited financial statements

a) Please confirm that the data in the table is correct. If the data is not correct, please update and provide an explanation.

b) Please provide the 2013 audited pension and OPEB costs in the grey shaded area of the table. If the audited costs are not available, please provide unaudited numbers.

c) Please provide an explanation of the increase in pension and OPEB costs from a negative expense or surplus position of -$12.4 million in 2005 through an expense position in 2014 of $37.2 million.

d) Please explain the unaccounted difference of $1.3 million in the 2014 Budget of Pension & OPEB costs, as outlined in the table above comparing the evidence in D1-16-1-1 and D1-3-1.

e) Please describe any specific actions that EGD has taken to ensure prudent management of its pension and OPEB costs and provide necessary evidence. Please factor into EGD’s response that fact these costs have been recovered from ratepayers over the past number of years and are now being trued-up through the variance account starting January 1, 2013.

Witnesses: J. Shem
R. Small
B. Yuzwa

RESPONSE

a) Yes, the data in the table is correct for the consolidated results of EGD, which also include a wholly owned subsidiary, St. Lawrence Gas Company, Inc.

b) The audited consolidated 2013 pension and OPEB costs are not yet available.

c) The increase in pension costs from 2005 to 2014 is mainly a result of the expiration of the transitional asset, the growth in employee population, and the significant decrease in discount rates. The decrease in OPEB costs from 2005 to 2014 is mainly a result of the expiration of the transitional obligation.

d) The unaccounted for difference of $1.3 million in Table 1 is due to pension costs that is attributable to EGD from its parent company, Enbridge Inc., which costs relate to current EGD employees who are eligible for a supplementary pension plan.

e) The plan is overseen by the Pension Administration Group at EGD, under the direction of the Pension Committee at Enbridge Inc. The pension fund investments are managed by various third party investment managers. The pension committees meet on a quarterly basis to review the performance of the pension plan.

Witnesses: J. Shem
R. Small
B. Yuzwa

UNDERTAKING TCU3.18

UNDERTAKING

Technical Conference TR 3, page 75

For each of six- and eight-inch pipe segments, EGDI to provide the average peak load in each of the extra high-pressure segments, then add the Rate 125 load, and advise what the minimum pipe size is to provide service to both.

RESPONSE

A 6 inch diameter (NPS 6) XHP pipeline would be sufficient to serve a Rate 125 customer, as well as, other customers on the distribution system. Average peak flows across all 6 inch and 8 inch diameter (NPS 6 and NPS 8) XHP pipeline segments are 6.3 and 15.0 10^3 m^3/hr., respectively. The addition of a Rate 125 customer to these average flows could be accommodated on 6 inch and 8 inch diameter (NPS 6 and NPS 8) XHP pipelines without exceeding acceptable velocities. Note that Rate 125 customers may be considerably larger than the minimum eligibility requirement for Rate 125. In such cases, the existing system may not be sufficient to attach a Rate 125 customer without reinforcement. The design considerations for the reinforcement project would be a function of the customer’s contract parameters, geographic location (i.e., within the integrated network pressures can vary from location to location), environmental, and pipeline route considerations. Should reinforcement of the XHP system be needed to attach Rate 125 customer (either alone or in tandem with other loads), then once the XHP pipeline is put into service the associated annualized costs (i.e., the associated annual revenue requirement) will be recovered in the test year across all customer classes applying the Board approved cost allocation and rate design methodology. The cost of the XHP system is recovered from all customer classes based on the Delivery Demand TP allocator. For example, based on the 2014 Delivery Demand TP allocator, Rate 125 would be allocated approximately 8.6% of the reinforcement pipeline revenue requirement (this approach is also discussed in responses to APPrO Interrogatory Response #11, 13 and 14, found at Exhibits I.C30.EGDI.APPrO. 11, 13 and 14).

Witness: E. Naczynski

UNDERTAKING TCU3.19

UNDERTAKING

Technical Conference TR 3, page 78

With reference to I.C30.EGD.APPrO.6c(iii) and (iv), EGDI to compute on a hypothetical basis, the rate impact for Rate 125 of excluding six-inch pipe and eight-inch pipe.

RESPONSE

On a hypothetical basis, the table below summarizes the impact of not allocating costs associated with XHP mains of 4 inch, 6 inch, and 8 inch diameters and below to Rate 125 customers for each year in the 2014 to 2018 period.

Table 1

Capacity TP Allocated to Rate 125

	As Proposed ($millions)	**Excluding < 4 inch ($millions)**	**Excluding < 6 inch ($millions)**	**Excluding < 8 inch ($millions)**
	Col. 1	Col. 2	Col. 3	Col. 4
2014	9.96	9.02	8.29	7.37
2015	10.53	9.55	8.79	7.83
2016	13.15	12.13	11.32	10.32
2017	13.65	12.56	11.71	10.65
2018	14.20	13.05	12.15	11.01

The original response to APPrO Interrogatory #30 found at Exhibit I.C.30.EGD.APPRO.6 C (iv) depicted the allocated costs to Rate 125 associated with the XHP mains as proposed by the Company and an example assuming 4 inch pipe diameter was excluded. This interrogatory response excluded the impact of the GTA project associated with XHP mains as the GTA project is proposed to be treated as a stand-alone item and is not included in the Capacity TP account. In order to depict the annual rate impact to Rate 125, the cost of the GTA project allocated to Rate 125 must be included and is therefore included in Table 1 of this undertaking response.

The table below summarizes the Rate 125 annual rate impacts which would occur if the costs associated with the XHP mains of 4 inch, 6 inch, and 8 inch diameters and below were not allocated to the Rate 125 customers. The rate impacts are a function of the

Witness: A. Kacicnik

results of the fully allocated cost study and the application of the rate design principles and objectives which were used to develop the Company's proposed Rate 125 as depicted in Column 1.

Table 2

Rate Impact Rate 125

	As Proposed	**Excluding < 4 inch**	**Excluding < 6 inch**	**Excluding < 8 inch**
	Col. 1	Col. 2	Col. 3	Col. 4
2014	-0.9%	-9.6%	-16.4%	-24.9%
2015	2.1%	2.1%	2.0%	1.8%
2016	10.0%	10.0%	10.0%	10.0%
2017	9.9%	9.9%	9.9%	9.9%
2018	9.9%	9.9%	9.9%	9.9%

The Company notes that this approach would also affect the level of site restoration costs refund to be allocated to Rate 125 customers. For example, the impact on the 2014 level of the Rate 125 refund is depicted below.

Site Restoration Cost Refund Allocated to Rate 125

	As Proposed ($thousand)	**Excluding < 4 inch ($thousand)**	**Excluding < 6 inch ($thousand)**	**Excluding < 8 inch ($thousand)**
2014	759	659	581	479

Witness: A. Kacicnik

UNDERTAKING TCU3.20

UNDERTAKING

Technical Conference TR 3, page 91

EGDI to make best efforts to estimate a range of amounts that may be cleared in the existing and proposed deferral and variance accounts for each year of the IR term.

RESPONSE

EGD is unable to estimate a range of amounts that may be cleared in the existing and proposed deferral and variance accounts for each year of the IR term.

Each of the accounts proposed for deferral and variance treatment are subject to wide and often erratic influences. The Company is not in a position within the timeframes given to reasonably assess the factors that may impact these accounts, and ultimately what the financial outcomes of them might be.

By definition, the expected amounts related to deferral and variance accounts are $0 going forward. That is, if a cost amount could reasonably be forecast, then the forecast would be included within the appropriate budget.

The only account the Company knows with certainty is the $4.4M annually to be cleared through the TIACDA.

Witness: R. Small