BOARD STAFF INTERROGATORY #1

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T1/S1/

Please outline the benefits to the utility's ratepayers under the proposed approach to ratemaking. What is the utility "incented" to achieve under the customized incentive ratemaking approach?

RESPONSE

The Customized IR plan is a framework used to establish Allowed Revenue. The plan itemizes planned capital expenditures and embeds productivity in a variety of ways to establish the Allowed Revenue. With the Allowed Revenue established and pre-set, the Customized IR plan effectively becomes a Revenue Cap. As described in the pre-filed evidence at Exhibit A2, Tab 1, Schedule 1, page 13, paragraph 30.

> The result is that the Company is "at risk" for costs over the projected Allowed Revenue amounts and is incented to manage costs within that level, as there is no sharing for cost overruns. Unlike an annual Cost of Service ("COS") approach, this will create fixed Allow Revenue amounts that are decoupled from actual costs over the IR plan term. The Company will not have recourse to request rate relief over the plan term absent a 300 basis point shortfall against allowed ROE which is unfound in COS regulation.

As a result, the Company is incented to manage its costs effectively, and to strive for further productivity enhancements, if available. This is discussed at Exhibit A2, Tab 1, Schedule 2. At the same time, the Performance Measurement framework (discussed at Exhibit A2, Tab 11, Schedules 1 and 2) will increase transparency and accountability. The Performance Measurement framework will provide visibility into the Company's efforts in implementing sustainable productivity initiatives and an effective mechanism to communicate performance and outcomes over the IR term.

London Economics International LLC ("LEI") summed this up at pages 4 to 5 of their report (Exhibit A2, Tab 10, Schedule 1):

Witnesses: R. Fischer
M. Lister

LEI finds that Enbridge's proposed Customized IR plan is compelling and in particular is designed to deliver successful results against the following objectives:

- *protecting consumers in respect of price and reliability* – by design of allowed revenue amounts with strong built-in productivity measures directed by Enbridge's Executive Management Team, customers will not be exposed to any higher rates than dictated by the allowed revenue amounts and ongoing historical approach to adjusting revenue for changes in volumes. The method for establishing the allowed revenue amounts is also better suited for smoothing the rate impact of capital investments between rebasing reviews. In consideration of Enbridge's application, this "bill impact" protection will be critical to support rate stability in light of expected large scale investments in projects to improve gas network reliability (notably GTA and Ottawa projects).[2] Furthermore, the earnings sharing mechanism ("ESM") will provide additional protections for customers to ensure that Enbridge is delivering on the efficient capital spending included in the forecast fixed revenue amounts. The allowed revenue amounts will also support Enbridge's investment in strengthening network integrity and safety for the benefit of customers;

- *encouraging efficient utilities* – the embedded productivity measures will provide strong incentives for Enbridge to manage total costs of operation. Furthermore, Enbridge is accepting the risks in more than $160 million of variable capex costs which creates additional strong incentives for Enbridge to manage its cost performance within the term of the plan as it will need to fund any over-expenditure within its allowed revenue amount. Enbridge's supporting evidence, see Exhibit D1, Tab 3, Schedule 1, clearly demonstrates that Enbridge has embedded strong productivity improvements within forecasted Other O&M costs, the subject of the Customized IR plan, as these will continue to decline in real terms over the ratemaking period even while customer numbers increase;

- *quality of service* – the performance measures that Enbridge is proposing under the Customized IR plan provide clear service benchmarks which Enbridge must achieve; and

[2] It should also be noted, based on Enbridge's ongoing application for the GTA, there will be bill impact protection from projected reduction in gas costs once the GTA project is completed, as well as the return of part of the site restoration to the cost reserve.

- *industry financial viability* – as part of the allowed revenue amount under the Customized IR plan, Enbridge has included a forecast of the allowed rate of return, alongside other critical assumptions such as the schedule of capital investments, customer and volume forecast, productivity improvements in operations, and general inflation. This implies that Enbridge will have an opportunity to earn a fair return on its investments and appropriately recover capex, but only if it indeed can deliver on the productivity and operating cost budgets it has forecast alongside the capital investment requirements. The theory of applying a traditional price cap using a generic Total Factor Productivity ("TFP") based X factor falls apart under such non-steady state conditions, as the Board has recognized in its regulatory guidelines for electricity distribution utilities and Ontario Power Generation. Enbridge's proposal for a Customized IR plan combats this shortcoming of the TFP approach.

Enbridge's ratepayers benefit from Allowed Revenue which has embedded productivity, resulting in lower cost recovery through rates than what would be the case in an annual test year cost of service application. Further, the inclusion of the Earnings Sharing Mechanism and Sustainable Efficiency Incentive Mechanism not only incents Enbridge to find further efficiencies, but results in a sharing of those efficiencies in a sustainable manner, with a possibility for even lower rates, not only during the IR term but beyond the end of the IR term as well.

Witnesses: R. Fischer
M. Lister

BOARD STAFF INTERROGATORY #2

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T1/S2/para 41

The Company's evidence speaks to how the proposed IR plan is effectively a revenue cap that is decoupled from costs over the term of the plan and that EGD is taking the risk that it will be able to manage within that revenue cap.

How is this concept different than a cost of service model where revenues are set on a prospective test year basis and the utility is at risk to manage actual costs within that revenue allowance?

RESPONSE

Please see response to SEC Interrogatory #4, found at Exhibit I.A1.EGDI.SEC.4.

Witnesses: R. Fischer
S. Kancharla
M. Lister

BOARD STAFF INTERROGATORY #3

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T1/S3/para 13

The evidence speaks about the Fair Return Standard and the utility's expectations of entitlements to certain financial returns.

a) Under incentive regulation, which contemplates allowed revenues being disconnected from cost of service-based revenues, please explain why the Fair Return Standard is relevant.

b) Please comment on whether the Board's stated objectives for incentive regulation include meeting a Fair Return Standard.

c) Does the utility believe that the Fair Return Standard is applicable in any context other than in establishing appropriate regulated cost of capital guidance?

RESPONSE

a) The Board addressed the application of the Fair Return Standard ("FRS") in 2009 in a consultative process on cost of capital and recognized that the standard was composed of three prongs – comparability, financial integrity and capital attraction. The Board further recognized that the application of the standard was not optional, but is a legal requirement that must be met both individually and in totality.[1] Within the Cost of Capital Report, the Board noted that the cost of capital (which must meet the FRS) is one input into the setting of rates.[2]

Enbridge's position is that requirements of the FRS apply equally whether rates are determined on a forward year test year basis in a cost of service application or a multi-year incentive regulation framework such as the proposed Customized IR plan. Any ratemaking model must be designed so as to allow the utility opportunity to earn a reasonable fair return.

[1] Ontario Energy Board, EB-2009-0084, *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (December 11, 2009) at (i).
[2] *Ibid*., at p. 15.

Witnesses: R. Fischer
S. Kancharla
M. Lister

The Board has recognized the importance of a utility being able to earn a fair return as being an important goal to be fostered. This is seen, for example, within a document titled ‘Energy Sector Regulation – A Brief Overview’ posted on the OEB website on the page titled “About the OEB: What We Do”. In that document, the Board states that:

> Utilities are well served if they are financially viable businesses. Utilities must have a reasonable opportunity to recoup costs and earn a fair return for the significant financial investment they make in order to supply and deliver energy to consumers.[3]

This principle applies equally whether a utility is under cost of service or IR regulation.

b) Yes, the Board’s objectives for IR for gas utilities do include meeting a FRS. The Board’s IR objectives are set out within the final 2005 Report of the Natural Gas Forum. In the NGF Report, the Board found that:

> …a multi-year incentive regulation (IR) plan can be developed that will meet its (the Board’s) criteria for an effective ratemaking framework: sustainable gains in efficiency, appropriate quality of service and an attractive investment environment…The Board will establish the key parameters that will underpin the IR framework to ensure that its criteria are met and that all stakeholders have the same expectations of the plan.[4]

The criterion stated above relating to ensuring ‘an attractive investment environment’ is entirely consistent with the expectation of the FRS, which is that a utility will earn a return on capital equivalent to the return that investors require to keep their capital invested and to invest new capital in the utility.[5] Therefore, it is Enbridge’s position that the FRS is incorporated in the Board’s stated objectives for incentive regulation.

Yes. Enbridge’s position is that the Board is required to ensure that the just and reasonable rates that it sets incorporate a return on capital invested that meets the FRS. The effect is that the Board will meet its objective for IR to create an environment that is conducive to investment, and will meet its statutory objective to facilitate a financially viable gas industry for the transmission, distribution and storage of gas.[6]

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[3] Ontario Energy Board, *Energy Sector Regulation – A Brief Overview* at page 2. (http://www.ontarioenergyboard.ca/OEB/_Documents/Documents/Energy_Sector_Regulation-Overview.pdf)
[4] *Natural Gas Regulation in Ontario: A Renewed Policy Framework,* Report on the Ontario Energy Board Natural Gas Forum, March 20, 2005 (RP-2004-0213), p. 22.
[5] Ontario Energy Board, EB-2009-0084, *Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities* (December 11, 2009) at p. 16
[6] See *OEB Act, 1998*, at s. 2(5).

Witnesses: R. Fischer
S. Kancharla
M. Lister

BOARD STAFF INTERROGATORY #4

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T1/S3/para 23

Please provide the Company's actual and Board-approved annual return on equity for each year during the period 2000 to 2013, including the most recently-available forecast for 2013.

RESPONSE

The information is provided in the table on the following page.

EGD's September 30, 2013 Financial Statements and Management Discussion and Analysis identify the correction of an error, which occurred in Enbridge's recording of costs in 2010 to 2012 and in prior months within 2013. As a result of this error, EGD's Utility Income and ROE results for 2010 to 2012 were overstated. This means that the amount of earnings shared with ratepayers was overstated. Please note, though, that EGD is not seeking an adjustment to the previously Board approved and reported ratepayer earning sharing amounts for 2010 to 2012.

Please see response to SEC Interrogatory #78, found at Exhibit I.B17.EGDI.SEC.78 for further discussion of the accounting error noted above.

Witnesses: R. Fischer
S. Kancharla
M. Lister

Fiscal Year		Board Approved ROE	Before Earnings Sharing Normalized Actual ROE	Before Earnings Sharing Actual ROE	After Earnings Sharing Normalized Actual ROE	After Earnings Sharing Actual ROE
		%	%	%	%	%
2000		9.730%	10.829%	8.229%	(a)	(a)
2001		9.540%	10.029%	10.800%	"	"
2002		9.660%	11.805%	8.982%	"	"
2003		9.690%	9.743%	13.140%	"	"
2004		9.690%	10.828%	12.342%	10.660%	12.165%
2005		9.570%	10.343%	10.343%	(a)	(a)
2006		8.740%	10.343%	7.200%	"	"
2007		8.390%	10.722%	11.639%	"	"
2008		8.660%	10.208%	11.867%	9.936%	11.586%
2009		8.310%	11.203%	12.361%	10.261%	11.422%
2010	(c)	8.370%	11.103%	10.248%	10.241%	9.386%
2011	(c)	7.940%	10.378%	10.433%	9.661%	9.719%
2012	(c)	7.520%	9.275%	7.622%	8.900%	7.244%
2013	(b)	8.930%	-	-	-	-

(a) There was no earnings sharing mechanism in these years, therefore ROE results are the same as in the before earnings sharing columns.

(b) The Company is not in a position to provide an estimate of 2013 results.

(c) These are the previously reported actual and normalized ROE's which have not taken account the impact of the accounting error identified in EGDI's September 30, 2013 Financial results.

Witnesses: R. Fischer
S. Kancharla
M. Lister

BOARD STAFF INTERROGATORY #5

INTERROGATORY

ISSUE: A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T1/S1/P 16 of 40

Enbridge says that its "most significant forecasting challenge has been the uncertainty of safety and integrity spending requirements." In light of the challenges that Enbridge has faced in forecasting its capital spending for safety and integrity requirements:

a) Please explain why Enbridge is proposing to recover these capital expenditures through a Customized IR plan that requires forecasts of these expenditures?

b) Please explain why Enbridge is not using Y factors and/or Z factors, if appropriate, for recovering these capital expenditures?

RESPONSE

a) Please see the response to Board Staff Interrogatory #10, found at Exhibit I.A1.EGDI.STAFF.10 and CCC Interrogatory #3, found at Exhibit I.A1.EGDI.CCC.3.

b) Please see the response to Exhibit I.A1.EGDI.STAFF.10.

Witnesses: R. Fischer
M. Lister

BOARD STAFF INTERROGATORY #6

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T1/S1/P 21 of 40

Enbridge says one of the main factors contributing to increased capital spending requirements is relocation requirements e.g. resulting from the Pan-Am games coming to Toronto in 2015. Enbridge says that "franchise agreements demand that the Company comply with relocation activity as directed by the municipalities."

a) Please explain why Enbridge is not using a Z factor to recover the costs of mandates from municipalities rather than through a Customized IR plan?

b) What is Enbridge's degree of confidence in relation to forecasting municipalities' future relocation demands? Please explain.

RESPONSE

a) Enbridge considers the use of Z-factors as a "non-routine adjustment intended to safeguard customers and the gas utility against unexpected cost increases or cost decreases that are outside of management control". (see Exhibit A2, Tab 4, Schedule 1, p. 1, para. 3). It is not clear that relocations costs would be "unexpected" therefore Enbridge has not relied on Z-factor treatment for such costs. That said if there were material changes to the scope of work expected of Enbridge, then it may need to apply for Z-factor relief, provided the Company can demonstrate to the Board that all of the conditions for Z-factor relief have been met. Enbridge has proposed variance account treatment related to relocations 2017 and 2018 (see Exhibit D1, Tab 8, Schedule 6).

b) For purposes of long range forecasting, Enbridge utilizes historic trends to anticipate future relocation demands. As the period of spend gets closer, forecasting becomes more refined as municipalities define their programs in greater detail, causing the requirement for relocations to be more definitive. The confidence level of the forecast is dependent on the timing and level of detail provided by the municipalities.

Witnesses: R. Fischer
L. Lawler
M. Lister

BOARD STAFF INTERROGATORY #7

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T1/S1/P 27 of 40

Enbridge says that a "traditional" IR plan "is problematic in an environment where capital spending pressures, the associated growth in depreciation expense and other cost elements driven by capital investments more than outweigh the growth in revenue from an I-X formula".

Please confirm that the Board has approved gas IR plans that include Y factors designed to recover the costs of capital investments that would not otherwise be recovered in an "inflation minus X" rate adjustment formula (e.g., Enbridge's 2nd generation IR plan).

RESPONSE

Confirmed.

Witnesses: R. Fischer
M. Lister

BOARD STAFF INTERROGATORY #8

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T1/S2/P 7 of 19

Enbridge says that "many of the project forecast costs within the 2014 to 2016 Capital Budget contain significant uncertainty, and as a result, actual project costs may vary significantly."

Please explain whether the uncertainties (and the associated risks) that actual costs may vary significantly from forecast costs, has impacted Enbridge's rationale in choosing the Customized IR plan as its IR model?

RESPONSE

Cost uncertainty or that actual costs may vary significantly from forecast costs was not a factor that impacted Enbridge's rationale to propose the Customized IR plan.

The Company reviewed a traditional I-X model for its 2nd Generation IR plan against the final budgeted costs, however, there was a significant challenge of adopting that model which is described in evidence contained in Exhibit A2, Tab 1, Schedule 3.

The challenge identified was not that forecast risk and uncertainty could not be accommodated in a traditional I-X model, but rather the conclusion that an I-X of greater than 3.4% (Exhibit A2, Tab 1, Schedule 3, p. 11) is required to afford Enbridge a reasonable opportunity to earn a fair return. Concentric Energy Advisors, Inc. recommended an I-X of only 2.5%, clearly well below that required by Enbridge. The solution was the proposed Customized IR plan which more effectively accommodates the forecast growth in capital needs in an IR framework.

Witnesses: R. Fischer
M. Lister

BOARD STAFF INTERROGATORY #9

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T1/S3/P 9 and 10 and 11 and 13 of 19

In the "Analysis and Interpretation" of Scenarios 1 through 4, please explain why the Company cannot adjust the amounts proposed through the Y factor, or a similar mechanism, to fully recover all of its projected costs over the 2014 – 2018 period.

RESPONSE

Enbridge reviewed the choices for initiatives to be categorized as a Y-Factor and the "Analysis and Interpretation" section reflects those initiatives that Enbridge observes have traditionally qualified and been approved by the Board. The Company, in deciding on which available Incentive Rate Plan model as Y-Factors would best meet the Board's objectives, determined that the Customized IR Plan would be best.

Witnesses: R. Fischer
S. Kancharla
M. Lister

BOARD STAFF INTERROGATORY #10

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: B2/T1/S1/P 25 and 26 of 39

Enbridge says that much of the uncertainty associated with system integrity and reliability spending is due to: 1) the fact that the scope and requirements of these programs will not be known until related studies are completed and there is practical experience with the programs; and 2) the Company anticipates more stringent pipeline integrity management legislation, such as that contemplated in the United States but does not know when this will be implemented.

a) Please explain why Enbridge has forecasted capital expenditures to comply with government mandates that are only being "contemplated" but do not yet exist?

b) Please explain why Enbridge is using a Customized IR plan rather than a Y factor and/or Z factor, if appropriate, as a means of accommodating investment requirements that may, or may not, arise in the future.

RESPONSE

a) Please refer to Exhibit B2, Tab 1, Schedule 1, pages 26 and 27, paragraph 80, which states that "the Company also recognizes that it may not be appropriate to include its uncertain (or potential) costs within the Capital Budget being presented to support its Customized IR application. The solution that was reached was to identify that group of costs for each year, but not include these costs, which are referred to as "variable costs" throughout this document, within the filed 2014 to 2016 Capital Budget."

b) In the pre-filed evidence, Enbridge explains why a model with Y-Factors was ultimately rejected in favour of a Customized IR plan application. This discussion can be found at Exhibit A2, Tab 1, Schedule 3, paragraphs 7 to 9. Specifically, the Company commented:

Witnesses: R. Fischer
L. Lawler
M. Lister
J. Sanders

> EGD's 1st Generation IR model relied on an I-X escalator supplemented with a revenue cap per customer calculator and Y-Factors for specific incremental projects not subject to the revenue escalator. These "add-ons" to the traditional I-X model were designed to recognize the unique needs of the business during the term of the 1st Generation IR relating to funding customer growth and specific incremental projects not included in the 2007 base revenue requirement. These "add-ons" necessarily increased the complexity of the IR model. As the need for capital increases, additional "add-ons" in the form of new Y-Factors or other mechanisms such as capital trackers, would be required to increase the possibility that an I-X framework could work for EGD in the coming years. The inherent complexity of the 1st Generation IR framework would, as a result increase, further straining the applicability of a formula-based model for EGD's 2nd Generation IR term.

This application does contain a Z-Factor component as a means of accommodating investment requirements that may, or may not, arise in the future, provided they qualify under the Z-Factor criteria.

Witnesses: R. Fischer
L. Lawler
M. Lister
J. Sanders

BOARD STAFF INTERROGATORY #11

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: B2/T1/S1/P 27 of 39

Enbridge says that its proposed capital budget has identified a group of "variable costs" that are not included in the budget, with the result that "Enbridge will be at risk for the "variable" costs associated with capital projects".

Please explain how Enbridge will assure the Board that any costs that Enbridge proposes to Z factor were not previously part of the group of "variable costs" that the Company has excluded from its Customized IR plan.

RESPONSE

Enbridge indicated in its Application that, though it is providing a forecast of potential "variable costs", they were not included in the capital budget and Enbridge is taking the risk that the "variable costs" will be incurred and spent during the IR term. As such, the costs do not meet the Z-Factor criteria that the costs be linked to an unexpected cause (See Exhibit A2, Tab 4, Schedule 1, para. 3).

Witnesses: R. Fischer
M. Lister
J. Sanders

BOARD STAFF INTERROGATORY #12

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T9/S1Incentive Ratemaking Report (CEA)/P 21 of 125

Please provide all evidence of which Concentric Energy Advisors is aware that shows that heating degree days is a statistically significant driver of gas distribution costs.

RESPONSE

As explained in Exhibit A2, Tab 9, Schedule 1, page 21, the industry study group companies for Concentric's industry benchmarking and productivity analyses were selected based on criteria that identified companies that are similar to Enbridge, i.e. representative of Enbridge's operating circumstances. Concentric designed a "cold weather" criterion to identify U.S. distribution companies that have construction and operating conditions that are similar to those experienced by Enbridge and that would affect plant and O&M costs.

Specifically, the weather-related construction and operating conditions that Enbridge and other cold-weather gas distribution companies experience include the following:

(a) Cold weather gas distribution companies are restricted to performing non-emergency mains and services construction only during non-winter months when the ground is not frozen and when the cold weather utilities can obtain permits to work in city streets. Because a cold weather gas distribution company's construction work is limited to non-winter months, crews and equipment are underutilized in the winter, which increases the "per unit" costs of construction compared to a warm weather gas distribution company that could spread the work and the fixed costs of the crews and equipment over all 12 months.[1]

(b) It is more difficult, and therefore expensive, for cold weather gas distribution companies to locate and repair leaks in the winter, through the frozen ground

[1] This is also true for the outside construction companies that are hired by cold weather utilities, which cannot keep their construction crews fully utilized throughout the year. Total annual compensation for these construction crews must account for the seasonality of the work, and the training and experience that is required of these crews, to work on underground gas distribution systems.

Witnesses: M. Bartos - Concentric
J. Coyne – Concentric
J. Simpson – Concentric

(c) Cold weather gas distribution company mains and services experience a condition called "frost heave", which causes the ground around a gas distribution company's distribution mains to rise and fall as the moisture in the soil freezes and thaws, which can cause leaks in the mains.

(d) Work-related travel in a cold weather gas distribution company's service territory is affected by winter storms, which results in increased overtime for meter reading, service calls, emergency response, and other related activities.

In addition, gas distribution companies must design and manage their distribution systems to provide reliable, uninterrupted service on a specifically defined extremely cold day, referred to as the "design day." To ensure reliable service, the design day standard for a cold weather gas distribution company is much greater than for a warm weather gas distribution company, for a fixed level of annual deliveries. Thus, the distribution system of a cold weather gas distribution company will have to be constructed with greater hourly and daily capacity with appropriately sized storage and peaking facilities, at greater cost of materials, to allow for greater design day deliveries.

These differences between cold and warm weather gas distribution companies are well understood in the industry, such that construction and operating conditions experienced by cold and warm weather gas distribution companies, for example Enbridge and SDG&E (San Diego Gas and Electric), are fundamentally different, and thus the costs associated with those construction and operating conditions are also fundamentally different.

Concentric developed the "cold weather" criterion to identify cold weather gas distribution companies that have average annual degree days that are within 45% of Enbridge's average annual degree days and that therefore have construction and operating conditions that are similar to those experienced by Enbridge. Concentric is confident that the annual degree day standard is an appropriate proxy for other cold weather variables that directly affect costs but that are not reported such as, (a) design day demand; (b) the number of days that non-emergency construction is prohibited; (c) occurrences of frost heave, (d) the number of days that the ground is frozen, or (e) number of storms that impede travel. However, Concentric does not believe that heating degree days is necessarily statistically correlated with gas distribution costs because these operating circumstances or conditions are a permanent feature of the utility's cost structure and do not vary year to year with heating degree days.

While Concentric is not aware of any study that shows that heating degree days is a statistically significant driver of gas distribution costs, based on the foregoing we are confident that weather conditions are an important distinguishing characteristic of gas distribution costs.

Witnesses: M. Bartos - Concentric
J. Coyne – Concentric
J. Simpson – Concentric

BOARD STAFF INTERROGATORY #13

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T9/S1/Incentive Ratemaking Report (CEA)/P 31 of 125

Concentric Energy Advisors writes that EGD's customer growth rate of 2.6% "is higher than all other companies in the industry study group."

a) Please provide the time period used to calculate the customer growth rate for EGD.

b) Please provide comparable customer growth rates for every other gas distributor in the industry study group, including the customer numbers for each distributor at the beginning and end of the sample period used to calculate customer growth.

RESPONSE

a) The time period 2000 to 2011 was used to calculate the customer growth rate for EGD.

b) The comparable customer growth rates, as well as number of customers at the beginning and end of the sample period used to calculate customer growth for every other gas distributor in the industry study group are shown in the table on the following page:

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

Company Name (State)	2000 Customer Count	2011 Customer Count	2000-2011 Growth Rate
CenterPoint Energy Resources Corp. (MN)	688,513	805,026	1.42%
Consumers Energy Company (MI)	1,594,484	1,707,987	0.63%
Baltimore Gas and Electric Company (MD)	596,644	653,154	0.82%
Laclede Gas Company (MO)	633,151	638,717	0.08%
National Fuel Gas Distribution Corporation (NY)	520,014	517,451	-0.04%
Northern Illinois Gas Company (IL)	1,962,235	2,184,884	0.98%
Columbia Gas of Ohio, Incorporated (OH)	1,365,431	1,396,393	0.20%
Northwest Natural Gas Company (OR,WA)	510,979	676,775	2.55%
Public Service Electric and Gas Company (NJ)	1,621,128	1,779,350	0.85%
Puget Sound Energy, Inc. (WA)	580,292	756,706	2.41%
Questar Gas Company (UT)	680,112	884,455	2.39%
Southern Union Company (MO)	487,304	491,794	0.08%
Public Service Company of Colorado (CO)	1,082,591	1,310,531	1.74%
Ameren Corporation (CILCO,CIPS,IP)	776,005	812,905	0.42%
Consolidated Edison, Inc. (NY)	1,167,055	1,198,027	0.24%
Dominion - East Ohio Gas Company (OH)	1,234,870	1,181,925	-0.40%
DTE Energy Company (MI)	1,219,275	1,230,396	0.08%
Iberdrola, S.A. (NY)	532,418	563,937	0.52%
Integrys Energy Group, Inc. (IL)	989,594	985,819	-0.03%
National Grid (MA)	747,037	857,035	1.25%
National Grid (NY)	2,212,152	2,350,183	0.55%
NiSource Inc. (IN)	755,378	838,311	0.95%
Vectren Corporation (IN)	624,857	673,311	0.68%
Washington Gas Light Company (DC,MD,VA,WV)	879,895	1,091,542	1.96%
Wisconsin Energy Corporation (We Energies) (WI)	943,586	1,064,144	1.09%[1]

[1] There was a formula error in the work paper that produced a slightly different growth rate for Wisconsin Energy Corporation (We Energies) (WI) of 1.17%. This difference is irrelevant to the outcome of the analysis.

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

BOARD STAFF INTERROGATORY #14

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T9/S1/Incentive Ratemaking Report (CEA)/P 58 of 125

Concentric Energy Advisors writes that it "calculated projected capital-related revenue requirements (for Enbridge) based on data provided by the Company."

Please provide all data that Enbridge provided to Concentric Energy Advisors that was used to calculate the Company's projected capital-related revenues requirements over the 2014-2016 period.

RESPONSE

Attached please find all data that Enbridge provided to Concentric Energy Advisors that was used to calculate the Company's projected capital-related revenues requirements over the 2014 to 2016 period.

Witnesses: M. Bartos - Concentric
J. Coyne – Concentric
J. Simpson – Concentric

IMC Threshold	20.0%
$DeprExp_1$	$237,303,000
RB_0	$3,889,484,575
G_2013	1.53%
G_2014	1.69%
G_2015	1.73%
G_2016	1.75%
G_2017	
G_2018	

RB_0 (Rebasing) Work Book

Final Rate Order p 2 of 7	3,945,300,000	Source: Rebasing Rev Rec Support
CIS	(70,500,000)	
rounding	36185	
	3,874,836,185	
Adj to 2013 Accum Depr for SRC	$ 14,648,390	
	3,889,484,575	

Customer Growth Rate Workbook (G_2014, …)
Source: [EGD Utility OM_ 2012 Actuals to 2016 Budget_20130528.xlsx]Unlock Customer

	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Budget 2013	Budget 2014	Budget 2015	Budget 2016
Total Unlock Customers	1,824,789	1,865,020	1,887,605	1,926,294	1,960,378	1,994,903	2,025,462	2,059,619	2,095,302	2,131,887
		2.2047%	1.2110%	2.0496%	1.7694%	1.7611%	1.5319%	1.6864%	1.7325%	1.7460%

Rebasing Depreciation Rate, adjusted for SRC	0.00%

ROR

2014		2015		2016	
	Pre Tax Wtd Cost		Pre Tax Wtd Cost		Pre Tax Wtd Cost
	7.98%		8.19%		8.36%

$ROR_{pretax}^{rebasing}$	8.003%	
$ROR_{aftertax}^{rebasing}$	5.862%	
$Plant^{Rebasing}$	$ 6,622,300,000	tab: Rebasing Rev Req Support

P

Source I-Factor Forecast 4-25-2013.XZLS	2012	2013	2014	2015	2016
TFP I-X	2.38%	2.36%	2.45%	2.45%	2.45%
		2.17%	2.23%	2.23%	2.23%

	2014	2015	2016
Composite Depreciation Rate Excluding SRC	3.58%	3.55%	3.50%

File: Capital component of IR escalation_v1 05 24 13 Rev 06 18 13.xlsx Tab: capital structure

Capital Structure (excl Customer Care CIS)

	2013 ADR	2014	2015	2016	
Rate base excluding CIS	4,091.5	4,384.3	4,752.6	5,492.0	Note on 2013 ADR: Refer to Page 7 of 7 (2013 Utility capital structure) of Rate Order
Medium and Long Term Debt (net)	2,461.9	2,596.9	2,918.4	3,367.0	
Component % of Rate Base	0.6	0.6	0.6	0.6	
Cost Rate	0.1	0.1	0.1	0.1	
Return Component LTD	0.0	0.0	0.0	0.0	
	142.8	144.7	157.3	179.6	
Short Term Debt	56.7	109.0	23.2	47.9	
Component % of Rate Base	0.0	0.0	0.0	0.0	
Cost Rate	0.0	0.0	0.0	0.0	
Return Component STD	0.0	0.0	0.0	0.0	
	$ 1.2	$ 1.8	$ 0.5	$ 1.6	
Preference Shares (net)	100.0	100.0	100.0	100.0	
Component % of Rate Base	0.0	0.0	0.0	0.0	
Cost Rate	0.0	0.0	0.0	0.0	
Return Component Pref Shares	0.0	0.0	0.0	0.0	
	3.3	3.1	3.8	4.4	
Common Equity	1,473.0	1,578.3	1,710.9	1,977.1	
Component % of Rate Base	0.4	0.4	0.4	0.4	
Cost Rate	0.1	0.1	0.1	0.1	
Return Component Common Equity	0.0	0.0	0.0	0.0	
	131.5	146.3	166.3	200.0	
Tax Rate	26.50%	26.50%	26.50%	26.50%	
Pre-tax					
Cost of LT debt	143	145	157	180	
Cost of ST debt	1	2	0	2	
	144	146	158	181	
After tax					
Cost of debt (after tax)	106	108	116	133	
Pref dividend	3	3	4	4	
Return on equity	132	146	166	200	
		0.03			
	241	257	286	338	
ROR after tax	5.882%	5.862%	6.019%	6.148%	
ROR Pre tax	**8.003%**	**7.975%**	**8.188%**	**8.364%**	

BOARD FINAL DECISION
CHANGE IN REVENUE REQUIREMENT
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Interim Rate Order (Note 1) ($Millions)	Col. 2 Final Decision Adjustments	Col. 3 Excl. CIS Board Final Decision ($Millions)	Col. 4 Cust. Care / CIS (Note 2) ($Millions)	Col. 5 Board Final Decision EGD Total ($Millions)
	Cost of capital					
1.	Rate base	4,091.5	-	4,091.5	70.5	4,162.0
2.	Required rate of return	6.85	(0.04)	6.81	6.44	6.80
3.		280.3	(1.7)	278.6	4.6	283.2
	Cost of service					
4.	Gas costs	1,342.8	-	1,342.8	-	1,342.8
5.	Operation and maintenance	325.5	-	325.5	89.4	414.9
6.	Depreciation and amortization	266.6	-	266.6	12.7	279.3
7.	Fixed financing costs	2.3	-	2.3	-	2.3
8.	Debt redemption premium amortization	-	-	-	-	-
9.	Company share of IR agreement tax savings	-	-	-	-	-
10.	Municipal and other taxes	39.3	-	39.3	-	39.3
11.		1,976.5	-	1,976.5	102.1	2,078.6
	Miscellaneous operating and non-operating revenue					
12.	Other operating revenue	(44.3)	-	(44.3)	-	(44.3)
13.	Interest and property rental	-	-	-	-	-
14.	Other income	(0.7)	-	(0.7)	-	(0.7)
15.		(45.0)	-	(45.0)	-	(45.0)
	Income taxes on earnings					
16.	Excluding tax shield	86.4	-	86.4	9.0	95.4
17.	Tax shield provided by interest expense	(38.1)	-	(38.1)	(0.9)	(39.0)
18.		48.3	-	48.3	8.1	56.4
	Taxes on sufficiency / (deficiency)					
19.	Gross sufficiency / (deficiency)	15.0	2.0	17.0	-	17.0
20.	Net sufficiency / (deficiency)	11.0	1.5	12.5	-	12.5
21.		(4.0)	(0.5)	(4.5)	-	(4.5)
22.	**Sub-total revenue requirement**	2,256.1	(2.2)	2,253.9	114.8	2,368.7
23.	Customer Care Rate Smoothing V/A Adjustment	-	-	-	(4.6)	(4.6)
24.	**Total revenue requirement**	2,256.1	(2.2)	2,253.9	110.2	2,364.1
	Revenue at existing Rates					
25.	Gas sales	1,969.5	-	1,969.5	80.2	2,049.7
26.	Transportation service	299.8	-	299.8	19.0	318.8
27.	Transmission, compression and storage	1.7	-	1.7	-	1.7
28.	Rounding adjustment	0.1	(0.2)	(0.1)	-	(0.1)
29.	Revenue at existing rates	2,271.1	(0.2)	2,270.9	99.2	2,370.1
30.	**Gross revenue sufficiency / (deficiency)**	15.0	2.0	17.0	(11.0)	6.0

Note 1: Information from Col. 3 of Interim Rate Order, Appendix A, Page 1, Dated: 2012-11-29.
Note 2: Information from Col. 3 of Exhibit F3, Tab 1, Schedule 1, Page 2, Filed: 2012-01-31.

BOARD FINAL DECISION
UTILITY RATE BASE
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Interim Rate Order (Note 1) ($Millions)	Col. 2 Final Decision Adjustments ($Millions)	Col. 3 Excl. CIS Board Final Decision ($Millions)	Col. 4 Cust. Care / CIS (Note 2) ($Millions)	Col. 5 Board Final Decision Rate Base EGD Total ($Millions)
	Property, Plant, and Equipment					
1.	Cost or redetermined value	6,622.3	-	6,622.3	127.1	6,749.4
2.	Accumulated depreciation	(2,747.5)	-	(2,747.5)	(56.6)	(2,804.1)
3.		3,874.8	-	3,874.8	70.5	3,945.3
	Allowance for Working Capital					
4.	Accounts receivable merchandise finance plan	-	-	-	-	-
5.	Accounts receivable rebillable projects	1.3	-	1.3	-	1.3
6.	Materials and supplies	31.9	-	31.9	-	31.9
7.	Mortgages receivable	0.2	-	0.2	-	0.2
8.	Customer security deposits	(68.7)	-	(68.7)	-	(68.7)
9.	Prepaid expenses	1.8	-	1.8	-	1.8
10.	Gas in storage	248.4	-	248.4	-	248.4
11.	Working cash allowance	1.8	-	1.8	-	1.8
12.	Total Working Capital	216.7	-	216.7	-	216.7
13.	Utility Rate Base	4,091.5	-	4,091.5	70.5	4,162.0

Rakesh: Should I be using $3,874.8 for the net PPE? Is the Customer care/CIS PPE the $70.5?

Note 1: Information from Col. 3 of Interim Rate Order, Appendix A, Page 2, Dated: 2012-11-29.
Note 2: Information from Col. 2 of Exhibit F3, Tab 1, Schedule 3, page 1, Filed: 2012-01-31.

BOARD FINAL DECISION
UTILITY CAPITAL STRUCTURE
2013 TEST YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Indicated Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long term debt	2,461.9	60.17	5.80	3.490
2.	Short term debt/(investment)	56.7	1.39	2.00	0.028
3.		2,518.6	61.56		3.518
4.	Preference shares	100.0	2.44	3.20	0.078
5.	Common equity	1,472.9	36.00	8.93	3.215
6.		4,091.5	100.00		6.811
7.	Utility income	($Millions)			291.2
8.	Rate base	($Millions)			4,091.5
9.	Indicated rate of return				7.117%
10.	Sufficiency in rate of return				0.306 %
11.	Net sufficiency	($Millions)			12.5
12.	Gross sufficiency	($Millions)			17.0
13.	Customer Care/CIS deficiency	($Millions)			(11.0)
14.	Total gross sufficiency	($Millions)			6.0
15.	Revenue at existing rates	($Millions)			2,370.1
16.	Revenue requirement	($Millions)			2,364.1
17.	Total gross revenue sufficiency	($Millions)			6.0

Capex effect to RateBase

2013 Account	GROSS PPE and AOA's	Opening Balance 2013	Closing	Average of Monthly Avgs 2013	Revised to Match ADR AOA Growth	2014 Depr. Rate	Gross Depr. Provision ($M)	Adjustment and / or Disallowals ($M)	
	Underground Storage	ADR							
450/459	Crowland			-	-	0.00%	-	-	
450/451	Land and Gas Storage Rights	47.3		46.7	(0.6)	1.16%	0.5	0.1	
452.00	Structures, and Improvements	16.0		16.0	-	1.84%	0.3	-	
453.00	Wells	46.0		46.3	0.3	1.55%	0.7	-	
454.00	Well Equipment	9.4		9.4	-	5.56%	0.5	-	
455.00	Field Lines	63.0		63.1	0.1	1.55%	1.0	-	
456.00	Compressor Equipment	97.7		97.6	(0.1)	2.69%	2.6	-	
457.00	Measuring and Regulating Equipment	13.4		13.5	0.1	3.04%	0.4	-	
458.00	Base Pressure Gas	40.9		40.9	-	0.00%	-	-	
Total Underground Storage Plant		333.7		333.5	(0.2)		6.0	0.1	
				333.5					
	Distribution Plant								
470.00	Land	24.9		27.6	2.7	0.00%	-	-	
470.01	Offers to purchase	7.5		7.5	-	1.16%	0.1	-	
472.00	Structures and Improvements	121.9		121.7	(0.2)	5.64%	6.9	0.4	
473/474	Services, House Regs,and Meter Installs.	2,204.8		2,235.9	31.1	2.45%	54.8	-	
476.00	NGV Station Compressors	2.7		2.6	(0.1)	5.97%	0.2	-	
478.00	Meters	397.1		404.9	7.8	9.22%	37.3	-	
475.00	Mains	2,785.3		2,836.1	50.8	2.49%	70.6	4.0	
477.00	Measuring and Regulating	350.5		362.0	11.5	2.10%	7.6	-	
WIP	Construction work-in-progress completed	-		-	-	0.00%	-	-	
Total Distribution Plant		5,894.7		5,998.3	103.6		177.5	4.3	
				5,998.3					
	General Plant								
482.50	Leasehold Improvements	5.5		7.9	2.4	10.00%	0.8	-	
483.00	Office Furniture and Equipment	20.6		21.3	0.7	10.74%	2.3	(0.3)	
484.00	Transportation Equipment	48.0		48.1	0.1	10.56%	5.1	-	
484.01	NGV conversion kits	8.0		8.1	0.1	9.00%	0.7	-	
485.00	Heavy Work Equipment	20.9		21.2	0.3	3.58%	0.8	-	
486.00	Tools and Work Equipment	37.5		37.7	0.2	4.08%	1.5	-	
487.70	Rental Equipment	1.0		1.0	-	0.74%	-	-	
487.80	NGV Rental Compressors	3.6		3.5	(0.1)	8.01%	0.3	-	
84.02/487.9	NGV Cylinders	2.6		2.7	0.1	18.93%	0.5	(0.1)	
488.00	Communication structures and equipment	3.2		3.5	0.3	9.71%	0.3	-	
489.00	C.I.S.	127.1		**5.9**	5.9	10.00%	0.6	-	
490.00	Computer Equipment	141.5		136.5	(5.0)	27.38%	37.4	(1.0)	
Total General Plant		419.5		297.4	5.0		50.3	(1.5)	
				297.4			14.84%		
402.50	**Other Plant**	0.5		0.5	-	1.50%	-	-	
105.02	**Plant Held for Future Use**	1.7		1.7	-	4.30%	0.1	-	
	Total	6,650.1		6,631.4	108.4		233.9	3.4	237.3

-

2014 GROSS PPE and AOA's

Account		Depr. Rate
	Underground Storage	
450/459	Crowland	0.00%
450/451	Land and Gas Storage Rights	1.16%
452.00	Structures, and Improvements	1.84%
453.00	Wells	1.55%
454.00	Well Equipment	5.56%
455.00	Field Lines	1.55%
456.00	Compressor Equipment	2.69%
457.00	Measuring and Regulating Equipment	3.04%
458.00	Base Pressure Gas	0.00%
Total Underground Storage Plant		
	Distribution Plant	
470.00	Land	0.00%
470.01	Offers to purchase	1.18%
471.00	Land Rights	1.18%
472.00	Structures and Improvements	5.64%
473/474	Services, House Regs,and Meter Installs.	2.45%
476.00	NGV Station Compressors	5.97%
478.00	Meters	9.22%
475.00	Mains	2.49%
477.00	Measuring and Regulating	2.10%
WIP	Construction work-in-progress completed	0.00%
Total Distribution Plant		
	General Plant	
482.50	Leasehold Improvements	10.00%
483.00	Office Furniture and Equipment	10.74%
484.00	Transportation Equipment	10.56%
484.01	NGV conversion kits	9.00%
485.00	Heavy Work Equipment	3.58%
486.00	Tools and Work Equipment	4.08%
487.70	Rental Equipment	0.74%
487.80	NGV Rental Compressors	8.01%
84.02/487.9	NGV Cylinders	18.93%
488.00	Communication structures and equipment	9.71%
489.00	C.I.S.	10.00%
490.00	Computer Equipment	27.38%
Total General Plant		
402.50	**Other Plant**	1.50%
105.02	**Plant Held for Future Use**	4.30%
	Total	

Ottawa and GTA Combined

File: GTA & Ottawa combined 6-14-2013.xlsx Tab: Ottawa_PPE Project Annual

Ottawa Only

	2014		
Land Rights	0.0	0.0	0.0
Mains - Coated & Wrapped S	43,558.2	(534.9)	43,023.3
Regulating Equipment	4,896.1	(44.9)	4,851.2
Land	476.3	0.0	476.3
	0.0	0.0	0.0
	0.0	0.0	0.0
Gross/Accum/Net AOA's	48,930.6	(579.8)	48,350.8
Land Rights	0.0		
Mains - Coated & Wrapped S	1,167.1		
Regulating Equipment	97.9		
Land	0.0		
	0.0		
	0.0		
Depreciation Expense	1,265.0		

Ottawa and GTA combined

	2015		
Land Rights	18,618.3	(14.7)	18,603.6
Mains - Coated & Wrapped S	132,085.9	(1,965.4)	130,120.5
Regulating Equipment	20,603.4	(173.0)	20,430.4
Land	769.1	0.0	769.1
	0.0	0.0	0.0
	0.0	0.0	0.0
Gross/Accum/Net AOA's	172,076.7	(2,153.1)	169,923.6
Land Rights	175.8		
Mains - Coated & Wrapped S	3,213.8		
Regulating Equipment	367.2		
Land	0.0		
	0.0		
	0.0		
Depreciation Expense	3,756.8		

Ottawa and GTA combined

	2016		
Land Rights	89,368.0	(703.2)	88,664.8
Mains - Coated & Wrapped S	461,294.7	(10,839.3)	450,455.4
Regulating Equipment	79,482.1	(1,299.7)	78,182.4
Land	1,803.0	0.0	1,803.0
	0.0	0.0	0.0
	0.0	0.0	0.0
Gross/Accum/Net AOA's	631,947.8	(12,842.2)	619,105.6
Land Rights	1,054.8		
Mains - Coated & Wrapped S	12,916.8		
Regulating Equipment	1,669.2		
Land	0.0		
	0.0		
	0.0		
Depreciation Expense	15,640.8		

LOCAL STORAGE PLANT, PLANT HELD FOR FUTURE USE, AND OTHER PLANT - CONTINUITY WORKSHEETS
CALENDAR 2014 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	
														Net change	Average of
Local Storage Plant	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.		Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
A/c # 440.00 Land															
Opening balance	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5		
Expenditures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	0.0	21.5
Plant Held for														Net change	Average of
Future Use - Gross	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.		Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
A/c # 102.00															
Opening balance	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9		
Expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	0.0	1,670.9
Plant Held for															
Future Use - Accum. Depr.															
A/c # 105.02															
Opening balance	(1,171.6)	(1,171.6)	(1,175.0)	(1,178.4)	(1,181.8)	(1,185.2)	(1,188.6)	(1,192.0)	(1,195.4)	(1,198.8)	(1,202.2)	(1,205.6)	(1,209.0)		
Provision		(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.5)	(40.9)	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Costs net of Proceeds		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	(1,171.6)	(1,175.0)	(1,178.4)	(1,181.8)	(1,185.2)	(1,188.6)	(1,192.0)	(1,195.4)	(1,198.8)	(1,202.2)	(1,205.6)	(1,209.0)	(1,212.5)	(40.9)	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	(1,171.6)	(1,175.0)	(1,178.4)	(1,181.8)	(1,185.2)	(1,188.6)	(1,192.0)	(1,195.4)	(1,198.8)	(1,202.2)	(1,205.6)	(1,209.0)	(1,212.5)	(40.9)	(1,192.0)
Plant Held for Future Use - Net	499.3	495.9	492.5	489.1	485.7	482.3	478.9	475.5	472.1	468.7	465.3	461.9	458.4	(40.9)	478.9
														Net change	Average of
Other Plant - Gross	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.		Monthly Avgs.
A/c # 402.50	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
Intangible Plant (Peterborough)															
Opening balance	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3		
Expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	0.0	465.3
Other Plant - Acc.Depr.															
A/c # 402.50															
Intangible Plant (Peterborough)															
Opening balance	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)		
Provision		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Costs net of Proceeds		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	0.0	(465.3)
Other Plant - Net	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
UNDERGROUND STORAGE PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

Underground Storage Plant - Net. After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1
451 Land rights Tecumseh	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7
451.1 Land rights intangibles Tecumseh	14,960.5	14,925.4	14,901.4	14,871.8	14,836.7	14,804.5	14,774.9	14,740.2	14,709.7	14,675.7	14,639.1	14,640.3	14,750.5	14,781.3
452 Struct. & Improve. Tecumseh	13,759.3	13,807.4	14,120.1	14,299.4	14,344.4	14,460.0	14,638.4	19,093.0	19,244.5	19,308.1	19,312.8	20,224.7	23,749.6	16,800.6
453 Wells Tecumseh	33,787.6	33,746.1	33,810.4	33,822.2	33,781.9	33,771.5	33,787.3	33,754.0	33,762.2	33,735.2	33,684.2	33,994.8	35,349.0	33,851.5
454 Well Equipment Tecumseh	3,927.0	3,882.7	3,838.4	3,794.1	3,749.7	3,705.4	3,661.1	3,616.8	3,572.4	3,528.1	3,483.8	3,439.5	3,395.1	3,661.1
455 Field Lines Tecumseh	39,952.7	39,875.0	39,865.1	39,823.0	39,749.6	39,697.6	39,664.1	39,599.4	39,561.3	39,500.4	39,423.3	39,576.7	40,397.9	39,709.2
456 Compressor Equip. Tecumseh	68,172.2	67,950.4	67,860.4	67,707.4	67,493.1	67,320.5	70,483.6	70,278.4	70,124.9	69,926.9	69,697.4	69,916.5	71,434.8	69,046.9
457 Meas. & Reg. Tecumseh	8,847.3	8,809.0	8,774.4	8,738.3	8,700.8	8,664.9	8,630.2	8,593.8	8,558.9	8,522.7	8,485.5	8,460.7	8,472.2	8,633.2
458 Base Pressure Gas Tecumseh	40,957.7	40,958.1	40,958.9	40,959.7	40,960.6	40,962.1	40,963.5	40,964.5	40,967.4	40,968.8	40,970.8	40,972.2	40,975.7	40,964.4
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Underground Storage - After Adj.	229,608.1	229,197.9	229,372.9	229,259.7	228,860.6	228,630.3	231,846.9	235,883.9	235,745.1	235,409.7	234,940.7	236,469.2	243,768.6	232,692.0

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION UNDERGROUND STORAGE PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

Underground Storage Plant - Accum. Depr. After Adjustments	Col. 1 Dec. $(000)	Col. 2 Jan. $(000)	Col. 3 Feb. $(000)	Col. 4 Mar. $(000)	Col. 5 April $(000)	Col. 6 May $(000)	Col. 7 June $(000)	Col. 8 July $(000)	Col. 9 Aug. $(000)	Col. 10 Sep. $(000)	Col. 11 Oct. $(000)	Col. 12 Nov. $(000)	Col. 13 Dec. $(000)	Col. 14 Monthly Avgs. $(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451 Land rights Tecumseh	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7
451.1 Land rights intangibles Tecumseh	(24,651.5)	(24,689.8)	(24,728.1)	(24,766.4)	(24,804.7)	(24,843.0)	(24,881.3)	(24,919.6)	(24,958.0)	(24,996.3)	(25,034.7)	(25,073.1)	(25,111.5)	(24,881.4)
452 Struct. & Improve. Tecumseh	(5,705.6)	(5,735.4)	(5,765.4)	(5,795.9)	(5,826.7)	(5,857.6)	(5,888.8)	(5,920.3)	(5,958.7)	(5,997.4)	(6,036.2)	(6,075.1)	(6,115.3)	(5,897.3)
453 Wells Tecumseh	(17,183.6)	(17,216.3)	(17,249.1)	(17,281.2)	(17,311.8)	(17,340.8)	(17,368.8)	(17,396.6)	(17,424.4)	(17,452.3)	(17,480.7)	(17,510.4)	(17,542.2)	(17,366.3)
454 Well Equipment Tecumseh	(5,640.1)	(5,684.4)	(5,728.7)	(5,773.0)	(5,817.4)	(5,861.7)	(5,906.0)	(5,950.3)	(5,994.7)	(6,039.0)	(6,083.3)	(6,127.6)	(6,172.0)	(5,906.0)
455 Field Lines Tecumseh	(24,206.3)	(24,299.0)	(24,391.9)	(24,482.9)	(24,570.8)	(24,655.4)	(24,737.7)	(24,819.5)	(24,901.4)	(24,983.6)	(25,066.9)	(25,152.8)	(25,242.5)	(24,732.2)
456 Compressor Equip. Tecumseh	(35,626.8)	(35,887.6)	(36,148.9)	(36,406.8)	(36,659.0)	(36,904.9)	(37,146.6)	(37,394.9)	(37,643.3)	(37,892.4)	(38,143.7)	(38,400.0)	(38,664.2)	(37,147.8)
457 Meas. & Reg. Tecumseh	(5,752.7)	(5,792.1)	(5,831.5)	(5,870.6)	(5,909.2)	(5,947.2)	(5,984.9)	(6,022.5)	(6,060.1)	(6,097.7)	(6,135.5)	(6,173.7)	(6,212.6)	(5,984.0)
458 Base Pressure Gas Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Undgnd Storage Acc. Dep. - After Adj.	(117,264.9)	(117,802.9)	(118,341.9)	(118,875.1)	(119,397.9)	(119,908.9)	(120,412.4)	(120,922.0)	(121,438.9)	(121,957.0)	(122,479.3)	(123,011.0)	(123,558.6)	(120,413.3)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS DISTRIBUTION PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

Underground Storage Plant-Gross After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1
451 Land rights Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451.1 Land rights intangibles Tecumseh	39,612.0	39,615.2	39,629.5	39,638.2	39,641.4	39,647.5	39,656.2	39,659.8	39,667.7	39,672.0	39,673.8	39,713.4	39,862.0	39,662.6
452 Struct. & Improve. Tecumseh	19,464.9	19,542.8	19,885.5	20,095.3	20,171.1	20,317.6	20,527.2	25,013.3	25,203.2	25,305.5	25,349.0	26,299.8	29,864.9	22,697.9
453 Wells Tecumseh	50,971.2	50,962.4	51,059.5	51,103.4	51,093.7	51,112.3	51,156.1	51,150.6	51,186.6	51,187.5	51,164.9	51,505.2	52,891.2	51,217.8
454 Well Equipment Tecumseh	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1
455 Field Lines Tecumseh	64,159.0	64,174.0	64,257.0	64,305.9	64,320.4	64,353.0	64,401.8	64,418.9	64,462.7	64,484.0	64,490.2	64,729.5	65,640.4	64,441.4
456 Compressor Equip. Tecumseh	103,799.0	103,838.0	104,009.3	104,114.2	104,152.1	104,225.4	107,630.2	107,673.3	107,768.2	107,819.3	107,841.1	108,316.5	110,099.0	106,194.7
457 Meas. & Reg. Tecumseh	14,600.0	14,601.1	14,605.9	14,608.9	14,610.0	14,612.1	14,615.1	14,616.3	14,619.0	14,620.4	14,621.0	14,634.4	14,684.8	14,617.2
458 Base Pressure Gas Tecumseh	40,957.7	40,958.1	40,958.9	40,959.7	40,960.6	40,962.1	40,963.5	40,964.5	40,967.4	40,968.8	40,970.8	40,972.2	40,975.7	40,964.4
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Undgnd Storage Gross - After Adj.	346,873.0	347,000.8	347,714.8	348,134.8	348,258.5	348,539.2	352,259.3	356,805.9	357,184.0	357,366.7	357,420.0	359,480.2	367,327.2	353,105.2

Underground Storage Plant-Depreciation Rates	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Annual Prov.
	%	%	%	%	%	%	%	%	%	%	%	%	%
450/459 Crowland (Avg of all other storage categories)	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	2.480%
450 Land Tecumseh	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
451 Land rights Tecumseh	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	1.160%
451.1 Land rights intangibles Tecumseh	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	1.160%
452 Struct. & Improve. Tecumseh	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	1.840%
453 Wells Tecumseh	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	1.550%
454 Well Equipment Tecumseh	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	5.560%
455 Field Lines Tecumseh	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	1.550%
456 Compressor Equip. Tecumseh	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	2.690%
457 Meas. & Reg. Tecumseh	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	3.040%
458 Base Pressure Gas Tecumseh	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
??? Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%

Underground Storage Plant-Depreciation Provision - After Adjustments	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Depr.Provision
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451 Land rights Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451.1 Land rights intangibles Tecumseh	(38.3)	(38.3)	(38.3)	(38.3)	(38.3)	(38.3)	(38.3)	(38.3)	(38.3)	(38.3)	(38.4)	(38.4)	(459.8)
452 Struct. & Improve. Tecumseh	(29.8)	(30.0)	(30.5)	(30.8)	(30.9)	(31.2)	(31.5)	(38.4)	(38.6)	(38.8)	(38.9)	(40.3)	(409.7)
453 Wells Tecumseh	(65.8)	(65.8)	(66.0)	(66.0)	(66.0)	(66.0)	(66.1)	(66.1)	(66.1)	(66.1)	(66.1)	(66.5)	(792.6)
454 Well Equipment Tecumseh	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(531.6)
455 Field Lines Tecumseh	(82.9)	(82.9)	(83.0)	(83.1)	(83.1)	(83.1)	(83.2)	(83.2)	(83.3)	(83.3)	(83.3)	(83.6)	(998.0)
456 Compressor Equip. Tecumseh	(232.7)	(232.8)	(233.2)	(233.4)	(233.5)	(233.6)	(241.3)	(241.4)	(241.6)	(241.7)	(241.7)	(242.8)	(2,849.7)
457 Meas. & Reg. Tecumseh	(37.0)	(37.0)	(37.0)	(37.0)	(37.0)	(37.0)	(37.0)	(37.0)	(37.0)	(37.0)	(37.0)	(37.1)	(444.1)
458 Base Pressure Gas Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	(530.8)	(531.1)	(532.3)	(532.9)	(533.1)	(533.5)	(541.7)	(548.7)	(549.2)	(549.5)	(549.7)	(553.0)	(6,485.5)

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
GENERAL PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

General Plant - Net.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	3,493.3	3,462.1	3,430.9	6,949.7	6,889.0	6,828.3	6,767.6	6,706.9	6,646.2	7,955.4	7,883.2	7,811.0	7,738.8	6,412.2
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	200.3	205.9	211.5	217.1	222.7	228.3	233.9	240.5	247.1	253.7	260.3	267.9	275.6	235.6
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	13,448.1	13,515.7	13,358.1	13,250.7	13,270.8	13,251.3	13,318.0	13,361.4	13,331.5	13,319.8	13,254.2	13,595.7	15,862.7	13,456.9
484.00 Transportation equipment	34,573.6	34,308.7	33,888.7	33,503.5	33,206.6	32,882.7	32,618.3	32,339.0	32,009.2	31,692.2	31,338.3	31,266.2	32,523.3	32,716.8
484.01 N.G.V .kits Co. vehicles	3,071.3	3,033.9	2,974.4	2,919.9	2,878.1	2,832.5	2,795.5	2,756.5	2,710.4	2,666.1	2,616.7	2,607.7	2,789.5	2,810.2
484.02 N.G.V. cyl. Co. vehicles	65.1	66.3	65.0	64.3	64.9	65.2	66.4	67.4	67.5	68.0	67.8	72.2	97.8	68.0
485.00 Heavy work equipment	13,951.6	13,928.0	13,865.8	13,812.2	13,780.6	13,742.4	13,719.2	13,692.3	13,653.0	13,617.0	13,571.8	13,597.1	13,955.1	13,744.4
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	22,934.4	22,880.8	22,757.0	22,649.1	22,581.6	22,502.1	22,450.0	22,391.5	22,310.4	22,235.4	22,144.0	22,181.2	22,825.1	22,496.9
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	(13.1)	61.6	68.0	89.6	150.1	198.9	274.2	343.1	390.1	442.8	479.3	640.4	1,389.9	318.9
487.80 N.G.V. compressor stations	1,132.6	1,216.1	1,202.4	1,210.4	1,273.3	1,319.2	1,402.3	1,476.0	1,518.0	1,568.0	1,594.7	1,797.6	2,832.7	1,463.4
487.90 N.G.V. rental cylinders	714.9	689.0	659.7	631.1	604.4	577.0	550.9	524.4	496.8	469.4	441.2	419.1	425.6	552.8
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	2,813.8	2,782.2	2,750.6	2,719.0	2,687.4	2,655.8	2,624.2	2,592.6	2,561.0	2,529.4	2,497.8	2,466.2	2,434.5	2,624.2
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	20,740.2	19,674.9	18,776.9	17,824.6	16,979.7	15,955.8	15,164.0	14,101.0	13,301.4	13,651.2	12,632.0	11,649.4	12,789.9	15,539.7
491.00 Software acquired intangibles	32,101.3	30,832.6	29,673.3	28,491.4	27,833.5	26,618.5	30,382.3	29,057.4	27,899.5	27,441.5	26,178.3	24,946.4	24,997.7	28,158.7
491.00 Software developed intangibles	37,376.6	36,456.5	35,860.6	35,155.4	40,351.1	39,398.9	41,079.3	40,006.0	39,446.3	41,157.0	40,192.2	39,294.8	42,587.2	39,031.7
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net General Plant - After Adj.	186,604.0	183,114.3	179,542.9	179,488.0	182,773.8	179,056.9	183,446.1	179,656.0	176,588.4	179,066.9	175,151.8	172,612.9	183,525.4	179,630.4

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION GENERAL PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

General plant - Acc. Depr.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	(5,307.5)	(5,338.7)	(5,369.9)	(5,401.1)	(5,461.8)	(5,522.5)	(5,583.2)	(5,643.9)	(5,704.6)	(5,765.4)	(5,837.6)	(5,909.8)	(5,982.0)	(5,598.6)
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	(2,907.6)	(2,907.8)	(2,908.0)	(2,908.3)	(2,908.5)	(2,908.7)	(2,908.9)	(2,909.2)	(2,909.4)	(2,909.6)	(2,909.8)	(2,910.0)	(2,910.2)	(2,908.9)
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	(5,898.0)	(6,009.6)	(6,122.9)	(6,235.8)	(6,348.7)	(6,462.8)	(6,577.7)	(6,694.3)	(6,812.3)	(6,931.1)	(7,050.8)	(7,171.0)	(7,295.3)	(6,584.5)
484.00 Transportation equipment	(14,877.1)	(15,238.0)	(15,599.8)	(15,961.2)	(16,322.3)	(16,683.9)	(17,046.0)	(17,408.8)	(17,772.4)	(18,136.4)	(18,500.7)	(18,865.1)	(19,231.9)	(17,049.1)
484.01 N.G.V .kits Co. vehicles	(5,171.6)	(5,212.6)	(5,253.6)	(5,294.5)	(5,335.3)	(5,376.1)	(5,416.9)	(5,457.7)	(5,498.5)	(5,539.3)	(5,580.0)	(5,620.7)	(5,661.6)	(5,416.8)
484.02 N.G.V. cyl. Co. vehicles	(817.3)	(816.7)	(816.2)	(815.6)	(815.1)	(814.5)	(814.0)	(813.4)	(812.9)	(812.3)	(811.8)	(811.2)	(810.6)	(814.0)
485.00 Heavy work equipment	(8,234.2)	(8,277.4)	(8,320.6)	(8,363.8)	(8,407.0)	(8,450.2)	(8,493.4)	(8,536.7)	(8,580.0)	(8,623.3)	(8,666.7)	(8,710.0)	(8,753.5)	(8,493.6)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	(15,652.5)	(15,692.7)	(15,732.9)	(15,772.8)	(15,812.5)	(15,852.0)	(15,891.5)	(15,930.9)	(15,970.3)	(16,009.5)	(16,048.6)	(16,087.5)	(16,126.7)	(15,890.9)
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	(1,021.2)	(1,020.1)	(1,019.1)	(1,018.1)	(1,017.1)	(1,016.1)	(1,015.1)	(1,014.2)	(1,013.3)	(1,012.5)	(1,011.7)	(1,010.9)	(1,010.2)	(1,015.3)
487.80 N.G.V. compressor stations	(2,332.8)	(2,335.1)	(2,338.0)	(2,340.7)	(2,343.6)	(2,346.9)	(2,350.5)	(2,354.7)	(2,359.5)	(2,364.5)	(2,370.0)	(2,375.7)	(2,382.7)	(2,353.1)
487.90 N.G.V. rental cylinders	(1,164.4)	(1,194.0)	(1,223.7)	(1,253.4)	(1,283.1)	(1,312.9)	(1,342.7)	(1,372.6)	(1,402.5)	(1,432.5)	(1,462.5)	(1,492.5)	(1,522.7)	(1,343.0)
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	(1,093.7)	(1,125.0)	(1,156.3)	(1,187.7)	(1,219.0)	(1,250.3)	(1,281.7)	(1,313.0)	(1,344.3)	(1,375.7)	(1,407.0)	(1,438.3)	(1,469.8)	(1,281.7)
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	(15,256.9)	(16,086.7)	(16,909.3)	(17,729.6)	(18,545.9)	(19,361.3)	(20,170.5)	(20,980.1)	(21,782.0)	(22,583.9)	(23,421.0)	(24,252.5)	(25,079.4)	(20,165.9)
491.00 Software acquired intangibles	(26,656.3)	(27,315.6)	(27,961.5)	(28,596.1)	(29,218.7)	(29,840.5)	(30,449.3)	(31,154.0)	(31,845.1)	(32,526.0)	(33,211.8)	(33,884.9)	(34,545.9)	(30,550.4)
491.00 Software developed intangibles	(18,343.2)	(18,814.3)	(19,277.5)	(19,738.3)	(20,194.9)	(20,751.5)	(21,301.1)	(21,890.2)	(22,470.7)	(23,051.5)	(23,673.0)	(24,288.3)	(24,898.7)	(21,422.7)
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gen. Plant Acc. Depr. - After Adj.	(124,734.3)	(127,384.3)	(130,009.3)	(132,617.0)	(135,233.5)	(137,950.2)	(140,642.5)	(143,473.7)	(146,277.8)	(149,073.5)	(151,963.0)	(154,828.4)	(157,681.2)	(140,888.5)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS GENERAL PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
General plant - gross After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	8,800.8	8,800.8	8,800.8	12,350.8	12,350.8	12,350.8	12,350.8	12,350.8	12,350.8	13,720.8	13,720.8	13,720.8	13,720.8	12,010.8
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	3,107.9	3,113.7	3,119.5	3,125.4	3,131.2	3,137.0	3,142.8	3,149.7	3,156.5	3,163.3	3,170.1	3,177.9	3,185.8	3,144.5
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	19,346.1	19,525.3	19,481.0	19,486.5	19,619.5	19,714.1	19,895.7	20,055.7	20,143.8	20,250.9	20,305.0	20,766.7	23,158.0	20,041.4
484.00 Transportation equipment	49,450.7	49,546.7	49,488.5	49,464.7	49,528.9	49,566.6	49,664.3	49,747.8	49,781.6	49,828.6	49,839.0	50,131.3	51,755.2	49,765.9
484.01 N.G.V .kits Co. vehicles	8,242.9	8,246.5	8,228.0	8,214.4	8,213.4	8,208.6	8,212.4	8,214.2	8,208.9	8,205.4	8,196.7	8,228.4	8,451.1	8,227.0
484.02 N.G.V. cyl. Co. vehicles	882.4	883.0	881.2	879.9	880.0	879.7	880.4	880.8	880.4	880.3	879.6	883.4	908.4	882.0
485.00 Heavy work equipment	22,185.8	22,205.4	22,186.4	22,176.0	22,187.6	22,192.6	22,212.6	22,229.0	22,233.0	22,240.3	22,238.5	22,307.1	22,708.6	22,238.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	38,586.9	38,573.5	38,489.9	38,421.9	38,394.1	38,354.1	38,341.5	38,322.4	38,280.7	38,244.9	38,192.6	38,268.7	38,951.8	38,387.8
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	1,008.1	1,081.7	1,087.1	1,107.7	1,167.2	1,215.0	1,289.3	1,357.3	1,403.4	1,455.3	1,491.0	1,651.3	2,400.1	1,334.2
487.80 N.G.V. compressor stations	3,465.4	3,551.2	3,540.4	3,551.1	3,616.9	3,666.1	3,752.8	3,830.7	3,877.5	3,932.5	3,964.7	4,173.3	5,215.4	3,816.5
487.90 N.G.V. rental cylinders	1,879.3	1,883.0	1,883.4	1,884.5	1,887.5	1,889.9	1,893.6	1,897.0	1,899.3	1,901.9	1,903.7	1,911.6	1,948.3	1,895.8
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	3,907.5	3,907.2	3,906.9	3,906.7	3,906.4	3,906.1	3,905.9	3,905.6	3,905.3	3,905.1	3,904.8	3,904.5	3,904.3	3,905.9
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	35,997.1	35,761.6	35,686.2	35,554.2	35,525.6	35,317.1	35,334.5	35,081.1	35,083.4	36,235.1	36,053.0	35,901.9	37,869.3	35,705.6
491.00 Software acquired intangibles	58,757.6	58,148.2	57,634.8	57,087.5	57,052.2	56,459.0	60,831.6	60,211.4	59,744.6	59,967.5	59,390.1	58,831.3	59,543.6	58,709.1
491.00 Software developed intangibles	55,719.8	55,270.8	55,138.1	54,893.7	60,546.0	60,150.4	62,380.4	61,896.2	61,917.0	64,208.5	63,865.2	63,583.1	67,485.9	60,454.4
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
General Plant Gross - After Adj.	311,338.3	310,498.6	309,552.2	312,105.0	318,007.3	317,007.1	324,088.6	323,129.7	322,866.2	328,140.4	327,114.8	327,441.3	341,206.6	320,518.9

General plant - Depreciation Rates	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Annual
	%	%	%	%	%	%	%	%	%	%	%	%	%
482.50 Leasehold improvements	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	10.00%
483.1 Office equipment over 6.6 yrs.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
483.1 Office equipment over 15 yrs.	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.150%
483.2 Office furniture over 6.6 yrs.	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	10.740%
483.2 Office furniture over 20 yrs.	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	10.740%
484.00 Transportation equipment	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	10.560%
484.01 N.G.V .kits Co. vehicles	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	9.000%
484.02 N.G.V. cyl. Co. vehicles	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	2.100%
485.00 Heavy work equipment	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	3.580%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
486.00 Tools & work euip. over 2.69 yrs	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	4.080%
486.00 Tools & work euip. 4.0%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	4.080%
487.70 V.R.A.'S	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.740%
487.70 V.R.A.'S Post F2003 5%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.740%
487.80 N.G.V. compressor stations	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	8.010%
487.90 N.G.V. rental cylinders	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	18.930%
488.00 Communication str & equip	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	9.710%
488.00 Communication str & equip 20yrs	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	9.710%
490.00 Computer equipment	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	36.630%
490.00 Computer equipment 2003 B 20%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	36.630%
491.00 Software acquired intangibles	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	26.320%
491.00 Software developed intangibles	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	21.240%
491.00 CIS software acquired intangibles	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	10.000%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%

General plant -
Depreciation Provision - After Adjustments

	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Depr.Provision
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	(73.3)	(73.3)	(73.3)	(102.9)	(102.9)	(102.9)	(102.9)	(102.9)	(102.9)	(114.3)	(114.3)	(114.3)	(1,180.2)
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(4.8)
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	(173.1)	(174.8)	(174.4)	(174.4)	(175.6)	(176.4)	(178.1)	(179.5)	(180.3)	(181.2)	(181.7)	(185.9)	(2,135.4)
484.00 Transportation equipment	(435.2)	(436.0)	(435.5)	(435.3)	(435.9)	(436.2)	(437.0)	(437.8)	(438.1)	(438.5)	(438.6)	(441.2)	(5,245.3)
484.01 N.G.V .kits Co. vehicles	(61.8)	(61.8)	(61.7)	(61.6)	(61.6)	(61.6)	(61.6)	(61.6)	(61.6)	(61.5)	(61.5)	(61.7)	(739.6)
484.02 N.G.V. cyl. Co. vehicles	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(18.0)
485.00 Heavy work equipment	(66.2)	(66.2)	(66.2)	(66.2)	(66.2)	(66.2)	(66.3)	(66.3)	(66.3)	(66.4)	(66.3)	(66.5)	(795.3)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	(131.2)	(131.1)	(130.9)	(130.6)	(130.5)	(130.4)	(130.4)	(130.3)	(130.2)	(130.0)	(129.9)	(130.1)	(1,565.6)
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	(0.6)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.8)	(0.8)	(0.9)	(0.9)	(0.9)	(1.0)	(9.4)
487.80 N.G.V. compressor stations	(23.1)	(23.7)	(23.6)	(23.7)	(24.1)	(24.5)	(25.0)	(25.6)	(25.9)	(26.2)	(26.5)	(27.9)	(299.8)
487.90 N.G.V. rental cylinders	(29.6)	(29.7)	(29.7)	(29.7)	(29.8)	(29.8)	(29.9)	(29.9)	(30.0)	(30.0)	(30.0)	(30.2)	(358.3)
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(379.2)
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	(1,098.8)	(1,091.6)	(1,089.3)	(1,085.3)	(1,084.4)	(1,078.1)	(1,078.6)	(1,070.9)	(1,070.9)	(1,106.1)	(1,100.5)	(1,095.9)	(13,050.4)
491.00 Software acquired intangibles	(1,288.8)	(1,275.4)	(1,264.1)	(1,252.1)	(1,251.3)	(1,238.3)	(1,334.2)	(1,320.6)	(1,310.4)	(1,315.3)	(1,302.6)	(1,290.4)	(15,443.5)
491.00 Software developed intangibles	(986.2)	(978.3)	(975.9)	(971.6)	(1,071.7)	(1,064.7)	(1,104.1)	(1,095.6)	(1,095.9)	(1,136.5)	(1,130.4)	(1,125.4)	(12,736.3)
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	(4,401.4)	(4,376.1)	(4,358.8)	(4,367.6)	(4,468.2)	(4,443.3)	(4,582.4)	(4,555.3)	(4,546.9)	(4,640.4)	(4,616.7)	(4,604.0)	(53,961.1)

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
DISTRIBUTION PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
Distribution plant - Net.														
After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
470.00 Land	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	5,536.6	5,529.3	5,522.0	5,514.7	5,507.3	5,500.0	5,492.7	5,485.4	5,478.0	5,470.7	5,463.4	5,456.1	5,448.7	5,492.7
472.00 Structures & improvements	108,244.8	108,022.5	107,968.1	108,240.9	108,637.6	108,897.3	109,219.8	109,233.8	109,163.3	109,028.3	108,920.4	108,739.4	108,816.0	108,716.8
473/474 Services, house regs. & meter inst	1,232,471.4	1,244,893.7	1,250,743.8	1,256,168.8	1,261,138.9	1,266,170.2	1,271,898.6	1,278,292.2	1,284,873.4	1,291,831.2	1,298,825.5	1,307,687.4	1,320,771.9	1,274,095.4
475.00 Mains	1,693,893.5	1,748,310.6	1,758,429.0	1,768,331.5	1,777,399.6	1,784,984.7	1,791,962.0	1,799,490.9	1,805,494.8	1,812,576.9	1,821,997.1	1,830,975.6	1,852,185.7	1,789,416.0
476.00 Company NGV compressor stations	717.9	707.9	696.0	685.2	675.9	666.0	662.1	655.9	648.7	648.6	645.1	638.4	669.3	668.6
477.00 Measuring & regulating equip.	185,651.1	190,099.3	190,805.9	191,752.8	192,671.5	193,625.1	194,815.6	195,906.9	196,713.8	197,729.9	199,246.3	200,401.4	203,727.2	194,871.5
478.00 Meters	286,309.9	284,328.7	282,393.9	280,487.0	278,608.8	277,037.5	275,745.0	274,317.9	273,001.3	271,645.1	270,495.2	269,471.0	269,413.9	276,282.8
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Distribution Plant - After Adj.	3,540,548.0	3,609,614.8	3,624,281.5	3,638,903.7	3,652,362.4	3,664,603.6	3,677,518.6	3,691,105.8	3,703,096.1	3,716,653.5	3,733,315.8	3,751,092.1	3,788,755.5	3,677,266.6

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION DISTRIBUTION PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

Distribution plant - Acc. Depr. After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
470.00 Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	(1,910.2)	(1,917.5)	(1,924.8)	(1,932.1)	(1,939.5)	(1,946.8)	(1,954.1)	(1,961.4)	(1,968.8)	(1,976.1)	(1,983.4)	(1,990.7)	(1,998.1)	(1,954.1)
472.00 Structures & improvements	(13,504.8)	(14,097.1)	(14,691.5)	(15,288.7)	(15,892.0)	(16,502.3)	(16,619.8)	(17,245.8)	(17,876.3)	(18,511.3)	(19,149.2)	(19,790.2)	(20,433.6)	(16,886.1)
473/474 Services, house regs. & meter inst	(1,037,790.6)	(1,036,192.0)	(1,034,532.8)	(1,033,359.7)	(1,032,976.2)	(1,033,224.0)	(1,033,873.6)	(1,034,774.8)	(1,035,587.9)	(1,036,377.0)	(1,036,765.3)	(1,036,413.5)	(1,034,492.0)	(1,035,018.2)
475.00 Mains	(1,230,047.3)	(1,229,441.0)	(1,228,867.1)	(1,229,176.3)	(1,230,898.8)	(1,234,062.0)	(1,238,236.1)	(1,242,709.9)	(1,247,156.6)	(1,251,521.5)	(1,255,417.6)	(1,258,173.8)	(1,259,254.6)	(1,240,859.3)
476.00 Company NGV compressor stations	(1,882.1)	(1,885.4)	(1,888.7)	(1,892.0)	(1,895.2)	(1,898.4)	(1,901.6)	(1,904.8)	(1,907.9)	(1,911.0)	(1,914.1)	(1,917.2)	(1,920.5)	(1,901.5)
477.00 Measuring & regulating equip.	(191,496.9)	(191,985.0)	(192,481.6)	(192,984.0)	(193,495.2)	(194,015.3)	(194,542.6)	(195,073.9)	(195,608.0)	(196,143.9)	(196,680.5)	(197,215.5)	(197,746.5)	(194,570.6)
478.00 Meters	(130,369.7)	(132,487.9)	(134,607.1)	(136,727.7)	(138,850.0)	(140,974.2)	(143,102.5)	(145,237.3)	(147,377.6)	(149,524.1)	(151,676.8)	(153,837.2)	(156,006.2)	(143,132.5)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dist. Plant Acc. Dep. - After Adj.	(2,607,001.6)	(2,608,005.9)	(2,608,993.6)	(2,611,360.5)	(2,615,946.9)	(2,622,623.0)	(2,630,230.3)	(2,638,907.9)	(2,647,483.1)	(2,655,964.9)	(2,663,586.9)	(2,669,338.1)	(2,671,851.5)	(2,634,322.3)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS DISTRIBUTION PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
Distribution plant - gross After Adjustm	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
470.00 Land	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8
470.01 Offers t	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land ri	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8
472.00 Structu	121,749.6	122,119.6	122,659.6	123,529.6	124,529.6	125,399.6	125,839.6	126,479.6	127,039.6	127,539.6	128,069.6	128,529.6	129,249.6	125,602.9
473/474 Servic	2,270,262.0	2,281,085.7	2,285,276.6	2,289,528.5	2,294,115.1	2,299,394.2	2,305,772.2	2,313,067.0	2,320,461.3	2,328,208.2	2,335,590.8	2,344,100.9	2,355,263.9	2,309,113.6
475.00 Mains	2,923,940.8	2,977,751.6	2,987,296.1	2,997,507.8	3,008,298.4	3,019,046.7	3,030,198.1	3,042,200.8	3,052,651.4	3,064,098.4	3,077,414.7	3,089,149.4	3,111,440.3	3,030,275.3
476.00 Compa	2,600.0	2,593.3	2,584.7	2,577.2	2,571.1	2,564.4	2,563.7	2,560.7	2,556.6	2,559.6	2,559.2	2,555.6	2,589.8	2,570.1
477.00 Measu	377,148.0	382,084.3	383,287.5	384,736.8	386,166.7	387,640.4	389,358.2	390,980.8	392,321.8	393,873.8	395,926.8	397,616.9	401,473.7	389,442.1
478.00 Meters	416,679.6	416,816.6	417,001.0	417,214.7	417,458.8	418,011.7	418,847.5	419,555.2	420,378.9	421,169.2	422,172.0	423,308.2	425,420.1	419,415.3
4??.00 Availab	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Distribution P	6,147,549.6	6,217,620.7	6,233,275.1	6,250,264.2	6,268,309.3	6,287,226.6	6,307,748.9	6,330,013.7	6,350,579.2	6,372,618.4	6,396,902.7	6,420,430.2	6,460,607.0	6,311,588.9

Distribution plant - Depreciation Rates	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Annual
	%	%	%	%	%	%	%	%	%	%	%	%	%
470.00 Land	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
470.01 Offers to purchase lan	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
471.00 Land rights intangibles	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	1.180%
472.00 Structures & improven	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	7.550%
473/474 Services, house regs	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	2.450%
475.00 Mains	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	2.454%
476.00 Company NGV compr	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	5.970%
477.00 Measuring & regulatin	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	2.100%
478.00 Meters	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	9.220%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%

Distribution plant - Depreciation Provision - Aft	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Depr.Provision
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	
470.00 Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
470.01 Offers to purchase lan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(87.6)
472.00 Structures & improven	(766.0)	(768.3)	(771.7)	(777.2)	(783.5)	(789.0)	(791.7)	(795.8)	(799.3)	(802.4)	(805.8)	(808.7)	(9,459.4)
473/474 Services, house regs	(4,635.1)	(4,657.2)	(4,665.8)	(4,674.5)	(4,683.8)	(4,694.6)	(4,707.6)	(4,722.5)	(4,737.6)	(4,753.4)	(4,768.5)	(4,785.9)	(56,486.5)
475.00 Mains	(5,978.2)	(6,088.3)	(6,107.8)	(6,128.7)	(6,150.7)	(6,172.7)	(6,195.5)	(6,220.0)	(6,241.4)	(6,264.8)	(6,292.0)	(6,316.0)	(74,156.1)
476.00 Company NGV compr	(12.9)	(12.9)	(12.9)	(12.8)	(12.8)	(12.8)	(12.8)	(12.7)	(12.7)	(12.7)	(12.7)	(12.7)	(153.4)
477.00 Measuring & regulatin	(660.0)	(668.6)	(670.8)	(673.3)	(675.8)	(678.4)	(681.4)	(684.2)	(686.6)	(689.3)	(692.9)	(695.8)	(8,157.1)
478.00 Meters	(3,201.5)	(3,202.5)	(3,204.0)	(3,205.6)	(3,207.5)	(3,211.7)	(3,218.1)	(3,223.6)	(3,229.9)	(3,236.0)	(3,243.7)	(3,252.4)	(38,636.5)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	(15,261.0)	(15,405.1)	(15,440.3)	(15,479.4)	(15,521.4)	(15,566.5)	(15,614.4)	(15,666.1)	(15,714.8)	(15,765.9)	(15,822.9)	(15,878.8)	(187,136.6)

LOCAL STORAGE PLANT, PLANT HELD FOR FUTURE USE, AND OTHER PLANT - CONTINUITY WORKSHEETS
CALENDAR 2015 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14 Net change	Average of Monthly Avgs.
Local Storage Plant	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.		
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
A/c # 440.00 Land															
Opening balance	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5		
Expenditures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	0.0	21.5
Plant Held for Future Use - Gross	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Net change	Average of Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
A/c # 102.00															
Opening balance	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9		
Expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	0.0	1,670.9
Plant Held for Future Use - Accum. Depr.															
A/c # 105.02															
Opening balance	(1,212.5)	(1,212.5)	(1,215.9)	(1,219.3)	(1,222.7)	(1,226.1)	(1,229.5)	(1,232.9)	(1,236.3)	(1,239.7)	(1,243.1)	(1,246.5)	(1,249.9)		
Provision		(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.5)	(40.9)	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Costs net of Proceeds		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	(1,212.5)	(1,215.9)	(1,219.3)	(1,222.7)	(1,226.1)	(1,229.5)	(1,232.9)	(1,236.3)	(1,239.7)	(1,243.1)	(1,246.5)	(1,249.9)	(1,253.4)	(40.9)	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	(1,212.5)	(1,215.9)	(1,219.3)	(1,222.7)	(1,226.1)	(1,229.5)	(1,232.9)	(1,236.3)	(1,239.7)	(1,243.1)	(1,246.5)	(1,249.9)	(1,253.4)	(40.9)	(1,232.9)
Plant Held for Future Use - Net	458.4	455.0	451.6	448.2	444.8	441.4	438.0	434.6	431.2	427.8	424.4	421.0	417.5	(40.9)	438.0
Other Plant - Gross	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Net change	Average of Monthly Avgs.
A/c # 402.50	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
Intangible Plant (Peterborough)															
Opening balance	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3		
Expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	0.0	465.3
Other Plant - Acc.Depr.															
A/c # 402.50															
Intangible Plant (Peterborough)															
Opening balance	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)		
Provision		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Costs net of Proceeds		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	0.0	(465.3)
Other Plant - Net	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
UNDERGROUND STORAGE PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

Underground Storage Plant - Net. After Adjustments	Col. 1 Dec. $(000)	Col. 2 Jan. $(000)	Col. 3 Feb. $(000)	Col. 4 Mar. $(000)	Col. 5 April $(000)	Col. 6 May $(000)	Col. 7 June $(000)	Col. 8 July $(000)	Col. 9 Aug. $(000)	Col. 10 Sep. $(000)	Col. 11 Oct. $(000)	Col. 12 Nov. $(000)	Col. 13 Dec. $(000)	Col. 14 Monthly Avgs. $(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1
451 Land rights Tecumseh	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7
451.1 Land rights intangibles Tecumseh	14,750.5	14,723.0	14,732.9	14,724.0	14,696.1	14,678.3	14,669.4	14,642.9	14,631.1	14,606.9	14,574.4	14,670.3	15,136.5	14,691.1
452 Struct. & Improve. Tecumseh	23,749.6	23,746.5	23,888.0	23,956.5	23,951.7	23,985.4	24,053.5	28,862.3	28,912.0	28,913.6	28,883.0	29,348.5	31,242.7	26,333.1
453 Wells Tecumseh	35,349.0	35,331.9	35,510.2	37,904.7	37,884.7	37,918.2	37,999.2	37,989.0	38,055.4	38,056.7	38,014.0	38,640.7	41,197.0	37,631.5
454 Well Equipment Tecumseh	3,395.1	3,350.8	3,306.5	3,262.2	3,217.8	3,173.5	3,129.2	3,084.9	3,040.5	2,996.2	2,951.9	2,907.6	2,863.2	3,129.2
455 Field Lines Tecumseh	40,397.9	40,335.2	40,394.1	40,393.6	40,334.2	40,310.4	40,317.6	40,268.5	40,266.9	40,224.6	40,154.4	40,498.8	42,041.5	40,393.2
456 Compressor Equip. Tecumseh	71,434.8	71,179.6	70,983.2	70,760.4	70,512.9	70,287.0	71,607.5	71,369.6	71,154.9	70,920.0	70,669.9	70,618.6	71,146.7	70,946.2
457 Meas. & Reg. Tecumseh	8,472.2	8,433.3	8,395.9	8,358.0	8,319.8	8,282.5	8,245.8	8,208.6	8,172.0	8,134.8	8,097.2	8,064.5	8,046.4	8,247.6
458 Base Pressure Gas Tecumseh	40,975.7	40,976.1	40,976.9	40,977.7	40,978.6	40,980.1	40,981.5	40,982.5	40,985.4	40,986.8	40,988.8	40,990.2	40,993.7	40,982.4
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Underground Storage - After Adj.	243,768.6	243,320.2	243,431.5	245,580.9	245,139.6	244,859.2	246,247.5	250,652.1	250,462.0	250,083.4	249,577.4	250,983.0	257,911.5	247,598.1

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION UNDERGROUND STORAGE PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

Underground Storage Plant - Accum. Depr. After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451 Land rights Tecumseh	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7
451.1 Land rights intangibles Tecumseh	(25,111.5)	(25,150.0)	(25,188.6)	(25,227.2)	(25,265.8)	(25,304.4)	(25,343.0)	(25,381.7)	(25,420.4)	(25,459.1)	(25,497.8)	(25,536.6)	(25,575.5)	(25,343.2)
452 Struct. & Improve. Tecumseh	(6,115.3)	(6,161.0)	(6,206.9)	(6,253.1)	(6,299.4)	(6,345.8)	(6,392.3)	(6,439.0)	(6,493.1)	(6,547.4)	(6,601.8)	(6,656.2)	(6,711.4)	(6,400.8)
453 Wells Tecumseh	(17,542.2)	(17,616.9)	(17,691.8)	(17,766.1)	(17,842.2)	(17,917.0)	(17,990.9)	(18,064.8)	(18,138.8)	(18,213.1)	(18,288.0)	(18,364.0)	(18,442.5)	(17,990.5)
454 Well Equipment Tecumseh	(6,172.0)	(6,216.3)	(6,260.6)	(6,304.9)	(6,349.3)	(6,393.6)	(6,437.9)	(6,482.2)	(6,526.6)	(6,570.9)	(6,615.2)	(6,659.5)	(6,703.9)	(6,437.9)
455 Field Lines Tecumseh	(25,242.5)	(25,341.0)	(25,439.7)	(25,536.7)	(25,631.0)	(25,722.2)	(25,811.4)	(25,900.1)	(25,989.0)	(26,078.3)	(26,168.5)	(26,261.3)	(26,357.9)	(25,806.6)
456 Compressor Equip. Tecumseh	(38,664.2)	(38,936.9)	(39,210.1)	(39,479.9)	(39,744.4)	(40,003.1)	(40,257.8)	(40,515.0)	(40,772.3)	(41,030.1)	(41,290.0)	(41,554.4)	(41,825.5)	(40,253.2)
457 Meas. & Reg. Tecumseh	(6,212.6)	(6,252.0)	(6,291.4)	(6,330.5)	(6,369.1)	(6,407.3)	(6,445.2)	(6,482.9)	(6,520.6)	(6,558.4)	(6,596.3)	(6,634.6)	(6,673.6)	(6,444.3)
458 Base Pressure Gas Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Undgnd Storage Acc. Dep. - After Adj.	(123,558.6)	(124,172.4)	(124,787.4)	(125,396.7)	(125,999.5)	(126,591.7)	(127,176.8)	(127,764.0)	(128,359.1)	(128,955.6)	(129,555.9)	(130,164.9)	(130,788.6)	(127,174.8)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS DISTRIBUTION PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

Underground Storage Plant-Gross After Adjustments	Col. 1 Dec. $(000)	Col. 2 Jan. $(000)	Col. 3 Feb. $(000)	Col. 4 Mar. $(000)	Col. 5 April $(000)	Col. 6 May $(000)	Col. 7 June $(000)	Col. 8 July $(000)	Col. 9 Aug. $(000)	Col. 10 Sep. $(000)	Col. 11 Oct. $(000)	Col. 12 Nov. $(000)	Col. 13 Dec. $(000)	Col. 14 Monthly Avgs. $(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1
451 Land rights Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451.1 Land rights intangibles Tecumseh	39,862.0	39,873.0	39,921.5	39,951.2	39,961.9	39,982.7	40,012.4	40,024.6	40,051.5	40,066.0	40,072.2	40,206.9	40,712.0	40,034.2
452 Struct. & Improve. Tecumseh	29,864.9	29,907.5	30,094.9	30,209.6	30,251.1	30,331.2	30,445.8	35,301.3	35,405.1	35,461.0	35,484.8	36,004.7	37,954.1	32,733.9
453 Wells Tecumseh	52,891.2	52,948.8	53,202.0	55,670.8	55,726.9	55,835.2	55,990.1	56,053.8	56,194.2	56,269.8	56,302.0	57,004.7	59,639.5	55,622.0
454 Well Equipment Tecumseh	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1
455 Field Lines Tecumseh	65,640.4	65,676.2	65,833.8	65,930.3	65,965.2	66,032.6	66,129.0	66,168.6	66,255.9	66,302.9	66,322.9	66,760.1	68,399.4	66,199.8
456 Compressor Equip. Tecumseh	110,099.0	110,116.5	110,193.3	110,240.3	110,257.3	110,290.1	111,865.3	111,884.6	111,927.2	111,950.1	111,959.9	112,173.0	112,972.2	111,199.4
457 Meas. & Reg. Tecumseh	14,684.8	14,685.3	14,687.3	14,688.5	14,688.9	14,689.8	14,691.0	14,691.5	14,692.6	14,693.2	14,693.5	14,699.1	14,720.0	14,691.9
458 Base Pressure Gas Tecumseh	40,975.7	40,976.1	40,976.9	40,977.7	40,978.6	40,980.1	40,981.5	40,982.5	40,985.4	40,986.8	40,988.8	40,990.2	40,993.7	40,982.4
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Undgnd Storage Gross - After Adj.	367,327.2	367,492.6	368,218.9	370,977.6	371,139.1	371,450.9	373,424.3	378,416.1	378,821.1	379,039.0	379,133.3	381,147.9	388,700.1	374,772.8

Underground Storage Plant- Depreciation Rates	Jan. %	Feb. %	Mar. %	April %	May %	June %	July %	Aug. %	Sep. %	Oct. %	Nov. %	Dec. %	Annual Prov. %
450/459 Crowland (Avg of all other storage categories)	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	2.480%
450 Land Tecumseh	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
451 Land rights Tecumseh	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	1.160%
451.1 Land rights intangibles Tecumseh	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	1.160%
452 Struct. & Improve. Tecumseh	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	1.840%
453 Wells Tecumseh	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	1.550%
454 Well Equipment Tecumseh	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	5.560%
455 Field Lines Tecumseh	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	1.550%
456 Compressor Equip. Tecumseh	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	2.690%
457 Meas. & Reg. Tecumseh	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	3.040%
458 Base Pressure Gas Tecumseh	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
??? Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%

Underground Storage Plant- Depreciation Provision - After Adjustments	Jan. $(000)	Feb. $(000)	Mar. $(000)	April $(000)	May $(000)	June $(000)	July $(000)	Aug. $(000)	Sep. $(000)	Oct. $(000)	Nov. $(000)	Dec. $(000)	Depr.Provision $(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451 Land rights Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451.1 Land rights intangibles Tecumseh	(38.5)	(38.5)	(38.6)	(38.6)	(38.6)	(38.6)	(38.7)	(38.7)	(38.7)	(38.7)	(38.7)	(38.9)	(463.8)
452 Struct. & Improve. Tecumseh	(45.8)	(45.9)	(46.1)	(46.3)	(46.4)	(46.5)	(46.7)	(54.1)	(54.3)	(54.4)	(54.4)	(55.2)	(596.1)
453 Wells Tecumseh	(68.3)	(68.4)	(68.7)	(71.9)	(72.0)	(72.1)	(72.3)	(72.4)	(72.6)	(72.7)	(72.7)	(73.6)	(857.7)
454 Well Equipment Tecumseh	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(531.6)
455 Field Lines Tecumseh	(84.8)	(84.8)	(85.0)	(85.2)	(85.2)	(85.3)	(85.4)	(85.5)	(85.6)	(85.6)	(85.7)	(86.2)	(1,024.3)
456 Compressor Equip. Tecumseh	(246.8)	(246.8)	(247.0)	(247.1)	(247.2)	(247.2)	(250.8)	(250.8)	(250.9)	(251.0)	(251.0)	(251.5)	(2,988.1)
457 Meas. & Reg. Tecumseh	(37.2)	(37.2)	(37.2)	(37.2)	(37.2)	(37.2)	(37.2)	(37.2)	(37.2)	(37.2)	(37.2)	(37.2)	(446.4)
458 Base Pressure Gas Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	(565.7)	(565.9)	(566.9)	(570.6)	(570.9)	(571.2)	(575.4)	(583.0)	(583.6)	(583.9)	(584.0)	(586.9)	(6,908.0)

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
GENERAL PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

General Plant - Net.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	7,738.8	7,666.6	7,594.4	7,522.3	10,450.1	10,352.9	10,255.8	10,158.6	10,061.4	9,964.3	9,867.1	9,889.9	9,791.8	9,379.1
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	275.6	281.2	286.8	292.4	298.0	303.6	309.2	315.8	322.4	329.0	335.6	343.2	350.8	310.9
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	15,862.7	15,898.7	15,706.9	15,565.5	15,552.6	15,499.3	15,532.7	15,542.3	15,477.4	15,430.5	15,328.8	15,638.2	17,893.6	15,670.9
484.00 Transportation equipment	32,523.3	32,238.1	31,797.8	31,392.4	31,075.3	30,731.1	30,446.5	30,147.0	29,797.0	29,459.9	29,085.9	28,993.7	30,230.5	30,545.1
484.01 N.G.V .kits Co. vehicles	2,789.5	2,731.6	2,668.8	2,607.3	2,548.8	2,489.6	2,432.4	2,374.9	2,315.9	2,257.4	2,197.9	2,147.6	2,140.4	2,436.4
484.02 N.G.V. cyl. Co. vehicles	97.8	121.2	121.9	127.7	146.4	161.1	184.6	206.0	220.0	236.0	246.6	298.4	545.3	199.3
485.00 Heavy work equipment	13,955.1	13,930.0	13,866.2	13,811.1	13,778.0	13,738.2	13,713.4	13,685.0	13,644.1	13,606.5	13,559.8	13,583.5	13,939.9	13,738.6
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	22,825.1	22,770.3	22,645.2	22,536.0	22,467.1	22,386.2	22,332.7	22,272.8	22,190.3	22,113.9	22,021.0	22,056.7	22,698.9	22,379.5
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	1,389.9	1,463.8	1,469.4	1,490.2	1,550.0	1,598.0	1,672.5	1,740.6	1,786.7	1,838.7	1,874.4	2,034.9	2,785.2	1,717.2
487.80 N.G.V. compressor stations	2,832.7	2,909.8	2,884.9	2,882.6	2,938.1	2,975.7	3,052.4	3,119.2	3,152.8	3,194.8	3,212.3	3,414.8	4,491.1	3,116.6
487.90 N.G.V. rental cylinders	425.6	398.7	368.3	338.6	310.9	282.5	255.4	227.9	199.3	170.9	141.7	118.7	125.1	257.4
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	2,434.5	2,402.9	2,371.3	2,339.7	2,308.1	2,276.5	2,244.9	2,213.3	2,181.7	2,150.1	2,118.5	2,087.0	2,055.5	2,244.9
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	12,789.9	11,674.1	10,774.6	9,825.5	8,900.8	7,900.6	7,194.5	6,178.5	5,494.2	6,204.5	5,287.7	4,430.3	6,136.0	7,777.4
491.00 Software acquired intangibles	24,997.7	23,723.8	22,627.6	21,497.8	20,392.9	19,233.1	18,313.5	17,152.7	16,261.6	16,493.0	15,438.7	14,437.0	15,491.1	18,818.0
491.00 Software developed intangibles	42,587.2	41,442.4	40,544.8	39,568.3	38,603.3	37,526.3	51,609.5	50,214.9	49,209.9	49,915.1	48,612.3	47,363.5	49,267.7	45,044.8
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
489.00 WAMS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	58,550.0	2,439.6
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net General Plant - After Adj.	183,525.4	179,653.2	175,728.9	171,797.4	171,320.4	167,454.7	179,550.0	175,549.5	172,314.7	173,364.6	169,328.3	166,837.4	236,492.9	176,075.7

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION GENERAL PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

General plant - Acc. Depr. After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	(5,982.0)	(6,054.2)	(6,126.4)	(6,198.5)	(6,270.7)	(6,367.9)	(6,465.0)	(6,562.2)	(6,659.4)	(6,756.5)	(6,853.7)	(6,950.9)	(7,049.0)	(6,481.7)
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	(2,910.2)	(2,910.5)	(2,910.7)	(2,910.9)	(2,911.1)	(2,911.3)	(2,911.5)	(2,911.8)	(2,912.0)	(2,912.2)	(2,912.4)	(2,912.6)	(2,912.8)	(2,911.5)
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	(7,295.3)	(7,480.6)	(7,667.8)	(7,854.9)	(8,042.5)	(8,231.7)	(8,422.0)	(8,614.4)	(8,808.6)	(9,003.9)	(9,200.6)	(9,398.1)	(9,600.0)	(8,431.1)
484.00 Transportation equipment	(19,231.9)	(19,611.8)	(19,992.6)	(20,372.9)	(20,752.9)	(21,133.5)	(21,514.6)	(21,896.3)	(22,278.8)	(22,661.6)	(23,044.7)	(23,427.9)	(23,813.9)	(21,517.5)
484.01 N.G.V .kits Co. vehicles	(5,661.6)	(5,704.2)	(5,746.7)	(5,788.9)	(5,831.1)	(5,873.1)	(5,914.9)	(5,956.7)	(5,998.4)	(6,039.9)	(6,081.3)	(6,122.6)	(6,163.7)	(5,914.2)
484.02 N.G.V. cyl. Co. vehicles	(810.6)	(810.1)	(809.6)	(809.1)	(808.6)	(808.2)	(807.9)	(807.5)	(807.2)	(806.9)	(806.6)	(806.4)	(806.4)	(808.1)
485.00 Heavy work equipment	(8,753.5)	(8,797.8)	(8,842.2)	(8,886.5)	(8,930.8)	(8,975.2)	(9,019.6)	(9,064.0)	(9,108.5)	(9,153.0)	(9,197.5)	(9,242.0)	(9,286.8)	(9,019.8)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	(16,126.7)	(16,177.0)	(16,227.4)	(16,277.5)	(16,327.5)	(16,377.3)	(16,427.1)	(16,476.8)	(16,526.5)	(16,576.0)	(16,625.5)	(16,674.8)	(16,724.5)	(16,426.6)
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	(1,010.2)	(1,010.0)	(1,009.8)	(1,009.7)	(1,009.5)	(1,009.4)	(1,009.4)	(1,009.4)	(1,009.4)	(1,009.5)	(1,009.6)	(1,009.7)	(1,009.9)	(1,009.6)
487.80 N.G.V. compressor stations	(2,382.7)	(2,396.7)	(2,411.3)	(2,425.8)	(2,440.4)	(2,455.5)	(2,470.9)	(2,487.0)	(2,503.6)	(2,520.4)	(2,537.7)	(2,555.3)	(2,574.3)	(2,473.6)
487.90 N.G.V. rental cylinders	(1,522.7)	(1,553.4)	(1,584.2)	(1,615.0)	(1,645.8)	(1,676.7)	(1,707.6)	(1,738.6)	(1,769.6)	(1,800.7)	(1,831.8)	(1,862.9)	(1,894.2)	(1,707.9)
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	(1,469.8)	(1,501.1)	(1,532.4)	(1,563.8)	(1,595.1)	(1,626.4)	(1,657.8)	(1,689.1)	(1,720.4)	(1,751.8)	(1,783.1)	(1,814.3)	(1,845.6)	(1,657.8)
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	(25,079.4)	(25,403.3)	(25,703.0)	(25,984.5)	(26,245.5)	(26,486.2)	(26,703.9)	(26,906.5)	(27,084.3)	(27,246.8)	(27,435.8)	(27,602.6)	(27,748.5)	(26,601.4)
491.00 Software acquired intangibles	(34,545.9)	(34,726.6)	(34,883.3)	(35,019.4)	(35,133.7)	(35,226.3)	(35,295.6)	(35,346.1)	(35,372.3)	(35,379.5)	(35,391.9)	(35,381.5)	(35,349.1)	(35,175.3)
491.00 Software developed intangibles	(24,898.7)	(25,514.7)	(26,121.3)	(26,722.8)	(27,317.7)	(27,906.0)	(28,485.7)	(29,324.9)	(30,154.3)	(30,980.5)	(31,833.9)	(32,679.3)	(33,517.9)	(28,854.1)
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
489.00 WAMS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gen. Plant Acc. Depr. - After Adj.	(157,681.2)	(159,652.0)	(161,568.7)	(163,440.2)	(165,262.9)	(167,064.7)	(168,813.5)	(170,791.3)	(172,713.3)	(174,599.2)	(176,546.1)	(178,440.9)	(180,296.6)	(168,990.2)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS GENERAL PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

General plant - gross After Adjustments	Col. 1 Dec. $(000)	Col. 2 Jan. $(000)	Col. 3 Feb. $(000)	Col. 4 Mar. $(000)	Col. 5 April $(000)	Col. 6 May $(000)	Col. 7 June $(000)	Col. 8 July $(000)	Col. 9 Aug. $(000)	Col. 10 Sep. $(000)	Col. 11 Oct. $(000)	Col. 12 Nov. $(000)	Col. 13 Dec. $(000)	Col. 14 Monthly Avgs. $(000)
482.50 Leasehold improvements	13,720.8	13,720.8	13,720.8	13,720.8	16,720.8	16,720.8	16,720.8	16,720.8	16,720.8	16,720.8	16,720.8	16,840.8	16,840.8	15,860.8
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	3,185.8	3,191.7	3,197.5	3,203.3	3,209.1	3,214.9	3,220.7	3,227.6	3,234.4	3,241.2	3,248.0	3,255.8	3,263.6	3,222.4
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	23,158.0	23,379.3	23,374.7	23,420.4	23,595.1	23,731.0	23,954.7	24,156.7	24,286.0	24,434.4	24,529.4	25,036.3	27,493.6	24,102.0
484.00 Transportation equipment	51,755.2	51,849.9	51,790.4	51,765.3	51,828.2	51,864.6	51,961.1	52,043.3	52,075.8	52,121.5	52,130.6	52,421.6	54,044.4	52,062.7
484.01 N.G.V .kits Co. vehicles	8,451.1	8,435.8	8,415.5	8,396.2	8,379.9	8,362.7	8,347.3	8,331.6	8,314.3	8,297.3	8,279.2	8,270.2	8,304.1	8,350.6
484.02 N.G.V. cyl. Co. vehicles	908.4	931.3	931.5	936.8	955.0	969.3	992.5	1,013.5	1,027.2	1,042.9	1,053.2	1,104.8	1,351.7	1,007.3
485.00 Heavy work equipment	22,708.6	22,727.8	22,708.4	22,697.6	22,708.8	22,713.4	22,733.0	22,749.0	22,752.6	22,759.5	22,757.3	22,825.5	23,226.7	22,758.4
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	38,951.8	38,947.3	38,872.6	38,813.5	38,794.6	38,763.5	38,759.8	38,749.6	38,716.8	38,689.9	38,646.5	38,731.5	39,423.4	38,806.1
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	2,400.1	2,473.8	2,479.2	2,499.9	2,559.5	2,607.4	2,681.9	2,750.0	2,796.1	2,848.2	2,884.0	3,044.6	3,795.1	2,726.9
487.80 N.G.V. compressor stations	5,215.4	5,306.5	5,296.2	5,308.4	5,378.5	5,431.2	5,523.3	5,606.2	5,656.4	5,715.2	5,750.0	5,970.1	7,065.4	5,590.2
487.90 N.G.V. rental cylinders	1,948.3	1,952.1	1,952.5	1,953.6	1,956.7	1,959.2	1,963.0	1,966.5	1,968.9	1,971.6	1,973.5	1,981.6	2,019.3	1,965.3
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	3,904.3	3,904.0	3,903.7	3,903.5	3,903.2	3,902.9	3,902.7	3,902.4	3,902.1	3,901.9	3,901.6	3,901.3	3,901.1	3,902.7
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	37,869.3	37,077.4	36,477.6	35,810.0	35,146.3	34,386.8	33,898.4	33,085.0	32,578.5	33,451.3	32,723.5	32,032.9	33,884.5	34,378.7
491.00 Software acquired intangibles	59,543.6	58,450.4	57,510.9	56,517.2	55,526.6	54,459.4	53,609.1	52,498.8	51,633.9	51,872.5	50,830.6	49,818.5	50,840.2	53,993.3
491.00 Software developed intangibles	67,485.9	66,957.1	66,666.1	66,291.1	65,921.0	65,432.3	80,095.2	79,539.8	79,364.2	80,895.6	80,446.2	80,042.8	82,785.6	73,898.9
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
489.00 WAMS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	58,550.0	2,439.6
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
General Plant Gross - After Adj.	341,206.6	339,305.2	337,297.6	335,237.6	336,583.3	334,519.4	348,363.5	346,340.8	345,028.0	347,963.8	345,874.4	345,278.3	416,789.5	345,065.9

General plant - Depreciation Rates	Jan. %	Feb. %	Mar. %	April %	May %	June %	July %	Aug. %	Sep. %	Oct. %	Nov. %	Dec. %	Annual %
482.50 Leasehold improvements	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	10.00%
483.1 Office equipment over 6.6 yrs.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
483.1 Office equipment over 15 yrs.	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.150%
483.2 Office furniture over 6.6 yrs.	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	10.740%
483.2 Office furniture over 20 yrs.	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	10.740%
484.00 Transportation equipment	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	10.560%
484.01 N.G.V .kits Co. vehicles	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	9.000%
484.02 N.G.V. cyl. Co. vehicles	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	2.100%
485.00 Heavy work equipment	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	3.580%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
486.00 Tools & work euip. over 2.69 yrs	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	4.080%
486.00 Tools & work euip. 4.0%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	4.080%
487.70 V.R.A.'S	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.740%
487.70 V.R.A.'S Post F2003 5%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.740%
487.80 N.G.V. compressor stations	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	8.010%
487.90 N.G.V. rental cylinders	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	18.930%
488.00 Communication str & equip	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	9.710%
488.00 Communication str & equip 20yrs	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	9.710%
490.00 Computer equipment	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	36.630%
490.00 Computer equipment 2003 B 20%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	36.630%
491.00 Software acquired intangibles	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	26.320%
491.00 Software developed intangibles	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	21.240%
491.00 CIS software acquired intangibles	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	10.000%
489.00 WAMS	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	10.000%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%

General plant - Depreciation Provision - After Adjustments	Jan. $(000)	Feb. $(000)	Mar. $(000)	April $(000)	May $(000)	June $(000)	July $(000)	Aug. $(000)	Sep. $(000)	Oct. $(000)	Nov. $(000)	Dec. $(000)	Depr.Provision $(000)
482.50 Leasehold improvements	(114.3)	(114.3)	(114.3)	(114.3)	(139.3)	(139.3)	(139.3)	(139.3)	(139.3)	(139.3)	(139.3)	(140.3)	(1,572.6)
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(4.8)
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	(207.3)	(209.2)	(209.2)	(209.6)	(211.2)	(212.4)	(214.4)	(216.2)	(217.4)	(218.7)	(219.5)	(224.1)	(2,569.2)
484.00 Transportation equipment	(455.4)	(456.3)	(455.8)	(455.5)	(456.1)	(456.4)	(457.3)	(458.0)	(458.3)	(458.7)	(458.7)	(461.3)	(5,487.8)
484.01 N.G.V .kits Co. vehicles	(63.4)	(63.3)	(63.1)	(63.0)	(62.8)	(62.7)	(62.6)	(62.5)	(62.4)	(62.2)	(62.1)	(62.0)	(752.1)
484.02 N.G.V. cyl. Co. vehicles	(1.6)	(1.6)	(1.6)	(1.6)	(1.7)	(1.7)	(1.7)	(1.8)	(1.8)	(1.8)	(1.8)	(1.9)	(20.6)
485.00 Heavy work equipment	(67.7)	(67.8)	(67.7)	(67.7)	(67.7)	(67.8)	(67.8)	(67.9)	(67.9)	(67.9)	(67.9)	(68.1)	(813.9)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	(132.4)	(132.4)	(132.2)	(132.0)	(131.9)	(131.8)	(131.8)	(131.7)	(131.6)	(131.5)	(131.4)	(131.7)	(1,582.4)
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	(1.5)	(1.5)	(1.5)	(1.5)	(1.6)	(1.6)	(1.7)	(1.7)	(1.7)	(1.8)	(1.8)	(1.9)	(19.8)
487.80 N.G.V. compressor stations	(34.8)	(35.4)	(35.4)	(35.4)	(35.9)	(36.3)	(36.9)	(37.4)	(37.8)	(38.1)	(38.4)	(39.9)	(441.7)
487.90 N.G.V. rental cylinders	(30.7)	(30.8)	(30.8)	(30.8)	(30.9)	(30.9)	(31.0)	(31.0)	(31.1)	(31.1)	(31.1)	(31.3)	(371.5)
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(379.2)
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	(1,156.0)	(1,131.8)	(1,113.5)	(1,093.1)	(1,072.8)	(1,049.7)	(1,034.7)	(1,009.9)	(994.5)	(1,021.1)	(998.9)	(977.8)	(12,653.8)
491.00 Software acquired intangibles	(1,306.0)	(1,282.0)	(1,261.4)	(1,239.6)	(1,217.9)	(1,194.5)	(1,175.8)	(1,151.5)	(1,132.5)	(1,137.7)	(1,114.9)	(1,092.7)	(14,306.5)
491.00 Software developed intangibles	(1,194.5)	(1,185.1)	(1,180.0)	(1,173.4)	(1,166.8)	(1,158.2)	(1,417.7)	(1,407.9)	(1,404.7)	(1,431.9)	(1,423.9)	(1,416.8)	(15,560.9)
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
489.00 WAMS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	(4,797.6)	(4,743.5)	(4,698.5)	(4,649.5)	(4,628.6)	(4,575.3)	(4,804.7)	(4,748.8)	(4,713.0)	(4,773.8)	(4,721.7)	(4,681.8)	(56,536.8)

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
DISTRIBUTION PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

Distribution plant - Net.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
470.00 Land	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	29,028.8	29,028.8	29,028.8	27,994.9
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	5,448.7	5,441.4	5,434.1	5,426.8	5,419.4	5,412.1	5,404.8	5,397.5	5,390.2	5,382.9	94,743.6	94,648.4	94,553.1	24,008.5
472.00 Structures & improvements	108,816.0	109,318.5	109,707.5	110,300.3	110,695.4	110,402.3	110,288.9	110,031.6	109,792.0	109,518.9	109,343.2	109,264.3	109,410.5	109,814.7
473/474 Services, house regs. & meter inst	1,320,771.9	1,332,418.2	1,338,374.4	1,343,930.9	1,349,116.7	1,354,481.1	1,360,671.2	1,367,641.1	1,374,799.0	1,382,354.3	1,389,911.3	1,399,367.1	1,413,176.6	1,363,336.6
475.00 Mains	1,852,185.7	1,864,779.2	1,877,297.2	1,890,186.9	1,902,307.6	1,913,158.6	1,924,082.8	1,935,141.7	1,943,931.6	1,954,137.1	2,383,429.8	2,394,305.9	2,421,474.5	2,009,965.7
476.00 Company NGV compressor stations	669.3	659.3	647.6	637.0	627.8	618.1	614.5	608.5	601.5	601.6	598.3	591.7	623.7	621.0
477.00 Measuring & regulating equip.	203,727.2	205,011.7	206,330.2	208,005.4	209,642.3	211,334.1	213,378.1	215,276.1	216,754.1	218,540.4	295,437.3	297,294.4	302,352.5	229,170.3
478.00 Meters	269,413.9	267,501.4	265,638.9	263,806.2	262,004.0	260,537.9	259,377.0	258,067.3	256,878.1	255,644.4	254,636.4	253,765.5	253,955.8	259,961.8
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Distribution Plant - After Adj.	3,788,755.5	3,812,852.5	3,831,152.7	3,850,016.3	3,867,536.0	3,883,667.0	3,901,540.1	3,919,886.6	3,935,869.3	3,953,902.4	4,557,128.7	4,578,266.1	4,624,575.5	4,024,873.5

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION DISTRIBUTION PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

Distribution plant - Acc. Depr. After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
470.00 Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	(1,998.1)	(2,005.4)	(2,012.7)	(2,020.0)	(2,027.4)	(2,034.7)	(2,042.0)	(2,049.3)	(2,056.6)	(2,063.9)	(2,071.2)	(2,166.4)	(2,261.7)	(2,056.6)
472.00 Structures & improvements	(20,433.6)	(20,547.8)	(21,165.5)	(21,789.3)	(22,420.9)	(21,560.7)	(22,190.7)	(22,824.7)	(23,461.0)	(24,100.7)	(24,743.1)	(25,388.7)	(26,039.1)	(22,785.8)
473/474 Services, house regs. & meter inst	(1,034,492.0)	(1,033,322.8)	(1,032,096.4)	(1,031,319.9)	(1,031,274.0)	(1,031,799.7)	(1,032,686.1)	(1,033,813.3)	(1,034,856.4)	(1,035,881.6)	(1,036,529.3)	(1,036,489.4)	(1,034,955.8)	(1,033,732.7)
475.00 Mains	(1,259,254.6)	(1,259,524.7)	(1,259,736.6)	(1,260,776.1)	(1,263,136.4)	(1,266,840.7)	(1,271,490.6)	(1,276,430.8)	(1,281,355.2)	(1,286,212.5)	(1,290,642.6)	(1,294,995.8)	(1,297,796.1)	(1,274,138.9)
476.00 Company NGV compressor stations	(1,920.5)	(1,923.6)	(1,926.6)	(1,929.6)	(1,932.7)	(1,935.6)	(1,938.6)	(1,941.5)	(1,944.5)	(1,947.4)	(1,950.4)	(1,953.3)	(1,956.2)	(1,938.5)
477.00 Measuring & regulating equip.	(197,746.5)	(198,276.7)	(198,809.9)	(199,349.7)	(199,899.1)	(200,458.3)	(201,025.7)	(201,598.6)	(202,175.7)	(202,756.0)	(203,338.6)	(204,052.0)	(204,763.3)	(201,082.9)
478.00 Meters	(156,006.2)	(158,191.5)	(160,378.9)	(162,568.8)	(164,761.5)	(166,957.2)	(169,158.5)	(171,367.8)	(173,584.0)	(175,808.1)	(178,039.8)	(180,280.9)	(182,532.5)	(169,197.2)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dist. Plant Acc. Dep. - After Adj.	(2,671,851.5)	(2,673,792.5)	(2,676,126.6)	(2,679,753.4)	(2,685,452.0)	(2,691,586.9)	(2,700,532.2)	(2,710,026.0)	(2,719,433.4)	(2,728,770.2)	(2,737,315.0)	(2,745,326.5)	(2,750,304.7)	(2,704,932.6)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS DISTRIBUTION PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
Distribution plant - gross After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
470.00 Land	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	29,028.8	29,028.8	29,028.8	27,994.9
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	96,814.8	96,814.8	96,814.8	26,065.1
472.00 Structures & improvements	129,249.6	129,866.3	130,873.0	132,089.6	133,116.3	131,963.0	132,479.6	132,856.3	133,253.0	133,619.6	134,086.3	134,653.0	135,449.6	132,600.5
473/474 Services, house regs. & meter inst.	2,355,263.9	2,365,741.0	2,370,470.8	2,375,250.8	2,380,390.7	2,386,280.8	2,393,357.3	2,401,454.4	2,409,655.4	2,418,235.9	2,426,440.6	2,435,856.5	2,448,132.4	2,397,069.4
475.00 Mains	3,111,440.3	3,124,303.9	3,137,033.8	3,150,963.0	3,165,444.0	3,179,999.3	3,195,573.4	3,211,572.5	3,225,286.8	3,240,349.6	3,674,072.4	3,689,301.7	3,719,270.6	3,284,104.7
476.00 Company NGV compressor stations	2,589.8	2,582.9	2,574.2	2,566.6	2,560.5	2,553.7	2,553.1	2,550.0	2,546.0	2,549.0	2,548.7	2,545.0	2,579.9	2,559.5
477.00 Measuring & regulating equip.	401,473.7	403,288.4	405,140.1	407,355.1	409,541.4	411,792.4	414,403.8	416,874.7	418,929.8	421,296.4	498,775.9	501,346.4	507,115.8	430,253.3
478.00 Meters	425,420.1	425,692.9	426,017.8	426,375.0	426,765.5	427,495.1	428,535.5	429,435.1	430,462.1	431,452.5	432,676.2	434,046.4	436,488.3	429,159.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Distribution Plant Gross - After Adj.	6,460,607.0	6,486,645.0	6,507,279.3	6,529,769.7	6,552,988.0	6,575,253.9	6,602,072.3	6,629,912.6	6,655,302.7	6,682,672.6	7,294,443.7	7,323,592.6	7,374,880.2	6,729,806.4
Distribution plant - Depreciation Rates		Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Annual
		%	%	%	%	%	%	%	%	%	%	%	%	%
470.00 Land		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
470.01 Offers to purchase land		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
471.00 Land rights intangibles		0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	1.180%
472.00 Structures & improvements		0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	7.550%
473/474 Services, house regs. & meter inst.		0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	2.450%
475.00 Mains		0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	2.454%
476.00 Company NGV compressor stations		0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	5.970%
477.00 Measuring & regulating equip.		0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	2.100%
478.00 Meters		0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	9.220%
4??.00 Available		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
Distribution plant - Depreciation Provision - After Adjustments		Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Depr.Provision
		$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	
470.00 Land		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
470.01 Offers to purchase land		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles		(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(95.2)	(95.2)	(263.4)
472.00 Structures & improvements		(813.2)	(817.1)	(823.4)	(831.1)	(837.5)	(830.3)	(833.5)	(835.9)	(838.4)	(840.7)	(843.6)	(847.2)	(9,991.9)
473/474 Services, house regs. & meter inst.		(4,808.7)	(4,830.1)	(4,839.7)	(4,849.5)	(4,860.0)	(4,872.0)	(4,886.4)	(4,903.0)	(4,919.7)	(4,937.2)	(4,954.0)	(4,973.2)	(58,633.5)
475.00 Mains		(6,361.6)	(6,387.9)	(6,413.9)	(6,442.4)	(6,472.0)	(6,501.8)	(6,533.6)	(6,566.3)	(6,594.4)	(6,625.2)	(7,511.9)	(7,543.1)	(79,954.1)
476.00 Company NGV compressor stations		(12.9)	(12.8)	(12.8)	(12.8)	(12.7)	(12.7)	(12.7)	(12.7)	(12.7)	(12.7)	(12.7)	(12.7)	(152.9)
477.00 Measuring & regulating equip.		(702.6)	(705.8)	(709.0)	(712.9)	(716.7)	(720.6)	(725.2)	(729.5)	(733.1)	(737.3)	(872.9)	(877.4)	(8,943.0)
478.00 Meters		(3,268.6)	(3,270.7)	(3,273.2)	(3,276.0)	(3,279.0)	(3,284.6)	(3,292.6)	(3,299.5)	(3,307.4)	(3,315.0)	(3,324.4)	(3,334.9)	(39,525.9)
4??.00 Available		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		(15,974.9)	(16,031.7)	(16,079.3)	(16,132.0)	(16,185.2)	(16,229.3)	(16,291.3)	(16,354.2)	(16,413.0)	(16,475.4)	(17,614.7)	(17,683.7)	(197,464.7)

LOCAL STORAGE PLANT, PLANT HELD FOR FUTURE USE, AND OTHER PLANT - CONTINUITY WORKSHEETS
CALENDAR 2016 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	
														Net change	Average of
Local Storage Plant	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.		Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
A/c # 440.00 Land															
Opening balance	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5		
Expenditures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	0.0	21.5
Plant Held for														Net change	Average of
Future Use - Gross	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.		Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
A/c # 102.00															
Opening balance	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9		
Expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	0.0	1,670.9
Plant Held for															
Future Use - Accum. Depr.															
A/c # 105.02															
Opening balance	(1,253.4)	(1,253.4)	(1,256.8)	(1,260.2)	(1,263.6)	(1,267.0)	(1,270.4)	(1,273.8)	(1,277.2)	(1,280.6)	(1,284.0)	(1,287.4)	(1,290.8)		
Provision		(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.5)	(40.9)	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Costs net of Proceeds		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	(1,253.4)	(1,256.8)	(1,260.2)	(1,263.6)	(1,267.0)	(1,270.4)	(1,273.8)	(1,277.2)	(1,280.6)	(1,284.0)	(1,287.4)	(1,290.8)	(1,294.3)	(40.9)	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	(1,253.4)	(1,256.8)	(1,260.2)	(1,263.6)	(1,267.0)	(1,270.4)	(1,273.8)	(1,277.2)	(1,280.6)	(1,284.0)	(1,287.4)	(1,290.8)	(1,294.3)	(40.9)	(1,273.8)
Plant Held for Future Use - Net	417.5	414.1	410.7	407.3	403.9	400.5	397.1	393.7	390.3	386.9	383.5	380.1	376.6	(40.9)	397.1
														Net change	Average of
Other Plant - Gross	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.		Monthly Avgs.
A/c # 402.50	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
Intangible Plant (Peterborough)															
Opening balance	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3		
Expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	0.0	465.3
Other Plant - Acc.Depr.															
A/c # 402.50															
Intangible Plant (Peterborough)															
Opening balance	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)		
Provision		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Costs net of Proceeds		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	0.0	(465.3)
Other Plant - Net	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
UNDERGROUND STORAGE PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
Underground Storage Plant - Net. After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1
451 Land rights Tecumseh	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7
451.1 Land rights intangibles Tecumseh	15,136.5	15,097.1	15,057.8	15,018.4	14,979.1	14,939.7	14,900.4	14,861.0	14,821.7	14,782.3	14,743.0	14,703.6	14,664.2	14,900.4
452 Struct. & Improve. Tecumseh	31,242.7	31,270.8	31,591.4	31,764.6	31,789.4	31,892.3	32,064.8	32,100.4	32,250.7	32,303.9	32,292.0	33,283.3	37,164.1	32,233.9
453 Wells Tecumseh	41,197.0	41,147.2	41,210.0	44,173.0	44,120.2	44,098.7	44,104.8	44,058.6	44,056.4	44,016.7	43,951.6	44,271.3	45,701.1	43,554.8
454 Well Equipment Tecumseh	2,863.2	2,818.9	2,774.6	2,730.3	2,685.9	2,641.6	2,597.3	2,553.0	2,508.6	2,464.3	2,420.0	2,375.7	2,331.3	2,597.3
455 Field Lines Tecumseh	42,041.5	41,954.8	41,916.3	41,855.1	41,772.1	41,704.8	41,651.0	41,575.0	41,517.9	41,444.6	41,359.7	41,438.3	41,991.5	41,683.8
456 Compressor Equip. Tecumseh	71,146.7	70,872.7	70,608.8	70,342.8	70,076.6	69,818.5	69,566.6	69,310.7	69,058.8	68,803.1	68,543.3	68,314.7	68,182.1	69,581.8
457 Meas. & Reg. Tecumseh	8,046.4	8,007.3	7,968.8	7,930.3	7,891.9	7,854.1	7,816.7	7,779.1	7,741.8	7,704.2	7,666.3	7,630.3	7,600.2	7,817.8
458 Base Pressure Gas Tecumseh	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Underground Storage - After Adj.	257,911.5	257,406.3	257,365.2	260,052.0	259,552.7	259,187.2	258,939.1	258,475.3	258,193.4	257,756.6	257,213.4	258,254.7	263,872.0	258,607.3

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION UNDERGROUND STORAGE PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

Underground Storage Plant - Accum. Depr. After Adjustments	Col. 1 Dec. $(000)	Col. 2 Jan. $(000)	Col. 3 Feb. $(000)	Col. 4 Mar. $(000)	Col. 5 April $(000)	Col. 6 May $(000)	Col. 7 June $(000)	Col. 8 July $(000)	Col. 9 Aug. $(000)	Col. 10 Sep. $(000)	Col. 11 Oct. $(000)	Col. 12 Nov. $(000)	Col. 13 Dec. $(000)	Col. 14 Monthly Avgs. $(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451 Land rights Tecumseh	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7
451.1 Land rights intangibles Tecumseh	(25,575.5)	(25,614.9)	(25,654.2)	(25,693.6)	(25,732.9)	(25,772.3)	(25,811.6)	(25,851.0)	(25,890.3)	(25,929.7)	(25,969.0)	(26,008.4)	(26,047.8)	(25,811.6)
452 Struct. & Improve. Tecumseh	(6,711.4)	(6,726.2)	(6,741.2)	(6,756.6)	(6,772.4)	(6,788.2)	(6,804.1)	(6,820.4)	(6,836.8)	(6,853.3)	(6,870.0)	(6,886.8)	(6,905.0)	(6,805.4)
453 Wells Tecumseh	(18,442.5)	(18,525.4)	(18,608.4)	(18,690.9)	(18,776.0)	(18,859.8)	(18,942.8)	(19,025.6)	(19,108.6)	(19,191.8)	(19,275.4)	(19,360.1)	(19,446.7)	(18,942.5)
454 Well Equipment Tecumseh	(6,703.9)	(6,748.2)	(6,792.5)	(6,836.8)	(6,881.2)	(6,925.5)	(6,969.8)	(7,014.1)	(7,058.5)	(7,102.8)	(7,147.1)	(7,191.4)	(7,235.8)	(6,969.8)
455 Field Lines Tecumseh	(26,357.9)	(26,453.4)	(26,549.1)	(26,643.2)	(26,734.7)	(26,823.4)	(26,910.0)	(26,996.3)	(27,082.7)	(27,169.3)	(27,256.8)	(27,346.5)	(27,439.1)	(26,905.3)
456 Compressor Equip. Tecumseh	(41,825.5)	(42,102.5)	(42,379.8)	(42,654.0)	(42,923.2)	(43,187.0)	(43,447.1)	(43,706.4)	(43,965.7)	(44,225.4)	(44,486.9)	(44,752.6)	(45,024.2)	(43,438.0)
457 Meas. & Reg. Tecumseh	(6,673.6)	(6,712.9)	(6,752.2)	(6,791.2)	(6,829.8)	(6,868.0)	(6,905.9)	(6,943.7)	(6,981.5)	(7,019.3)	(7,057.3)	(7,095.6)	(7,134.3)	(6,905.1)
458 Base Pressure Gas Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Undgnd Storage Acc. Dep. - After Adj.	(130,788.6)	(131,381.8)	(131,975.7)	(132,564.6)	(133,148.5)	(133,722.5)	(134,289.6)	(134,855.8)	(135,422.4)	(135,989.9)	(136,560.8)	(137,139.7)	(137,731.2)	(134,276.0)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS DISTRIBUTION PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
Underground Storage Plant-Gross After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1
451 Land rights Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451.1 Land rights intangibles Tecumseh	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0
452 Struct. & Improve. Tecumseh	37,954.1	37,997.0	38,332.6	38,521.2	38,561.8	38,680.5	38,868.9	38,920.8	39,087.5	39,157.2	39,162.0	40,170.1	44,069.1	39,039.3
453 Wells Tecumseh	59,639.5	59,672.6	59,818.4	62,863.9	62,896.2	62,958.5	63,047.6	63,084.2	63,165.0	63,208.5	63,227.0	63,631.4	65,147.8	62,497.2
454 Well Equipment Tecumseh	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1
455 Field Lines Tecumseh	68,399.4	68,408.2	68,465.4	68,498.3	68,506.8	68,528.2	68,561.0	68,571.3	68,600.6	68,613.9	68,616.5	68,784.8	69,430.6	68,589.2
456 Compressor Equip. Tecumseh	112,972.2	112,975.2	112,988.6	112,996.8	112,999.8	113,005.5	113,013.7	113,017.1	113,024.5	113,028.5	113,030.2	113,067.3	113,206.3	113,019.7
457 Meas. & Reg. Tecumseh	14,720.0	14,720.2	14,721.0	14,721.5	14,721.7	14,722.1	14,722.6	14,722.8	14,723.3	14,723.5	14,723.6	14,725.9	14,734.5	14,723.0
458 Base Pressure Gas Tecumseh	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Undgnd Storage Gross - After Adj.	388,700.1	388,788.1	389,340.9	392,616.6	392,701.2	392,909.7	393,228.7	393,331.1	393,615.8	393,746.5	393,774.2	395,394.4	401,603.2	392,883.3

Underground Storage Plant- Depreciation Rates	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Annual Prov.
	%	%	%	%	%	%	%	%	%	%	%	%	%
450/459 Crowland (Avg of all other storage categories)	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	2.480%
450 Land Tecumseh	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
451 Land rights Tecumseh	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	1.160%
451.1 Land rights intangibles Tecumseh	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	1.160%
452 Struct. & Improve. Tecumseh	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	1.840%
453 Wells Tecumseh	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	1.550%
454 Well Equipment Tecumseh	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	5.560%
455 Field Lines Tecumseh	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	1.550%
456 Compressor Equip. Tecumseh	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	2.690%
457 Meas. & Reg. Tecumseh	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	3.040%
458 Base Pressure Gas Tecumseh	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
??? Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%

Underground Storage Plant- Depreciation Provision - After Adjustments	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Depr.Provision
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451 Land rights Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451.1 Land rights intangibles Tecumseh	(39.4)	(39.4)	(39.4)	(39.4)	(39.4)	(39.4)	(39.4)	(39.4)	(39.4)	(39.4)	(39.4)	(39.4)	(472.8)
452 Struct. & Improve. Tecumseh	(58.2)	(58.3)	(58.8)	(59.1)	(59.1)	(59.3)	(59.6)	(59.7)	(59.9)	(60.0)	(60.0)	(61.6)	(713.6)
453 Wells Tecumseh	(77.0)	(77.1)	(77.3)	(81.2)	(81.2)	(81.3)	(81.4)	(81.5)	(81.6)	(81.6)	(81.7)	(82.2)	(965.1)
454 Well Equipment Tecumseh	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(531.6)
455 Field Lines Tecumseh	(88.3)	(88.4)	(88.4)	(88.5)	(88.5)	(88.5)	(88.6)	(88.6)	(88.6)	(88.6)	(88.6)	(88.8)	(1,062.4)
456 Compressor Equip. Tecumseh	(253.2)	(253.3)	(253.3)	(253.3)	(253.3)	(253.3)	(253.3)	(253.3)	(253.4)	(253.4)	(253.4)	(253.5)	(3,040.0)
457 Meas. & Reg. Tecumseh	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(447.6)
458 Base Pressure Gas Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	(597.7)	(598.1)	(598.8)	(603.1)	(603.1)	(603.4)	(603.9)	(604.1)	(604.5)	(604.6)	(604.7)	(607.1)	(7,233.1)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS GENERAL PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

General plant - gross	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	/onthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	16,840.8	16,840.8	16,840.8	16,840.8	16,840.8	16,840.8	16,840.8	16,840.8	16,840.8	16,840.8	16,840.8	17,110.8	17,110.8	16,874.6
483.1 Office equipment over 6.6 y	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yr	3,263.6	3,269.4	3,275.2	3,281.0	3,286.8	3,292.6	3,298.5	3,305.3	3,312.1	3,318.9	3,325.7	3,333.5	3,341.4	3,300.1
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	27,493.6	27,634.6	27,564.2	27,541.0	27,638.4	27,699.5	27,842.8	27,965.7	28,020.5	28,093.4	28,116.1	28,524.3	30,757.9	27,980.5
484.00 Transportation equipment	54,044.4	54,137.8	54,079.7	54,061.7	54,146.3	54,200.0	54,323.7	54,430.9	54,480.2	54,544.8	54,566.7	54,917.5	56,821.9	54,443.5
484.01 N.G.V .kits Co. vehicles	8,304.1	8,288.9	8,268.6	8,249.4	8,233.2	8,216.1	8,200.9	8,185.3	8,168.0	8,151.1	8,133.1	8,124.3	8,159.2	8,204.2
484.02 N.G.V. cyl. Co. vehicles	1,351.7	1,375.1	1,375.4	1,380.8	1,399.4	1,414.1	1,437.8	1,459.3	1,473.4	1,489.4	1,500.0	1,552.8	1,805.1	1,453.0
485.00 Heavy work equipment	23,226.7	23,273.8	23,256.7	23,253.9	23,287.8	23,310.6	23,358.4	23,400.3	23,421.5	23,448.2	23,459.7	23,588.6	24,272.4	23,400.8
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	39,423.4	39,413.2	39,332.7	39,267.9	39,243.2	39,206.4	39,197.0	39,181.1	39,142.5	39,109.9	39,060.7	39,140.0	39,826.3	39,243.3
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	3,795.1	3,868.9	3,874.3	3,895.1	3,954.8	4,002.7	4,077.4	4,145.7	4,191.9	4,244.1	4,280.0	4,441.0	5,193.1	4,122.5
487.80 N.G.V. compressor stations	13,065.4	13,161.9	13,152.1	13,165.9	13,240.5	13,296.8	13,394.4	13,482.3	13,536.0	13,598.6	13,636.1	13,867.9	15,017.4	13,464.5
487.90 N.G.V. rental cylinders	2,019.3	2,023.2	2,023.6	2,024.7	2,027.9	2,030.5	2,034.4	2,038.0	2,040.5	2,043.3	2,045.2	2,053.6	2,092.4	2,036.7
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip	3,901.1	3,900.8	3,900.5	3,900.2	3,900.0	3,899.7	3,899.4	3,899.1	3,898.9	3,898.6	3,898.3	3,898.0	3,897.8	3,899.4
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003	33,884.5	33,364.7	33,107.4	32,757.4	32,412.9	31,937.4	31,832.3	31,283.2	31,153.4	32,908.6	32,476.4	32,095.1	35,188.0	32,488.8
491.00 Software acquired intangibl	50,840.2	49,579.3	48,415.7	47,217.7	46,021.7	44,777.2	44,870.0	43,598.2	42,481.8	42,064.3	40,835.8	39,626.2	39,704.6	44,563.4
491.00 Software developed intangi	82,785.6	81,517.4	80,492.0	79,380.9	78,274.8	77,047.5	87,301.1	86,005.7	85,098.2	85,934.0	84,746.8	83,606.7	85,679.8	82,803.2
491.00 CIS software acquired intan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
489.00 WAMS	58,550.0	58,550.0	58,550.0	58,550.0	58,550.0	58,550.0	58,550.0	70,626.0	70,626.0	70,626.0	70,626.0	70,626.0	70,626.0	64,084.8
Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(5,964.5)
General Plant Gross - After Adj.	422,789.5	420,199.8	417,508.9	414,768.4	412,458.5	409,721.9	420,458.9	429,846.9	427,885.7	430,314.0	427,547.4	426,506.3	439,494.1	416,398.8

General plant -
Depreciation Rates

Depreciation Rates	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Annual
	%	%	%	%	%	%	%	%	%	%	%	%	%
482.50 Leasehold improvements	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	10.00%
483.1 Office equipment over 6.6 yrs.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
483.1 Office equipment over 15 yrs.	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.150%
483.2 Office furniture over 6.6 yrs.	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	10.740%
483.2 Office furniture over 20 yrs.	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	10.740%
484.00 Transportation equipment	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	10.560%
484.01 N.G.V .kits Co. vehicles	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	9.000%
484.02 N.G.V. cyl. Co. vehicles	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	2.100%
485.00 Heavy work equipment	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	3.580%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
486.00 Tools & work euip. over 2.69 yrs	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	4.080%
486.00 Tools & work euip. 4.0%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	4.080%
487.70 V.R.A.'S	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.740%
487.70 V.R.A.'S Post F2003 5%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.740%
487.80 N.G.V. compressor stations	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	8.010%
487.90 N.G.V. rental cylinders	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	18.930%
488.00 Communication str & equip	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	9.710%
488.00 Communication str & equip 20yrs	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	9.710%
490.00 Computer equipment	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	36.630%
490.00 Computer equipment 2003 B 20%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	36.630%
491.00 Software acquired intangibles	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	26.320%
491.00 Software developed intangibles	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	21.240%
491.00 CIS software acquired intangibles	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	10.000%
489.00 WAMS	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	10.000%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%

General plant -
Depreciation Provision - After Adjustments

Depreciation Provision - After Adjustments	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	epr.Provision
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	(140.3)	(140.3)	(140.3)	(140.3)	(140.3)	(140.3)	(140.3)	(140.3)	(140.3)	(140.3)	(140.3)	(142.6)	(1,685.9)
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(4.8)
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	(246.1)	(247.3)	(246.7)	(246.5)	(247.4)	(247.9)	(249.2)	(250.3)	(250.8)	(251.4)	(251.6)	(255.3)	(2,990.5)
484.00 Transportation equipment	(475.6)	(476.4)	(475.9)	(475.7)	(476.5)	(477.0)	(478.0)	(479.0)	(479.4)	(480.0)	(480.2)	(483.3)	(5,737.0)
484.01 N.G.V .kits Co. vehicles	(62.3)	(62.2)	(62.0)	(61.9)	(61.7)	(61.6)	(61.5)	(61.4)	(61.3)	(61.1)	(61.0)	(60.9)	(738.9)
484.02 N.G.V. cyl. Co. vehicles	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.5)	(2.5)	(2.6)	(2.6)	(2.6)	(2.6)	(2.7)	(30.1)
485.00 Heavy work equipment	(69.3)	(69.4)	(69.4)	(69.4)	(69.5)	(69.5)	(69.7)	(69.8)	(69.9)	(70.0)	(70.0)	(70.4)	(836.3)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	(134.0)	(134.0)	(133.7)	(133.5)	(133.4)	(133.3)	(133.3)	(133.2)	(133.1)	(133.0)	(132.8)	(133.1)	(1,600.4)
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	(2.3)	(2.4)	(2.4)	(2.4)	(2.4)	(2.5)	(2.5)	(2.6)	(2.6)	(2.6)	(2.6)	(2.7)	(30.0)
487.80 N.G.V. compressor stations	(87.2)	(87.9)	(87.8)	(87.9)	(88.4)	(88.8)	(89.4)	(90.0)	(90.4)	(90.8)	(91.0)	(92.6)	(1,072.2)
487.90 N.G.V. rental cylinders	(31.9)	(31.9)	(31.9)	(31.9)	(32.0)	(32.0)	(32.1)	(32.1)	(32.2)	(32.2)	(32.3)	(32.4)	(384.9)
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.5)	(31.5)	(31.5)	(31.5)	(378.8)
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	(1,034.3)	(1,018.5)	(1,010.6)	(999.9)	(989.4)	(974.9)	(971.7)	(954.9)	(951.0)	(1,004.5)	(991.3)	(979.7)	(11,880.7)
491.00 Software acquired intangibles	(1,115.1)	(1,087.4)	(1,061.9)	(1,035.6)	(1,009.4)	(982.1)	(984.1)	(956.3)	(931.8)	(922.6)	(895.7)	(869.1)	(11,851.1)
491.00 Software developed intangibles	(1,465.3)	(1,442.9)	(1,424.7)	(1,405.0)	(1,385.5)	(1,363.7)	(1,545.2)	(1,522.3)	(1,506.2)	(1,521.0)	(1,500.0)	(1,479.8)	(17,561.6)
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
489.00 WAMS	(487.9)	(487.9)	(487.9)	(487.9)	(487.9)	(487.9)	(487.9)	(588.6)	(588.6)	(588.6)	(588.6)	(588.6)	(6,358.3)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	(5,386.0)	(5,322.9)	(5,269.6)	(5,212.3)	(5,158.2)	(5,096.0)	(5,279.4)	(5,315.4)	(5,272.1)	(5,332.6)	(5,271.9)	(5,225.1)	(63,141.5)

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
DISTRIBUTION PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

Distribution plant - Net. After Adjustments	Col. 1 Dec. $(000)	Col. 2 Jan. $(000)	Col. 3 Feb. $(000)	Col. 4 Mar. $(000)	Col. 5 April $(000)	Col. 6 May $(000)	Col. 7 June $(000)	Col. 8 July $(000)	Col. 9 Aug. $(000)	Col. 10 Sep. $(000)	Col. 11 Oct. $(000)	Col. 12 Nov. $(000)	Col. 13 Dec. $(000)	Col. 14 Monthly Avgs. $(000)
470.00 Land	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	94,553.1	94,457.9	94,362.7	94,267.5	94,172.3	94,077.1	93,981.9	93,886.7	93,791.5	93,696.3	93,601.1	93,505.9	93,410.7	93,981.9
472.00 Structures & improvements	109,410.5	109,090.8	108,878.4	108,772.7	108,483.8	108,307.8	108,999.3	109,454.7	109,675.5	109,369.5	109,125.9	108,854.0	108,819.3	109,010.6
473/474 Services, house regs. & meter inst	1,413,176.6	1,425,529.4	1,432,144.5	1,438,364.6	1,444,327.2	1,450,648.0	1,458,022.1	1,466,431.8	1,475,028.8	1,484,076.1	1,493,072.6	1,504,095.8	1,519,828.2	1,461,520.3
475.00 Mains	2,412,992.4	2,423,201.7	2,433,334.1	2,443,982.8	2,453,815.1	2,462,658.6	2,471,856.4	2,481,036.3	2,488,113.9	2,496,825.7	2,507,499.6	2,518,341.1	2,547,522.1	2,471,743.5
476.00 Company NGV compressor stations	623.7	613.9	602.1	591.5	582.5	572.9	569.5	563.7	556.9	557.4	554.4	548.0	581.1	576.3
477.00 Measuring & regulating equip.	302,352.5	302,979.5	303,632.6	304,557.3	305,452.0	306,387.6	307,591.3	308,683.6	309,455.7	310,463.1	312,033.2	313,195.0	316,799.1	307,833.9
478.00 Meters	253,955.8	252,106.1	250,311.1	248,548.5	246,819.1	245,461.2	244,440.5	243,254.6	242,201.4	241,098.4	240,244.6	239,541.9	240,013.2	245,084.3
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Distribution Plant - After Adj.	4,616,093.4	4,637,008.1	4,652,294.3	4,668,113.7	4,682,680.8	4,697,142.0	4,714,489.8	4,732,340.2	4,747,852.5	4,765,115.3	4,785,160.2	4,807,110.5	4,856,002.5	4,718,779.6

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION DISTRIBUTION PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

Distribution plant - Acc. Depr. After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
470.00 Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	(2,261.7)	(2,356.9)	(2,452.1)	(2,547.3)	(2,642.5)	(2,737.7)	(2,832.9)	(2,928.1)	(3,023.3)	(3,118.5)	(3,213.7)	(3,308.9)	(3,404.1)	(2,832.9)
472.00 Structures & improvements	(26,039.1)	(26,695.5)	(27,354.6)	(23,626.9)	(24,182.5)	(24,745.2)	(24,890.3)	(25,031.6)	(25,677.5)	(26,340.1)	(27,000.4)	(27,659.0)	(28,330.3)	(25,865.7)
473/474 Services, house regs. & meter inst.	(1,034,955.8)	(1,034,263.5)	(1,033,521.8)	(1,033,196.1)	(1,033,544.1)	(1,034,414.6)	(1,035,614.8)	(1,037,043.0)	(1,038,396.8)	(1,039,739.6)	(1,040,736.8)	(1,041,104.5)	(1,040,087.4)	(1,036,591.4)
475.00 Mains	(1,297,278.1)	(1,299,399.2)	(1,301,466.2)	(1,304,296.3)	(1,308,344.9)	(1,313,632.2)	(1,319,791.2)	(1,326,219.2)	(1,332,632.7)	(1,338,985.0)	(1,344,943.6)	(1,349,935.5)	(1,353,494.4)	(1,322,600.0)
476.00 Company NGV compressor stations	(1,956.2)	(1,959.1)	(1,962.0)	(1,964.9)	(1,967.6)	(1,970.4)	(1,973.2)	(1,976.0)	(1,978.6)	(1,981.3)	(1,984.0)	(1,986.7)	(1,989.3)	(1,973.0)
477.00 Measuring & regulating equip.	(204,763.3)	(205,477.8)	(206,194.4)	(206,916.5)	(207,646.8)	(208,385.4)	(209,130.8)	(209,880.5)	(210,633.3)	(211,388.3)	(212,144.8)	(212,900.9)	(213,654.5)	(209,159.0)
478.00 Meters	(182,532.5)	(184,761.2)	(186,992.8)	(189,227.8)	(191,466.4)	(193,708.9)	(195,958.2)	(198,216.9)	(200,483.9)	(202,760.2)	(205,045.5)	(207,341.8)	(209,650.3)	(196,004.6)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dist. Plant Acc. Dep. - After Adj.	(2,749,786.7)	(2,754,913.2)	(2,759,943.9)	(2,761,775.8)	(2,769,794.8)	(2,779,594.4)	(2,790,191.4)	(2,801,295.3)	(2,812,826.1)	(2,824,313.0)	(2,835,068.8)	(2,844,237.3)	(2,850,610.3)	(2,795,026.6)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS DISTRIBUTION PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
Distribution plant - gross After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
470.00 Land	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8
472.00 Structures & improvements	135,449.6	135,786.3	136,233.0	132,399.6	132,666.3	133,053.0	133,889.6	134,486.3	135,353.0	135,709.6	136,126.3	136,513.0	137,149.6	134,876.3
473/474 Services, house regs. & meter inst.	2,448,132.4	2,459,792.9	2,465,666.3	2,471,560.7	2,477,871.3	2,485,062.6	2,493,636.9	2,503,474.8	2,513,425.6	2,523,815.7	2,533,809.4	2,545,200.3	2,559,915.6	2,498,111.7
475.00 Mains (with Adj)	3,710,270.5	3,722,600.9	3,734,800.3	3,748,279.1	3,762,160.0	3,776,290.8	3,791,647.6	3,807,255.5	3,820,746.6	3,835,810.7	3,852,443.2	3,868,276.6	3,901,016.5	3,802,800.0
mains Adj														
476.00 Company NGV compressor stations	2,579.9	2,573.0	2,564.1	2,556.4	2,550.1	2,543.3	2,542.7	2,539.7	2,535.5	2,538.7	2,538.4	2,534.7	2,570.4	2,549.3
477.00 Measuring & regulating equip.	507,115.8	508,457.3	509,827.0	511,473.8	513,098.8	514,773.0	516,722.1	518,564.1	520,089.0	521,851.4	524,178.0	526,095.9	530,453.6	516,992.9
478.00 Meters	436,488.3	436,867.3	437,303.9	437,776.3	438,285.5	439,170.1	440,398.7	441,471.5	442,685.3	443,858.6	445,290.1	446,883.7	449,663.5	441,088.9
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Distribution Plant Gross - After Adj.	7,365,880.1	7,391,921.3	7,412,238.2	7,429,889.5	7,452,475.6	7,476,736.4	7,504,681.2	7,533,635.5	7,560,678.6	7,589,428.3	7,620,229.0	7,651,347.8	7,706,612.8	7,522,262.7

Distribution plant - Depreciation Rates	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Annual
	%	%	%	%	%	%	%	%	%	%	%	%	%
470.00 Land	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
470.01 Offers to purchase land	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
471.00 Land rights intangibles	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	1.180%
472.00 Structures & improvements	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	7.550%
473/474 Services, house regs. & meter inst.	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	2.450%
475.00 Mains	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	2.454%
476.00 Company NGV compressor stations	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	5.970%
477.00 Measuring & regulating equip.	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	2.100%
478.00 Meters	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	9.220%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%

Distribution plant - Depreciation Provision - After Adjustments	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Depr.Provision
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	
470.00 Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	(95.2)	(95.2)	(95.2)	(95.2)	(95.2)	(95.2)	(95.2)	(95.2)	(95.2)	(95.2)	(95.2)	(95.2)	(1,142.4)
472.00 Structures & improvements	(852.2)	(854.3)	(857.1)	(833.0)	(834.7)	(837.1)	(842.4)	(846.1)	(851.6)	(853.8)	(856.5)	(858.9)	(10,177.7)
473/474 Services, house regs. & meter inst.	(4,998.3)	(5,022.1)	(5,034.1)	(5,046.1)	(5,059.0)	(5,073.7)	(5,091.2)	(5,111.3)	(5,131.6)	(5,152.8)	(5,173.2)	(5,196.5)	(61,089.9)
475.00 Mains	(7,586.0)	(7,611.2)	(7,636.1)	(7,663.7)	(7,692.0)	(7,720.9)	(7,752.3)	(7,784.3)	(7,811.8)	(7,842.6)	(7,876.6)	(7,909.0)	(92,886.5)
476.00 Company NGV compressor stations	(12.8)	(12.8)	(12.8)	(12.7)	(12.7)	(12.7)	(12.6)	(12.6)	(12.6)	(12.6)	(12.6)	(12.6)	(152.1)
477.00 Measuring & regulating equip.	(887.5)	(889.8)	(892.2)	(895.1)	(897.9)	(900.9)	(904.3)	(907.5)	(910.2)	(913.2)	(917.3)	(920.7)	(10,836.6)
478.00 Meters	(3,353.7)	(3,356.6)	(3,360.0)	(3,363.6)	(3,367.5)	(3,374.3)	(3,383.7)	(3,392.0)	(3,401.3)	(3,410.3)	(3,421.3)	(3,433.6)	(40,617.9)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	(17,785.7)	(17,842.0)	(17,887.5)	(17,909.4)	(17,959.0)	(18,014.8)	(18,081.7)	(18,149.0)	(18,214.3)	(18,280.5)	(18,352.7)	(18,426.5)	(216,903.1)

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
GENERAL PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

General Plant - Net. After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	9,791.8	9,699.7	9,607.6	9,515.5	9,423.5	9,331.4	9,239.3	9,147.2	9,055.2	8,963.1	8,871.0	9,048.9	8,954.6	9,273.0
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	350.8	356.4	362.0	367.6	373.2	378.8	384.4	391.0	397.6	404.2	410.8	418.3	425.9	386.1
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	17,893.6	17,874.8	17,643.4	17,459.8	17,397.0	17,297.0	17,278.7	17,238.7	17,129.5	17,037.9	16,895.5	17,138.4	19,203.1	17,411.6
484.00 Transportation equipment	30,230.5	29,925.1	29,467.4	29,050.2	28,735.9	28,389.9	28,113.4	27,819.4	27,466.5	27,128.4	26,747.1	26,694.5	28,192.5	28,229.1
484.01 N.G.V .kits Co. vehicles	2,140.4	2,083.7	2,021.9	1,961.6	1,904.3	1,846.3	1,790.4	1,734.1	1,676.2	1,618.9	1,560.6	1,511.6	1,506.6	1,794.4
484.02 N.G.V. cyl. Co. vehicles	545.3	568.4	568.4	573.5	591.8	606.2	629.5	650.6	664.2	679.7	689.8	742.1	993.8	644.5
485.00 Heavy work equipment	13,939.9	13,941.5	13,878.8	13,830.4	13,818.7	13,795.8	13,797.9	13,793.9	13,769.1	13,749.7	13,715.0	13,797.7	14,435.0	13,839.7
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	22,698.9	22,642.5	22,515.8	22,405.1	22,334.7	22,252.3	22,197.3	22,135.9	22,051.9	21,974.0	21,879.6	21,913.9	22,554.8	22,244.2
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	2,785.2	2,858.4	2,863.1	2,883.1	2,942.1	2,989.3	3,063.1	3,130.6	3,175.9	3,227.1	3,262.1	3,422.2	4,173.1	3,108.0
487.80 N.G.V. compressor stations	10,491.1	10,561.2	10,524.4	10,511.4	10,559.0	10,587.8	10,657.6	10,716.9	10,741.5	10,774.7	10,782.3	10,983.9	12,101.7	10,724.8
487.90 N.G.V. rental cylinders	125.1	97.1	65.6	34.8	6.1	(23.3)	(51.4)	(79.9)	(109.5)	(138.9)	(169.2)	(193.1)	(186.8)	(49.4)
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	2,055.5	2,023.9	1,992.3	1,960.7	1,929.1	1,897.5	1,865.9	1,834.3	1,802.7	1,771.2	1,739.7	1,708.3	1,676.9	1,866.0
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	6,136.0	5,156.6	4,455.5	3,669.6	2,899.9	2,009.7	1,504.4	558.3	48.3	1,427.2	565.2	(232.7)	2,455.3	2,196.5
491.00 Software acquired intangibles	15,491.1	14,396.4	13,426.7	12,448.1	11,497.8	10,525.2	10,917.2	9,942.6	9,151.2	9,083.2	8,213.4	7,389.4	7,880.0	10,723.1
491.00 Software developed intangibles	49,267.7	47,853.2	46,703.9	45,487.1	44,295.0	43,001.2	53,210.1	51,688.5	50,577.7	51,226.3	49,837.1	48,516.0	50,428.2	48,520.3
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
489.00 WAMS	58,550.0	58,062.1	57,574.2	57,086.3	56,598.4	56,110.5	55,622.6	67,210.7	66,622.1	66,033.5	65,444.9	64,856.3	64,267.8	61,052.5
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net General Plant - After Adj.	242,492.9	238,101.0	233,671.0	229,244.8	225,306.5	220,995.6	230,220.4	237,912.8	234,220.1	234,960.2	230,444.9	227,715.7	239,062.5	231,964.4

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION GENERAL PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

General plant - Acc. Depr. After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	(7,049.0)	(7,141.1)	(7,233.2)	(7,325.3)	(7,417.3)	(7,509.4)	(7,601.5)	(7,693.6)	(7,785.6)	(7,877.7)	(7,969.8)	(8,061.9)	(8,156.2)	(7,601.6)
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	(2,912.8)	(2,913.0)	(2,913.2)	(2,913.4)	(2,913.6)	(2,913.8)	(2,914.1)	(2,914.3)	(2,914.5)	(2,914.7)	(2,914.9)	(2,915.2)	(2,915.5)	(2,914.1)
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	(9,600.0)	(9,759.8)	(9,920.8)	(10,081.2)	(10,241.4)	(10,402.5)	(10,564.1)	(10,727.0)	(10,891.0)	(11,055.5)	(11,220.6)	(11,385.9)	(11,554.8)	(10,568.9)
484.00 Transportation equipment	(23,813.9)	(24,212.7)	(24,612.3)	(25,011.5)	(25,410.4)	(25,810.1)	(26,210.3)	(26,611.5)	(27,013.7)	(27,416.4)	(27,819.6)	(28,223.0)	(28,629.4)	(26,214.4)
484.01 N.G.V .kits Co. vehicles	(6,163.7)	(6,205.2)	(6,246.7)	(6,287.8)	(6,328.9)	(6,369.8)	(6,410.5)	(6,451.2)	(6,491.8)	(6,532.2)	(6,572.5)	(6,612.7)	(6,652.6)	(6,409.8)
484.02 N.G.V. cyl. Co. vehicles	(806.4)	(806.7)	(807.0)	(807.3)	(807.6)	(807.9)	(808.3)	(808.7)	(809.2)	(809.7)	(810.2)	(810.7)	(811.3)	(808.5)
485.00 Heavy work equipment	(9,286.8)	(9,332.3)	(9,377.9)	(9,423.5)	(9,469.1)	(9,514.8)	(9,560.5)	(9,606.4)	(9,652.4)	(9,698.5)	(9,744.7)	(9,790.9)	(9,837.4)	(9,561.1)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	(16,724.5)	(16,770.7)	(16,816.9)	(16,862.8)	(16,908.5)	(16,954.1)	(16,999.7)	(17,045.2)	(17,090.6)	(17,135.9)	(17,181.1)	(17,226.1)	(17,271.5)	(16,999.1)
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	(1,009.9)	(1,010.5)	(1,011.2)	(1,012.0)	(1,012.7)	(1,013.4)	(1,014.3)	(1,015.1)	(1,016.0)	(1,017.0)	(1,017.9)	(1,018.8)	(1,020.0)	(1,014.5)
487.80 N.G.V. compressor stations	(2,574.3)	(2,600.7)	(2,627.7)	(2,654.5)	(2,681.5)	(2,709.0)	(2,736.8)	(2,765.4)	(2,794.5)	(2,823.9)	(2,853.8)	(2,884.0)	(2,915.7)	(2,739.7)
487.90 N.G.V. rental cylinders	(1,894.2)	(1,926.1)	(1,958.0)	(1,989.9)	(2,021.8)	(2,053.8)	(2,085.8)	(2,117.9)	(2,150.0)	(2,182.2)	(2,214.4)	(2,246.7)	(2,279.2)	(2,086.1)
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	(1,845.6)	(1,876.9)	(1,908.2)	(1,939.5)	(1,970.9)	(2,002.2)	(2,033.5)	(2,064.8)	(2,096.2)	(2,127.4)	(2,158.6)	(2,189.7)	(2,220.9)	(2,033.4)
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	(27,748.5)	(28,208.1)	(28,651.9)	(29,087.8)	(29,513.0)	(29,927.7)	(30,327.9)	(30,724.9)	(31,105.1)	(31,481.4)	(31,911.2)	(32,327.8)	(32,732.7)	(30,292.3)
491.00 Software acquired intangibles	(35,349.1)	(35,182.9)	(34,989.0)	(34,769.6)	(34,523.9)	(34,252.0)	(33,952.8)	(33,655.6)	(33,330.6)	(32,981.1)	(32,622.4)	(32,236.8)	(31,824.6)	(33,840.3)
491.00 Software developed intangibles	(33,517.9)	(33,664.2)	(33,788.1)	(33,893.8)	(33,979.8)	(34,046.3)	(34,091.0)	(34,317.2)	(34,520.5)	(34,707.7)	(34,909.7)	(35,090.7)	(35,251.6)	(34,282.8)
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
489.00 WAMS	0.0	(487.9)	(975.8)	(1,463.7)	(1,951.6)	(2,439.5)	(2,927.4)	(3,415.3)	(4,003.9)	(4,592.5)	(5,181.1)	(5,769.7)	(6,358.2)	(3,032.3)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gen. Plant Acc. Depr. - After Adj.	(180,296.6)	(182,098.8)	(183,837.9)	(185,523.6)	(187,152.0)	(188,726.3)	(190,238.5)	(191,934.1)	(193,665.6)	(195,353.8)	(197,102.5)	(198,790.6)	(200,431.6)	(190,398.9)

BOARD STAFF INTERROGATORY #15

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T9/S1/Incentive Ratemaking Report (CEA)/P 61 and 63 and 65 and 67 of 125

Please provide all data, spreadsheets, computer programs, and related analysis that Concentric Energy Advisors used to prepare the results summarized in:

a) Figure 30
b) Figure 31
c) Figure 32
d) Figure 33

RESPONSE

Attached please find all data, spreadsheets, computer programs, and related analysis that Concentric Energy Advisors used to prepare the results summarized in Figures 30 to 36.

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

IMC Threshold	20.0%
$DeprExp_1$	$237,303,000
RB_0	$3,889,484,575
G_2013	1.53%
G_2014	1.69%
G_2015	1.73%
G_2016	1.75%
G_2017	
G_2018	

RB_0 (Rebasing) Work Book		
Final Rate Order p 2 of 7	3,945,300,000	Source: Rebasing Rev Rec Support
CIS	(70,500,000)	
rounding	36185	
	3,874,836,185	
Adj to 2013 Accum Depr for SRC	$ 14,648,390	
	3,889,484,575	

Customer Growth Rate Workbook (G_2014, …)

Source: [EGD Utility OM_ 2012 Actuals to 2016 Budget_20130528.xlsx]Unlock Customer

	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Budget 2013	Budget 2014	Budget 2015	Budget 2016
Total Unlock Customers	1,824,789	1,865,020	1,887,605	1,926,294	1,960,378	1,994,903	2,025,462	2,059,619	2,095,302	2,131,887
		2.2047%	1.2110%	2.0496%	1.7694%	1.7611%	1.5319%	1.6864%	1.7325%	1.7460%

Rebasing Depreciation Rate, adjusted for SRC 3.53%

ROR

2014		2015		2016	
	Pre Tax Wtd Cost		Pre Tax Wtd Cost		Pre Tax Wtd Cost
	7.98%		8.19%		8.36%

$ROR_{pretax}^{rebasing}$	8.003%
$ROR_{aftertax}^{rebasing}$	5.862%

$Plant^{Rebasing}$ $ 6,622,300,000 tab: Rebasing Rev Req Support

P

Source I-Factor Forecast 4-25-2013.XZLS	2012	2013	2014	2015	2016
TFP I-X	2.38%	2.36%	2.45%	2.45%	2.45%
		2.17%	2.23%	2.23%	2.23%

	2014	2015	2016
Composite Depreciation Rate Excluding SRC	3.58%	3.55%	3.50%

File: Capital component of IR escalation_v1 05 24 13 Rev 06 18 13.xlsx Tab: capital structure

Capital Structure (excl Customer Care CIS)

	2013 ADR	2014	2015	2016
Rate base excluding CIS	4,091.5	4,384.3	4,752.6	5,492.0
Medium and Long Term Debt (net)	2,461.9	2,596.9	2,918.4	3,367.0
Component % of Rate Base	0.6	0.6	0.6	0.6
Cost Rate	0.1	0.1	0.1	0.1
Return Component LTD	0.0	0.0	0.0	0.0
	142.8	144.7	157.3	179.6
Short Term Debt	56.7	109.0	23.2	47.9
Component % of Rate Base	0.0	0.0	0.0	0.0
Cost Rate	0.0	0.0	0.0	0.0
Return Component STD	0.0	0.0	0.0	0.0
	$ 1.2	$ 1.8	$ 0.5	$ 1.6
Preference Shares (net)	100.0	100.0	100.0	100.0
Component % of Rate Base	0.0	0.0	0.0	0.0
Cost Rate	0.0	0.0	0.0	0.0
Return Component Pref Shares	0.0	0.0	0.0	0.0
	3.3	3.1	3.8	4.4
Common Equity	1,473.0	1,578.3	1,710.9	1,977.1
Component % of Rate Base	0.4	0.4	0.4	0.4
Cost Rate	0.1	0.1	0.1	0.1
Return Component Common Equity	0.0	0.0	0.0	0.0
	131.5	146.3	166.3	200.0

Note on 2013 ADR: Refer to Page 7 of 7 (2013 Utility capital structure) of Rate Order

	2013 ADR	2014	2015	2016
Tax Rate	26.50%	26.50%	26.50%	26.50%
Pre-tax				
Cost of LT debt	143	145	157	180
Cost of ST debt	1	2	0	2
	144	146	158	181
After tax				
Cost of debt (after tax)	106	108	116	133
Pref dividend	3	3	4	4
Return on equity	132	146	166	200
		0.03		
	241	257	286	338
ROR after tax	5.882%	5.862%	6.019%	6.148%
ROR Pre tax	**8.003%**	**7.975%**	**8.188%**	**8.364%**

BOARD FINAL DECISION
CHANGE IN REVENUE REQUIREMENT
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Interim Rate Order (Note 1) ($Millions)	Col. 2 Final Decision Adjustments	Col. 3 Excl. CIS Board Final Decision ($Millions)	Col. 4 Cust. Care / CIS (Note 2) ($Millions)	Col. 5 Board Final Decision EGD Total ($Millions)
	Cost of capital					
1.	Rate base	4,091.5	-	4,091.5	70.5	4,162.0
2.	Required rate of return	6.85	(0.04)	6.81	6.44	6.80
3.		280.3	(1.7)	278.6	4.6	283.2
	Cost of service					
4.	Gas costs	1,342.8	-	1,342.8	-	1,342.8
5.	Operation and maintenance	325.5	-	325.5	89.4	414.9
6.	Depreciation and amortization	266.6	-	266.6	12.7	279.3
7.	Fixed financing costs	2.3	-	2.3	-	2.3
8.	Debt redemption premium amortization	-	-	-	-	-
9.	Company share of IR agreement tax savings	-	-	-	-	-
10.	Municipal and other taxes	39.3	-	39.3	-	39.3
11.		1,976.5	-	1,976.5	102.1	2,078.6
	Miscellaneous operating and non-operating revenue					
12.	Other operating revenue	(44.3)	-	(44.3)	-	(44.3)
13.	Interest and property rental	-	-	-	-	-
14.	Other income	(0.7)	-	(0.7)	-	(0.7)
15.		(45.0)	-	(45.0)	-	(45.0)
	Income taxes on earnings					
16.	Excluding tax shield	86.4	-	86.4	9.0	95.4
17.	Tax shield provided by interest expense	(38.1)	-	(38.1)	(0.9)	(39.0)
18.		48.3	-	48.3	8.1	56.4
	Taxes on sufficiency / (deficiency)					
19.	Gross sufficiency / (deficiency)	15.0	2.0	17.0	-	17.0
20.	Net sufficiency / (deficiency)	11.0	1.5	12.5	-	12.5
21.		(4.0)	(0.5)	(4.5)	-	(4.5)
22.	**Sub-total revenue requirement**	2,256.1	(2.2)	2,253.9	114.8	2,368.7
23.	Customer Care Rate Smoothing V/A Adjustment	-	-	-	(4.6)	(4.6)
24.	**Total revenue requirement**	2,256.1	(2.2)	2,253.9	110.2	2,364.1
	Revenue at existing Rates					
25.	Gas sales	1,969.5	-	1,969.5	80.2	2,049.7
26.	Transportation service	299.8	-	299.8	19.0	318.8
27.	Transmission, compression and storage	1.7	-	1.7	-	1.7
28.	Rounding adjustment	0.1	(0.2)	(0.1)	-	(0.1)
29.	Revenue at existing rates	2,271.1	(0.2)	2,270.9	99.2	2,370.1
30.	**Gross revenue sufficiency / (deficiency)**	15.0	2.0	17.0	(11.0)	6.0

Note 1: Information from Col. 3 of Interim Rate Order, Appendix A, Page 1, Dated: 2012-11-29.
Note 2: Information from Col. 3 of Exhibit F3, Tab 1, Schedule 1, Page 2, Filed: 2012-01-31.

BOARD FINAL DECISION
UTILITY RATE BASE
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Interim Rate Order (Note 1) ($Millions)	Col. 2 Final Decision Adjustments ($Millions)	Col. 3 Excl. CIS Board Final Decision ($Millions)	Col. 4 Cust. Care / CIS (Note 2) ($Millions)	Col. 5 Board Final Decision Rate Base EGD Total ($Millions)
	Property, Plant, and Equipment					
1.	Cost or redetermined value	6,622.3	-	6,622.3	127.1	6,749.4
2.	Accumulated depreciation	(2,747.5)	-	(2,747.5)	(56.6)	(2,804.1)
3.		3,874.8	-	3,874.8	70.5	3,945.3
	Allowance for Working Capital					
4.	Accounts receivable merchandise finance plan	-	-	-	-	-
5.	Accounts receivable rebillable projects	1.3	-	1.3	-	1.3
6.	Materials and supplies	31.9	-	31.9	-	31.9
7.	Mortgages receivable	0.2	-	0.2	-	0.2
8.	Customer security deposits	(68.7)	-	(68.7)	-	(68.7)
9.	Prepaid expenses	1.8	-	1.8	-	1.8
10.	Gas in storage	248.4	-	248.4	-	248.4
11.	Working cash allowance	1.8	-	1.8	-	1.8
12.	Total Working Capital	216.7	-	216.7	-	216.7
13.	Utility Rate Base	4,091.5	-	4,091.5	70.5	4,162.0

Rakesh: Should I be using $3,874.8 for the net PPE? Is the Customer care/CIS PPE the $70.5?

Note 1: Information from Col. 3 of Interim Rate Order, Appendix A, Page 2, Dated: 2012-11-29.
Note 2: Information from Col. 2 of Exhibit F3, Tab 1, Schedule 3, page 1, Filed: 2012-01-31.

BOARD FINAL DECISION
UTILITY CAPITAL STRUCTURE
2013 TEST YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Indicated Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long term debt	2,461.9	60.17	5.80	3.490
2.	Short term debt/(investment)	56.7	1.39	2.00	0.028
3.		2,518.6	61.56		3.518
4.	Preference shares	100.0	2.44	3.20	0.078
5.	Common equity	1,472.9	36.00	8.93	3.215
6.		4,091.5	100.00		6.811
7.	Utility income	($Millions)			291.2
8.	Rate base	($Millions)			4,091.5
9.	Indicated rate of return				7.117%
10.	Sufficiency in rate of return				0.306 %
11.	Net sufficiency	($Millions)			12.5
12.	Gross sufficiency	($Millions)			17.0
13.	Customer Care/CIS deficiency	($Millions)			(11.0)
14.	Total gross sufficiency	($Millions)			6.0
15.	Revenue at existing rates	($Millions)			2,370.1
16.	Revenue requirement	($Millions)			2,364.1
17.	Total gross revenue sufficiency	($Millions)			6.0

Capex effect to RateBase

2013 Account	GROSS PPE and AOA's	Opening Balance 2013	Closing	Average of Monthly Avgs 2013	Revised to Match ADR AOA Growth	2014 Depr. Rate	Gross Depr. Provision ($M)	Adjustment and / or Disallowals ($M)	
	Underground Storage	ADR							
450/459	Crowland			-	-	0.00%	-	-	
450/451	Land and Gas Storage Rights	47.3		46.7	(0.6)	1.16%	0.5	0.1	
452.00	Structures, and Improvements	16.0		16.0	-	1.84%	0.3	-	
453.00	Wells	46.0		46.3	0.3	1.55%	0.7	-	
454.00	Well Equipment	9.4		9.4	-	5.56%	0.5	-	
455.00	Field Lines	63.0		63.1	0.1	1.55%	1.0	-	
456.00	Compressor Equipment	97.7		97.6	(0.1)	2.69%	2.6	-	
457.00	Measuring and Regulating Equipment	13.4		13.5	0.1	3.04%	0.4	-	
458.00	Base Pressure Gas	40.9		40.9	-	0.00%	-	-	
Total Underground Storage Plant		333.7		333.5	(0.2)		6.0	0.1	
				333.5					
	Distribution Plant								
470.00	Land	24.9		27.6	2.7	0.00%	-	-	
470.01	Offers to purchase	7.5		7.5	-	1.16%	0.1	-	
472.00	Structures and Improvements	121.9		121.7	(0.2)	5.64%	6.9	0.4	
473/474	Services, House Regs,and Meter Installs.	2,204.8		2,235.9	31.1	2.45%	54.8	-	
476.00	NGV Station Compressors	2.7		2.6	(0.1)	5.97%	0.2	-	
478.00	Meters	397.1		404.9	7.8	9.22%	37.3	-	
475.00	Mains	2,785.3		2,836.1	50.8	2.49%	70.6	4.0	
477.00	Measuring and Regulating	350.5		362.0	11.5	2.10%	7.6	-	
WIP	Construction work-in-progress completed	-		-	-	0.00%	-	-	
Total Distribution Plant		5,894.7		5,998.3	103.6		177.5	4.3	
				5,998.3					
	General Plant								
482.50	Leasehold Improvements	5.5		7.9	2.4	10.00%	0.8	-	
483.00	Office Furniture and Equipment	20.6		21.3	0.7	10.74%	2.3	(0.3)	
484.00	Transportation Equipment	48.0		48.1	0.1	10.56%	5.1	-	
484.01	NGV conversion kits	8.0		8.1	0.1	9.00%	0.7	-	
485.00	Heavy Work Equipment	20.9		21.2	0.3	3.58%	0.8	-	
486.00	Tools and Work Equipment	37.5		37.7	0.2	4.08%	1.5	-	
487.70	Rental Equipment	1.0		1.0	-	0.74%	-	-	
487.80	NGV Rental Compressors	3.6		3.5	(0.1)	8.01%	0.3	-	
84.02/487.9	NGV Cylinders	2.6		2.7	0.1	18.93%	0.5	(0.1)	
488.00	Communication structures and equipment	3.2		3.5	0.3	9.71%	0.3	-	
489.00	C.I.S.	127.1		**5.9**	5.9	10.00%	0.6	-	
490.00	Computer Equipment	141.5		136.5	(5.0)	27.38%	37.4	(1.0)	
Total General Plant		419.5		297.4	5.0		50.3	(1.5)	
				297.4			14.84%		
402.50	**Other Plant**	0.5		0.5	-	1.50%	-	-	
105.02	**Plant Held for Future Use**	1.7		1.7	-	4.30%	0.1	-	
	Total	6,650.1		6,631.4	108.4		233.9	3.4	237.3
		-					3.527159%		

2014 GROSS PPE and AOA's

Account		Depr. Rate
	Underground Storage	
450/459	Crowland	0.00%
450/451	Land and Gas Storage Rights	1.16%
452.00	Structures, and Improvements	1.84%
453.00	Wells	1.55%
454.00	Well Equipment	5.56%
455.00	Field Lines	1.55%
456.00	Compressor Equipment	2.69%
457.00	Measuring and Regulating Equipment	3.04%
458.00	Base Pressure Gas	0.00%
Total Underground Storage Plant		
	Distribution Plant	
470.00	Land	0.00%
470.01	Offers to purchase	1.18%
471.00	Land Rights	1.18%
472.00	Structures and Improvements	5.64%
473/474	Services, House Regs,and Meter Installs.	2.45%
476.00	NGV Station Compressors	5.97%
478.00	Meters	9.22%
475.00	Mains	2.49%
477.00	Measuring and Regulating	2.10%
WIP	Construction work-in-progress completed	0.00%
Total Distribution Plant		
	General Plant	
482.50	Leasehold Improvements	10.00%
483.00	Office Furniture and Equipment	10.74%
484.00	Transportation Equipment	10.56%
484.01	NGV conversion kits	9.00%
485.00	Heavy Work Equipment	3.58%
486.00	Tools and Work Equipment	4.08%
487.70	Rental Equipment	0.74%
487.80	NGV Rental Compressors	8.01%
84.02/487.9	NGV Cylinders	18.93%
488.00	Communication structures and equipment	9.71%
489.00	C.I.S.	10.00%
490.00	Computer Equipment	27.38%
Total General Plant		
402.50	**Other Plant**	1.50%
105.02	**Plant Held for Future Use**	4.30%
	Total	

Capex effect to RateBase

2013 Account	GROSS PPE and AOA's	Opening Balance 2013	Closing Balance 2013	Yearend Growth	Average of Monthly Avgs 2013	Revised to Match ADR AOA Growth	Depr. Rate	Gross Depr. Provision ($M)	Adjustment and / or Disallowals ($M)	Depr. Provision ($M)
	Underground Storage	ADR								
450/459	Crowland				-	-				
450/451	Land and Gas Storage Rights	47.3			46.7	(0.6)				
452.00	Structures, and Improvements	16.0			16.0	-				
453.00	Wells	46.0			46.3	0.3				
454.00	Well Equipment	9.4			9.4	-				
455.00	Field Lines	63.0			63.1	0.1				
456.00	Compressor Equipment	97.7			97.6	(0.1)				
457.00	Measuring and Regulating Equipment	13.4			13.5	0.1				
458.00	Base Pressure Gas	40.9			40.9	-				
Total Underground Storage Plant		333.7			333.5	(0.2)				
					333.5					
	Distribution Plant									
470.00	Land	24.9			27.6	2.7	0.00%			
470.01	Offers to purchase	7.5			7.5	-	1.18%			
472.00	Structures and Improvements	121.9			121.7	(0.2)	5.64%			
473/474	Services, House Regs,and Meter Installs.	2,204.8			2,235.9	31.1	2.98%			
476.00	NGV Station Compressors	2.7			2.6	(0.1)	5.97%			
478.00	Meters	397.1			404.9	7.8	9.22%			
475.00	Mains	2,785.3			2,836.1	50.8	3.10%			
477.00	Measuring and Regulating	350.5			362.0	11.5	2.14%			
WIP	Construction work-in-progress completed	-			-	-	0.00%			
Total Distribution Plant		5,894.7			5,998.3	103.6				
					5,998.3					
	General Plant									
482.50	Leasehold Improvements	5.5			7.9	2.4				
483.00	Office Furniture and Equipment	20.6			21.3	0.7				
484.00	Transportation Equipment	48.0			48.1	0.1				
484.01	NGV conversion kits	8.0			8.1	0.1				
485.00	Heavy Work Equipment	20.9			21.2	0.3				
486.00	Tools and Work Equipment	37.5			37.7	0.2				
487.70	Rental Equipment	1.0			1.0	-				
487.80	NGV Rental Compressors	3.6			3.5	(0.1)				
84.02/487.9	NGV Cylinders	2.6			2.7	0.1				
488.00	Communication structures and equipment	3.2			3.5	0.3				
489.00	C.I.S.	127.1			133.0	5.9				
490.00	Computer Equipment	141.5			136.5	(5.0)				
Total General Plant		419.5			424.5	5.0				
					424.5					
402.50	**Other Plant**	0.5			0.5	-				
105.02	**Plant Held for Future Use**	1.7			1.7	-				
	Total	6,650.1			6,758.5	108.4				

2014 Account	GROSS PPE and AOA's	Opening Balance 2014	Closing Balance 2014	Yearend Growth	Average of Monthly Avgs 2014	AOA Growth	Depr. Rate	Gross Depr. Provision ($M)	Adjustment and / or Disallowals ($M)	Depr. Provision ($M)
	Underground Storage									
450/459	Crowland				-					
450/~~451~~	Land Tecumseh				3,742.1					
451	Land Rights Tecumseh				-					
451.1	Land Rights intangibles Tecumseh				39,662.6					
452.00	Structures, and Improvements Tecumseh				22,697.9					
453.00	Wells Tecumseh				51,217.8					
454.00	Well Equipment Tecumseh				9,567.1					
455.00	Field Lines Tecumseh				64,441.4					
456.00	Compressor Equipment Tecumseh				106,194.7					
457.00	Measuring and Regulating Tecumseh				14,617.2					
458.00	Base Pressure Gas Tecumseh				40,964.4					
Total Underground Storage Plant					353,105.2					
	Distribution Plant									
470.00	Land				27,722.8					
470.01	Offers to purchase land				-					
471.00	Land Rights Intangibles				7,446.8					
472.00	Structures and Improvements				125,602.9					
473/474	Services, House Regs,and Meter Installs.				2,309,113.6					
475.00	Mains				3,030,275.3					
476.00	Company NGV Compressor Stations				2,570.1					
477.00	Measuring and Regulating Equip				389,442.1					
478.00	Meters				419,415.3					
WIP	Construction work-in-progress completed									
Total Distribution Plant					6,311,588.9					
	General Plant									
482.50	Leasehold Improvements				12,010.8					
483.1	Office Equipment over 6.6 years				-					
483.1	Office Equipment over 15 years				3,144.5					
483.2	Office Furniture over 6.6				-					
483.2	Office Furniture over 20 years				20,041.4					
484.00	Transportation Equipment				49,765.9					
484.01	NGV kits Co. vehicles				8,227.0					
484.02	N.G.V cyl. Co. vehicles				882.0					
485.00	Heavy Work Equipment				22,238.0					
4??.00	Available				-					
486.00	Tools and Work Equipment over 2.69 years				-					
486.00	Tools and Work Equipment 4.0%				38,387.8					
487.70	VRA'S				-					
487.70	VRAs Post F2300 5%				1,334.2					
487.80	NGV compressor stations				3,816.5					
487.90	NGV rental Cylinders				1,895.8					
488.00	Communication structures and equipment				-					
488.00	Communication structures and equipment 20 years				3,905.9					
490.00	Computer Equipment				-					
490.00	Computer Equipment 2003 B 20%				35,705.6					
491.00	Software acquired intangibles				58,709.1					
491.00	Software developed intangibles				60,454.4					
491.00	CIS Software acquired intangibles				-					
Total General Plant					320,518.9					
402.50	**Other Plant**				465.3					
105.02	**Plant Held for Future Use**				1,670.9			40.9		40.9
	Total				6,987,349.2					

2015 Account	GROSS PPE and AOA's	Opening Balance 2015	Closing Balance 2015	Yearend Growth	Average of Monthly Avgs 2015	AOA Growth	Depr. Rate	Gross Depr. Provision ($M)	Adjustment and / or Disallowals ($M)	Depr. Provision ($M)
	Underground Storage									
450/459	Crowland				-					
450/~~451~~	Land Tecumseh				3,742.1					
451	Land Rights Tecumseh				-					
451.1	Land Rights intangibles Tecumseh				40,034.2					
452.00	Structures, and Improvements Tecumseh				32,733.9					
453.00	Wells Tecumseh				55,622.0					
454.00	Well Equipment Tecumseh				9,567.1					
455.00	Field Lines Tecumseh				66,199.8					
456.00	Compressor Equipment Tecumseh				111,199.4					
457.00	Measuring and Regulating Tecumseh				14,691.9					
458.00	Base Pressure Gas Tecumseh				40,982.4					
Total Underground Storage Plant					374,772.8					
	Distribution Plant									
470.00	Land				27,994.9					
470.01	Offers to purchase land				-					
471.00	Land Rights Intangibles				26,065.1					
472.00	Structures and Improvements				132,600.5					
473/474	Services, House Regs,and Meter Installs.				2,397,069.4					
475.00	Mains				3,284,104.7					
476.00	Company NGV Compressor Stations				2,559.5					
477.00	Measuring and Regulating Equip				430,253.3					
478.00	Meters				429,159.0					
WIP	Construction work-in-progress completed									
Total Distribution Plant					6,729,806.4					
	General Plant									
482.50	Leasehold Improvements				15,860.8					
483.1	Office Equipment over 6.6 years				-					
483.1	Office Equipment over 15 years				3,222.4					
483.2	Office Furniture over 6.6				-					
483.2	Office Furniture over 20 years				24,102.0					
484.00	Transportation Equipment				52,062.7					
484.01	NGV kits Co. vehicles				8,350.6					
484.02	N.G.V cyl. Co. vehicles				1,007.3					
485.00	Heavy Work Equipment				22,758.4					
4??.00	Available				-					
486.00	Tools and Work Equipment over 2.69 years				-					
486.00	Tools and Work Equipment 4.0%				38,806.1					
487.70	VRA'S				-					
487.70	VRAs Post F2300 5%				2,726.9					
487.80	NGV compressor stations				5,590.2					
487.90	NGV rental Cylinders				1,965.3					
488.00	Communication structures and equipment				-					
488.00	Communication structures and equipment 20 years				3,902.7					
490.00	Computer Equipment				-					
490.00	Computer Equipment 2003 B 20%				34,378.7					
491.00	Software acquired intangibles				53,993.3					
491.00	Software developed intangibles				73,898.9					
491.00	CIS Software acquired intangibles				-					
489.00	WAMS				2,439.6					
Total General Plant					345,065.9					
402.50	**Other Plant**				465.3			-		-
105.02	**Plant Held for Future Use**				1,670.9			40.9		40.9
	Total				7,451,781.3			40.9		40.9

2016 Account	GROSS PPE and AOA's	Opening Balance 2016	Closing Balance 2016	Yearend Growth	Average of Monthly Avgs 2016	AOA Growth		
	Underground Storage							
450/459	Crowland				-			
450/~~451~~	Land Tecumseh				3,742.1			
451	Land Rights Tecumseh				-			
451.1	Land Rights intangibles Tecumseh				40,712.0			
452.00	Structures, and Improvements Tecumseh				39,039.3			
453.00	Wells Tecumseh				62,497.2			
454.00	Well Equipment Tecumseh				9,567.1			
455.00	Field Lines Tecumseh				68,589.2			
456.00	Compressor Equipment Tecumseh				113,019.7			
457.00	Measuring and Regulating Tecumseh				14,723.0			
458.00	Base Pressure Gas Tecumseh				40,993.7			
Total Underground Storage Plant					392,883.3			
	Distribution Plant							
470.00	Land				29,028.8			
470.01	Offers to purchase land				-			
471.00	Land Rights Intangibles				96,814.8			
472.00	Structures and Improvements				134,876.3			
473/474	Services, House Regs,and Meter Installs.				2,498,111.7			
475.00	Mains				3,802,800.0			
476.00	Company NGV Compressor Stations				2,549.3			
477.00	Measuring and Regulating Equip				516,992.9			
478.00	Meters				441,088.9			
WIP	Construction work-in-progress completed				-			
Total Distribution Plant					7,522,262.7			
	General Plant							
482.50	Leasehold Improvements				16,874.6			
483.1	Office Equipment over 6.6 years				-			
483.1	Office Equipment over 15 years				3,300.1			
483.2	Office Furniture over 6.6				-			
483.2	Office Furniture over 20 years				27,980.5			
484.00	Transportation Equipment				54,443.5			
484.01	NGV kits Co. vehicles				8,204.2			
484.02	N.G.V cyl. Co. vehicles				1,453.0			
485.00	Heavy Work Equipment				23,400.8			
4??.00	Available				-			
486.00	Tools and Work Equipment over 2.69 years				-			
486.00	Tools and Work Equipment 4.0%				39,243.3			
487.70	VRA'S				-			
487.70	VRAs Post F2300 5%				4,122.5			
487.80	NGV compressor stations				13,464.5			
487.90	NGV rental Cylinders				2,036.7			
488.00	Communication structures and equipment				-			
488.00	Communication structures and equipment 20 years				3,899.4			
490.00	Computer Equipment				-			
490.00	Computer Equipment 2003 B 20%				32,488.8			
491.00	Software acquired intangibles				44,563.4			
491.00	Software developed intangibles				82,803.2			
491.00	CIS Software acquired intangibles				-			
4??.00	WAMS?				64,084.8			
	Adj				(5,964.5)			
Total General Plant					416,398.8			
402.50	**Other Plant**				465.3		-	-
105.02	**Plant Held for Future Use**				1,670.9		40.9	40.9
	Total				8,333,681.0		40.9	40.9

	2013	2014	2015	2016
Average of Monthly Avgs Plant				
Underground Storage	333.5	353,105	374,773	392,883
Distribution Plant	5998.3	6,311,589	6,729,806	7,522,263
General Plant	424.5	320,519	345,066	416,399
Other Plant	0.5	465	465	465
Plant Held for Future Use	1.7	1,671	1,671	1,671
Affiliate Shared Assets Value		(10,400)	(10,900)	(11,900)
Total ($000,000)	6758.50	6,976,949	7,440,881	8,321,781
		6,977,000	7,441,000	8,322,000
Total	$6,758,500,000	$6,976,949,200	$7,440,881,300	$8,321,781,000
Average Monthly Plant Additions		$218,449,200	$463,932,100	$880,899,700
Provision for Depreciation				
Underground Storage		6,485.50	6,908.00	7,233.10
Distribution Plant		187,136.60	197,464.70	216,903.10
General Plant		53,961.10	56,536.80	63,141.50
Other Plant		-	-	-
Plant Held for Future Use		40.90	40.90	40.90
Adjustment		2,475.90	2,949.60	3,881.40
Total ($000,000)		250,100.00	263,900.00	291,200.00
Composite Depreciation Rate		3.58%	3.55%	3.50%
Total		250,100,000	263,900,000	291,200,000
Accumulated Depreciation calculated on Average of monthly Averages Plant)				
Underground Storage		120,413.30	127,174.80	134,276.00
Distribution Plant		2,634,322.30	2,704,932.60	2,795,026.60
General Plant		140,888.50	168,990.20	190,398.90
Other Plant		465.30	465.30	465.30
Plant Held for Future Use		1,192.00	1,232.90	1,273.80
Affiliate Shared Assets Value		(1,600.00)	(2,200.00)	(2,800.00)
Total ($000,000)		2,895,681.4	3,000,595.8	3,118,640.6

Plant-related Rate Base (Average of Monthly Averages Plant)

	2013	2014	2015	2016
Average of Monthly Avgs Plant				
Underground Storage		353,100	374,800	392,900
Distribution Plant		6,311,600	6,729,800	7,522,300
General Plant		320,500	345,100	416,400
Other Plant		500	500	500
Plant Held for Future Use		1,700	1,700	1,700
Affiliate Shared Assets Value		(10,400)	(10,900)	(11,900)
Total ($000,000)		6,977,000	7,441,000	8,321,900
Total		$6,977,000,000	$7,441,000,000	$8,321,900,000
Provision for Depreciation				
Underground Storage		6,500.00	6,900.00	7,200.00
Distribution Plant		187,100.00	197,500.00	216,900.00
General Plant		54,000.00	56,500.00	63,100.00
Other Plant		-	-	-
Plant Held for Future Use		-	-	-
Adj		2,500.00	3,000.00	4,000.00
Total ($000,000)		250,100.00	263,900.00	291,200.00
Composite Depreciation Rate				
Total		250,100,000	263,900,000	291,200,000
Accumulated Depreciation calculated on Average of monthly Averages Plant)				
Underground Storage		120,400.00	127,200.00	134,300.00
Distribution Plant		2,634,300.00	2,704,900.00	2,795,000.00
General Plant		140,900.00	169,000.00	190,400.00
Other Plant		500.00	500.00	500.00
Plant Held for Future Use		1,200.00	1,200.00	1,300.00
Affiliate Shared Assets Value		(1,600.00)	(2,200.00)	(2,800.00)
Total ($000,000)				

Plant-related Rate Base (Average of Monthly Averages Plant)

GTA OTT Adds to Plt

	2013	2014	2015	2016
Average of Monthly Avgs Plant				
Underground Storage				
Distribution Plant		48,930.60	172,076.70	631,947.80
General Plant				
Other Plant				
Plant Held for Future Use				
Total ($000,000)		48,930.60	172,076.70	631,947.80
Total		$48,930,600	$172,076,700	$631,947,800
Provision for Depreciation				
Underground Storage				
Distribution Plant		1,265.00	3,756.80	15,640.80
General Plant				
Other Plant				
Plant Held for Future Use				
Total ($000,000)		1,265.00	3,756.80	15,640.80
Composite Depreciation Rate		2.59%	2.18%	2.48%
Total		1,265,000	3,756,800	15,640,800
		Composite Depreciation rates are calculated ba		
Accumulated Depreciation calculated on Average of monthly Averages Plant)				
Underground Storage				
Distribution Plant		(579.80)	(2,153.10)	(12,842.20)
General Plant				
Other Plant				
Plant Held for Future Use				
Total ($000)		(579.80)	(2,153.10)	(12,842.20)
Total	-	(579,800)	(2,153,100)	(12,842,200)

Plant-related Rate Base (Average of Monthly Averages Plant)

Ottawa and GTA Combined

File: GTA & Ottawa combined 6-14-2013.xlsx Tab: Ottawa_PPE Project Annual

Ottawa Only

	2014		
Land Rights	0.0	0.0	0.0
Mains - Coated & Wrapped S	43,558.2	(534.9)	43,023.3
Regulating Equipment	4,896.1	(44.9)	4,851.2
Land	476.3	0.0	476.3
	0.0	0.0	0.0
	0.0	0.0	0.0
Gross/Accum/Net AOA's	48,930.6	(579.8)	48,350.8
Land Rights	0.0		
Mains - Coated & Wrapped S	1,167.1		
Regulating Equipment	97.9		
Land	0.0		
	0.0		
	0.0		
Depreciation Expense	1,265.0		

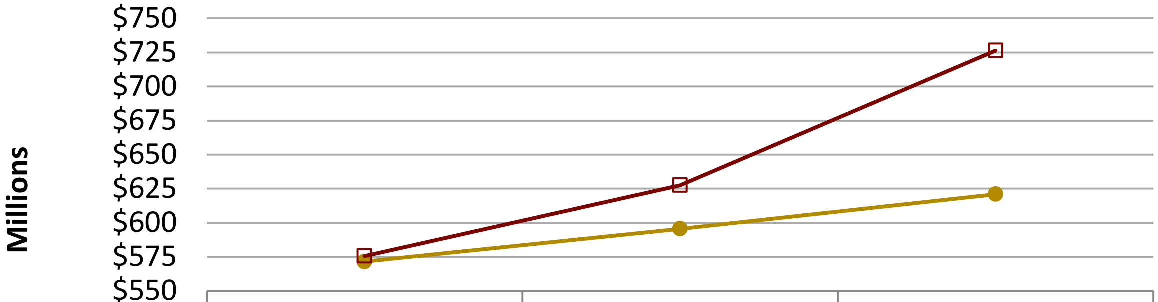
Ottawa and GTA combined

	2015		
Land Rights	18,618.3	(14.7)	18,603.6
Mains - Coated & Wrapped S	132,085.9	(1,965.4)	130,120.5
Regulating Equipment	20,603.4	(173.0)	20,430.4
Land	769.1	0.0	769.1
	0.0	0.0	0.0
	0.0	0.0	0.0
Gross/Accum/Net AOA's	172,076.7	(2,153.1)	169,923.6
Land Rights	175.8		
Mains - Coated & Wrapped S	3,213.8		
Regulating Equipment	367.2		
Land	0.0		
	0.0		
	0.0		
Depreciation Expense	3,756.8		

Ottawa and GTA combined

	2016		
Land Rights	89,368.0	(703.2)	88,664.8
Mains - Coated & Wrapped S	461,294.7	(10,839.3)	450,455.4
Regulating Equipment	79,482.1	(1,299.7)	78,182.4
Land	1,803.0	0.0	1,803.0
	0.0	0.0	0.0
	0.0	0.0	0.0
Gross/Accum/Net AOA's	631,947.8	(12,842.2)	619,105.6
Land Rights	1,054.8		
Mains - Coated & Wrapped S	12,916.8		
Regulating Equipment	1,669.2		
Land	0.0		
	0.0		
	0.0		
Depreciation Expense	15,640.8		

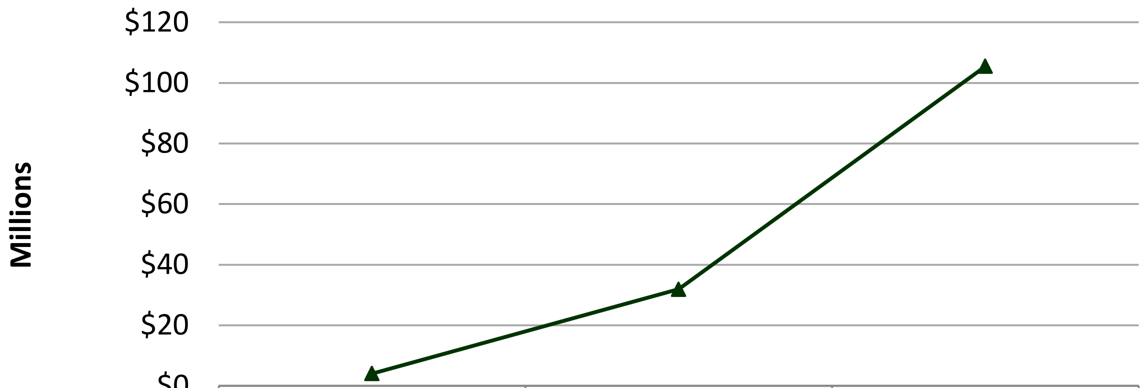
I-X Analysis: Total EGD Capital-Related Revenue Requirement and Revenues



	1	2	3
Revenues	$571,500,000	$595,600,000	$620,900,000
Rev Req	$575,600,000	$627,500,000	$726,400,000

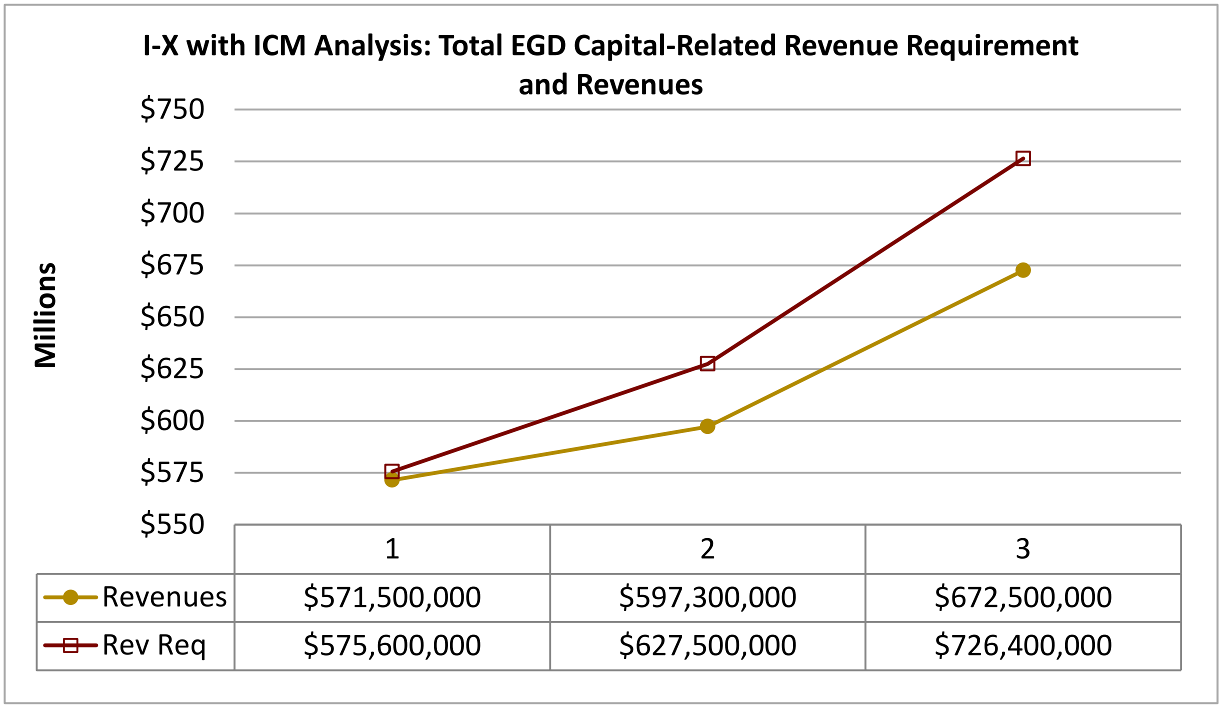
Assumptions:

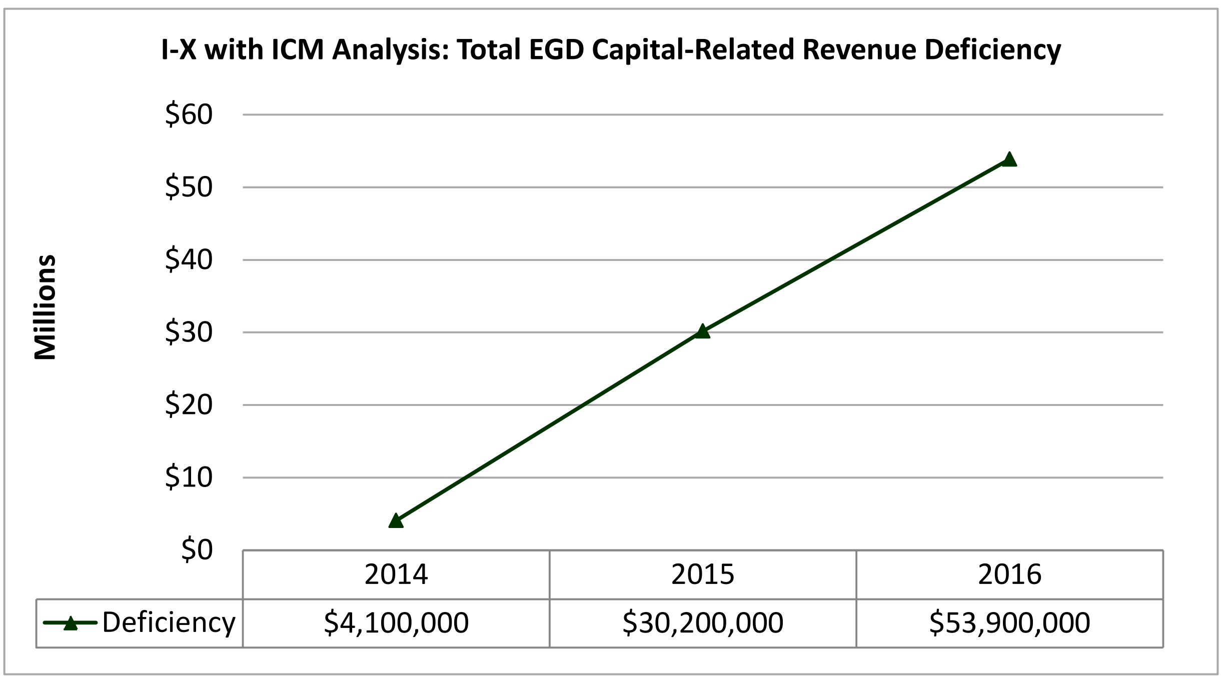
I-X Analysis: Total EGD Capital-Related Revenue Deficiency



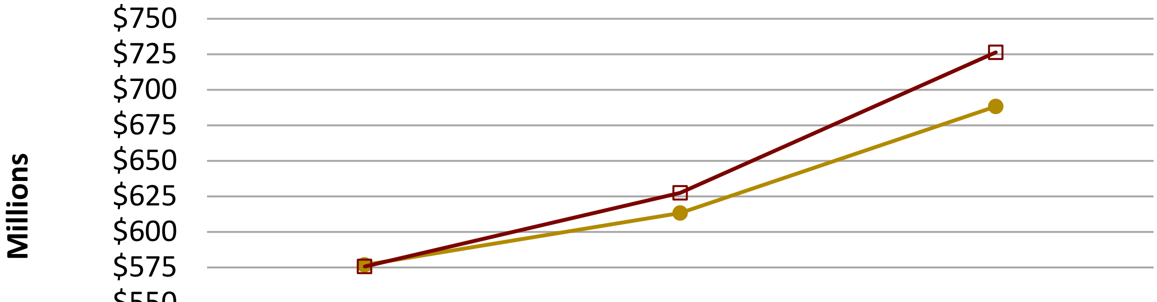
	2014	2015	2016
Deficiency	$4,100,000	$31,900,000	$105,500,000

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


I-X with ICM Analysis: Total EGD Capital-Related Revenue Requirement and Revenues
Millions
$750
$725
$700
$675
$650
$625
$600
$575
$550
1
2
3
Revenues
$571,500,000
$597,300,000
$672,500,000
Rev Req
$575,600,000
$627,500,000
$726,400,000


I-X with ICM Analysis: Total EGD Capital-Related Revenue Deficiency
Millions
$60
$50
$40
$30
$20
$10
$0
2014
2015
2016
Deficiency
$4,100,000
$30,200,000
$53,900,000

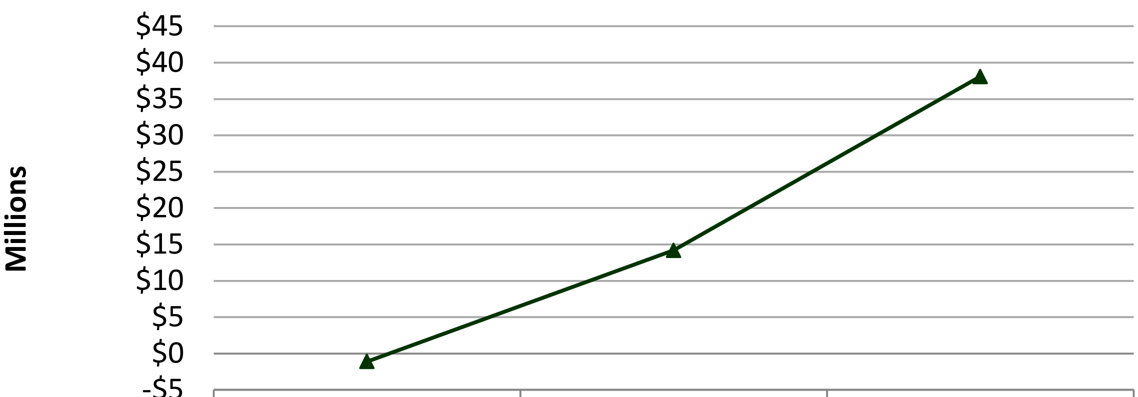
I-X with Y Factor Analysis: Total EGD Capital-Related Revenue Requirement and Revenues



	2014	2015	2016
Revenues	$576,700,000	$613,300,000	$688,300,000
Rev Req	$575,600,000	$627,500,000	$726,400,000

Assumptions:

I-X with Y Factor Analysis: Total EGD Capital-Related Revenue Deficiency



	2014	2015	2016
Deficiency	-$1,100,000	$14,200,000	$38,100,000

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

TABLES FOR REPORT:

Figure 30 Rate Option 1: Revenues based on I-X rate adjustments		2014	2015	2016
1	**Revenue Requirement**			
2	Average of Monthly Avgs Plant	$ 6,977,000,000	$ 7,441,000,000	$ 8,321,900,000
3	Depreciation Rate	3.58%	3.55%	3.50%
4	Depreciation Expense	$ (250,100,000)	$ (263,900,000)	$ (291,200,000)
5	Average of Monthly Avgs Rate Base	$ 4,081,300,000	$ 4,440,400,000	$ 5,203,200,000
6	ROR^{Pretax}	7.98%	8.19%	8.36%
7	Return: ROR^{Pretax} x RB	$ 325,500,000	$ 363,600,000	$ 435,200,000
8	Revenue Requirement: Return + DeprExp	$ 575,600,000	$ 627,500,000	$ 726,400,000
9	**Revenues**			
10	Rebasing Return	$ 311,300,000	$ 311,300,000	$ 311,300,000
11	Rebasing Depreciation Expense	$ 237,300,000	$ 237,300,000	$ 237,300,000
12	P (Percent increase in Rates)	2.45%	2.45%	2.45%
13	G (Percent increase in Customers)	1.69%	1.73%	1.75%
14	(1 + P) x (1 + G)	1.04173	1.08571	1.13171
15				
16	$Revenues_{Plant\text{-}related}$ = [Rebasing Return + Depreciation] x (1+P) x (1+G)	$ 571,500,000	$ 595,600,000	$ 620,900,000
17				
18	Deficiency (Surplus) in Revenues	$ 4,100,000	$ 31,900,000	$ 105,500,000

TABLES FOR REPORT:

	Figure 32: Rate Option 2: Revenues based on I-X and General Purpose Capital tracker rate a	2014	2015	2016
1	**Revenue Requirement**			
2	Average of Monthly Avgs Plant	$ 6,977,000,000	$ 7,441,000,000	$ 8,321,900,000
3	Depreciation Rate	3.58%	3.55%	3.50%
4	Depreciation Expense	$ (250,100,000)	$ (263,900,000)	$ (291,200,000)
5	Average of Monthly Avgs Rate Base	$ 4,081,300,000	$ 4,440,400,000	$ 5,203,200,000
6	ROR^{Pretax}	7.98%	8.19%	8.36%
7	Return: ROR^{Pretax} x RB	$ 325,500,000	$ 363,600,000	$ 435,200,000
8	Revenue Requirement: Return + DeprExp	$ 575,600,000	$ 627,500,000	$ 726,400,000
9	**Revenues**			
10	Rebasing Return	$ 311,300,000	$ 311,300,000	$ 311,300,000
11	Rebasing Depreciation Expense	$ 237,300,000	$ 237,300,000	$ 237,300,000
12	P (Percent increase in Rates)	2.45%	2.45%	2.45%
13	G (Percent increase in Customers)	1.69%	1.73%	1.75%
14	(1 + P) x (1 + G)	1.04173	1.08571	1.13171
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
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%
19	$RateBase_{rebasing}$ x (G + P + GxP)	$ 162,300,000	$ 164,200,000	$ 164,800,000
20	Threshold (1.2) x $DeprExp_{rebasing}$	$ 284,800,000	$ 284,800,000	$ 284,800,000
21	Threshold	$ 447,100,000	$ 449,000,000	$ 449,600,000
22				
23	Plant Additions	$ 218,400,000	$ 463,900,000	$ 880,900,000
24	Plant Additions above Threshold	$ -	$ 14,900,000	$ 431,300,000
25	Total Plant Above Threshold	$ -	$ 14,900,000	$ 446,200,000
26	Depreciation	$ -	$ 500,000	$ 15,600,000
27	Accumulated Depreciation	$ -	$ 500,000	$ 16,100,000
28	Rate Base above Threshold	$ -	$ 14,400,000	$ 430,100,000
29	ICM Revenues	$ -	$ 1,700,000	$ 51,600,000
30				
31	Total Revenues	$ 571,500,000	$ 597,300,000	$ 672,500,000
32	Deficiency (Surplus) in Revenues	$ 4,100,000	$ 30,200,000	$ 53,900,000

TABLES FOR REPORT:

	Figure 34: Rate Option 3: Revenues based on I-X plus Special Project Capital Tracker	2014	2015	2016
1	**Revenue Requirement**			
2	Average of Monthly Avgs Plant	$ 6,977,000,000	$ 7,441,000,000	$ 8,321,900,000
3	Depreciation Rate	3.58%	3.55%	3.50%
4	Depreciation Expense	$ (250,100,000)	$ (263,900,000)	$ (291,200,000)
5	Average of Monthly Avgs Rate Base	$ 4,081,300,000	$ 4,440,400,000	$ 5,203,200,000
6	ROR^{Pretax}	7.98%	8.19%	8.36%
7	Return: ROR^{Pretax} x RB	$ 325,500,000	$ 363,600,000	$ 435,200,000
8	Revenue Requirement: Return + DeprExp	$ 575,600,000	$ 627,500,000	$ 726,400,000
9	**Revenues**			
10	Rebasing Return	$ 311,300,000	$ 311,300,000	$ 311,300,000
11	Rebasing Depreciation Expense	$ 237,300,000	$ 237,300,000	$ 237,300,000
12	P (Percent increase in Rates)	2.45%	2.45%	2.45%
13	G (Percent increase in Customers)	1.69%	1.73%	1.75%
14	(1 + P) x (1 + G)	1.04173	1.08571	1.13171
15	I-X RevenuesPlant-related = [Rebasing Return + Depreciation] x (1+P) x (1+G)	$ 571,500,000	$ 595,600,000	$ 620,900,000
16	GTA, Ottawa Plant	$ 48,900,000	$ 172,100,000	$ 631,900,000
17	Depreciation Rate	2.66%	2.21%	2.47%
18	GTA, Ottawa Depreciation Expense	$ (1,300,000)	$ (3,800,000)	$ (15,600,000)
19	GTA, Ottawa Rate Base	$ 48,400,000	$ 169,900,000	$ 619,100,000
20	RORPretax	7.98%	8.19%	8.36%
21	GTA, Ottawa Return: ROR^{Pretax} x RB	$ 3,900,000	$ 13,900,000	$ 51,800,000
22	GTA, Ottawa Revenue Requirement	$ 5,200,000	$ 17,700,000	$ 67,400,000
23	Total Revenues (I-X plus Y Factor)	$ 576,700,000	$ 613,300,000	$ 688,300,000
24				
25	Revenue Deficiency (with I-X and Y Factor)	$ (1,100,000)	$ 14,200,000	$ 38,100,000

TABLES FOR REPORT:

Figure 36: Rate Option 4: Revenues based on EGD's Proposed Customized Building Blocks		2014	2015	2016
1	**Revenue Requirement**			
2	Average of Monthly Avgs Plant	$ 6,976,900,000	$ 7,440,900,000	$ 8,321,800,000
3	Depreciation Rate	3.58%	3.55%	3.50%
4	Depreciation Expense	$ (250,100,000)	$ (263,900,000)	$ (291,200,000)
5	Average of Monthly Avgs Rate Base	$ 4,081,300,000	$ 4,440,400,000	$ 5,203,200,000
6	RORPretax	7.98%	8.19%	8.36%
7	Return: ROR Pretax x RB	$ 325,500,000	$ 363,600,000	$ 435,200,000
8	Revenue Requirement: Return + DeprExp	$ 575,600,000	$ 627,500,000	$ 726,400,000
9	**Revenues**			
10	Total Revenues (Customized IR)	$ 575,600,000	$ 627,500,000	$ 726,400,000

LOCAL STORAGE PLANT, PLANT HELD FOR FUTURE USE, AND OTHER PLANT - CONTINUITY WORKSHEETS
CALENDAR 2014 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	
Local Storage Plant	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Net change	Average of Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
A/c # 440.00 Land															
Opening balance	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5		
Expenditures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	0.0	21.5
Plant Held for Future Use - Gross	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Net change	Average of Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
A/c # 102.00															
Opening balance	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9		
Expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	0.0	1,670.9
Plant Held for Future Use - Accum. Depr.															
A/c # 105.02															
Opening balance	(1,171.6)	(1,171.6)	(1,175.0)	(1,178.4)	(1,181.8)	(1,185.2)	(1,188.6)	(1,192.0)	(1,195.4)	(1,198.8)	(1,202.2)	(1,205.6)	(1,209.0)		
Provision		(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.5)	(40.9)	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Costs net of Proceeds		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	(1,171.6)	(1,175.0)	(1,178.4)	(1,181.8)	(1,185.2)	(1,188.6)	(1,192.0)	(1,195.4)	(1,198.8)	(1,202.2)	(1,205.6)	(1,209.0)	(1,212.5)	(40.9)	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	(1,171.6)	(1,175.0)	(1,178.4)	(1,181.8)	(1,185.2)	(1,188.6)	(1,192.0)	(1,195.4)	(1,198.8)	(1,202.2)	(1,205.6)	(1,209.0)	(1,212.5)	(40.9)	(1,192.0)
Plant Held for Future Use - Net	499.3	495.9	492.5	489.1	485.7	482.3	478.9	475.5	472.1	468.7	465.3	461.9	458.4	(40.9)	478.9
Other Plant - Gross	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Net change	Average of Monthly Avgs.
A/c # 402.50	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
Intangible Plant (Peterborough)															
Opening balance	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3		
Expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	0.0	465.3
Other Plant - Acc.Depr.															
A/c # 402.50															
Intangible Plant (Peterborough)															
Opening balance	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)		
Provision		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Costs net of Proceeds		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	0.0	(465.3)
Other Plant - Net	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
UNDERGROUND STORAGE PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
Underground Storage Plant - Net. After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1
451 Land rights Tecumseh	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7
451.1 Land rights intangibles Tecumseh	14,960.5	14,925.4	14,901.4	14,871.8	14,836.7	14,804.5	14,774.9	14,740.2	14,709.7	14,675.7	14,639.1	14,640.3	14,750.5	14,781.3
452 Struct. & Improve. Tecumseh	13,759.3	13,807.4	14,120.1	14,299.4	14,344.4	14,460.0	14,638.4	19,093.0	19,244.5	19,308.1	19,312.8	20,224.7	23,749.6	16,800.6
453 Wells Tecumseh	33,787.6	33,746.1	33,810.4	33,822.2	33,781.9	33,771.5	33,787.3	33,754.0	33,762.2	33,735.2	33,684.2	33,994.8	35,349.0	33,851.5
454 Well Equipment Tecumseh	3,927.0	3,882.7	3,838.4	3,794.1	3,749.7	3,705.4	3,661.1	3,616.8	3,572.4	3,528.1	3,483.8	3,439.5	3,395.1	3,661.1
455 Field Lines Tecumseh	39,952.7	39,875.0	39,865.1	39,823.0	39,749.6	39,697.6	39,664.1	39,599.4	39,561.3	39,500.4	39,423.3	39,576.7	40,397.9	39,709.2
456 Compressor Equip. Tecumseh	68,172.2	67,950.4	67,860.4	67,707.4	67,493.1	67,320.5	70,483.6	70,278.4	70,124.9	69,926.9	69,697.4	69,916.5	71,434.8	69,046.9
457 Meas. & Reg. Tecumseh	8,847.3	8,809.0	8,774.4	8,738.3	8,700.8	8,664.9	8,630.2	8,593.8	8,558.9	8,522.7	8,485.5	8,460.7	8,472.2	8,633.2
458 Base Pressure Gas Tecumseh	40,957.7	40,958.1	40,958.9	40,959.7	40,960.6	40,962.1	40,963.5	40,964.5	40,967.4	40,968.8	40,970.8	40,972.2	40,975.7	40,964.4
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Underground Storage - After Adj.	229,608.1	229,197.9	229,372.9	229,259.7	228,860.6	228,630.3	231,846.9	235,883.9	235,745.1	235,409.7	234,940.7	236,469.2	243,768.6	232,692.0

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION UNDERGROUND STORAGE PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

Underground Storage Plant - Accum. Depr. After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451 Land rights Tecumseh	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7
451.1 Land rights intangibles Tecumseh	(24,651.5)	(24,689.8)	(24,728.1)	(24,766.4)	(24,804.7)	(24,843.0)	(24,881.3)	(24,919.6)	(24,958.0)	(24,996.3)	(25,034.7)	(25,073.1)	(25,111.5)	(24,881.4)
452 Struct. & Improve. Tecumseh	(5,705.6)	(5,735.4)	(5,765.4)	(5,795.9)	(5,826.7)	(5,857.6)	(5,888.8)	(5,920.3)	(5,958.7)	(5,997.4)	(6,036.2)	(6,075.1)	(6,115.3)	(5,897.3)
453 Wells Tecumseh	(17,183.6)	(17,216.3)	(17,249.1)	(17,281.2)	(17,311.8)	(17,340.8)	(17,368.8)	(17,396.6)	(17,424.4)	(17,452.3)	(17,480.7)	(17,510.4)	(17,542.2)	(17,366.3)
454 Well Equipment Tecumseh	(5,640.1)	(5,684.4)	(5,728.7)	(5,773.0)	(5,817.4)	(5,861.7)	(5,906.0)	(5,950.3)	(5,994.7)	(6,039.0)	(6,083.3)	(6,127.6)	(6,172.0)	(5,906.0)
455 Field Lines Tecumseh	(24,206.3)	(24,299.0)	(24,391.9)	(24,482.9)	(24,570.8)	(24,655.4)	(24,737.7)	(24,819.5)	(24,901.4)	(24,983.6)	(25,066.9)	(25,152.8)	(25,242.5)	(24,732.2)
456 Compressor Equip. Tecumseh	(35,626.8)	(35,887.6)	(36,148.9)	(36,406.8)	(36,659.0)	(36,904.9)	(37,146.6)	(37,394.9)	(37,643.3)	(37,892.4)	(38,143.7)	(38,400.0)	(38,664.2)	(37,147.8)
457 Meas. & Reg. Tecumseh	(5,752.7)	(5,792.1)	(5,831.5)	(5,870.6)	(5,909.2)	(5,947.2)	(5,984.9)	(6,022.5)	(6,060.1)	(6,097.7)	(6,135.5)	(6,173.7)	(6,212.6)	(5,984.0)
458 Base Pressure Gas Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Undgnd Storage Acc. Dep. - After Adj.	(117,264.9)	(117,802.9)	(118,341.9)	(118,875.1)	(119,397.9)	(119,908.9)	(120,412.4)	(120,922.0)	(121,438.9)	(121,957.0)	(122,479.3)	(123,011.0)	(123,558.6)	(120,413.3)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS DISTRIBUTION PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
Underground Storage Plant-Gross After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1
451 Land rights Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451.1 Land rights intangibles Tecumseh	39,612.0	39,615.2	39,629.5	39,638.2	39,641.4	39,647.5	39,656.2	39,659.8	39,667.7	39,672.0	39,673.8	39,713.4	39,862.0	39,662.6
452 Struct. & Improve. Tecumseh	19,464.9	19,542.8	19,885.5	20,095.3	20,171.1	20,317.6	20,527.2	25,013.3	25,203.2	25,305.5	25,349.0	26,299.8	29,864.9	22,697.9
453 Wells Tecumseh	50,971.2	50,962.4	51,059.5	51,103.4	51,093.7	51,112.3	51,156.1	51,150.6	51,186.6	51,187.5	51,164.9	51,505.2	52,891.2	51,217.8
454 Well Equipment Tecumseh	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1
455 Field Lines Tecumseh	64,159.0	64,174.0	64,257.0	64,305.9	64,320.4	64,353.0	64,401.8	64,418.9	64,462.7	64,484.0	64,490.2	64,729.5	65,640.4	64,441.4
456 Compressor Equip. Tecumseh	103,799.0	103,838.0	104,009.3	104,114.2	104,152.1	104,225.4	107,630.2	107,673.3	107,768.2	107,819.3	107,841.1	108,316.5	110,099.0	106,194.7
457 Meas. & Reg. Tecumseh	14,600.0	14,601.1	14,605.9	14,608.9	14,610.0	14,612.1	14,615.1	14,616.3	14,619.0	14,620.4	14,621.0	14,634.4	14,684.8	14,617.2
458 Base Pressure Gas Tecumseh	40,957.7	40,958.1	40,958.9	40,959.7	40,960.6	40,962.1	40,963.5	40,964.5	40,967.4	40,968.8	40,970.8	40,972.2	40,975.7	40,964.4
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Undgnd Storage Gross - After Adj.	346,873.0	347,000.8	347,714.8	348,134.8	348,258.5	348,539.2	352,259.3	356,805.9	357,184.0	357,366.7	357,420.0	359,480.2	367,327.2	353,105.2

Underground Storage Plant- Depreciation Rates	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Annual Prov.
	%	%	%	%	%	%	%	%	%	%	%	%	%
450/459 Crowland (Avg of all other storage categories)	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	2.480%
450 Land Tecumseh	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
451 Land rights Tecumseh	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	1.160%
451.1 Land rights intangibles Tecumseh	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	1.160%
452 Struct. & Improve. Tecumseh	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	1.840%
453 Wells Tecumseh	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	1.550%
454 Well Equipment Tecumseh	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	5.560%
455 Field Lines Tecumseh	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	1.550%
456 Compressor Equip. Tecumseh	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	2.690%
457 Meas. & Reg. Tecumseh	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	3.040%
458 Base Pressure Gas Tecumseh	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
??? Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%

Underground Storage Plant- Depreciation Provision - After Adjustments	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Depr.Provision
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451 Land rights Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451.1 Land rights intangibles Tecumseh	(38.3)	(38.3)	(38.3)	(38.3)	(38.3)	(38.3)	(38.3)	(38.3)	(38.3)	(38.3)	(38.4)	(38.4)	(459.8)
452 Struct. & Improve. Tecumseh	(29.8)	(30.0)	(30.5)	(30.8)	(30.9)	(31.2)	(31.5)	(38.4)	(38.6)	(38.8)	(38.9)	(40.3)	(409.7)
453 Wells Tecumseh	(65.8)	(65.8)	(66.0)	(66.0)	(66.0)	(66.0)	(66.1)	(66.1)	(66.1)	(66.1)	(66.1)	(66.5)	(792.6)
454 Well Equipment Tecumseh	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(531.6)
455 Field Lines Tecumseh	(82.9)	(82.9)	(83.0)	(83.1)	(83.1)	(83.1)	(83.2)	(83.2)	(83.3)	(83.3)	(83.3)	(83.6)	(998.0)
456 Compressor Equip. Tecumseh	(232.7)	(232.8)	(233.2)	(233.4)	(233.5)	(233.6)	(241.3)	(241.4)	(241.6)	(241.7)	(241.7)	(242.8)	(2,849.7)
457 Meas. & Reg. Tecumseh	(37.0)	(37.0)	(37.0)	(37.0)	(37.0)	(37.0)	(37.0)	(37.0)	(37.0)	(37.0)	(37.0)	(37.1)	(444.1)
458 Base Pressure Gas Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	(530.8)	(531.1)	(532.3)	(532.9)	(533.1)	(533.5)	(541.7)	(548.7)	(549.2)	(549.5)	(549.7)	(553.0)	(6,485.5)

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
GENERAL PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

General Plant - Net. After Adjustments	Col. 1 Dec. $(000)	Col. 2 Jan. $(000)	Col. 3 Feb. $(000)	Col. 4 Mar. $(000)	Col. 5 April $(000)	Col. 6 May $(000)	Col. 7 June $(000)	Col. 8 July $(000)	Col. 9 Aug. $(000)	Col. 10 Sep. $(000)	Col. 11 Oct. $(000)	Col. 12 Nov. $(000)	Col. 13 Dec. $(000)	Col. 14 Monthly Avgs. $(000)
482.50 Leasehold improvements	3,493.3	3,462.1	3,430.9	6,949.7	6,889.0	6,828.3	6,767.6	6,706.9	6,646.2	7,955.4	7,883.2	7,811.0	7,738.8	6,412.2
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	200.3	205.9	211.5	217.1	222.7	228.3	233.9	240.5	247.1	253.7	260.3	267.9	275.6	235.6
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	13,448.1	13,515.7	13,358.1	13,250.7	13,270.8	13,251.3	13,318.0	13,361.4	13,331.5	13,319.8	13,254.2	13,595.7	15,862.7	13,456.9
484.00 Transportation equipment	34,573.6	34,308.7	33,888.7	33,503.5	33,206.6	32,882.7	32,618.3	32,339.0	32,009.2	31,692.2	31,338.3	31,266.2	32,523.3	32,716.8
484.01 N.G.V .kits Co. vehicles	3,071.3	3,033.9	2,974.4	2,919.9	2,878.1	2,832.5	2,795.5	2,756.5	2,710.4	2,666.1	2,616.7	2,607.7	2,789.5	2,810.2
484.02 N.G.V. cyl. Co. vehicles	65.1	66.3	65.0	64.3	64.9	65.2	66.4	67.4	67.5	68.0	67.8	72.2	97.8	68.0
485.00 Heavy work equipment	13,951.6	13,928.0	13,865.8	13,812.2	13,780.6	13,742.4	13,719.2	13,692.3	13,653.0	13,617.0	13,571.8	13,597.1	13,955.1	13,744.4
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	22,934.4	22,880.8	22,757.0	22,649.1	22,581.6	22,502.1	22,450.0	22,391.5	22,310.4	22,235.4	22,144.0	22,181.2	22,825.1	22,496.9
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	(13.1)	61.6	68.0	89.6	150.1	198.9	274.2	343.1	390.1	442.8	479.3	640.4	1,389.9	318.9
487.80 N.G.V. compressor stations	1,132.6	1,216.1	1,202.4	1,210.4	1,273.3	1,319.2	1,402.3	1,476.0	1,518.0	1,568.0	1,594.7	1,797.6	2,832.7	1,463.4
487.90 N.G.V. rental cylinders	714.9	689.0	659.7	631.1	604.4	577.0	550.9	524.4	496.8	469.4	441.2	419.1	425.6	552.8
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	2,813.8	2,782.2	2,750.6	2,719.0	2,687.4	2,655.8	2,624.2	2,592.6	2,561.0	2,529.4	2,497.8	2,466.2	2,434.5	2,624.2
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	20,740.2	19,674.9	18,776.9	17,824.6	16,979.7	15,955.8	15,164.0	14,101.0	13,301.4	13,651.2	12,632.0	11,649.4	12,789.9	15,539.7
491.00 Software acquired intangibles	32,101.3	30,832.6	29,673.3	28,491.4	27,833.5	26,618.5	30,382.3	29,057.4	27,899.5	27,441.5	26,178.3	24,946.4	24,997.7	28,158.7
491.00 Software developed intangibles	37,376.6	36,456.5	35,860.6	35,155.4	40,351.1	39,398.9	41,079.3	40,006.0	39,446.3	41,157.0	40,192.2	39,294.8	42,587.2	39,031.7
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net General Plant - After Adj.	186,604.0	183,114.3	179,542.9	179,488.0	182,773.8	179,056.9	183,446.1	179,656.0	176,588.4	179,066.9	175,151.8	172,612.9	183,525.4	179,630.4

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION GENERAL PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

General plant - Acc. Depr. After Adjustments	Col. 1 Dec. $(000)	Col. 2 Jan. $(000)	Col. 3 Feb. $(000)	Col. 4 Mar. $(000)	Col. 5 April $(000)	Col. 6 May $(000)	Col. 7 June $(000)	Col. 8 July $(000)	Col. 9 Aug. $(000)	Col. 10 Sep. $(000)	Col. 11 Oct. $(000)	Col. 12 Nov. $(000)	Col. 13 Dec. $(000)	Col. 14 Monthly Avgs. $(000)
482.50 Leasehold improvements	(5,307.5)	(5,338.7)	(5,369.9)	(5,401.1)	(5,461.8)	(5,522.5)	(5,583.2)	(5,643.9)	(5,704.6)	(5,765.4)	(5,837.6)	(5,909.8)	(5,982.0)	(5,598.6)
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	(2,907.6)	(2,907.8)	(2,908.0)	(2,908.3)	(2,908.5)	(2,908.7)	(2,908.9)	(2,909.2)	(2,909.4)	(2,909.6)	(2,909.8)	(2,910.0)	(2,910.2)	(2,908.9)
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	(5,898.0)	(6,009.6)	(6,122.9)	(6,235.8)	(6,348.7)	(6,462.8)	(6,577.7)	(6,694.3)	(6,812.3)	(6,931.1)	(7,050.8)	(7,171.0)	(7,295.3)	(6,584.5)
484.00 Transportation equipment	(14,877.1)	(15,238.0)	(15,599.8)	(15,961.2)	(16,322.3)	(16,683.9)	(17,046.0)	(17,408.8)	(17,772.4)	(18,136.4)	(18,500.7)	(18,865.1)	(19,231.9)	(17,049.1)
484.01 N.G.V .kits Co. vehicles	(5,171.6)	(5,212.6)	(5,253.6)	(5,294.5)	(5,335.3)	(5,376.1)	(5,416.9)	(5,457.7)	(5,498.5)	(5,539.3)	(5,580.0)	(5,620.7)	(5,661.6)	(5,416.8)
484.02 N.G.V. cyl. Co. vehicles	(817.3)	(816.7)	(816.2)	(815.6)	(815.1)	(814.5)	(814.0)	(813.4)	(812.9)	(812.3)	(811.8)	(811.2)	(810.6)	(814.0)
485.00 Heavy work equipment	(8,234.2)	(8,277.4)	(8,320.6)	(8,363.8)	(8,407.0)	(8,450.2)	(8,493.4)	(8,536.7)	(8,580.0)	(8,623.3)	(8,666.7)	(8,710.0)	(8,753.5)	(8,493.6)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	(15,652.5)	(15,692.7)	(15,732.9)	(15,772.8)	(15,812.5)	(15,852.0)	(15,891.5)	(15,930.9)	(15,970.3)	(16,009.5)	(16,048.6)	(16,087.5)	(16,126.7)	(15,890.9)
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	(1,021.2)	(1,020.1)	(1,019.1)	(1,018.1)	(1,017.1)	(1,016.1)	(1,015.1)	(1,014.2)	(1,013.3)	(1,012.5)	(1,011.7)	(1,010.9)	(1,010.2)	(1,015.3)
487.80 N.G.V. compressor stations	(2,332.8)	(2,335.1)	(2,338.0)	(2,340.7)	(2,343.6)	(2,346.9)	(2,350.5)	(2,354.7)	(2,359.5)	(2,364.5)	(2,370.0)	(2,375.7)	(2,382.7)	(2,353.1)
487.90 N.G.V. rental cylinders	(1,164.4)	(1,194.0)	(1,223.7)	(1,253.4)	(1,283.1)	(1,312.9)	(1,342.7)	(1,372.6)	(1,402.5)	(1,432.5)	(1,462.5)	(1,492.5)	(1,522.7)	(1,343.0)
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	(1,093.7)	(1,125.0)	(1,156.3)	(1,187.7)	(1,219.0)	(1,250.3)	(1,281.7)	(1,313.0)	(1,344.3)	(1,375.7)	(1,407.0)	(1,438.3)	(1,469.8)	(1,281.7)
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	(15,256.9)	(16,086.7)	(16,909.3)	(17,729.6)	(18,545.9)	(19,361.3)	(20,170.5)	(20,980.1)	(21,782.0)	(22,583.9)	(23,421.0)	(24,252.5)	(25,079.4)	(20,165.9)
491.00 Software acquired intangibles	(26,656.3)	(27,315.6)	(27,961.5)	(28,596.1)	(29,218.7)	(29,840.5)	(30,449.3)	(31,154.0)	(31,845.1)	(32,526.0)	(33,211.8)	(33,884.9)	(34,545.9)	(30,550.4)
491.00 Software developed intangibles	(18,343.2)	(18,814.3)	(19,277.5)	(19,738.3)	(20,194.9)	(20,751.5)	(21,301.1)	(21,890.2)	(22,470.7)	(23,051.5)	(23,673.0)	(24,288.3)	(24,898.7)	(21,422.7)
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gen. Plant Acc. Depr. - After Adj.	(124,734.3)	(127,384.3)	(130,009.3)	(132,617.0)	(135,233.5)	(137,950.2)	(140,642.5)	(143,473.7)	(146,277.8)	(149,073.5)	(151,963.0)	(154,828.4)	(157,681.2)	(140,888.5)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS GENERAL PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

General plant - gross After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	8,800.8	8,800.8	8,800.8	12,350.8	12,350.8	12,350.8	12,350.8	12,350.8	12,350.8	13,720.8	13,720.8	13,720.8	13,720.8	12,010.8
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	3,107.9	3,113.7	3,119.5	3,125.4	3,131.2	3,137.0	3,142.8	3,149.7	3,156.5	3,163.3	3,170.1	3,177.9	3,185.8	3,144.5
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	19,346.1	19,525.3	19,481.0	19,486.5	19,619.5	19,714.1	19,895.7	20,055.7	20,143.8	20,250.9	20,305.0	20,766.7	23,158.0	20,041.4
484.00 Transportation equipment	49,450.7	49,546.7	49,488.5	49,464.7	49,528.9	49,566.6	49,664.3	49,747.8	49,781.6	49,828.6	49,839.0	50,131.3	51,755.2	49,765.9
484.01 N.G.V .kits Co. vehicles	8,242.9	8,246.5	8,228.0	8,214.4	8,213.4	8,208.6	8,212.4	8,214.2	8,208.9	8,205.4	8,196.7	8,228.4	8,451.1	8,227.0
484.02 N.G.V. cyl. Co. vehicles	882.4	883.0	881.2	879.9	880.0	879.7	880.4	880.8	880.4	880.3	879.6	883.4	908.4	882.0
485.00 Heavy work equipment	22,185.8	22,205.4	22,186.4	22,176.0	22,187.6	22,192.6	22,212.6	22,229.0	22,233.0	22,240.3	22,238.5	22,307.1	22,708.6	22,238.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	38,586.9	38,573.5	38,489.9	38,421.9	38,394.1	38,354.1	38,341.5	38,322.4	38,280.7	38,244.9	38,192.6	38,268.7	38,951.8	38,387.8
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	1,008.1	1,081.7	1,087.1	1,107.7	1,167.2	1,215.0	1,289.3	1,357.3	1,403.4	1,455.3	1,491.0	1,651.3	2,400.1	1,334.2
487.80 N.G.V. compressor stations	3,465.4	3,551.2	3,540.4	3,551.1	3,616.9	3,666.1	3,752.8	3,830.7	3,877.5	3,932.5	3,964.7	4,173.3	5,215.4	3,816.5
487.90 N.G.V. rental cylinders	1,879.3	1,883.0	1,883.4	1,884.5	1,887.5	1,889.9	1,893.6	1,897.0	1,899.3	1,901.9	1,903.7	1,911.6	1,948.3	1,895.8
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	3,907.5	3,907.2	3,906.9	3,906.7	3,906.4	3,906.1	3,905.9	3,905.6	3,905.3	3,905.1	3,904.8	3,904.5	3,904.3	3,905.9
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	35,997.1	35,761.6	35,686.2	35,554.2	35,525.6	35,317.1	35,334.5	35,081.1	35,083.4	36,235.1	36,053.0	35,901.9	37,869.3	35,705.6
491.00 Software acquired intangibles	58,757.6	58,148.2	57,634.8	57,087.5	57,052.2	56,459.0	60,831.6	60,211.4	59,744.6	59,967.5	59,390.1	58,831.3	59,543.6	58,709.1
491.00 Software developed intangibles	55,719.8	55,270.8	55,138.1	54,893.7	60,546.0	60,150.4	62,380.4	61,896.2	61,917.0	64,208.5	63,865.2	63,583.1	67,485.9	60,454.4
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
General Plant Gross - After Adj.	311,338.3	310,498.6	309,552.2	312,105.0	318,007.3	317,007.1	324,088.6	323,129.7	322,866.2	328,140.4	327,114.8	327,441.3	341,206.6	320,518.9

General plant - Depreciation Rates	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Annual
	%	%	%	%	%	%	%	%	%	%	%	%	%
482.50 Leasehold improvements	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	10.00%
483.1 Office equipment over 6.6 yrs.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
483.1 Office equipment over 15 yrs.	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.150%
483.2 Office furniture over 6.6 yrs.	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	10.740%
483.2 Office furniture over 20 yrs.	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	10.740%
484.00 Transportation equipment	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	10.560%
484.01 N.G.V .kits Co. vehicles	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	9.000%
484.02 N.G.V. cyl. Co. vehicles	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	2.100%
485.00 Heavy work equipment	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	3.580%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
486.00 Tools & work euip. over 2.69 yrs	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	4.080%
486.00 Tools & work euip. 4.0%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	4.080%
487.70 V.R.A.'S	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.740%
487.70 V.R.A.'S Post F2003 5%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.740%
487.80 N.G.V. compressor stations	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	8.010%
487.90 N.G.V. rental cylinders	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	18.930%
488.00 Communication str & equip	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	9.710%
488.00 Communication str & equip 20yrs	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	9.710%
490.00 Computer equipment	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	36.630%
490.00 Computer equipment 2003 B 20%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	36.630%
491.00 Software acquired intangibles	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	26.320%
491.00 Software developed intangibles	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	21.240%
491.00 CIS software acquired intangibles	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	10.000%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%

General plant -
Depreciation Provision - After Adjustments

	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Depr.Provision
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	(73.3)	(73.3)	(73.3)	(102.9)	(102.9)	(102.9)	(102.9)	(102.9)	(102.9)	(114.3)	(114.3)	(114.3)	(1,180.2)
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(4.8)
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	(173.1)	(174.8)	(174.4)	(174.4)	(175.6)	(176.4)	(178.1)	(179.5)	(180.3)	(181.2)	(181.7)	(185.9)	(2,135.4)
484.00 Transportation equipment	(435.2)	(436.0)	(435.5)	(435.3)	(435.9)	(436.2)	(437.0)	(437.8)	(438.1)	(438.5)	(438.6)	(441.2)	(5,245.3)
484.01 N.G.V .kits Co. vehicles	(61.8)	(61.8)	(61.7)	(61.6)	(61.6)	(61.6)	(61.6)	(61.6)	(61.6)	(61.5)	(61.5)	(61.7)	(739.6)
484.02 N.G.V. cyl. Co. vehicles	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(18.0)
485.00 Heavy work equipment	(66.2)	(66.2)	(66.2)	(66.2)	(66.2)	(66.2)	(66.3)	(66.3)	(66.3)	(66.4)	(66.3)	(66.5)	(795.3)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	(131.2)	(131.1)	(130.9)	(130.6)	(130.5)	(130.4)	(130.4)	(130.3)	(130.2)	(130.0)	(129.9)	(130.1)	(1,565.6)
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	(0.6)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.8)	(0.8)	(0.9)	(0.9)	(0.9)	(1.0)	(9.4)
487.80 N.G.V. compressor stations	(23.1)	(23.7)	(23.6)	(23.7)	(24.1)	(24.5)	(25.0)	(25.6)	(25.9)	(26.2)	(26.5)	(27.9)	(299.8)
487.90 N.G.V. rental cylinders	(29.6)	(29.7)	(29.7)	(29.7)	(29.8)	(29.8)	(29.9)	(29.9)	(30.0)	(30.0)	(30.0)	(30.2)	(358.3)
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(379.2)
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	(1,098.8)	(1,091.6)	(1,089.3)	(1,085.3)	(1,084.4)	(1,078.1)	(1,078.6)	(1,070.9)	(1,070.9)	(1,106.1)	(1,100.5)	(1,095.9)	(13,050.4)
491.00 Software acquired intangibles	(1,288.8)	(1,275.4)	(1,264.1)	(1,252.1)	(1,251.3)	(1,238.3)	(1,334.2)	(1,320.6)	(1,310.4)	(1,315.3)	(1,302.6)	(1,290.4)	(15,443.5)
491.00 Software developed intangibles	(986.2)	(978.3)	(975.9)	(971.6)	(1,071.7)	(1,064.7)	(1,104.1)	(1,095.6)	(1,095.9)	(1,136.5)	(1,130.4)	(1,125.4)	(12,736.3)
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	(4,401.4)	(4,376.1)	(4,358.8)	(4,367.6)	(4,468.2)	(4,443.3)	(4,582.4)	(4,555.3)	(4,546.9)	(4,640.4)	(4,616.7)	(4,604.0)	(53,961.1)

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
DISTRIBUTION PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

Distribution plant - Net. After Adjustments	Col. 1 Dec. $(000)	Col. 2 Jan. $(000)	Col. 3 Feb. $(000)	Col. 4 Mar. $(000)	Col. 5 April $(000)	Col. 6 May $(000)	Col. 7 June $(000)	Col. 8 July $(000)	Col. 9 Aug. $(000)	Col. 10 Sep. $(000)	Col. 11 Oct. $(000)	Col. 12 Nov. $(000)	Col. 13 Dec. $(000)	Col. 14 Monthly Avgs. $(000)
470.00 Land	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	5,536.6	5,529.3	5,522.0	5,514.7	5,507.3	5,500.0	5,492.7	5,485.4	5,478.0	5,470.7	5,463.4	5,456.1	5,448.7	5,492.7
472.00 Structures & improvements	108,244.8	108,022.5	107,968.1	108,240.9	108,637.6	108,897.3	109,219.8	109,233.8	109,163.3	109,028.3	108,920.4	108,739.4	108,816.0	108,716.8
473/474 Services, house regs. & meter inst	1,232,471.4	1,244,893.7	1,250,743.8	1,256,168.8	1,261,138.9	1,266,170.2	1,271,898.6	1,278,292.2	1,284,873.4	1,291,831.2	1,298,825.5	1,307,687.4	1,320,771.9	1,274,095.4
475.00 Mains	1,693,893.5	1,748,310.6	1,758,429.0	1,768,331.5	1,777,399.6	1,784,984.7	1,791,962.0	1,799,490.9	1,805,494.8	1,812,576.9	1,821,997.1	1,830,975.6	1,852,185.7	1,789,416.0
476.00 Company NGV compressor stations	717.9	707.9	696.0	685.2	675.9	666.0	662.1	655.9	648.7	648.6	645.1	638.4	669.3	668.6
477.00 Measuring & regulating equip.	185,651.1	190,099.3	190,805.9	191,752.8	192,671.5	193,625.1	194,815.6	195,906.9	196,713.8	197,729.9	199,246.3	200,401.4	203,727.2	194,871.5
478.00 Meters	286,309.9	284,328.7	282,393.9	280,487.0	278,608.8	277,037.5	275,745.0	274,317.9	273,001.3	271,645.1	270,495.2	269,471.0	269,413.9	276,282.8
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Distribution Plant - After Adj.	3,540,548.0	3,609,614.8	3,624,281.5	3,638,903.7	3,652,362.4	3,664,603.6	3,677,518.6	3,691,105.8	3,703,096.1	3,716,653.5	3,733,315.8	3,751,092.1	3,788,755.5	3,677,266.6

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION DISTRIBUTION PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
Distribution plant - Acc. Depr.														
After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
470.00 Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	(1,910.2)	(1,917.5)	(1,924.8)	(1,932.1)	(1,939.5)	(1,946.8)	(1,954.1)	(1,961.4)	(1,968.8)	(1,976.1)	(1,983.4)	(1,990.7)	(1,998.1)	(1,954.1)
472.00 Structures & improvements	(13,504.8)	(14,097.1)	(14,691.5)	(15,288.7)	(15,892.0)	(16,502.3)	(16,619.8)	(17,245.8)	(17,876.3)	(18,511.3)	(19,149.2)	(19,790.2)	(20,433.6)	(16,886.1)
473/474 Services, house regs. & meter inst	(1,037,790.6)	(1,036,192.0)	(1,034,532.8)	(1,033,359.7)	(1,032,976.2)	(1,033,224.0)	(1,033,873.6)	(1,034,774.8)	(1,035,587.9)	(1,036,377.0)	(1,036,765.3)	(1,036,413.5)	(1,034,492.0)	(1,035,018.2)
475.00 Mains	(1,230,047.3)	(1,229,441.0)	(1,228,867.1)	(1,229,176.3)	(1,230,898.8)	(1,234,062.0)	(1,238,236.1)	(1,242,709.9)	(1,247,156.6)	(1,251,521.5)	(1,255,417.6)	(1,258,173.8)	(1,259,254.6)	(1,240,859.3)
476.00 Company NGV compressor stations	(1,882.1)	(1,885.4)	(1,888.7)	(1,892.0)	(1,895.2)	(1,898.4)	(1,901.6)	(1,904.8)	(1,907.9)	(1,911.0)	(1,914.1)	(1,917.2)	(1,920.5)	(1,901.5)
477.00 Measuring & regulating equip.	(191,496.9)	(191,985.0)	(192,481.6)	(192,984.0)	(193,495.2)	(194,015.3)	(194,542.6)	(195,073.9)	(195,608.0)	(196,143.9)	(196,680.5)	(197,215.5)	(197,746.5)	(194,570.6)
478.00 Meters	(130,369.7)	(132,487.9)	(134,607.1)	(136,727.7)	(138,850.0)	(140,974.2)	(143,102.5)	(145,237.3)	(147,377.6)	(149,524.1)	(151,676.8)	(153,837.2)	(156,006.2)	(143,132.5)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dist. Plant Acc. Dep. - After Adj.	(2,607,001.6)	(2,608,005.9)	(2,608,993.6)	(2,611,360.5)	(2,615,946.9)	(2,622,623.0)	(2,630,230.3)	(2,638,907.9)	(2,647,483.1)	(2,655,964.9)	(2,663,586.9)	(2,669,338.1)	(2,671,851.5)	(2,634,322.3)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS DISTRIBUTION PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2014 TEST YEAR

Distribution plant - gross After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
470.00 Land	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8
472.00 Structures & improvements	121,749.6	122,119.6	122,659.6	123,529.6	124,529.6	125,399.6	125,839.6	126,479.6	127,039.6	127,539.6	128,069.6	128,529.6	129,249.6	125,602.9
473/474 Services, house regs. & m	2,270,262.0	2,281,085.7	2,285,276.6	2,289,528.5	2,294,115.1	2,299,394.2	2,305,772.2	2,313,067.0	2,320,461.3	2,328,208.2	2,335,590.8	2,344,100.9	2,355,263.9	2,309,113.6
475.00 Mains	2,923,940.8	2,977,751.6	2,987,296.1	2,997,507.8	3,008,298.4	3,019,046.7	3,030,198.1	3,042,200.8	3,052,651.4	3,064,098.4	3,077,414.7	3,089,149.4	3,111,440.3	3,030,275.3
476.00 Company NGV compressor	2,600.0	2,593.3	2,584.7	2,577.2	2,571.1	2,564.4	2,563.7	2,560.7	2,556.6	2,559.6	2,559.2	2,555.6	2,589.8	2,570.1
477.00 Measuring & regulating equi	377,148.0	382,084.3	383,287.5	384,736.8	386,166.7	387,640.4	389,358.2	390,980.8	392,321.8	393,873.8	395,926.8	397,616.9	401,473.7	389,442.1
478.00 Meters	416,679.6	416,816.6	417,001.0	417,214.7	417,458.8	418,011.7	418,847.5	419,555.2	420,378.9	421,169.2	422,172.0	423,308.2	425,420.1	419,415.3
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Distribution Plant Gross - After A	6,147,549.6	6,217,620.7	6,233,275.1	6,250,264.2	6,268,309.3	6,287,226.6	6,307,748.9	6,330,013.7	6,350,579.2	6,372,618.4	6,396,902.7	6,420,430.2	6,460,607.0	6,311,588.9

Distribution plant - Depreciation Rates	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Annual
	%	%	%	%	%	%	%	%	%	%	%	%	%
470.00 Land	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
470.01 Offers to purchase land	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
471.00 Land rights intangibles	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	1.180%
472.00 Structures & improvements	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	7.550%
473/474 Services, house regs. & meter inst.	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	2.450%
475.00 Mains	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	2.454%
476.00 Company NGV compressor stations	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	5.970%
477.00 Measuring & regulating equip.	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	2.100%
478.00 Meters	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	9.220%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%

Distribution plant - Depreciation Provision - After Adjustments	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Depr.Provision
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	
470.00 Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(87.6)
472.00 Structures & improvements	(766.0)	(768.3)	(771.7)	(777.2)	(783.5)	(789.0)	(791.7)	(795.8)	(799.3)	(802.4)	(805.8)	(808.7)	(9,459.4)
473/474 Services, house regs. & meter inst.	(4,635.1)	(4,657.2)	(4,665.8)	(4,674.5)	(4,683.8)	(4,694.6)	(4,707.6)	(4,722.5)	(4,737.6)	(4,753.4)	(4,768.5)	(4,785.9)	(56,486.5)
475.00 Mains	(5,978.2)	(6,088.3)	(6,107.8)	(6,128.7)	(6,150.7)	(6,172.7)	(6,195.5)	(6,220.0)	(6,241.4)	(6,264.8)	(6,292.0)	(6,316.0)	(74,156.1)
476.00 Company NGV compressor stations	(12.9)	(12.9)	(12.9)	(12.8)	(12.8)	(12.8)	(12.8)	(12.7)	(12.7)	(12.7)	(12.7)	(12.7)	(153.4)
477.00 Measuring & regulating equip.	(660.0)	(668.6)	(670.8)	(673.3)	(675.8)	(678.4)	(681.4)	(684.2)	(686.6)	(689.3)	(692.9)	(695.8)	(8,157.1)
478.00 Meters	(3,201.5)	(3,202.5)	(3,204.0)	(3,205.6)	(3,207.5)	(3,211.7)	(3,218.1)	(3,223.6)	(3,229.9)	(3,236.0)	(3,243.7)	(3,252.4)	(38,636.5)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	(15,261.0)	(15,405.1)	(15,440.3)	(15,479.4)	(15,521.4)	(15,566.5)	(15,614.4)	(15,666.1)	(15,714.8)	(15,765.9)	(15,822.9)	(15,878.8)	(187,136.6)

LOCAL STORAGE PLANT, PLANT HELD FOR FUTURE USE, AND OTHER PLANT - CONTINUITY WORKSHEETS
CALENDAR 2015 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	
Local Storage Plant	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Net change	Average of Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
A/c # 440.00 Land															
Opening balance	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5		
Expenditures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	0.0	21.5
Plant Held for Future Use - Gross	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Net change	Average of Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
A/c # 102.00															
Opening balance	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9		
Expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	0.0	1,670.9
Plant Held for Future Use - Accum. Depr.															
A/c # 105.02															
Opening balance	(1,212.5)	(1,212.5)	(1,215.9)	(1,219.3)	(1,222.7)	(1,226.1)	(1,229.5)	(1,232.9)	(1,236.3)	(1,239.7)	(1,243.1)	(1,246.5)	(1,249.9)		
Provision		(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.5)	(40.9)	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Costs net of Proceeds		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	(1,212.5)	(1,215.9)	(1,219.3)	(1,222.7)	(1,226.1)	(1,229.5)	(1,232.9)	(1,236.3)	(1,239.7)	(1,243.1)	(1,246.5)	(1,249.9)	(1,253.4)	(40.9)	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	(1,212.5)	(1,215.9)	(1,219.3)	(1,222.7)	(1,226.1)	(1,229.5)	(1,232.9)	(1,236.3)	(1,239.7)	(1,243.1)	(1,246.5)	(1,249.9)	(1,253.4)	(40.9)	(1,232.9)
Plant Held for Future Use - Net	458.4	455.0	451.6	448.2	444.8	441.4	438.0	434.6	431.2	427.8	424.4	421.0	417.5	(40.9)	438.0
Other Plant - Gross	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Net change	Average of Monthly Avgs.
A/c # 402.50	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
Intangible Plant (Peterborough)															
Opening balance	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3		
Expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	0.0	465.3
Other Plant - Acc.Depr.															
A/c # 402.50															
Intangible Plant (Peterborough)															
Opening balance	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)		
Provision		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Costs net of Proceeds		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	0.0	(465.3)
Other Plant - Net	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
UNDERGROUND STORAGE PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
Underground Storage Plant - Net. After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1
451 Land rights Tecumseh	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7
451.1 Land rights intangibles Tecumseh	14,750.5	14,723.0	14,732.9	14,724.0	14,696.1	14,678.3	14,669.4	14,642.9	14,631.1	14,606.9	14,574.4	14,670.3	15,136.5	14,691.1
452 Struct. & Improve. Tecumseh	23,749.6	23,746.5	23,888.0	23,956.5	23,951.7	23,985.4	24,053.5	28,862.3	28,912.0	28,913.6	28,883.0	29,348.5	31,242.7	26,333.1
453 Wells Tecumseh	35,349.0	35,331.9	35,510.2	37,904.7	37,884.7	37,918.2	37,999.2	37,989.0	38,055.4	38,056.7	38,014.0	38,640.7	41,197.0	37,631.5
454 Well Equipment Tecumseh	3,395.1	3,350.8	3,306.5	3,262.2	3,217.8	3,173.5	3,129.2	3,084.9	3,040.5	2,996.2	2,951.9	2,907.6	2,863.2	3,129.2
455 Field Lines Tecumseh	40,397.9	40,335.2	40,394.1	40,393.6	40,334.2	40,310.4	40,317.6	40,268.5	40,266.9	40,224.6	40,154.4	40,498.8	42,041.5	40,393.2
456 Compressor Equip. Tecumseh	71,434.8	71,179.6	70,983.2	70,760.4	70,512.9	70,287.0	71,607.5	71,369.6	71,154.9	70,920.0	70,669.9	70,618.6	71,146.7	70,946.2
457 Meas. & Reg. Tecumseh	8,472.2	8,433.3	8,395.9	8,358.0	8,319.8	8,282.5	8,245.8	8,208.6	8,172.0	8,134.8	8,097.2	8,064.5	8,046.4	8,247.6
458 Base Pressure Gas Tecumseh	40,975.7	40,976.1	40,976.9	40,977.7	40,978.6	40,980.1	40,981.5	40,982.5	40,985.4	40,986.8	40,988.8	40,990.2	40,993.7	40,982.4
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Underground Storage - After Adj.	243,768.6	243,320.2	243,431.5	245,580.9	245,139.6	244,859.2	246,247.5	250,652.1	250,462.0	250,083.4	249,577.4	250,983.0	257,911.5	247,598.1

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION UNDERGROUND STORAGE PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

Underground Storage Plant - Accum. Depr. After Adjustments	Col. 1 Dec. $(000)	Col. 2 Jan. $(000)	Col. 3 Feb. $(000)	Col. 4 Mar. $(000)	Col. 5 April $(000)	Col. 6 May $(000)	Col. 7 June $(000)	Col. 8 July $(000)	Col. 9 Aug. $(000)	Col. 10 Sep. $(000)	Col. 11 Oct. $(000)	Col. 12 Nov. $(000)	Col. 13 Dec. $(000)	Col. 14 Monthly Avgs. $(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451 Land rights Tecumseh	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7
451.1 Land rights intangibles Tecumseh	(25,111.5)	(25,150.0)	(25,188.6)	(25,227.2)	(25,265.8)	(25,304.4)	(25,343.0)	(25,381.7)	(25,420.4)	(25,459.1)	(25,497.8)	(25,536.6)	(25,575.5)	(25,343.2)
452 Struct. & Improve. Tecumseh	(6,115.3)	(6,161.0)	(6,206.9)	(6,253.1)	(6,299.4)	(6,345.8)	(6,392.3)	(6,439.0)	(6,493.1)	(6,547.4)	(6,601.8)	(6,656.2)	(6,711.4)	(6,400.8)
453 Wells Tecumseh	(17,542.2)	(17,616.9)	(17,691.8)	(17,766.1)	(17,842.2)	(17,917.0)	(17,990.9)	(18,064.8)	(18,138.8)	(18,213.1)	(18,288.0)	(18,364.0)	(18,442.5)	(17,990.5)
454 Well Equipment Tecumseh	(6,172.0)	(6,216.3)	(6,260.6)	(6,304.9)	(6,349.3)	(6,393.6)	(6,437.9)	(6,482.2)	(6,526.6)	(6,570.9)	(6,615.2)	(6,659.5)	(6,703.9)	(6,437.9)
455 Field Lines Tecumseh	(25,242.5)	(25,341.0)	(25,439.7)	(25,536.7)	(25,631.0)	(25,722.2)	(25,811.4)	(25,900.1)	(25,989.0)	(26,078.3)	(26,168.5)	(26,261.3)	(26,357.9)	(25,806.6)
456 Compressor Equip. Tecumseh	(38,664.2)	(38,936.9)	(39,210.1)	(39,479.9)	(39,744.4)	(40,003.1)	(40,257.8)	(40,515.0)	(40,772.3)	(41,030.1)	(41,290.0)	(41,554.4)	(41,825.5)	(40,253.2)
457 Meas. & Reg. Tecumseh	(6,212.6)	(6,252.0)	(6,291.4)	(6,330.5)	(6,369.1)	(6,407.3)	(6,445.2)	(6,482.9)	(6,520.6)	(6,558.4)	(6,596.3)	(6,634.6)	(6,673.6)	(6,444.3)
458 Base Pressure Gas Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Undgnd Storage Acc. Dep. - After Adj.	(123,558.6)	(124,172.4)	(124,787.4)	(125,396.7)	(125,999.5)	(126,591.7)	(127,176.8)	(127,764.0)	(128,359.1)	(128,955.6)	(129,555.9)	(130,164.9)	(130,788.6)	(127,174.8)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS DISTRIBUTION PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
Underground Storage Plant-Gross After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1
451 Land rights Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451.1 Land rights intangibles Tecumseh	39,862.0	39,873.0	39,921.5	39,951.2	39,961.9	39,982.7	40,012.4	40,024.6	40,051.5	40,066.0	40,072.2	40,206.9	40,712.0	40,034.2
452 Struct. & Improve. Tecumseh	29,864.9	29,907.5	30,094.9	30,209.6	30,251.1	30,331.2	30,445.8	35,301.3	35,405.1	35,461.0	35,484.8	36,004.7	37,954.1	32,733.9
453 Wells Tecumseh	52,891.2	52,948.8	53,202.0	55,670.8	55,726.9	55,835.2	55,990.1	56,053.8	56,194.2	56,269.8	56,302.0	57,004.7	59,639.5	55,622.0
454 Well Equipment Tecumseh	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1
455 Field Lines Tecumseh	65,640.4	65,676.2	65,833.8	65,930.3	65,965.2	66,032.6	66,129.0	66,168.6	66,255.9	66,302.9	66,322.9	66,760.1	68,399.4	66,199.8
456 Compressor Equip. Tecumseh	110,099.0	110,116.5	110,193.3	110,240.3	110,257.3	110,290.1	111,865.3	111,884.6	111,927.2	111,950.1	111,959.9	112,173.0	112,972.2	111,199.4
457 Meas. & Reg. Tecumseh	14,684.8	14,685.3	14,687.3	14,688.5	14,688.9	14,689.8	14,691.0	14,691.5	14,692.6	14,693.2	14,693.5	14,699.1	14,720.0	14,691.9
458 Base Pressure Gas Tecumseh	40,975.7	40,976.1	40,976.9	40,977.7	40,978.6	40,980.1	40,981.5	40,982.5	40,985.4	40,986.8	40,988.8	40,990.2	40,993.7	40,982.4
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Undgnd Storage Gross - After Adj.	367,327.2	367,492.6	368,218.9	370,977.6	371,139.1	371,450.9	373,424.3	378,416.1	378,821.1	379,039.0	379,133.3	381,147.9	388,700.1	374,772.8

Underground Storage Plant- Depreciation Rates	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Annual Prov.
	%	%	%	%	%	%	%	%	%	%	%	%	%
450/459 Crowland (Avg of all other storage categories)	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	2.480%
450 Land Tecumseh	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
451 Land rights Tecumseh	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	1.160%
451.1 Land rights intangibles Tecumseh	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	1.160%
452 Struct. & Improve. Tecumseh	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	1.840%
453 Wells Tecumseh	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	1.550%
454 Well Equipment Tecumseh	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	5.560%
455 Field Lines Tecumseh	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	1.550%
456 Compressor Equip. Tecumseh	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	2.690%
457 Meas. & Reg. Tecumseh	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	3.040%
458 Base Pressure Gas Tecumseh	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
??? Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%

Underground Storage Plant- Depreciation Provision - After Adjustments	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Depr.Provision
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451 Land rights Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451.1 Land rights intangibles Tecumseh	(38.5)	(38.5)	(38.6)	(38.6)	(38.6)	(38.6)	(38.7)	(38.7)	(38.7)	(38.7)	(38.7)	(38.9)	(463.8)
452 Struct. & Improve. Tecumseh	(45.8)	(45.9)	(46.1)	(46.3)	(46.4)	(46.5)	(46.7)	(54.1)	(54.3)	(54.4)	(54.4)	(55.2)	(596.1)
453 Wells Tecumseh	(68.3)	(68.4)	(68.7)	(71.9)	(72.0)	(72.1)	(72.3)	(72.4)	(72.6)	(72.7)	(72.7)	(73.6)	(857.7)
454 Well Equipment Tecumseh	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(531.6)
455 Field Lines Tecumseh	(84.8)	(84.8)	(85.0)	(85.2)	(85.2)	(85.3)	(85.4)	(85.5)	(85.6)	(85.6)	(85.7)	(86.2)	(1,024.3)
456 Compressor Equip. Tecumseh	(246.8)	(246.8)	(247.0)	(247.1)	(247.2)	(247.2)	(250.8)	(250.8)	(250.9)	(251.0)	(251.0)	(251.5)	(2,988.1)
457 Meas. & Reg. Tecumseh	(37.2)	(37.2)	(37.2)	(37.2)	(37.2)	(37.2)	(37.2)	(37.2)	(37.2)	(37.2)	(37.2)	(37.2)	(446.4)
458 Base Pressure Gas Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	(565.7)	(565.9)	(566.9)	(570.6)	(570.9)	(571.2)	(575.4)	(583.0)	(583.6)	(583.9)	(584.0)	(586.9)	(6,908.0)

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
GENERAL PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

General Plant - Net.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	7,738.8	7,666.6	7,594.4	7,522.3	10,450.1	10,352.9	10,255.8	10,158.6	10,061.4	9,964.3	9,867.1	9,889.9	9,791.8	9,379.1
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	275.6	281.2	286.8	292.4	298.0	303.6	309.2	315.8	322.4	329.0	335.6	343.2	350.8	310.9
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	15,862.7	15,898.7	15,706.9	15,565.5	15,552.6	15,499.3	15,532.7	15,542.3	15,477.4	15,430.5	15,328.8	15,638.2	17,893.6	15,670.9
484.00 Transportation equipment	32,523.3	32,238.1	31,797.8	31,392.4	31,075.3	30,731.1	30,446.5	30,147.0	29,797.0	29,459.9	29,085.9	28,993.7	30,230.5	30,545.1
484.01 N.G.V .kits Co. vehicles	2,789.5	2,731.6	2,668.8	2,607.3	2,548.8	2,489.6	2,432.4	2,374.9	2,315.9	2,257.4	2,197.9	2,147.6	2,140.4	2,436.4
484.02 N.G.V. cyl. Co. vehicles	97.8	121.2	121.9	127.7	146.4	161.1	184.6	206.0	220.0	236.0	246.6	298.4	545.3	199.3
485.00 Heavy work equipment	13,955.1	13,930.0	13,866.2	13,811.1	13,778.0	13,738.2	13,713.4	13,685.0	13,644.1	13,606.5	13,559.8	13,583.5	13,939.9	13,738.6
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	22,825.1	22,770.3	22,645.2	22,536.0	22,467.1	22,386.2	22,332.7	22,272.8	22,190.3	22,113.9	22,021.0	22,056.7	22,698.9	22,379.5
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	1,389.9	1,463.8	1,469.4	1,490.2	1,550.0	1,598.0	1,672.5	1,740.6	1,786.7	1,838.7	1,874.4	2,034.9	2,785.2	1,717.2
487.80 N.G.V. compressor stations	2,832.7	2,909.8	2,884.9	2,882.6	2,938.1	2,975.7	3,052.4	3,119.2	3,152.8	3,194.8	3,212.3	3,414.8	4,491.1	3,116.6
487.90 N.G.V. rental cylinders	425.6	398.7	368.3	338.6	310.9	282.5	255.4	227.9	199.3	170.9	141.7	118.7	125.1	257.4
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	2,434.5	2,402.9	2,371.3	2,339.7	2,308.1	2,276.5	2,244.9	2,213.3	2,181.7	2,150.1	2,118.5	2,087.0	2,055.5	2,244.9
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	12,789.9	11,674.1	10,774.6	9,825.5	8,900.8	7,900.6	7,194.5	6,178.5	5,494.2	6,204.5	5,287.7	4,430.3	6,136.0	7,777.4
491.00 Software acquired intangibles	24,997.7	23,723.8	22,627.6	21,497.8	20,392.9	19,233.1	18,313.5	17,152.7	16,261.6	16,493.0	15,438.7	14,437.0	15,491.1	18,818.0
491.00 Software developed intangibles	42,587.2	41,442.4	40,544.8	39,568.3	38,603.3	37,526.3	51,609.5	50,214.9	49,209.9	49,915.1	48,612.3	47,363.5	49,267.7	45,044.8
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
489.00 WAMS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	58,550.0	2,439.6
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net General Plant - After Adj.	183,525.4	179,653.2	175,728.9	171,797.4	171,320.4	167,454.7	179,550.0	175,549.5	172,314.7	173,364.6	169,328.3	166,837.4	236,492.9	176,075.7

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION GENERAL PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

General plant - Acc. Depr. After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	(5,982.0)	(6,054.2)	(6,126.4)	(6,198.5)	(6,270.7)	(6,367.9)	(6,465.0)	(6,562.2)	(6,659.4)	(6,756.5)	(6,853.7)	(6,950.9)	(7,049.0)	(6,481.7)
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	(2,910.2)	(2,910.5)	(2,910.7)	(2,910.9)	(2,911.1)	(2,911.3)	(2,911.5)	(2,911.8)	(2,912.0)	(2,912.2)	(2,912.4)	(2,912.6)	(2,912.8)	(2,911.5)
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	(7,295.3)	(7,480.6)	(7,667.8)	(7,854.9)	(8,042.5)	(8,231.7)	(8,422.0)	(8,614.4)	(8,808.6)	(9,003.9)	(9,200.6)	(9,398.1)	(9,600.0)	(8,431.1)
484.00 Transportation equipment	(19,231.9)	(19,611.8)	(19,992.6)	(20,372.9)	(20,752.9)	(21,133.5)	(21,514.6)	(21,896.3)	(22,278.8)	(22,661.6)	(23,044.7)	(23,427.9)	(23,813.9)	(21,517.5)
484.01 N.G.V .kits Co. vehicles	(5,661.6)	(5,704.2)	(5,746.7)	(5,788.9)	(5,831.1)	(5,873.1)	(5,914.9)	(5,956.7)	(5,998.4)	(6,039.9)	(6,081.3)	(6,122.6)	(6,163.7)	(5,914.2)
484.02 N.G.V. cyl. Co. vehicles	(810.6)	(810.1)	(809.6)	(809.1)	(808.6)	(808.2)	(807.9)	(807.5)	(807.2)	(806.9)	(806.6)	(806.4)	(806.4)	(808.1)
485.00 Heavy work equipment	(8,753.5)	(8,797.8)	(8,842.2)	(8,886.5)	(8,930.8)	(8,975.2)	(9,019.6)	(9,064.0)	(9,108.5)	(9,153.0)	(9,197.5)	(9,242.0)	(9,286.8)	(9,019.8)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	(16,126.7)	(16,177.0)	(16,227.4)	(16,277.5)	(16,327.5)	(16,377.3)	(16,427.1)	(16,476.8)	(16,526.5)	(16,576.0)	(16,625.5)	(16,674.8)	(16,724.5)	(16,426.6)
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	(1,010.2)	(1,010.0)	(1,009.8)	(1,009.7)	(1,009.5)	(1,009.4)	(1,009.4)	(1,009.4)	(1,009.4)	(1,009.5)	(1,009.6)	(1,009.7)	(1,009.9)	(1,009.6)
487.80 N.G.V. compressor stations	(2,382.7)	(2,396.7)	(2,411.3)	(2,425.8)	(2,440.4)	(2,455.5)	(2,470.9)	(2,487.0)	(2,503.6)	(2,520.4)	(2,537.7)	(2,555.3)	(2,574.3)	(2,473.6)
487.90 N.G.V. rental cylinders	(1,522.7)	(1,553.4)	(1,584.2)	(1,615.0)	(1,645.8)	(1,676.7)	(1,707.6)	(1,738.6)	(1,769.6)	(1,800.7)	(1,831.8)	(1,862.9)	(1,894.2)	(1,707.9)
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	(1,469.8)	(1,501.1)	(1,532.4)	(1,563.8)	(1,595.1)	(1,626.4)	(1,657.8)	(1,689.1)	(1,720.4)	(1,751.8)	(1,783.1)	(1,814.3)	(1,845.6)	(1,657.8)
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	(25,079.4)	(25,403.3)	(25,703.0)	(25,984.5)	(26,245.5)	(26,486.2)	(26,703.9)	(26,906.5)	(27,084.3)	(27,246.8)	(27,435.8)	(27,602.6)	(27,748.5)	(26,601.4)
491.00 Software acquired intangibles	(34,545.9)	(34,726.6)	(34,883.3)	(35,019.4)	(35,133.7)	(35,226.3)	(35,295.6)	(35,346.1)	(35,372.3)	(35,379.5)	(35,391.9)	(35,381.5)	(35,349.1)	(35,175.3)
491.00 Software developed intangibles	(24,898.7)	(25,514.7)	(26,121.3)	(26,722.8)	(27,317.7)	(27,906.0)	(28,485.7)	(29,324.9)	(30,154.3)	(30,980.5)	(31,833.9)	(32,679.3)	(33,517.9)	(28,854.1)
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
489.00 WAMS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gen. Plant Acc. Depr. - After Adj.	(157,681.2)	(159,652.0)	(161,568.7)	(163,440.2)	(165,262.9)	(167,064.7)	(168,813.5)	(170,791.3)	(172,713.3)	(174,599.2)	(176,546.1)	(178,440.9)	(180,296.6)	(168,990.2)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS GENERAL PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

General plant - gross After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	13,720.8	13,720.8	13,720.8	13,720.8	16,720.8	16,720.8	16,720.8	16,720.8	16,720.8	16,720.8	16,720.8	16,840.8	16,840.8	15,860.8
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	3,185.8	3,191.7	3,197.5	3,203.3	3,209.1	3,214.9	3,220.7	3,227.6	3,234.4	3,241.2	3,248.0	3,255.8	3,263.6	3,222.4
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	23,158.0	23,379.3	23,374.7	23,420.4	23,595.1	23,731.0	23,954.7	24,156.7	24,286.0	24,434.4	24,529.4	25,036.3	27,493.6	24,102.0
484.00 Transportation equipment	51,755.2	51,849.9	51,790.4	51,765.3	51,828.2	51,864.6	51,961.1	52,043.3	52,075.8	52,121.5	52,130.6	52,421.6	54,044.4	52,062.7
484.01 N.G.V .kits Co. vehicles	8,451.1	8,435.8	8,415.5	8,396.2	8,379.9	8,362.7	8,347.3	8,331.6	8,314.3	8,297.3	8,279.2	8,270.2	8,304.1	8,350.6
484.02 N.G.V. cyl. Co. vehicles	908.4	931.3	931.5	936.8	955.0	969.3	992.5	1,013.5	1,027.2	1,042.9	1,053.2	1,104.8	1,351.7	1,007.3
485.00 Heavy work equipment	22,708.6	22,727.8	22,708.4	22,697.6	22,708.8	22,713.4	22,733.0	22,749.0	22,752.6	22,759.5	22,757.3	22,825.5	23,226.7	22,758.4
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	38,951.8	38,947.3	38,872.6	38,813.5	38,794.6	38,763.5	38,759.8	38,749.6	38,716.8	38,689.9	38,646.5	38,731.5	39,423.4	38,806.1
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	2,400.1	2,473.8	2,479.2	2,499.9	2,559.5	2,607.4	2,681.9	2,750.0	2,796.1	2,848.2	2,884.0	3,044.6	3,795.1	2,726.9
487.80 N.G.V. compressor stations	5,215.4	5,306.5	5,296.2	5,308.4	5,378.5	5,431.2	5,523.3	5,606.2	5,656.4	5,715.2	5,750.0	5,970.1	7,065.4	5,590.2
487.90 N.G.V. rental cylinders	1,948.3	1,952.1	1,952.5	1,953.6	1,956.7	1,959.2	1,963.0	1,966.5	1,968.9	1,971.6	1,973.5	1,981.6	2,019.3	1,965.3
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	3,904.3	3,904.0	3,903.7	3,903.5	3,903.2	3,902.9	3,902.7	3,902.4	3,902.1	3,901.9	3,901.6	3,901.3	3,901.1	3,902.7
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	37,869.3	37,077.4	36,477.6	35,810.0	35,146.3	34,386.8	33,898.4	33,085.0	32,578.5	33,451.3	32,723.5	32,032.9	33,884.5	34,378.7
491.00 Software acquired intangibles	59,543.6	58,450.4	57,510.9	56,517.2	55,526.6	54,459.4	53,609.1	52,498.8	51,633.9	51,872.5	50,830.6	49,818.5	50,840.2	53,993.3
491.00 Software developed intangibles	67,485.9	66,957.1	66,666.1	66,291.1	65,921.0	65,432.3	80,095.2	79,539.8	79,364.2	80,895.6	80,446.2	80,042.8	82,785.6	73,898.9
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
489.00 WAMS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	58,550.0	2,439.6
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
General Plant Gross - After Adj.	341,206.6	339,305.2	337,297.6	335,237.6	336,583.3	334,519.4	348,363.5	346,340.8	345,028.0	347,963.8	345,874.4	345,278.3	416,789.5	345,065.9

General plant - Depreciation Rates	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Annual
	%	%	%	%	%	%	%	%	%	%	%	%	%
482.50 Leasehold improvements	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	10.00%
483.1 Office equipment over 6.6 yrs.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
483.1 Office equipment over 15 yrs.	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.150%
483.2 Office furniture over 6.6 yrs.	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	10.740%
483.2 Office furniture over 20 yrs.	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	10.740%
484.00 Transportation equipment	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	10.560%
484.01 N.G.V .kits Co. vehicles	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	9.000%
484.02 N.G.V. cyl. Co. vehicles	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	2.100%
485.00 Heavy work equipment	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	3.580%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
486.00 Tools & work euip. over 2.69 yrs	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	4.080%
486.00 Tools & work euip. 4.0%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	4.080%
487.70 V.R.A.'S	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.740%
487.70 V.R.A.'S Post F2003 5%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.740%
487.80 N.G.V. compressor stations	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	8.010%
487.90 N.G.V. rental cylinders	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	18.930%
488.00 Communication str & equip	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	9.710%
488.00 Communication str & equip 20yrs	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	9.710%
490.00 Computer equipment	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	36.630%
490.00 Computer equipment 2003 B 20%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	36.630%
491.00 Software acquired intangibles	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	26.320%
491.00 Software developed intangibles	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	21.240%
491.00 CIS software acquired intangibles	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	10.000%
489.00 WAMS	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	10.000%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%

General plant -
Depreciation Provision - After Adjustments

	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Depr.Provision
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	(114.3)	(114.3)	(114.3)	(114.3)	(139.3)	(139.3)	(139.3)	(139.3)	(139.3)	(139.3)	(139.3)	(140.3)	(1,572.6)
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(4.8)
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	(207.3)	(209.2)	(209.2)	(209.6)	(211.2)	(212.4)	(214.4)	(216.2)	(217.4)	(218.7)	(219.5)	(224.1)	(2,569.2)
484.00 Transportation equipment	(455.4)	(456.3)	(455.8)	(455.5)	(456.1)	(456.4)	(457.3)	(458.0)	(458.3)	(458.7)	(458.7)	(461.3)	(5,487.8)
484.01 N.G.V .kits Co. vehicles	(63.4)	(63.3)	(63.1)	(63.0)	(62.8)	(62.7)	(62.6)	(62.5)	(62.4)	(62.2)	(62.1)	(62.0)	(752.1)
484.02 N.G.V. cyl. Co. vehicles	(1.6)	(1.6)	(1.6)	(1.6)	(1.7)	(1.7)	(1.7)	(1.8)	(1.8)	(1.8)	(1.8)	(1.9)	(20.6)
485.00 Heavy work equipment	(67.7)	(67.8)	(67.7)	(67.7)	(67.7)	(67.8)	(67.8)	(67.9)	(67.9)	(67.9)	(67.9)	(68.1)	(813.9)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	(132.4)	(132.4)	(132.2)	(132.0)	(131.9)	(131.8)	(131.8)	(131.7)	(131.6)	(131.5)	(131.4)	(131.7)	(1,582.4)
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	(1.5)	(1.5)	(1.5)	(1.5)	(1.6)	(1.6)	(1.7)	(1.7)	(1.7)	(1.8)	(1.8)	(1.9)	(19.8)
487.80 N.G.V. compressor stations	(34.8)	(35.4)	(35.4)	(35.4)	(35.9)	(36.3)	(36.9)	(37.4)	(37.8)	(38.1)	(38.4)	(39.9)	(441.7)
487.90 N.G.V. rental cylinders	(30.7)	(30.8)	(30.8)	(30.8)	(30.9)	(30.9)	(31.0)	(31.0)	(31.1)	(31.1)	(31.1)	(31.3)	(371.5)
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(379.2)
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	(1,156.0)	(1,131.8)	(1,113.5)	(1,093.1)	(1,072.8)	(1,049.7)	(1,034.7)	(1,009.9)	(994.5)	(1,021.1)	(998.9)	(977.8)	(12,653.8)
491.00 Software acquired intangibles	(1,306.0)	(1,282.0)	(1,261.4)	(1,239.6)	(1,217.9)	(1,194.5)	(1,175.8)	(1,151.5)	(1,132.5)	(1,137.7)	(1,114.9)	(1,092.7)	(14,306.5)
491.00 Software developed intangibles	(1,194.5)	(1,185.1)	(1,180.0)	(1,173.4)	(1,166.8)	(1,158.2)	(1,417.7)	(1,407.9)	(1,404.7)	(1,431.9)	(1,423.9)	(1,416.8)	(15,560.9)
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
489.00 WAMS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	(4,797.6)	(4,743.5)	(4,698.5)	(4,649.5)	(4,628.6)	(4,575.3)	(4,804.7)	(4,748.8)	(4,713.0)	(4,773.8)	(4,721.7)	(4,681.8)	(56,536.8)

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
DISTRIBUTION PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

Distribution plant - Net.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
470.00 Land	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	29,028.8	29,028.8	29,028.8	27,994.9
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	5,448.7	5,441.4	5,434.1	5,426.8	5,419.4	5,412.1	5,404.8	5,397.5	5,390.2	5,382.9	94,743.6	94,648.4	94,553.1	24,008.5
472.00 Structures & improvements	108,816.0	109,318.5	109,707.5	110,300.3	110,695.4	110,402.3	110,288.9	110,031.6	109,792.0	109,518.9	109,343.2	109,264.3	109,410.5	109,814.7
473/474 Services, house regs. & meter inst	1,320,771.9	1,332,418.2	1,338,374.4	1,343,930.9	1,349,116.7	1,354,481.1	1,360,671.2	1,367,641.1	1,374,799.0	1,382,354.3	1,389,911.3	1,399,367.1	1,413,176.6	1,363,336.6
475.00 Mains	1,852,185.7	1,864,779.2	1,877,297.2	1,890,186.9	1,902,307.6	1,913,158.6	1,924,082.8	1,935,141.7	1,943,931.6	1,954,137.1	2,383,429.8	2,394,305.9	2,421,474.5	2,009,965.7
476.00 Company NGV compressor stations	669.3	659.3	647.6	637.0	627.8	618.1	614.5	608.5	601.5	601.6	598.3	591.7	623.7	621.0
477.00 Measuring & regulating equip.	203,727.2	205,011.7	206,330.2	208,005.4	209,642.3	211,334.1	213,378.1	215,276.1	216,754.1	218,540.4	295,437.3	297,294.4	302,352.5	229,170.3
478.00 Meters	269,413.9	267,501.4	265,638.9	263,806.2	262,004.0	260,537.9	259,377.0	258,067.3	256,878.1	255,644.4	254,636.4	253,765.5	253,955.8	259,961.8
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Distribution Plant - After Adj.	3,788,755.5	3,812,852.5	3,831,152.7	3,850,016.3	3,867,536.0	3,883,667.0	3,901,540.1	3,919,886.6	3,935,869.3	3,953,902.4	4,557,128.7	4,578,266.1	4,624,575.5	4,024,873.5

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION DISTRIBUTION PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

Distribution plant - Acc. Depr. After Adjustments	Col. 1 Dec. $(000)	Col. 2 Jan. $(000)	Col. 3 Feb. $(000)	Col. 4 Mar. $(000)	Col. 5 April $(000)	Col. 6 May $(000)	Col. 7 June $(000)	Col. 8 July $(000)	Col. 9 Aug. $(000)	Col. 10 Sep. $(000)	Col. 11 Oct. $(000)	Col. 12 Nov. $(000)	Col. 13 Dec. $(000)	Col. 14 Monthly Avgs. $(000)
470.00 Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	(1,998.1)	(2,005.4)	(2,012.7)	(2,020.0)	(2,027.4)	(2,034.7)	(2,042.0)	(2,049.3)	(2,056.6)	(2,063.9)	(2,071.2)	(2,166.4)	(2,261.7)	(2,056.6)
472.00 Structures & improvements	(20,433.6)	(20,547.8)	(21,165.5)	(21,789.3)	(22,420.9)	(21,560.7)	(22,190.7)	(22,824.7)	(23,461.0)	(24,100.7)	(24,743.1)	(25,388.7)	(26,039.1)	(22,785.8)
473/474 Services, house regs. & meter inst	(1,034,492.0)	(1,033,322.8)	(1,032,096.4)	(1,031,319.9)	(1,031,274.0)	(1,031,799.7)	(1,032,686.1)	(1,033,813.3)	(1,034,856.4)	(1,035,881.6)	(1,036,529.3)	(1,036,489.4)	(1,034,955.8)	(1,033,732.7)
475.00 Mains	(1,259,254.6)	(1,259,524.7)	(1,259,736.6)	(1,260,776.1)	(1,263,136.4)	(1,266,840.7)	(1,271,490.6)	(1,276,430.8)	(1,281,355.2)	(1,286,212.5)	(1,290,642.6)	(1,294,995.8)	(1,297,796.1)	(1,274,138.9)
476.00 Company NGV compressor stations	(1,920.5)	(1,923.6)	(1,926.6)	(1,929.6)	(1,932.7)	(1,935.6)	(1,938.6)	(1,941.5)	(1,944.5)	(1,947.4)	(1,950.4)	(1,953.3)	(1,956.2)	(1,938.5)
477.00 Measuring & regulating equip.	(197,746.5)	(198,276.7)	(198,809.9)	(199,349.7)	(199,899.1)	(200,458.3)	(201,025.7)	(201,598.6)	(202,175.7)	(202,756.0)	(203,338.6)	(204,052.0)	(204,763.3)	(201,082.9)
478.00 Meters	(156,006.2)	(158,191.5)	(160,378.9)	(162,568.8)	(164,761.5)	(166,957.2)	(169,158.5)	(171,367.8)	(173,584.0)	(175,808.1)	(178,039.8)	(180,280.9)	(182,532.5)	(169,197.2)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dist. Plant Acc. Dep. - After Adj.	(2,671,851.5)	(2,673,792.5)	(2,676,126.6)	(2,679,753.4)	(2,685,452.0)	(2,691,586.9)	(2,700,532.2)	(2,710,026.0)	(2,719,433.4)	(2,728,770.2)	(2,737,315.0)	(2,745,326.5)	(2,750,304.7)	(2,704,932.6)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS DISTRIBUTION PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2015 TEST YEAR

Distribution plant - gross After Adjustments	Col. 1 Dec. $(000)	Col. 2 Jan. $(000)	Col. 3 Feb. $(000)	Col. 4 Mar. $(000)	Col. 5 April $(000)	Col. 6 May $(000)	Col. 7 June $(000)	Col. 8 July $(000)	Col. 9 Aug. $(000)	Col. 10 Sep. $(000)	Col. 11 Oct. $(000)	Col. 12 Nov. $(000)	Col. 13 Dec. $(000)	Col. 14 Monthly Avgs. $(000)
470.00 Land	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	27,722.8	29,028.8	29,028.8	29,028.8	27,994.9
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	7,446.8	96,814.8	96,814.8	96,814.8	26,065.1
472.00 Structures & improvements	129,249.6	129,866.3	130,873.0	132,089.6	133,116.3	131,963.0	132,479.6	132,856.3	133,253.0	133,619.6	134,086.3	134,653.0	135,449.6	132,600.5
473/474 Services, house regs. & meter inst.	2,355,263.9	2,365,741.0	2,370,470.8	2,375,250.8	2,380,390.7	2,386,280.8	2,393,357.3	2,401,454.4	2,409,655.4	2,418,235.9	2,426,440.6	2,435,856.5	2,448,132.4	2,397,069.4
475.00 Mains	3,111,440.3	3,124,303.9	3,137,033.8	3,150,963.0	3,165,444.0	3,179,999.3	3,195,573.4	3,211,572.5	3,225,286.8	3,240,349.6	3,674,072.4	3,689,301.7	3,719,270.6	3,284,104.7
476.00 Company NGV compressor stations	2,589.8	2,582.9	2,574.2	2,566.6	2,560.5	2,553.7	2,553.1	2,550.0	2,546.0	2,549.0	2,548.7	2,545.0	2,579.9	2,559.5
477.00 Measuring & regulating equip.	401,473.7	403,288.4	405,140.1	407,355.1	409,541.4	411,792.4	414,403.8	416,874.7	418,929.8	421,296.4	498,775.9	501,346.4	507,115.8	430,253.3
478.00 Meters	425,420.1	425,692.9	426,017.8	426,375.0	426,765.5	427,495.1	428,535.5	429,435.1	430,462.1	431,452.5	432,676.2	434,046.4	436,488.3	429,159.0
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Distribution Plant Gross - After Adj.	6,460,607.0	6,486,645.0	6,507,279.3	6,529,769.7	6,552,988.0	6,575,253.9	6,602,072.3	6,629,912.6	6,655,302.7	6,682,672.6	7,294,443.7	7,323,592.6	7,374,880.2	6,729,806.4

Distribution plant - Depreciation Rates	Jan. %	Feb. %	Mar. %	April %	May %	June %	July %	Aug. %	Sep. %	Oct. %	Nov. %	Dec. %	Annual %
470.00 Land	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
470.01 Offers to purchase land	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
471.00 Land rights intangibles	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	1.180%
472.00 Structures & improvements	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	7.550%
473/474 Services, house regs. & meter inst.	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	2.450%
475.00 Mains	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	2.454%
476.00 Company NGV compressor stations	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	5.970%
477.00 Measuring & regulating equip.	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	2.100%
478.00 Meters	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	9.220%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%

Distribution plant - Depreciation Provision - After Adjustments	Jan. $(000)	Feb. $(000)	Mar. $(000)	April $(000)	May $(000)	June $(000)	July $(000)	Aug. $(000)	Sep. $(000)	Oct. $(000)	Nov. $(000)	Dec. $(000)	Depr.Provision
470.00 Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(95.2)	(95.2)	(263.4)
472.00 Structures & improvements	(813.2)	(817.1)	(823.4)	(831.1)	(837.5)	(830.3)	(833.5)	(835.9)	(838.4)	(840.7)	(843.6)	(847.2)	(9,991.9)
473/474 Services, house regs. & meter inst.	(4,808.7)	(4,830.1)	(4,839.7)	(4,849.5)	(4,860.0)	(4,872.0)	(4,886.4)	(4,903.0)	(4,919.7)	(4,937.2)	(4,954.0)	(4,973.2)	(58,633.5)
475.00 Mains	(6,361.6)	(6,387.9)	(6,413.9)	(6,442.4)	(6,472.0)	(6,501.8)	(6,533.6)	(6,566.3)	(6,594.4)	(6,625.2)	(7,511.9)	(7,543.1)	(79,954.1)
476.00 Company NGV compressor stations	(12.9)	(12.8)	(12.8)	(12.8)	(12.7)	(12.7)	(12.7)	(12.7)	(12.7)	(12.7)	(12.7)	(12.7)	(152.9)
477.00 Measuring & regulating equip.	(702.6)	(705.8)	(709.0)	(712.9)	(716.7)	(720.6)	(725.2)	(729.5)	(733.1)	(737.3)	(872.9)	(877.4)	(8,943.0)
478.00 Meters	(3,268.6)	(3,270.7)	(3,273.2)	(3,276.0)	(3,279.0)	(3,284.6)	(3,292.6)	(3,299.5)	(3,307.4)	(3,315.0)	(3,324.4)	(3,334.9)	(39,525.9)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	(15,974.9)	(16,031.7)	(16,079.3)	(16,132.0)	(16,185.2)	(16,229.3)	(16,291.3)	(16,354.2)	(16,413.0)	(16,475.4)	(17,614.7)	(17,683.7)	(197,464.7)

LOCAL STORAGE PLANT, PLANT HELD FOR FUTURE USE, AND OTHER PLANT - CONTINUITY WORKSHEETS
CALENDAR 2016 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	
														Net change	Average of
Local Storage Plant	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.		Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
A/c # 440.00 Land															
Opening balance	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5		
Expenditures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	0.0	21.5
Plant Held for Future Use - Gross	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Net change	Average of Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
A/c # 102.00															
Opening balance	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9		
Expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	1,670.9	0.0	1,670.9
Plant Held for Future Use - Accum. Depr.															
A/c # 105.02															
Opening balance	(1,253.4)	(1,253.4)	(1,256.8)	(1,260.2)	(1,263.6)	(1,267.0)	(1,270.4)	(1,273.8)	(1,277.2)	(1,280.6)	(1,284.0)	(1,287.4)	(1,290.8)		
Provision		(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.5)	(40.9)	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Costs net of Proceeds		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	(1,253.4)	(1,256.8)	(1,260.2)	(1,263.6)	(1,267.0)	(1,270.4)	(1,273.8)	(1,277.2)	(1,280.6)	(1,284.0)	(1,287.4)	(1,290.8)	(1,294.3)	(40.9)	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	(1,253.4)	(1,256.8)	(1,260.2)	(1,263.6)	(1,267.0)	(1,270.4)	(1,273.8)	(1,277.2)	(1,280.6)	(1,284.0)	(1,287.4)	(1,290.8)	(1,294.3)	(40.9)	(1,273.8)
Plant Held for Future Use - Net	417.5	414.1	410.7	407.3	403.9	400.5	397.1	393.7	390.3	386.9	383.5	380.1	376.6	(40.9)	397.1
Other Plant - Gross	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Net change	Average of Monthly Avgs.
A/c # 402.50	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
Intangible Plant (Peterborough)															
Opening balance	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3		
Expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	465.3	0.0	465.3
Other Plant - Acc.Depr.															
A/c # 402.50															
Intangible Plant (Peterborough)															
Opening balance	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)		
Provision		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Retirements		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Costs net of Proceeds		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Sub-total	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	0.0	
Cumulative Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Closing balance	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	(465.3)	0.0	(465.3)
Other Plant - Net	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
UNDERGROUND STORAGE PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

Underground Storage Plant - Net. After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1
451 Land rights Tecumseh	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7
451.1 Land rights intangibles Tecumseh	15,136.5	15,097.1	15,057.8	15,018.4	14,979.1	14,939.7	14,900.4	14,861.0	14,821.7	14,782.3	14,743.0	14,703.6	14,664.2	14,900.4
452 Struct. & Improve. Tecumseh	31,242.7	31,270.8	31,591.4	31,764.6	31,789.4	31,892.3	32,064.8	32,100.4	32,250.7	32,303.9	32,292.0	33,283.3	37,164.1	32,233.9
453 Wells Tecumseh	41,197.0	41,147.2	41,210.0	44,173.0	44,120.2	44,098.7	44,104.8	44,058.6	44,056.4	44,016.7	43,951.6	44,271.3	45,701.1	43,554.8
454 Well Equipment Tecumseh	2,863.2	2,818.9	2,774.6	2,730.3	2,685.9	2,641.6	2,597.3	2,553.0	2,508.6	2,464.3	2,420.0	2,375.7	2,331.3	2,597.3
455 Field Lines Tecumseh	42,041.5	41,954.8	41,916.3	41,855.1	41,772.1	41,704.8	41,651.0	41,575.0	41,517.9	41,444.6	41,359.7	41,438.3	41,991.5	41,683.8
456 Compressor Equip. Tecumseh	71,146.7	70,872.7	70,608.8	70,342.8	70,076.6	69,818.5	69,566.6	69,310.7	69,058.8	68,803.1	68,543.3	68,314.7	68,182.1	69,581.8
457 Meas. & Reg. Tecumseh	8,046.4	8,007.3	7,968.8	7,930.3	7,891.9	7,854.1	7,816.7	7,779.1	7,741.8	7,704.2	7,666.3	7,630.3	7,600.2	7,817.8
458 Base Pressure Gas Tecumseh	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Underground Storage - After Adj.	257,911.5	257,406.3	257,365.2	260,052.0	259,552.7	259,187.2	258,939.1	258,475.3	258,193.4	257,756.6	257,213.4	258,254.7	263,872.0	258,607.3

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION UNDERGROUND STORAGE PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

Underground Storage Plant - Accum. Depr. After Adjustments	Col. 1 Dec. $(000)	Col. 2 Jan. $(000)	Col. 3 Feb. $(000)	Col. 4 Mar. $(000)	Col. 5 April $(000)	Col. 6 May $(000)	Col. 7 June $(000)	Col. 8 July $(000)	Col. 9 Aug. $(000)	Col. 10 Sep. $(000)	Col. 11 Oct. $(000)	Col. 12 Nov. $(000)	Col. 13 Dec. $(000)	Col. 14 Monthly Avgs. $(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451 Land rights Tecumseh	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7	1,501.7
451.1 Land rights intangibles Tecumseh	(25,575.5)	(25,614.9)	(25,654.2)	(25,693.6)	(25,732.9)	(25,772.3)	(25,811.6)	(25,851.0)	(25,890.3)	(25,929.7)	(25,969.0)	(26,008.4)	(26,047.8)	(25,811.6)
452 Struct. & Improve. Tecumseh	(6,711.4)	(6,726.2)	(6,741.2)	(6,756.6)	(6,772.4)	(6,788.2)	(6,804.1)	(6,820.4)	(6,836.8)	(6,853.3)	(6,870.0)	(6,886.8)	(6,905.0)	(6,805.4)
453 Wells Tecumseh	(18,442.5)	(18,525.4)	(18,608.4)	(18,690.9)	(18,776.0)	(18,859.8)	(18,942.8)	(19,025.6)	(19,108.6)	(19,191.8)	(19,275.4)	(19,360.1)	(19,446.7)	(18,942.5)
454 Well Equipment Tecumseh	(6,703.9)	(6,748.2)	(6,792.5)	(6,836.8)	(6,881.2)	(6,925.5)	(6,969.8)	(7,014.1)	(7,058.5)	(7,102.8)	(7,147.1)	(7,191.4)	(7,235.8)	(6,969.8)
455 Field Lines Tecumseh	(26,357.9)	(26,453.4)	(26,549.1)	(26,643.2)	(26,734.7)	(26,823.4)	(26,910.0)	(26,996.3)	(27,082.7)	(27,169.3)	(27,256.8)	(27,346.5)	(27,439.1)	(26,905.3)
456 Compressor Equip. Tecumseh	(41,825.5)	(42,102.5)	(42,379.8)	(42,654.0)	(42,923.2)	(43,187.0)	(43,447.1)	(43,706.4)	(43,965.7)	(44,225.4)	(44,486.9)	(44,752.6)	(45,024.2)	(43,438.0)
457 Meas. & Reg. Tecumseh	(6,673.6)	(6,712.9)	(6,752.2)	(6,791.2)	(6,829.8)	(6,868.0)	(6,905.9)	(6,943.7)	(6,981.5)	(7,019.3)	(7,057.3)	(7,095.6)	(7,134.3)	(6,905.1)
458 Base Pressure Gas Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Undgnd Storage Acc. Dep. - After Adj.	(130,788.6)	(131,381.8)	(131,975.7)	(132,564.6)	(133,148.5)	(133,722.5)	(134,289.6)	(134,855.8)	(135,422.4)	(135,989.9)	(136,560.8)	(137,139.7)	(137,731.2)	(134,276.0)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS DISTRIBUTION PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

Underground Storage Plant-Gross After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1	3,742.1
451 Land rights Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451.1 Land rights intangibles Tecumseh	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0	40,712.0
452 Struct. & Improve. Tecumseh	37,954.1	37,997.0	38,332.6	38,521.2	38,561.8	38,680.5	38,868.9	38,920.8	39,087.5	39,157.2	39,162.0	40,170.1	44,069.1	39,039.3
453 Wells Tecumseh	59,639.5	59,672.6	59,818.4	62,863.9	62,896.2	62,958.5	63,047.6	63,084.2	63,165.0	63,208.5	63,227.0	63,631.4	65,147.8	62,497.2
454 Well Equipment Tecumseh	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1	9,567.1
455 Field Lines Tecumseh	68,399.4	68,408.2	68,465.4	68,498.3	68,506.8	68,528.2	68,561.0	68,571.3	68,600.6	68,613.9	68,616.5	68,784.8	69,430.6	68,589.2
456 Compressor Equip. Tecumseh	112,972.2	112,975.2	112,988.6	112,996.8	112,999.8	113,005.5	113,013.7	113,017.1	113,024.5	113,028.5	113,030.2	113,067.3	113,206.3	113,019.7
457 Meas. & Reg. Tecumseh	14,720.0	14,720.2	14,721.0	14,721.5	14,721.7	14,722.1	14,722.6	14,722.8	14,723.3	14,723.5	14,723.6	14,725.9	14,734.5	14,723.0
458 Base Pressure Gas Tecumseh	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7	40,993.7
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Undgnd Storage Gross - After Adj.	388,700.1	388,788.1	389,340.9	392,616.6	392,701.2	392,909.7	393,228.7	393,331.1	393,615.8	393,746.5	393,774.2	395,394.4	401,603.2	392,883.3

Underground Storage Plant- Depreciation Rates	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Annual Prov.
	%	%	%	%	%	%	%	%	%	%	%	%	%
450/459 Crowland (Avg of all other storage categories)	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	0.2067%	2.480%
450 Land Tecumseh	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
451 Land rights Tecumseh	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	1.160%
451.1 Land rights intangibles Tecumseh	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	0.0967%	1.160%
452 Struct. & Improve. Tecumseh	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	0.1533%	1.840%
453 Wells Tecumseh	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	1.550%
454 Well Equipment Tecumseh	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	0.4633%	5.560%
455 Field Lines Tecumseh	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	0.1292%	1.550%
456 Compressor Equip. Tecumseh	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	0.2242%	2.690%
457 Meas. & Reg. Tecumseh	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	0.2533%	3.040%
458 Base Pressure Gas Tecumseh	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
??? Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%

Underground Storage Plant- Depreciation Provision - After Adjustments	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Depr.Provision
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
450/459 Crowland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 Land Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451 Land rights Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
451.1 Land rights intangibles Tecumseh	(39.4)	(39.4)	(39.4)	(39.4)	(39.4)	(39.4)	(39.4)	(39.4)	(39.4)	(39.4)	(39.4)	(39.4)	(472.8)
452 Struct. & Improve. Tecumseh	(58.2)	(58.3)	(58.8)	(59.1)	(59.1)	(59.3)	(59.6)	(59.7)	(59.9)	(60.0)	(60.0)	(61.6)	(713.6)
453 Wells Tecumseh	(77.0)	(77.1)	(77.3)	(81.2)	(81.2)	(81.3)	(81.4)	(81.5)	(81.6)	(81.6)	(81.7)	(82.2)	(965.1)
454 Well Equipment Tecumseh	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(44.3)	(531.6)
455 Field Lines Tecumseh	(88.3)	(88.4)	(88.4)	(88.5)	(88.5)	(88.5)	(88.6)	(88.6)	(88.6)	(88.6)	(88.6)	(88.8)	(1,062.4)
456 Compressor Equip. Tecumseh	(253.2)	(253.3)	(253.3)	(253.3)	(253.3)	(253.3)	(253.3)	(253.3)	(253.4)	(253.4)	(253.4)	(253.5)	(3,040.0)
457 Meas. & Reg. Tecumseh	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(447.6)
458 Base Pressure Gas Tecumseh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
??? Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	(597.7)	(598.1)	(598.8)	(603.1)	(603.1)	(603.4)	(603.9)	(604.1)	(604.5)	(604.6)	(604.7)	(607.1)	(7,233.1)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS GENERAL PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

General plant - gross	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	'onthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	16,840.8	16,840.8	16,840.8	16,840.8	16,840.8	16,840.8	16,840.8	16,840.8	16,840.8	16,840.8	16,840.8	17,110.8	17,110.8	16,874.6
483.1 Office equipment over 6.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 y	3,263.6	3,269.4	3,275.2	3,281.0	3,286.8	3,292.6	3,298.5	3,305.3	3,312.1	3,318.9	3,325.7	3,333.5	3,341.4	3,300.1
483.2 Office furniture over 6.6 yr:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs	27,493.6	27,634.6	27,564.2	27,541.0	27,638.4	27,699.5	27,842.8	27,965.7	28,020.5	28,093.4	28,116.1	28,524.3	30,757.9	27,980.5
484.00 Transportation equipment	54,044.4	54,137.8	54,079.7	54,061.7	54,146.3	54,200.0	54,323.7	54,430.9	54,480.2	54,544.8	54,566.7	54,917.5	56,821.9	54,443.5
484.01 N.G.V .kits Co. vehicles	8,304.1	8,288.9	8,268.6	8,249.4	8,233.2	8,216.1	8,200.9	8,185.3	8,168.0	8,151.1	8,133.1	8,124.3	8,159.2	8,204.2
484.02 N.G.V. cyl. Co. vehicles	1,351.7	1,375.1	1,375.4	1,380.8	1,399.4	1,414.1	1,437.8	1,459.3	1,473.4	1,489.4	1,500.0	1,552.8	1,805.1	1,453.0
485.00 Heavy work equipment	23,226.7	23,273.8	23,256.7	23,253.9	23,287.8	23,310.6	23,358.4	23,400.3	23,421.5	23,448.2	23,459.7	23,588.6	24,272.4	23,400.8
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.(	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	39,423.4	39,413.2	39,332.7	39,267.9	39,243.2	39,206.4	39,197.0	39,181.1	39,142.5	39,109.9	39,060.7	39,140.0	39,826.3	39,243.3
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	3,795.1	3,868.9	3,874.3	3,895.1	3,954.8	4,002.7	4,077.4	4,145.7	4,191.9	4,244.1	4,280.0	4,441.0	5,193.1	4,122.5
487.80 N.G.V. compressor station	13,065.4	13,161.9	13,152.1	13,165.9	13,240.5	13,296.8	13,394.4	13,482.3	13,536.0	13,598.6	13,636.1	13,867.9	15,017.4	13,464.5
487.90 N.G.V. rental cylinders	2,019.3	2,023.2	2,023.6	2,024.7	2,027.9	2,030.5	2,034.4	2,038.0	2,040.5	2,043.3	2,045.2	2,053.6	2,092.4	2,036.7
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip	3,901.1	3,900.8	3,900.5	3,900.2	3,900.0	3,899.7	3,899.4	3,899.1	3,898.9	3,898.6	3,898.3	3,898.0	3,897.8	3,899.4
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003	33,884.5	33,364.7	33,107.4	32,757.4	32,412.9	31,937.4	31,832.3	31,283.2	31,153.4	32,908.6	32,476.4	32,095.1	35,188.0	32,488.8
491.00 Software acquired intangib	50,840.2	49,579.3	48,415.7	47,217.7	46,021.7	44,777.2	44,870.0	43,598.2	42,481.8	42,064.3	40,835.8	39,626.2	39,704.6	44,563.4
491.00 Software developed intang	82,785.6	81,517.4	80,492.0	79,380.9	78,274.8	77,047.5	87,301.1	86,005.7	85,098.2	85,934.0	84,746.8	83,606.7	85,679.8	82,803.2
491.00 CIS software acquired inta	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
489.00 WAMS	58,550.0	58,550.0	58,550.0	58,550.0	58,550.0	58,550.0	58,550.0	70,626.0	70,626.0	70,626.0	70,626.0	70,626.0	70,626.0	64,084.8
Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(5,964.5)
General Plant Gross - After Adj.	422,789.5	420,199.8	417,508.9	414,768.4	412,458.5	409,721.9	420,458.9	429,846.9	427,885.7	430,314.0	427,547.4	426,506.3	439,494.1	416,398.8

General plant - Depreciation Rates	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Annual
	%	%	%	%	%	%	%	%	%	%	%	%	%
482.50 Leasehold improvements	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	10.00%
483.1 Office equipment over 6.6 yrs.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
483.1 Office equipment over 15 yrs.	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.0125%	0.150%
483.2 Office furniture over 6.6 yrs.	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	10.740%
483.2 Office furniture over 20 yrs.	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	0.8950%	10.740%
484.00 Transportation equipment	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	0.8800%	10.560%
484.01 N.G.V .kits Co. vehicles	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	0.7500%	9.000%
484.02 N.G.V. cyl. Co. vehicles	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	2.100%
485.00 Heavy work equipment	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	0.2983%	3.580%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
486.00 Tools & work euip. over 2.69 yrs	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	4.080%
486.00 Tools & work euip. 4.0%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	0.3400%	4.080%
487.70 V.R.A.'S	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.740%
487.70 V.R.A.'S Post F2003 5%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.0617%	0.740%
487.80 N.G.V. compressor stations	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	0.6675%	8.010%
487.90 N.G.V. rental cylinders	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	1.5775%	18.930%
488.00 Communication str & equip	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	9.710%
488.00 Communication str & equip 20yrs	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	0.8092%	9.710%
490.00 Computer equipment	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	36.630%
490.00 Computer equipment 2003 B 20%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	3.0525%	36.630%
491.00 Software acquired intangibles	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	2.1933%	26.320%
491.00 Software developed intangibles	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	1.7700%	21.240%
491.00 CIS software acquired intangibles	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	10.000%
489.00 WAMS	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	0.8333%	10.000%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%

General plant -
Depreciation Provision - After Adjustments

	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	epr.Provision
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	(140.3)	(140.3)	(140.3)	(140.3)	(140.3)	(140.3)	(140.3)	(140.3)	(140.3)	(140.3)	(140.3)	(142.6)	(1,685.9)
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(4.8)
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	(246.1)	(247.3)	(246.7)	(246.5)	(247.4)	(247.9)	(249.2)	(250.3)	(250.8)	(251.4)	(251.6)	(255.3)	(2,990.5)
484.00 Transportation equipment	(475.6)	(476.4)	(475.9)	(475.7)	(476.5)	(477.0)	(478.0)	(479.0)	(479.4)	(480.0)	(480.2)	(483.3)	(5,737.0)
484.01 N.G.V .kits Co. vehicles	(62.3)	(62.2)	(62.0)	(61.9)	(61.7)	(61.6)	(61.5)	(61.4)	(61.3)	(61.1)	(61.0)	(60.9)	(738.9)
484.02 N.G.V. cyl. Co. vehicles	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.5)	(2.5)	(2.6)	(2.6)	(2.6)	(2.6)	(2.7)	(30.1)
485.00 Heavy work equipment	(69.3)	(69.4)	(69.4)	(69.4)	(69.5)	(69.5)	(69.7)	(69.8)	(69.9)	(70.0)	(70.0)	(70.4)	(836.3)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	(134.0)	(134.0)	(133.7)	(133.5)	(133.4)	(133.3)	(133.3)	(133.2)	(133.1)	(133.0)	(132.8)	(133.1)	(1,600.4)
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	(2.3)	(2.4)	(2.4)	(2.4)	(2.4)	(2.5)	(2.5)	(2.6)	(2.6)	(2.6)	(2.6)	(2.7)	(30.0)
487.80 N.G.V. compressor stations	(87.2)	(87.9)	(87.8)	(87.9)	(88.4)	(88.8)	(89.4)	(90.0)	(90.4)	(90.8)	(91.0)	(92.6)	(1,072.2)
487.90 N.G.V. rental cylinders	(31.9)	(31.9)	(31.9)	(31.9)	(32.0)	(32.0)	(32.1)	(32.1)	(32.2)	(32.2)	(32.3)	(32.4)	(384.9)
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.6)	(31.5)	(31.5)	(31.5)	(31.5)	(378.8)
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	(1,034.3)	(1,018.5)	(1,010.6)	(999.9)	(989.4)	(974.9)	(971.7)	(954.9)	(951.0)	(1,004.5)	(991.3)	(979.7)	(11,880.7)
491.00 Software acquired intangibles	(1,115.1)	(1,087.4)	(1,061.9)	(1,035.6)	(1,009.4)	(982.1)	(984.1)	(956.3)	(931.8)	(922.6)	(895.7)	(869.1)	(11,851.1)
491.00 Software developed intangibles	(1,465.3)	(1,442.9)	(1,424.7)	(1,405.0)	(1,385.5)	(1,363.7)	(1,545.2)	(1,522.3)	(1,506.2)	(1,521.0)	(1,500.0)	(1,479.8)	(17,561.6)
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
489.00 WAMS	(487.9)	(487.9)	(487.9)	(487.9)	(487.9)	(487.9)	(487.9)	(588.6)	(588.6)	(588.6)	(588.6)	(588.6)	(6,358.3)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	(5,386.0)	(5,322.9)	(5,269.6)	(5,212.3)	(5,158.2)	(5,096.0)	(5,279.4)	(5,315.4)	(5,272.1)	(5,332.6)	(5,271.9)	(5,225.1)	(63,141.5)

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
DISTRIBUTION PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

Distribution plant - Net. After Adjustments	Col. 1 Dec. $(000)	Col. 2 Jan. $(000)	Col. 3 Feb. $(000)	Col. 4 Mar. $(000)	Col. 5 April $(000)	Col. 6 May $(000)	Col. 7 June $(000)	Col. 8 July $(000)	Col. 9 Aug. $(000)	Col. 10 Sep. $(000)	Col. 11 Oct. $(000)	Col. 12 Nov. $(000)	Col. 13 Dec. $(000)	Col. 14 Monthly Avgs. $(000)
470.00 Land	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	94,553.1	94,457.9	94,362.7	94,267.5	94,172.3	94,077.1	93,981.9	93,886.7	93,791.5	93,696.3	93,601.1	93,505.9	93,410.7	93,981.9
472.00 Structures & improvements	109,410.5	109,090.8	108,878.4	108,772.7	108,483.8	108,307.8	108,999.3	109,454.7	109,675.5	109,369.5	109,125.9	108,854.0	108,819.3	109,010.6
473/474 Services, house regs. & meter inst	1,413,176.6	1,425,529.4	1,432,144.5	1,438,364.6	1,444,327.2	1,450,648.0	1,458,022.1	1,466,431.8	1,475,028.8	1,484,076.1	1,493,072.6	1,504,095.8	1,519,828.2	1,461,520.3
475.00 Mains	2,412,992.4	2,423,201.7	2,433,334.1	2,443,982.8	2,453,815.1	2,462,658.6	2,471,856.4	2,481,036.3	2,488,113.9	2,496,825.7	2,507,499.6	2,518,341.1	2,547,522.1	2,471,743.5
476.00 Company NGV compressor stations	623.7	613.9	602.1	591.5	582.5	572.9	569.5	563.7	556.9	557.4	554.4	548.0	581.1	576.3
477.00 Measuring & regulating equip.	302,352.5	302,979.5	303,632.6	304,557.3	305,452.0	306,387.6	307,591.3	308,683.6	309,455.7	310,463.1	312,033.2	313,195.0	316,799.1	307,833.9
478.00 Meters	253,955.8	252,106.1	250,311.1	248,548.5	246,819.1	245,461.2	244,440.5	243,254.6	242,201.4	241,098.4	240,244.6	239,541.9	240,013.2	245,084.3
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Distribution Plant - After Adj.	4,616,093.4	4,637,008.1	4,652,294.3	4,668,113.7	4,682,680.8	4,697,142.0	4,714,489.8	4,732,340.2	4,747,852.5	4,765,115.3	4,785,160.2	4,807,110.5	4,856,002.5	4,718,779.6

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION DISTRIBUTION PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
Distribution plant - Acc. Depr. After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
470.00 Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	(2,261.7)	(2,356.9)	(2,452.1)	(2,547.3)	(2,642.5)	(2,737.7)	(2,832.9)	(2,928.1)	(3,023.3)	(3,118.5)	(3,213.7)	(3,308.9)	(3,404.1)	(2,832.9)
472.00 Structures & improvements	(26,039.1)	(26,695.5)	(27,354.6)	(23,626.9)	(24,182.5)	(24,745.2)	(24,890.3)	(25,031.6)	(25,677.5)	(26,340.1)	(27,000.4)	(27,659.0)	(28,330.3)	(25,865.7)
473/474 Services, house regs. & n	(1,034,955.8)	(1,034,263.5)	(1,033,521.8)	(1,033,196.1)	(1,033,544.1)	(1,034,414.6)	(1,035,614.8)	(1,037,043.0)	(1,038,396.8)	(1,039,739.6)	(1,040,736.8)	(1,041,104.5)	(1,040,087.4)	(1,036,591.4)
475.00 Mains	(1,297,278.1)	(1,299,399.2)	(1,301,466.2)	(1,304,296.3)	(1,308,344.9)	(1,313,632.2)	(1,319,791.2)	(1,326,219.2)	(1,332,632.7)	(1,338,985.0)	(1,344,943.6)	(1,349,935.5)	(1,353,494.4)	(1,322,600.0)
476.00 Company NGV compresso	(1,956.2)	(1,959.1)	(1,962.0)	(1,964.9)	(1,967.6)	(1,970.4)	(1,973.2)	(1,976.0)	(1,978.6)	(1,981.3)	(1,984.0)	(1,986.7)	(1,989.3)	(1,973.0)
477.00 Measuring & regulating equ	(204,763.3)	(205,477.8)	(206,194.4)	(206,916.5)	(207,646.8)	(208,385.4)	(209,130.8)	(209,880.5)	(210,633.3)	(211,388.3)	(212,144.8)	(212,900.9)	(213,654.5)	(209,159.0)
478.00 Meters	(182,532.5)	(184,761.2)	(186,992.8)	(189,227.8)	(191,466.4)	(193,708.9)	(195,958.2)	(198,216.9)	(200,483.9)	(202,760.2)	(205,045.5)	(207,341.8)	(209,650.3)	(196,004.6)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dist. Plant Acc. Dep. - After Adj.	(2,749,786.7)	(2,754,913.2)	(2,759,943.9)	(2,761,775.8)	(2,769,794.8)	(2,779,594.4)	(2,790,191.4)	(2,801,295.3)	(2,812,826.1)	(2,824,313.0)	(2,835,068.8)	(2,844,237.3)	(2,850,610.3)	(2,795,026.6)

MONTH END BALANCES OF PROPERTY, PLANT, AND EQUIPMENT
GROSS DISTRIBUTION PLANT - CONTINUITY WORKSHEETS AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
Distribution plant - gross														
After Adjustments	Dec.	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
470.00 Land	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8	29,028.8
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8	96,814.8
472.00 Structures & improvements	135,449.6	135,786.3	136,233.0	132,399.6	132,666.3	133,053.0	133,889.6	134,486.3	135,353.0	135,709.6	136,126.3	136,513.0	137,149.6	134,876.3
473/474 Services, house regs. & meter inst.	2,448,132.4	2,459,792.9	2,465,666.3	2,471,560.7	2,477,871.3	2,485,062.6	2,493,636.9	2,503,474.8	2,513,425.6	2,523,815.7	2,533,809.4	2,545,200.3	2,559,915.6	2,498,111.7
475.00 Mains (with Adj)	3,710,270.5	3,722,600.9	3,734,800.3	3,748,279.1	3,762,160.0	3,776,290.8	3,791,647.6	3,807,255.5	3,820,746.6	3,835,810.7	3,852,443.2	3,868,276.6	3,901,016.5	3,802,800.0
mains Adj														
476.00 Company NGV compressor stations	2,579.9	2,573.0	2,564.1	2,556.4	2,550.1	2,543.3	2,542.7	2,539.7	2,535.5	2,538.7	2,538.4	2,534.7	2,570.4	2,549.3
477.00 Measuring & regulating equip.	507,115.8	508,457.3	509,827.0	511,473.8	513,098.8	514,773.0	516,722.1	518,564.1	520,089.0	521,851.4	524,178.0	526,095.9	530,453.6	516,992.9
478.00 Meters	436,488.3	436,867.3	437,303.9	437,776.3	438,285.5	439,170.1	440,398.7	441,471.5	442,685.3	443,858.6	445,290.1	446,883.7	449,663.5	441,088.9
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Distribution Plant Gross - After Adj.	7,365,880.1	7,391,921.3	7,412,238.2	7,429,889.5	7,452,475.6	7,476,736.4	7,504,681.2	7,533,635.5	7,560,678.6	7,589,428.3	7,620,229.0	7,651,347.8	7,706,612.8	7,522,262.7

Distribution plant - Depreciation Rates	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Annual
	%	%	%	%	%	%	%	%	%	%	%	%	%
470.00 Land	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
470.01 Offers to purchase land	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%
471.00 Land rights intangibles	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	0.0983%	1.180%
472.00 Structures & improvements	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	0.6292%	7.550%
473/474 Services, house regs. & meter inst.	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	0.2042%	2.450%
475.00 Mains	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	0.2045%	2.454%
476.00 Company NGV compressor stations	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	0.4975%	5.970%
477.00 Measuring & regulating equip.	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	0.1750%	2.100%
478.00 Meters	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	0.7683%	9.220%
4??.00 Available	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.000%

Distribution plant - Depreciation Provision - After Adjustments	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Depr.Provision
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	
470.00 Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
470.01 Offers to purchase land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
471.00 Land rights intangibles	(95.2)	(95.2)	(95.2)	(95.2)	(95.2)	(95.2)	(95.2)	(95.2)	(95.2)	(95.2)	(95.2)	(95.2)	(1,142.4)
472.00 Structures & improvements	(852.2)	(854.3)	(857.1)	(833.0)	(834.7)	(837.1)	(842.4)	(846.1)	(851.6)	(853.8)	(856.5)	(858.9)	(10,177.7)
473/474 Services, house regs. & meter inst.	(4,998.3)	(5,022.1)	(5,034.1)	(5,046.1)	(5,059.0)	(5,073.7)	(5,091.2)	(5,111.3)	(5,131.6)	(5,152.8)	(5,173.2)	(5,196.5)	(61,089.9)
475.00 Mains	(7,586.0)	(7,611.2)	(7,636.1)	(7,663.7)	(7,692.0)	(7,720.9)	(7,752.3)	(7,784.3)	(7,811.8)	(7,842.6)	(7,876.6)	(7,909.0)	(92,886.5)
476.00 Company NGV compressor stations	(12.8)	(12.8)	(12.8)	(12.7)	(12.7)	(12.7)	(12.6)	(12.6)	(12.6)	(12.6)	(12.6)	(12.6)	(152.1)
477.00 Measuring & regulating equip.	(887.5)	(889.8)	(892.2)	(895.1)	(897.9)	(900.9)	(904.3)	(907.5)	(910.2)	(913.2)	(917.3)	(920.7)	(10,836.6)
478.00 Meters	(3,353.7)	(3,356.6)	(3,360.0)	(3,363.6)	(3,367.5)	(3,374.3)	(3,383.7)	(3,392.0)	(3,401.3)	(3,410.3)	(3,421.3)	(3,433.6)	(40,617.9)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	(17,785.7)	(17,842.0)	(17,887.5)	(17,909.4)	(17,959.0)	(18,014.8)	(18,081.7)	(18,149.0)	(18,214.3)	(18,280.5)	(18,352.7)	(18,426.5)	(216,903.1)

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
GENERAL PLANT - NET AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

General Plant - Net. After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	9,791.8	9,699.7	9,607.6	9,515.5	9,423.5	9,331.4	9,239.3	9,147.2	9,055.2	8,963.1	8,871.0	9,048.9	8,954.6	9,273.0
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	350.8	356.4	362.0	367.6	373.2	378.8	384.4	391.0	397.6	404.2	410.8	418.3	425.9	386.1
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	17,893.6	17,874.8	17,643.4	17,459.8	17,397.0	17,297.0	17,278.7	17,238.7	17,129.5	17,037.9	16,895.5	17,138.4	19,203.1	17,411.6
484.00 Transportation equipment	30,230.5	29,925.1	29,467.4	29,050.2	28,735.9	28,389.9	28,113.4	27,819.4	27,466.5	27,128.4	26,747.1	26,694.5	28,192.5	28,229.1
484.01 N.G.V .kits Co. vehicles	2,140.4	2,083.7	2,021.9	1,961.6	1,904.3	1,846.3	1,790.4	1,734.1	1,676.2	1,618.9	1,560.6	1,511.6	1,506.6	1,794.4
484.02 N.G.V. cyl. Co. vehicles	545.3	568.4	568.4	573.5	591.8	606.2	629.5	650.6	664.2	679.7	689.8	742.1	993.8	644.5
485.00 Heavy work equipment	13,939.9	13,941.5	13,878.8	13,830.4	13,818.7	13,795.8	13,797.9	13,793.9	13,769.1	13,749.7	13,715.0	13,797.7	14,435.0	13,839.7
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	22,698.9	22,642.5	22,515.8	22,405.1	22,334.7	22,252.3	22,197.3	22,135.9	22,051.9	21,974.0	21,879.6	21,913.9	22,554.8	22,244.2
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	2,785.2	2,858.4	2,863.1	2,883.1	2,942.1	2,989.3	3,063.1	3,130.6	3,175.9	3,227.1	3,262.1	3,422.2	4,173.1	3,108.0
487.80 N.G.V. compressor stations	10,491.1	10,561.2	10,524.4	10,511.4	10,559.0	10,587.8	10,657.6	10,716.9	10,741.5	10,774.7	10,782.3	10,983.9	12,101.7	10,724.8
487.90 N.G.V. rental cylinders	125.1	97.1	65.6	34.8	6.1	(23.3)	(51.4)	(79.9)	(109.5)	(138.9)	(169.2)	(193.1)	(186.8)	(49.4)
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	2,055.5	2,023.9	1,992.3	1,960.7	1,929.1	1,897.5	1,865.9	1,834.3	1,802.7	1,771.2	1,739.7	1,708.3	1,676.9	1,866.0
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	6,136.0	5,156.6	4,455.5	3,669.6	2,899.9	2,009.7	1,504.4	558.3	48.3	1,427.2	565.2	(232.7)	2,455.3	2,196.5
491.00 Software acquired intangibles	15,491.1	14,396.4	13,426.7	12,448.1	11,497.8	10,525.2	10,917.2	9,942.6	9,151.2	9,083.2	8,213.4	7,389.4	7,880.0	10,723.1
491.00 Software developed intangibles	49,267.7	47,853.2	46,703.9	45,487.1	44,295.0	43,001.2	53,210.1	51,688.5	50,577.7	51,226.3	49,837.1	48,516.0	50,428.2	48,520.3
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
489.00 WAMS	58,550.0	58,062.1	57,574.2	57,086.3	56,598.4	56,110.5	55,622.6	67,210.7	66,622.1	66,033.5	65,444.9	64,856.3	64,267.8	61,052.5
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net General Plant - After Adj.	242,492.9	238,101.0	233,671.0	229,244.8	225,306.5	220,995.6	230,220.4	237,912.8	234,220.1	234,960.2	230,444.9	227,715.7	239,062.5	231,964.4

MONTH END BALANCES OF PROPERTY, PLANT AND EQUIPMENT
ACCUMULATED DEPRECIATION GENERAL PLANT CONTINUITY WORKSHEET AFTER ADJUSTMENTS
CALENDAR 2016 TEST YEAR

General plant - Acc. Depr. After Adjustments	Col. 1 Dec.	Col. 2 Jan.	Col. 3 Feb.	Col. 4 Mar.	Col. 5 April	Col. 6 May	Col. 7 June	Col. 8 July	Col. 9 Aug.	Col. 10 Sep.	Col. 11 Oct.	Col. 12 Nov.	Col. 13 Dec.	Col. 14 Monthly Avgs.
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
482.50 Leasehold improvements	(7,049.0)	(7,141.1)	(7,233.2)	(7,325.3)	(7,417.3)	(7,509.4)	(7,601.5)	(7,693.6)	(7,785.6)	(7,877.7)	(7,969.8)	(8,061.9)	(8,156.2)	(7,601.6)
483.1 Office equipment over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.1 Office equipment over 15 yrs.	(2,912.8)	(2,913.0)	(2,913.2)	(2,913.4)	(2,913.6)	(2,913.8)	(2,914.1)	(2,914.3)	(2,914.5)	(2,914.7)	(2,914.9)	(2,915.2)	(2,915.5)	(2,914.1)
483.2 Office furniture over 6.6 yrs.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
483.2 Office furniture over 20 yrs.	(9,600.0)	(9,759.8)	(9,920.8)	(10,081.2)	(10,241.4)	(10,402.5)	(10,564.1)	(10,727.0)	(10,891.0)	(11,055.5)	(11,220.6)	(11,385.9)	(11,554.8)	(10,568.9)
484.00 Transportation equipment	(23,813.9)	(24,212.7)	(24,612.3)	(25,011.5)	(25,410.4)	(25,810.1)	(26,210.3)	(26,611.5)	(27,013.7)	(27,416.4)	(27,819.6)	(28,223.0)	(28,629.4)	(26,214.4)
484.01 N.G.V .kits Co. vehicles	(6,163.7)	(6,205.2)	(6,246.7)	(6,287.8)	(6,328.9)	(6,369.8)	(6,410.5)	(6,451.2)	(6,491.8)	(6,532.2)	(6,572.5)	(6,612.7)	(6,652.6)	(6,409.8)
484.02 N.G.V. cyl. Co. vehicles	(806.4)	(806.7)	(807.0)	(807.3)	(807.6)	(807.9)	(808.3)	(808.7)	(809.2)	(809.7)	(810.2)	(810.7)	(811.3)	(808.5)
485.00 Heavy work equipment	(9,286.8)	(9,332.3)	(9,377.9)	(9,423.5)	(9,469.1)	(9,514.8)	(9,560.5)	(9,606.4)	(9,652.4)	(9,698.5)	(9,744.7)	(9,790.9)	(9,837.4)	(9,561.1)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. over 2.69 yrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
486.00 Tools & work euip. 4.0%	(16,724.5)	(16,770.7)	(16,816.9)	(16,862.8)	(16,908.5)	(16,954.1)	(16,999.7)	(17,045.2)	(17,090.6)	(17,135.9)	(17,181.1)	(17,226.1)	(17,271.5)	(16,999.1)
487.70 V.R.A.'S	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
487.70 V.R.A.'S Post F2003 5%	(1,009.9)	(1,010.5)	(1,011.2)	(1,012.0)	(1,012.7)	(1,013.4)	(1,014.3)	(1,015.1)	(1,016.0)	(1,017.0)	(1,017.9)	(1,018.8)	(1,020.0)	(1,014.5)
487.80 N.G.V. compressor stations	(2,574.3)	(2,600.7)	(2,627.7)	(2,654.5)	(2,681.5)	(2,709.0)	(2,736.8)	(2,765.4)	(2,794.5)	(2,823.9)	(2,853.8)	(2,884.0)	(2,915.7)	(2,739.7)
487.90 N.G.V. rental cylinders	(1,894.2)	(1,926.1)	(1,958.0)	(1,989.9)	(2,021.8)	(2,053.8)	(2,085.8)	(2,117.9)	(2,150.0)	(2,182.2)	(2,214.4)	(2,246.7)	(2,279.2)	(2,086.1)
488.00 Communication str & equip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
488.00 Communication str & equip 20yrs	(1,845.6)	(1,876.9)	(1,908.2)	(1,939.5)	(1,970.9)	(2,002.2)	(2,033.5)	(2,064.8)	(2,096.2)	(2,127.4)	(2,158.6)	(2,189.7)	(2,220.9)	(2,033.4)
490.00 Computer equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
490.00 Computer equipment 2003 B 20%	(27,748.5)	(28,208.1)	(28,651.9)	(29,087.8)	(29,513.0)	(29,927.7)	(30,327.9)	(30,724.9)	(31,105.1)	(31,481.4)	(31,911.2)	(32,327.8)	(32,732.7)	(30,292.3)
491.00 Software acquired intangibles	(35,349.1)	(35,182.9)	(34,989.0)	(34,769.6)	(34,523.9)	(34,252.0)	(33,952.8)	(33,655.6)	(33,330.6)	(32,981.1)	(32,622.4)	(32,236.8)	(31,824.6)	(33,840.3)
491.00 Software developed intangibles	(33,517.9)	(33,664.2)	(33,788.1)	(33,893.8)	(33,979.8)	(34,046.3)	(34,091.0)	(34,317.2)	(34,520.5)	(34,707.7)	(34,909.7)	(35,090.7)	(35,251.6)	(34,282.8)
491.00 CIS software acquired intangibles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
489.00 WAMS	0.0	(487.9)	(975.8)	(1,463.7)	(1,951.6)	(2,439.5)	(2,927.4)	(3,415.3)	(4,003.9)	(4,592.5)	(5,181.1)	(5,769.7)	(6,358.2)	(3,032.3)
4??.00 Available	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gen. Plant Acc. Depr. - After Adj.	(180,296.6)	(182,098.8)	(183,837.9)	(185,523.6)	(187,152.0)	(188,726.3)	(190,238.5)	(191,934.1)	(193,665.6)	(195,353.8)	(197,102.5)	(198,790.6)	(200,431.6)	(190,398.9)

BOARD STAFF INTERROGATORY #16

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T9/S1/Incentive Ratemaking Report (CEA)/P 76 of 125

Footnote 80 says that, when Concentric Energy Advisors updated its study to include 2011 data, "a few additional data points were revised based on additional data becoming available." Please identify:

a) The historical data points that have changed.

b) The previous values for the identified data points, and the new values for the data points.

c) Whether the changes were due to earlier data being missing, revised, or inaccurate.

RESPONSE

The Attachment to Exhibit I.A1.EGDI.STAFF.16 contains a table that identifies the historical data points in the benchmarking analysis that were revised, the previous and new values, and the reason for the change.

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

Data Point	Company	Year	Previous Value	New Value	Reason for Change (Missing [1], Revised [2], Inaccurate [3], or Re-evaluated [4])
Avg Residential Gas Customers (Actual)	Baltimore Gas and Electric Company (MD)	2009	550,266	606,800	Re-evaluated
Avg Residential Gas Customers (Actual)	Baltimore Gas and Electric Company (MD)	2010	544,970	608,600	Re-evaluated
Avg Residential Gas Customers (Actual)	Laclede Gas Company (MO)	2010	599,640	586,974	Re-evaluated
Avg Residential Gas Customers (Actual)	Colonial Gas Company (MA)	2010	175,075	175,012	Re-evaluated
Avg Residential Gas Customers (Actual)	Niagara Mohawk Power Corporation (NY)	2010	424,323	452,934	Re-evaluated
Avg Residential Gas Customers (Actual)	Public Service Electric and Gas Company (NJ)	2009	1,579,436	1,610,629	Re-evaluated
Avg Residential Gas Customers (Actual)	Public Service Electric and Gas Company (NJ)	2010	1,572,573	1,616,162	Re-evaluated
Avg Residential Gas Customers (Actual)	UGI Central Penn Gas, Inc. (MD)	2010	427	423	Revised
Avg Small (or Comm) Gas Cust (Actual)	Public Service Electric and Gas Company (NJ)	2004	136,974	136,911	Re-evaluated
Avg Small (or Comm) Gas Cust (Actual)	Public Service Electric and Gas Company (NJ)	2005	137,619	137,568	Re-evaluated
Avg Small (or Comm) Gas Cust (Actual)	Public Service Electric and Gas Company (NJ)	2006	136,247	136,191	Re-evaluated
Avg Large (or Ind) Gas Customers (Actual)	Laclede Gas Company (MO)	2000	1,914	0	Re-evaluated
Avg Large (or Ind) Gas Customers (Actual)	Laclede Gas Company (MO)	2001	1,887	0	Re-evaluated
Avg Large (or Ind) Gas Customers (Actual)	Laclede Gas Company (MO)	2002	1,828	0	Re-evaluated
Avg Large (or Ind) Gas Customers (Actual)	Laclede Gas Company (MO)	2003	1,785	0	Re-evaluated
Avg Large (or Ind) Gas Customers (Actual)	Laclede Gas Company (MO)	2004	1,749	0	Re-evaluated
Avg Large (or Ind) Gas Customers (Actual)	Laclede Gas Company (MO)	2005	1,720	0	Re-evaluated
Avg Large (or Ind) Gas Customers (Actual)	Laclede Gas Company (MO)	2006	1,703	0	Re-evaluated
Avg Large (or Ind) Gas Customers (Actual)	Laclede Gas Company (MO)	2007	1,675	0	Re-evaluated
Avg Large (or Ind) Gas Customers (Actual)	Laclede Gas Company (MO)	2008	1,649	0	Re-evaluated
Avg Large (or Ind) Gas Customers (Actual)	Laclede Gas Company (MO)	2009	1,627	0	Re-evaluated
Avg Large (or Ind) Gas Customers (Actual)	Laclede Gas Company (MO)	2010	1,597	0	Re-evaluated
Avg Large (or Ind) Gas Customers (Actual)	Public Service Electric and Gas Company (NJ)	2004	7,462	7,442	Re-evaluated
Avg Large (or Ind) Gas Customers (Actual)	Public Service Electric and Gas Company (NJ)	2005	7,065	7,048	Re-evaluated
Avg Large (or Ind) Gas Customers (Actual)	Public Service Electric and Gas Company (NJ)	2006	6,740	6,719	Re-evaluated
Avg Transportation Customers (Actual)	Laclede Gas Company (MO)	2008	146	147	Re-evaluated
Avg Transportation Customers (Actual)	Laclede Gas Company (MO)	2009	147	145	Re-evaluated
Avg Transportation Customers (Actual)	Laclede Gas Company (MO)	2010	140	139	Re-evaluated
Avg Total Natural Gas Customers (Actual)	Baltimore Gas and Electric Company (MD)	2009	NA	650,800	Missing
Avg Total Natural Gas Customers (Actual)	Baltimore Gas and Electric Company (MD)	2010	NA	652,600	Missing
Avg Total Natural Gas Customers (Actual)	UGI Central Penn Gas, Inc. (MD)	2010	495	493	Revised
Residential Gas Sales Vol (Dth)	CenterPoint Energy Resources Corp. (MN)	2010	64,334,400	64,449,300	Revised
Residential Gas Sales Vol (Dth)	Baltimore Gas and Electric Company (MD)	2009	37,889,116	42,159,116	Re-evaluated
Residential Gas Sales Vol (Dth)	Baltimore Gas and Electric Company (MD)	2010	37,790,824	42,647,824	Re-evaluated
Residential Gas Sales Vol (Dth)	East Ohio Gas Company (OH)	2009	113,038,738	113,039,738	Inaccurate
Residential Gas Sales Vol (Dth)	East Ohio Gas Company (OH)	2010	942,902,155	109,932,155	Re-evaluated
Residential Gas Sales Vol (Dth)	Laclede Gas Company (MO)	2010	50,498,477	50,657,554	Re-evaluated
Residential Gas Sales Vol (Dth)	Niagara Mohawk Power Corporation (NY)	2010	37,548,460	48,075,998	Re-evaluated
Residential Gas Sales Vol (Dth)	Public Service Electric and Gas Company (NJ)	2009	140,300,588	142,264,772	Re-evaluated
Residential Gas Sales Vol (Dth)	Public Service Electric and Gas Company (NJ)	2010	131,890,538	135,686,007	Re-evaluated
Residential Gas Sales Vol (Dth)	UGI Utilities, Inc. (PA)	2009	21,059,875	21,380,638	Re-evaluated
Small (or Comm) Gas Sales Vol (Dth)	Public Service Electric and Gas Company (NJ)	2004	63,861,824	59,039,467	Re-evaluated
Small (or Comm) Gas Sales Vol (Dth)	Public Service Electric and Gas Company (NJ)	2005	69,802,033	55,986,505	Re-evaluated
Small (or Comm) Gas Sales Vol (Dth)	Public Service Electric and Gas Company (NJ)	2006	55,560,750	50,046,687	Re-evaluated
Small (or Comm) Gas Sales Vol (Dth)	Public Service Electric and Gas Company (NJ)	2007	57,013,022	52,881,755	Re-evaluated
Small (or Comm) Gas Sales Vol (Dth)	Public Service Electric and Gas Company (NJ)	2008	54,840,937	49,429,154	Re-evaluated
Small (or Comm) Gas Sales Vol (Dth)	Public Service Electric and Gas Company (NJ)	2009	52,921,584	48,096,976	Re-evaluated
Small (or Comm) Gas Sales Vol (Dth)	Public Service Electric and Gas Company (NJ)	2010	50,112,371	45,090,884	Re-evaluated
Large (or Ind) Gas Sales Vol (Dth)	Public Service Electric and Gas Company (NJ)	2004	11,749,297	5,179,412	Re-evaluated
Large (or Ind) Gas Sales Vol (Dth)	Public Service Electric and Gas Company (NJ)	2005	13,875,655	4,696,615	Re-evaluated
Large (or Ind) Gas Sales Vol (Dth)	Public Service Electric and Gas Company (NJ)	2006	8,226,202	3,774,544	Re-evaluated
Large (or Ind) Gas Sales Vol (Dth)	Public Service Electric and Gas Company (NJ)	2007	8,723,132	4,163,992	Re-evaluated
Large (or Ind) Gas Sales Vol (Dth)	Public Service Electric and Gas Company (NJ)	2008	7,596,814	3,904,326	Re-evaluated
Large (or Ind) Gas Sales Vol (Dth)	Public Service Electric and Gas Company (NJ)	2009	6,132,969	3,518,280	Re-evaluated
Large (or Ind) Gas Sales Vol (Dth)	Public Service Electric and Gas Company (NJ)	2010	15,369,629	3,174,355	Re-evaluated
Interdepartmental Gas Sales Vol (Dth)	Michigan Consolidated Gas Company (MI)	2010	277,424	138,712	Revised
Transport Gas for Others Volume (Dth)	Baltimore Gas and Electric Company (MD)	2010	47,168,000	44,079,279	Re-evaluated
Total Natural Gas Volume (Dth)	Washington Gas Light Company (DC,MD,VA)	2010	182,454,677	182,454,977	Re-evaluated
Total Natural Gas Volume (Dth)	Colonial Gas Company (MA)	2007	25,342,215	25,370,693	Revised
Total Natural Gas Volume (Dth)	Colonial Gas Company (MA)	2010	40,956,520	40,956,521	Revised
Accum Deprec-General-Gas ($000)	CenterPoint Energy Resources Corp. (MN)	2010	76,498	77,425	Revised
Nat Gas Storage Exp ($000)	Niagara Mohawk Power Corporation (NY)	2010	0	5	Revised
Transmission-Op & Maint Exp-Gas ($000)	Ameren Illinois Company	2010	4,398	4,341	Revised
Transmission-Op & Maint Exp-Gas ($000)	Philadelphia Gas Works Co. (PA)	2010	719	2,123	Revised
Distribution-Op & Maint Exp-Gas ($000)	Ameren Illinois Company	2010	56,691	54,477	Revised
Distribution-Op & Maint Exp-Gas ($000)	Orange and Rockland Utilities, Inc. (NY)	2010	19,896	19,935	Revised
Distribution-Op & Maint Exp-Gas ($000)	Niagara Mohawk Power Corporation (NY)	2010	44,793	44,079	Revised
Distribution-Op & Maint Exp-Gas ($000)	UGI Central Penn Gas, Inc. (PA)	2010	10,051	10,054	Revised
Customer Accts-Cust Acc Exp-Gas ($000)	Ameren Illinois Company	2010	31,487	29,581	Revised
Customer Accts-Cust Acc Exp-Gas ($000)	KeySpan Gas East Corporation (NY)	2010	39,590	39,593	Revised
Customer Accts-Cust Acc Exp-Gas ($000)	Niagara Mohawk Power Corporation (NY)	2010	26,998	26,773	Revised
Customer Svc-Cust Svc & Info-Gas ($000)	Ameren Illinois Company	2010	5,803	5,652	Revised
Customer Svc-Cust Svc & Info-Gas ($000)	Rochester Gas and Electric Corp (NY)	2009	263	2,630	Re-evaluated
Sales Expenses-Gas ($000)	Niagara Mohawk Power Corporation (NY)	2010	550	149	Revised
A&G-Operation & Maint Exp-Gas ($000)	Ameren Illinois Company	2010	59,919	54,382	Revised
A&G-Operation & Maint Exp-Gas ($000)	Niagara Mohawk Power Corporation (NY)	2010	106,164	106,286	Revised

Data Point	Company	Year	Previous Value	New Value	Reason for Change (Missing [1], Revised [2], Inaccurate [3], or Re-evaluated [4])
A&G-Employee Pensions & Benefits ($000)	Ameren Illinois Company	2010	17,978	14,029	Revised
A&G-Employee Pensions & Benefits ($000)	Niagara Mohawk Power Corporation (NY)	2010	36,861	40,265	Revised
Total Gas Sal & Wages ($000) - O&M	Philadelphia Gas Works Co. (PA)	2009	160,778	95,319	Re-evaluated
Calc. Total Gas Salary & Wages	Philadelphia Gas Works Co. (PA)	2009	178,841	106,028	Re-evaluated
Total Miles of Main (miles)	North Shore Gas Company (IL)	2009	2297	2,366	Re-evaluated
Total Miles of Main (miles)	North Shore Gas Company (IL)	2010	2371	2,341	Re-evaluated
Total Miles of Main (miles)	Peoples Gas Light and Coke Company (IL)	2009	4086	4,154	Re-evaluated
Total Miles of Main (miles)	Peoples Gas Light and Coke Company (IL)	2010	4159	4,131	Re-evaluated
Total Miles of Main (miles)	Northern Illinois Gas Company (IL)	2009	32,848	34,022	Re-evaluated
Total Miles of Main (miles)	Northern Illinois Gas Company (IL)	2010	32,864	34,037	Re-evaluated
Total Miles of Main (miles)	Public Service Company of Colorado (CO)	2009	21,408	21,242	Re-evaluated
Total Miles of Main (miles)	Public Service Company of Colorado (CO)	2010	21,467	21,302	Re-evaluated

[1] Missing items include data changed from NA to a value.
[2] Revised items include data where a source was revised or updated.
[3] Inaccurate items include those that were changed because of an error in the original data.
[4] Re-evaluated items include data that we re-examined, and determined information needed to be recategorized (for example, sales vs. transportation, commercial vs. industrial, firm vs. interruptible)

BOARD STAFF INTERROGATORY #17

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T9/S1/Incentive Ratemaking Report (CEA)/P 21 and 22 of 125

Given the business conditions that CEA has used to select peers for its benchmarking comparisons, please provide the following analyses:

a) An econometric model which estimates the impact of each of the identified business conditions on total gas distribution costs (i.e. capital costs plus OM&A costs) for the entire sample of gas distributors (i.e. the Industry Study Group plus Enbridge Gas Distribution).

b) An econometric model 'fitted' with the parameter estimates from part a) and is used to predict the costs of each gas distributor in the sample.

c) A comparison of the actual costs of each gas distributor in the sample with the predicted costs for that distributor estimated in part b).

d) An assessment of the statistical significance of the difference between each distributor's actual and predicted costs, as calculated in part c).

RESPONSE

Concentric has not prepared "(a)n econometric model which estimates the impact of each of the identified business conditions on total gas distribution costs (i.e. capital costs plus OM&A costs) for the entire sample of gas distributors (i.e. the Industry Study Group plus Enbridge Gas Distribution) because it is not possible to develop an econometric model that accurately measures the relationship between gas distribution company costs and cost drivers in the time that is available to respond to this interrogatory.

Witnesses: J. Coyne – Concentric
J. Simpson – Concentric
M. Bartos - Concentric

Specifically:

1) It is not possible to develop an econometric model that accurately measures the relationship between gas distribution company costs and cost drivers because several factors that are commonly understood to impact gas distribution costs are not reported or are not measured in a way that accurately reflects the true cost driver. Because these true cost drivers are not available or are not accurately measured, any econometric model of gas distribution costs will be biased, and the calculations requested in Interrogatory Staff 17 (b), (c) and (d) will not accurately measure any specific gas distribution company's predicted costs.

   Examples of factors that are commonly understood to impact gas distribution costs but that are not reported or are not measured in a way that accurately reflects the true cost driver include; (i) design day demand; (ii) number of days, by year, for each distribution company in the study that construction activities cannot be performed because the ground is frozen; (iii) number of days, by year, for each distribution company in the study that required maintenance and leak repair activities are difficult and costly to perform because the ground is frozen; (iv) miles of distribution system mains that are difficult and costly to perform construction or maintenance activities on because the mains are in close proximity to other underground utilities, which may include underground electric, telephone, internet, and fiber optic cable, in addition to water and sewer; (v) miles of main that are located below streets and highways; and the materials used for those streets and highways[1]; (vi) condition and location of streets and roads in the service territory and traffic congestion on those streets and roads, all of which affects employee travel times, and deployment of employees to respond to service or emergency calls; (vii) a number of factors that affect customer call center staffing and costs such as the number of residential low income customers, and state-specific regulatory directives and requirements that apply to all distribution company customers and especially to residential low income customers; and (viii) condition of the terrain that the distribution system is installed in.

[1] For example, the costs to perform construction and maintenance activities and to restore the work site will differ if the distribution mains are located below streets and highways constructed with cobble stones, concrete, and/or asphalt.

Witnesses: J. Coyne – Concentric
J. Simpson – Concentric
M. Bartos - Concentric

2) It is not possible to develop an econometric model that correctly measures the relationship between gas distribution company costs and cost drivers in the time that is available because – in addition to the data issues that are discussed above - Concentric would be required to collect the following data that is likely to be relevant cost drivers: miles of main, number of electricity customers, percentage of distribution mains that are not cast-iron or bare-steel, customer density, union vs. non-union labor, percent of workforce that is outsourced, Automatic Meter Reading penetration, demand side management expenditures, etc. Concentric currently does not have this data for all of the companies in the study group for all the years, and does not know if the data are available.

   For the reasons cited above, Concentric relied upon the selection of a proxy group with characteristics that represent Enbridge's operating circumstances because it is not possible to develop an econometric model that reliably measures the relationship between gas distribution company costs and cost drivers.

   Concentric has not formed an opinion as to whether the issues discussed above concerning factors that are commonly understood to impact gas distribution costs but that are not reported or are not measured in a way that accurately reflects the true cost driver would also apply to electric distribution company econometric cost models, including PEG's econometric cost model, prepared in support of incentive ratemaking for electricity distributors (Empirical Research in support of Incentive Rate-Setting: 2012 Update, Pacific Economics Group, September 2013).

   However, Concentric notes many of the specific factors discussed above that are commonly understood to impact gas distribution costs but that are not reported or are not measured in a way that accurately reflects the true cost driver do not apply to electric distributors, which typically have distribution systems that are largely if not entirely above ground. Concentric also notes that PEG's econometric cost model (PEG September 2013 Report, Table 12) includes a variable, System Capacity Peak Demand, that is comparable to the gas distribution factor, design day demand, which is commonly understood to impact gas distribution costs but that is not reported by gas distribution companies.

Witnesses: J. Coyne – Concentric
J. Simpson – Concentric
M. Bartos - Concentric

BOARD STAFF INTERROGATORY #18

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T10/S1/The Building Blocks Approach (LEI)/P 13 of 24

London Economics International (LEI) writes that "the Australian Energy Market Commission (AEMC) has reviewed whether or not to apply a TFP-based method for escalating rates (via an "I-X" framework) or to retain the building block approach...there was a concern that data problems could prevent such (TFP) studies from being sufficiently robust for purposes of ratemaking and that most importantly the lack of data "prevents proper testing of the conditions need for TFP methodology;" therefore the AEMC concluded that it is better to retain the building blocks approach.

a) In the review referenced by LEI, was the issue before the AEMC to replace the building block approach with a TFP-based approach, or whether a TFP-based regulatory option should be added to Australia's energy regulatory framework?

b) If the AEMC had decided not to make any changes based on its review, would the building block approach to incentive regulation have been retained?

c) At the conclusion of the review, did the AEMC decide to add a TFP-based regulatory option to Australia's energy regulatory framework?

d) In light of the answers to a) and b) above, please explain the basis for LEI's view that "the AEMC concluded that it is better to retain the building blocks approach."

RESPONSE

a) AEMC's objective of the 2008 to 2011 "Review Into the Use of Total Factor Productivity for the Determination of Prices and Revenues" was stated in the Final Report:

Witness: J. Frayer - London Economics International LLC

> “The objective is to advise the Ministerial Council on Energy (MCE) on whether permitting the use of a TFP methodology would contribute to the national gas objective (NGO) and/or national electricity objective (NEO) and, if so, to provide draft Rules.” [1]

AEMC explained further:

> “There are two possible applications of TFP in revenue regulation permitted under the national energy laws. TFP indices can be used to assist the Australian Energy Regulator (AER) in applying efficiency benchmarking to service providers’ costs under the existing building blocks approach. Alternatively, a TFP methodology could be applied in a more mechanistic manner where TFP indices are used to set the allowed rate of change of allowed revenues over the regulatory period. This methodology would be applied as an alternative to the existing building block approach established in the Rules. This Review was initiated following a Rule change proposal from the Victorian Minister for Energy and Resources which was based upon concerns about the efficiency of current prices and performance of service providers under the building block approach.”[2]

b) The building blocks approach would have been retained regardless of the findings of the review as consideration of not retaining building blocks approach to incentive regulation was not part of the review. At the start of the review, AEMC noted in its Framework and Issues Paper (December 2008):

> “The Review is not considering whether a TFP based methodology should **replace** *[emphasis added]* the existing framework but rather whether allowing the use of TFP in addition to the existing building block approach would provide benefits to customers, service providers and the AER in the relevant decision making processes.”[3]

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[1] AEMC (June 2011) *Review into the use of total factor productivity for the determination of prices and revenues, Final Report* June 30, 2011, p. i. For more information on the review, see http://www.aemc.gov.au/market-reviews/completed/review-into-the-use-of-total-factor-productivity-for-the-determination-of-prices-and-revenues.html
[2] Ibid.
[3] AEMC (December 2008) *Review into the use of Total Factor Productivity for the determination of prices and revenues, Framework and Issues Paper,* December 12, 2008, p. 2.

c) AEMC summarized findings and conclusions of the review in the Summary of the Final Report as follows:

> "…a number of conditions need to be satisfied for a TFP methodology to work properly and promote efficient regulatory decisions. We [AEMC] find that such conditions are not likely to be met at the present time. Crucially, the current lack of a sufficiently robust and consistent data-set means that it could be too problematic to reconstruct existing data for the purpose of a TFP methodology. Also the lack of data prevents proper testing of the other conditions needed for a TFP methodology."

Therefore, the AEMC decided to delay consideration of approving the use of a TFP methodology until better data was collected to test for the prerequisite conditions.

d) As is detailed in LEI's responses to Board Staff IR Question 18 (a) above, the goal of AEMC's review was to study the potential use of the TFP-based IR approach to complement the currently-used building blocks approach. AEMC concluded that the lack of appropriate data at the time would not allow for the TFP-based IR approach to work properly, and therefore it is still too early for the adoption of TFP-based IR model for regulated utilities in Australia. AEMC proposed that the TFP-based approach should be examined again in the future. Currently, however, the Australia regulator continues to use the building blocks approach. Total factor productivity studies are used to benchmark utilities and inform stakeholders on the development of the revenue requirement forecasts under the building blocks approach.

BOMA INTERROGATORY #1

INTERROGATORY

Ref: Evidence on sustainable efficiency improvements

a) Can Enbridge provide its plan to verify the actual performance of its proposed incentives for sustainable efficiency improvements? How does it propose to measure actual savings achieved versus the proposed baseline(s)?

RESPONSE

Enbridge has responded to various criticisms of the Sustainable Efficiency Incentive Mechanism ("SEIM") as it was originally filed and as result has updated its proposal for the SEIM to operate in a similar manner as the Efficiency Carryover Mechanism approved by the Alberta Utilities Commission in 2012. Please see the updated evidence filed at Exhibit A2, Tab 11, Schedule 3 for further details.

Witnesses: R. Fischer
M. Lister

BOMA INTERROGATORY #2

INTERROGATORY

Can Union provide a comparison showing the amount of money (over and above Board approved revenue requirement for 2013) that it proposes to recover from ratepayers over the five year plan period (the years 2014-2018), compared to what it would recover if it were to adopt the five year Union IRM Plan, recently agreed by the parties in a Settlement Agreement (EB-2013-0202), and applied the elements of that plan to its approved 2013 rates?

RESPONSE

Please see the table below:

Revenue Requirement (Net of Gas Cost)

$ Millions	**2013 Board Approved**	**2014**	**2015**	**2016**	**2017**	**2018**
Customized IR (As applied for)	1,021	1,012	1,058	1,171	1,227	1,286
Incremental over 2013 board approved		(10)	37	149	205	265
Approximation of Union IRM	1,021	974	989	1,050	1,061	1,080
Incremental over 2013 board approved		(47)	(32)	28	40	59

Assumptions for 'Approximation of Union IRM':

- Escalation factor assuming GDPIPI of 1.7%, with 60% productivity factor
- Revenue cap Model
- Y factor treatment for GTA and Ottawa project
- DSM, CIS/Customer Care, Pension cost and carrying cost of Gas In Storage as flow through items
- Adjustment for Reduction in depreciation expense with SRC in 2013 base
- Factor in tax impact of Site Restoration Cost adjustment

Allowed Revenue incremental to that approved by the Board for 2013 averages $129 million during each year of the IR term. The increase in Allowed Revenue is mainly a result of the rate base growth due to increased forecast safety and integrity capital spending and expected increases in forecast Allowed ROE.

Witnesses: R. Fischer
S. Kancharla

Enbridge's Customized IR plan sets out Allowed Revenue amounts for each year to allow the Company to safely and efficiently operate its business and have the opportunity to earn the Board-approved level of return. Adoption of Union's IRM plan would result in forecast annual average increases of Allowed Revenue of about $10 million, less than 10% of that required by Enbridge to provide it with a reasonable opportunity to earn its Allowed Return. Clearly, Union's plan will not work for Enbridge's circumstances.

Witnesses: R. Fischer
S. Kancharla

BOMA INTERROGATORY #3

INTERROGATORY

Ref: 2013 Approved Rates

a) Can Enbridge explain the extent to which, if at all, the approved 2013 rates are being used as a starting point for its five year IRM proposal?

b) Please provide the most recent available update for 2013 actuals, and the most recent forecast of expected full year actuals for 2013. Please indicate where it is appropriate to utilize normalized actual results instead of unnormalized actuals and provide such normalized results.

RESPONSE

a) The Board approved 2013 values are being used as a starting point for Property Plant & Equipment ("PP&E"), rate base, and capital structure for the five-year Customized IR term. All other financial items were developed from the ground up based on the updated inputs at the point of time when the regulatory budget was prepared.

b) Please refer to the following interrogatory response for the 9+3 forecast:

- O&M - Exhibit I.B17.EGDI.STAFF.50
- Capital - Exhibit I.B18.EGDI.SEC.86
- Volumes (unnormalized) - Exhibit I.C23.EGDI.VECC.6
- Unlocks - Exhibit I.C21.EGDI.VECC.7

Witness: S. Kancharla

CCC INTERROGATORY #1

INTERROGATORY

Issue A1 – Is Enbridge's proposal for a Customized IR plan for a 5-year term covering its 2014 through 2018 fiscal years appropriate?

(Ex. A2/T2/S1/p. 15) EGD has retained two experts (Concentric and London Economics) to assist it in building and evaluating the IR plan. Did EGD issue RFPs for this work? If so, please provide copies of those RFPs. If not, why not? Please provide the terms of reference for both the Concentric work and the London Economics work. What is the expected cost of the two expert reports and the related consulting work for each firm? How are those costs going to be recovered?

RESPONSE

Enbridge did issue an RFP for the work assigned to Concentric. The RFP is attached (Attachment #1). At the time the RFP was issued, Enbridge envisioned a single hearing that would include both a Cost of Service application and an Incentive Regulation (IR) application in 2012. Since the time when the RFP was issued, the Company made a decision to split the applications into separate rebasing and IR applications. A decision was later made to file a Customized IR plan in place of a traditional I-X plan. Understanding that the Company's performance during the IR term would be an issue in the rebasing case, Enbridge produced benchmarking results from the work undertaken by Concentric in the rebasing case (EB-2011-0354).

The terms of reference for the Concentric work are also attached. The total cost of the Concentric work to date is estimated to be $1,936 thousand. The final cost will be dependent on the effort required to respond to interrogatories, and participate in technical conferences, hearings, and related case activities. Approximately $384 thousand is apportioned to the 2013 regulatory proceedings cost budget, and the remainder is to be apportioned to the 2014 regulatory proceedings cost budget.

Enbridge did not issue an RFP for the work assigned to LEI (Attachment #3). An RFP was not issued because the scope for the LEI work was anticipated to be narrow and the timelines to the expected filing date were short.

The terms of reference for the LEI work are attached. The total cost of the LEI work is estimated to be $400 thousand, which is apportioned to the 2014 regulatory proceedings cost budget.

Witnesses: K. Culbert
R. Fischer
A. Kacicnik
M. Lister

Enbridge Gas Distribution Inc.
500 Consumers Road
North York, Ontario
M2J 1P8
PO Box 650
Scarborough ON M1K 5E3

Norm Ryckman
Director, Regulatory Affairs
phone: 416-753-6280
fax: (416) 495-6072
Email: norm.ryckman@enbridge.com

Re: Productivity Study Consultant RFP

Background

Enbridge Gas Distribution Inc. (“Enbridge”, “EGD” or “the Company”) is Canada’s largest natural gas distribution utility, having provided natural gas to its franchise areas for over 100 years. Enbridge provides natural gas distribution, transmission, and storage services to about 1.9 million customers in Ontario and through its subsidiary St. Lawrence Gas Co. Inc. in upper New York State, and its affiliate Gazifere Inc. in western Quebec. The Company is a wholly owned subsidiary of Enbridge Inc., a world leader in energy transportation, distribution and services.

The Company is regulated by the Ontario Energy Board (OEB). In 2007 the Company filed an application (EB-2007-0615) for a five-year, incentive rate plan covering the years 2008 to 2012, which concluded with a Settlement Agreement. The Company’s plan is based upon a revenue per customer cap which adjusts revenues to reflect system growth and inflation. A scaled productivity factor, calculated as a percentage of inflation, is also featured in the Company’s current IR plan. In addition, the plan includes an Earning Sharing Mechanism (ESM) where sharing occurs at 50/50 for earnings > 100 bp over the allowed ROE.

EGD’s Revenue Cap Formula:

$$RR_t = \frac{(RR_{t-1})}{(C_{t-1})} * (1+\mathit{GDP\ IPI} - X) * C_t + Y_t + Z_t$$

- RR= revenue requirement
- t = rate year
- C = average number of customers
- X = X factor or productivity
- GDP IPI = inflation factor, the GDP Price Index
- Y = specific categories of expense, added at cost of service
- Z = exogenous factors, beyond management’s control

RFP Expectations

Enbridge is now beginning to gather information as it prepares for its next generation Incentive Regulation plan (the “IR Plan”). This RFP is specifically aimed at providing Enbridge with the evidence it will require to support the Productivity Factor for its new IR Plan by performing a Productivity Study. In addition, Enbridge’s also requests a review and validation of benefits generated from the current IR plan. The successful consultant will also play a role in providing the Enbridge team with general advice about other IR parameters and the Company's IR Plan strategies.

The Productivity Study must also include the development of specific and quantitative recommendations for productivity that may be applicable to the Company's next generation IR proposal. Recommendations should be based on objective empirical research/data and consistent with the principles for effective incentive mechanisms and regulatory trends across North America.

This information will be used by Enbridge to aid in developing its IR strategy and positions, and it is expected that this material will be put forward as supporting evidence in its application for the next IR plan. As such, the scope of work may also include expert witness testimony and support.

Key Deliverables in this RFP

1. Develop a methodology for, and the production of, a productivity recommendation (X-Factor) for EGD's next IR plan.

2. Work with members of EGD's IR Strategy Development team to provide advice regarding various plan elements or IR parameters, including the X-Factor, and aid in the development of the strategy for advancing the Company's positions. This may include, but not be limited to, a review of EGD's performance in its first IR term, cost performance benchmarking, or advice related to research data on regulatory trends in other jurisdictions.

3. Provide support and endorsement for the Company's overall IR proposal, including specific plan elements.

4. Participate and provide presentations/submissions on behalf of the Company during any OEB consultative processes on IR, if required.

5. Provide evidence and testimony and represent the Company as an expert witness with respect to the productivity recommendation and potentially other IR parameters in a proceeding with the Ontario Energy Board (expected in late 2011 into 2012).

Please note that the quality of all documentation provided to the Company must be suitable for the purposes of regulatory filing.

Expected Project Process & Timelines

Members of EGD's IR strategy development team will be available to the consultant for regular contact as necessary. EGD expects there to be regular communications, perhaps weekly or bi-weekly, regarding status updates, or potentially directional change, or strategic evolution. We also anticipate meetings in person at various points through the process, as suggested and outlined below. Specifically, we anticipate at least one (potentially more) meetings with EGD's Sr. Management and Executives.

We also anticipate meetings with Stakeholders to socialize our ideas and to incorporate Stakeholder concerns and feedback where possible before we file our application. The Company intends to file its next generation IR Plan in late 2011 and proposes that the Key Deliverables be met as follows.

Scope of Work	Deliverable	Timing	Date
Initial Conference Call with IR Team to discuss expectations, process, and timing	Kickoff Meeting	Q4: 2010	Mid Dec. 2010
Develop Outline of productivity study methodology and recommendation	Outline	Q4: 2010	Early Jan 2011
Preliminary Draft of productivity study results with high level recommendation & direction	Preliminary Draft	Q1: 2011	Early Feb. 2011
Strategy session with EGD Sr. Managers & Executive Team	Strategy Session	Q1: 2011	Feb. 2011
First Draft productivity recommendation and supporting materials	First Draft	Q1: 2011	Feb. 2011
Incorporate Company Feedback	Incorporate Comments	Q2: 2011	Mar. 2011
Final Draft of productivity recommendation and endorsement of EGD IR positions	Final Draft	Q2: 2011	Apr. 2011
Meeting(s) with Stakeholders	Stakeholder Sessions	Q2: 2011	May. / Jun. 2011
Incorporate feedback from Stakeholders	Incorporate Comments	Q2: 2011	Jun. 2011
Draft Final Evidence	Evidence	Q3: 2011	Oct. 2011
Interrogatories, Testimony & other Case Support including settlement negotiations	Case support	2012	2012

Contents of Your Proposal

Responses to this RFP should outline the respondent's supporting knowledge, skills, experience, and accreditation necessary to convince EGD that the respondent is capable of delivering the Key Deliverables. Moreover, the respondent must comment on whether, due to positions taken in the past or for any other reason, they might be limited in their ability to provide the requested research, analysis, or support.

The proposal should include:

- a timeline for the respondent's delivery, relative to Enbridge's expected schedule described in the previous section
- key milestones, including interim reporting by the consultant
- proposed team members, qualifications, availability, and experience of each
- the degree to which EGD resources will be required to complete the study, if any
- the respondent's experience with productivity studies and / or IR plan methodologies
- the respondent's experience before regulatory commissions, including that of key team members, highlighting experience before Canadian regulators
- proposed fee structure, handling of expenses and disbursements, and treatment of travel time, etc.
- contact information for at least three (3) references that have recently been provided these or similar services by the respondent
- an indication of the respondent's willingness to provide proof of Commercial and Professional Liability Insurance, and WSIB standing prior to contract execution
- a schedule of fees for all respondent team members, and overall budget for the entire contract, broken down into estimates by major components
- all fees to be quoted in Canadian dollars, with HST extra

Deadline for submission

Responses will be considered if submitted between December 6 – December 10 and no later than 4:45pm local time on Friday December 10, 2010 and will be received by:

Ms. Mikki Rizvi **Enbridge Gas Distibution Inc.** **Regulatory Affairs, 5th Floor, VPC** **500 Consumers Road** **North York, Ontario** **M2J 1P8**	**By Fax: 416-495-6072** **By email: mikki.rizvi@enbridge.com** **Use of email is encouraged**

Contact

If further clarification or details are required to complete the RFP, please feel free to contact either Michael Lister or Mikki Rizvi.

Michael Lister
Manager, Regulatory Policy & Strategy
416-495-5043
Michael.Lister@enbridge.com

Mikki Rizvi
Sr. Policy & Compliance Advisor
416-495-5988
Mikki.Rizvi@enbridge.com

The Company recognizes the individuality that will be a component of each response.

It is recognized that each respondent may wish to follow a different path in preparing its response, and the Company will make best efforts to support individual requests for information and meetings. The Company reserves the right to share, or not to share, information exchanged as a result of individual meetings.

The Company reserves the right to select all, or part, of a proposal or not to select any of the proposals submitted in response to the RFP.

Yours truly,

Norm Ryckman
Director, Regulatory Affairs

CONCENTRIC ENERGY ADVISORS

December 8, 2010

Ms. Mikki Rizvi
Senior Policy & Compliance Advisor, Regulatory Affairs
Enbridge Gas Distribution Inc.
500 Consumers Road
North York, Ontario M2J 1P8
Email: mikki.rizvi@enbridge.com
Fax: (416) 495-6072

Re: Productivity Factor Study Consultant RFP

Dear Mikki,

Thank you for considering Concentric Energy Advisors, Inc. ("Concentric") to provide a Productivity Study related to Enbridge Gas Distribution's ("Enbridge", "EGD", or the "Company") next generation Incentive Regulation ("IR") plan.

Concentric is uniquely qualified to assist Enbridge with this important matter. Our specific experience in incentive rate plans and productivity studies in conjunction with our broader rate and regulatory work provides us with an in-depth perspective to bring to this assignment. Our firm brings recognizable expertise in U.S. and Canadian utility matters, as our expert witnesses have testified in numerous regulatory proceedings before most Canadian and U.S. jurisdictions. In addition, our knowledge of Ontario stakeholders and experience testifying before and working directly with the OEB staff and Board brings us an additional degree of accreditation. Details of Concentric's relevant experience are provided in Section IV of this proposal.

This proposal letter contains an introduction to Concentric, project team, relevant experience, proposed approach, timeline and budget. We would appreciate this opportunity to work with you and the Enbridge regulatory team again, and please do not hesitate to call me should you have any questions.

Sincerely,

James Coyne
Senior Vice President
508-263-6255

Concentric Energy Advisors, Inc.
Proposal for:
Productivity Study Consultant

Prepared for:
Enbridge Gas Distribution

December 8, 2010

I. Introduction to Concentric

Concentric is a regulatory and financial advisory firm focused on the North American energy and water utility industries. Headquartered in Marlborough, Massachusetts, Concentric specializes in a full range of regulatory advisory services and testimony, litigation support, M&A and other transaction-related financial advisory services, strategic consulting services including market analysis, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses and negotiations. Concentric provides its clients with immediate access to extensive industry experience and capabilities. Our senior staff is always intimately involved in the client project work. The firm's principals and affiliates have held executive positions with a number of prominent utility management consulting firms, utility companies, regulatory agencies, competitive energy suppliers and investment banks.

Concentric's staff has a significant breadth and depth of regulatory experience, having assisted clients throughout the U.S. and Canada with federal, state and provincial regulatory issues, including among other things, rate policy, strategic analyses/studies, resource planning, cost of service, cost allocation, rate design, rate of return, market power, tariff development, incentive rate programs, demand forecasting, terms and conditions of service, the development of new services, and prudence-related matters.

Concentric's clients have included regional transmission organizations, natural gas distribution companies, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, water utilities, governmental and regulatory agencies, trade associations, independent energy project developers, liquefied natural gas developers, engineering firms, and gas and power marketers throughout the U.S. and Canada. In addition, should it be required, Concentric staff members have provided testimony on hundreds of occasions in administrative and civil proceedings, on topics ranging from broad regulatory and economic policy to virtually all elements of the utility ratemaking process.

We believe that our combined expertise in rate policy matters, regulatory research, and experience in Ontario make us ideally suited to this assignment.

II. Approach, Timeline and Milestones

Concentric's approach to this assignment will be one that provides Enbridge with the substantial evidence required to effectively support the Company's proposal for its next generation Incentive Regulation Plan ("IR Plan"). We will capitalize on lessons learned from the prior IR Plan, provide research on other plans adopted in North American jurisdictions, investigate and quantify an appropriate "X Factor" for EGD's next plan, prepare expert evidence, assist the Company with responding to stakeholders, and provide the benefit of our substantial experience to EGD's team in support of this effort.

Our Understanding of the Existing Incentive Regulation Plan

Concentric understands that Enbridge is currently utilizing a revenue cap mechanism calculated on a per customer basis. We also understand that this plan evolved from Enbridge's original 1999 plan, and the subsequent 2005 Ontario Energy Board ("OEB", or "Board") Natural Gas Forum which established certain criteria for IR plan compliance, including:[1]

- Sustainable efficiency improvements
- Appropriate quality of service
- An environment conducive to investment

In 2007, Board Staff built upon those three criteria to establish additional IR principles:[2]

- Rates should be predictable and stable
- The rate adjustment mechanism should be clear
- The pursuit of efficiency should be encouraged
- Investment in the infrastructure required to maintain safety and reliability of the distribution system should be encouraged
- Customer service standards should be maintained
- Demand Side Management activities should be encouraged
- A balance between the financial viability of the utilities and the interests of natural gas consumers should be maintained
- System expansion into new communities should be facilitated
- The IR regulatory process should be efficient and transparent

Based on the components set out by the Board above, Enbridge established its IR objectives via a multi-year rate plan that would permit Enbridge to:[3]

- Maintain a safe and reliable system
- Meet service quality requirements
- Retain incremental ROE resulting from efficiency improvement initiatives
- Respond to the continuing demand for new customer attachment, recently at a pace of 45,000 to 50,000 new customers per year.

However, Enbridge was concerned that all of these objectives could not be met with a plan that did not adequately compensate the utility for the cost escalation and growth pressures it could face. Therefore, EGD proposed a plan comprised of a revenue per customer cap which would adjust revenues to reflect system growth and inflation. The plan also consisted of a scaled productivity factor (calculated as a percentage of inflation) as well as an Earning Sharing Mechanism.[4] We understand that parties to the agreement and their witnesses could not agree on a specific productivity factor, but ultimately settled on an "inflation coefficient" that trended from .60 in 2008 to .45 in 2012.[5] This plan was adopted in a settlement agreement which expires next year. It is our additional understanding that Enbridge is the only Ontario utility utilizing a revenue cap; all others are using a price cap. Retention of an ongoing revenue cap will therefore be a key issue in the development and support of the new plan.

1 EB-2007-0615, Exhibit B, Tab 1, Schedule 1.
2 Ibid.
3 Ibid.
4 EGD Incentive Regulation Consultant RFP.
5 EB-2007-0615, Decision, p. 12.

Approach

We understand that EGD seeks a consultant to prepare a report summarizing in detail the methodology and production of the consultant's recommended X-factor for EGD's next IR plan. In addition, EGD seeks a review and evaluation of the benefits derived from the Company's current IR plan. The study provided by Concentric to Enbridge will be based on rigorous and objective empirical research suitable for submission in a regulatory filing, and accompanied by expert testimony to support the recommendations provided in the study. These recommendations will be based on Concentric's research and analysis including regulatory precedents from North America, cost data for an appropriate comparator group and Enbridge, and an examination of the prior IR program and its effectiveness. Importantly, Concentric will convey it's analysis of this potentially complex subject in a manner that is both understandable and comprehensive for stakeholders and the Board. Concentric is well positioned to assist EGD with its request and proposes to fully satisfy Enbridge's requirements with the following work plan:

1. <u>Project kickoff with EGD IR Team to discuss expectations, process, and timing</u>
   Based on our prior work with the EDG team, we anticipate the kickoff will allow us to share high level thoughts on both the objective and subjective elements inherent in the formation of IR plan proposals. Of particular interest will be Enbridge's experiences under the prior Plan, positions taken by the parties, anticipated issues for the upcoming plan, and Concentric's experience in the development of IR plans. We also anticipate establishing communications schedules and protocols, and provision for sharing interim results and ideas.

2. <u>Develop an outline of the productivity study methodology and recommendation</u>
   The Productivity Study Outline will capture the benefits of Concentric's experience and research, aligned with EGD's expressed needs for the study, and will be logical build-up incorporating:
   - Scope of the Study
   - Relevant regulatory precedents in Ontario and other North American jurisdictions (some of this may have been captured in the first phase of Enbridge's RFP, in which case Concentric will cite this work in addition to its own research)
   - Research into productivity factors and methods established in other jurisdictions
     - General concepts
     - Gas
     - Electric
   - Methodology
     - Commonly employed techniques for estimating utility productivity
     - The Pacific Economics approach and critique (assuming PEG is retained by the Board)
     - Econometric vs. indexed based approaches
     - Other variations and alternatives
     - Selected methodology and basis
   - The appropriate study group for EGD (we believe the logical group will include a combination of Northeast US and Canadian gas companies)
   - Data utilized (will be a combination of sources, including)
     - Timeframe (min. of 10 years)

    - FERC Form 2 data (US companies)
    - Individual company filings (Canadian companies)
    - 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.)
    - Industry specific cost measures
    - Data limitations and issues
- Exclusions
    - Costs that should be excluded from the analysis because they are outside of EGD's control
    - Events or circumstances that should be isolated broadly or for specific companies
- Results and interpretation
    - Estimated productivity factors for EGD and the study group
    - Interpretation of the results and observed differences between EGD and comparators
    - US vs. Canadian company differences
    - Relation of the results over the historic time period to Enbridge's current and anticipated operating and commercial environment
- Comparison to other studies
    - PEG (if once again used by the Board)
    - Other parties to the proceeding (once submitted)
- Recommendations
    - Regulatory precedents and standards
    - Quantitative basis
    - Relation to EGD's operating circumstances
    - Relation to the broader IR Plan proposed
    - Base productivity factor
    - Appropriateness of a consumer dividend or "stretch" factor
    - The benefits of a continued revenue cap vs. price cap approach

Based on our kickoff discussion with the EDG team, our assessment of the Company's objectives, and review of the pros and cons of alternative approaches, we will provide a more detailed outline according to the project schedule.

3. <u>Preliminary draft of productivity study results with high level recommendation & direction</u>
Consistent with the broad study outline and project schedule, Concentric will provide an early draft of the Study results and our preliminary recommendations according to the project schedule. The study results will be primarily based on Concentric's research and analysis of productivity factors for a group of companies deemed comparable to Enbridge in contrast to Enbridge's actual cost experience. The comparable company analysis will determine the appropriate range of productivity experienced across the industry, and serve as the basis for the recommended productivity factor for Enbridge, after adjusting for any extenuating circumstances between the comparator group and Enbridge.

4. <u>Strategy session with EGD Sr. Managers & Executive Team</u>

Following completion of the draft study results and preliminary recommendations, Concentric's senior experts will meet with the EGD management and executive team to review the results, discuss implications, and strategize regarding the IR Plan proposal. In this discussion, we will bring the benefit of our experience and research in other jurisdictions, combined with our collective knowledge of EGD and the Ontario business and regulatory environment.

5. First draft productivity recommendation and supporting materials
Incorporating the results of our Study and capturing the initial comments from the EGD management and executive team, Concentric will complete its first complete draft of the Study and recommendations, with supporting exhibits.

6. Incorporate company feedback
Concentric will review company feedback on the 1st Draft and discuss where clarifications are required. We will either suggest changes or incorporate the feedback within the limitations of the supporting research and analysis.

7. Final draft of productivity recommendation and endorsement of EGD IR positions
Concentric will welcome any further comments on the 2nd Draft, and finalize the Study in a professional quality form suitable for submission to the Board and stakeholders. We will endorse and defend the Company's position on its proposed IR Plan based on the results of the Concentric Study.

8. Meeting(s) with Stakeholders
Senior members of the Concentric study team will be available for all stakeholder meetings, and will prepare summary materials in advance to assist in presenting the Study results and basis for our recommendations, and be prepared to respond to stakeholder concerns and questions.

9. Incorporate feedback from Stakeholders
Working with the EDG team, we will:
   - Distill stakeholder feedback into its specific areas of concern
   - Discuss the merits of any challenges or alternatives suggested
   - Consider the IR Plan implications of suggested changes
   - Suggest alternatives that are responsive while preserving the positions and objectives of the Company supported by the Study
   - Provide additional research or analysis where warranted
   - Reconsider or revise Concentric's recommendations incorporating stakeholder input as appropriate

10. Draft Final Evidence
Based on the foregoing, Concentric will prepare draft testimony for submission to the Board, including:
   - Concentric and witness qualifications
   - The Productivity Study
   - Stakeholder issues and reconciliation with Concentric's study and recommendations

- Recommendations to the Board

11. Interrogatories, Testimony & other case support including settlement negotiations
Concentric's study team will work closely with EGD's project team to provide timely support for the hearing or settlement process, including:
- Responses to intervenor interrogatories (draft and final)
- Review of opposing witness testimonies
- Development of interrogatories for opposing witnesses
- Assist EDG counsel with development of Q&A for opposing witnesses
- Settlement discussion support and assessment of opposing positions
- Assist counsel with drafting of briefs

Timeline for Delivery

The following is a timeline for the key project milestones as set out by EGD.

Scope of Work	Deliverable	Timing	Date
Project kickoff call with EGD IR Team to discuss expectations, process, and timing	Kickoff Meeting	Q4: 2010	Mid Dec. 2010
Develop an outline of the productivity study methodology and recommendation	Outline	Q4: 2010	Early Jan 2011
Preliminary draft of productivity study results with high level recommendation & direction	Preliminary Draft	Q1: 2011	Early Feb. 2011
Strategy session with EGD Sr. Managers & Executive Team	Strategy Session	Q1: 2011	Feb. 2011
First draft productivity recommendation and supporting materials	First Draft	Q1: 2011	Feb. 2011
Incorporate company feedback	Incorporate Comments	Q2: 2011	Mar. 2011
Final draft of productivity recommendation and endorsement of EGD IR positions	Final Draft	Q2: 2011	Apr. 2011
Meeting(s) with Stakeholders	Stakeholder Sessions	Q2: 2011	May. / Jun. 2011
Incorporate feedback from Stakeholders	Incorporate Comments	Q2: 2011	Jun. 2011
Draft Final Evidence	Evidence	Q3: 2011	Oct. 2011
Interrogatories, Testimony & other case support including settlement negotiations	Case support	2012	2012

III. PROPOSED PROJECT TEAM

Utilities and regulatory commissions regularly turn to Concentric for insights and research on leading edge regulatory policies and rate related matters. Concentric's proposed project team consists of senior regulatory experts with a wealth of experience in North American regulatory matters including incentive based regulation and productivity estimation. Concentric's combined experience includes more than 100 appearances before the FERC and NEB, as well as over 250 appearances before state and provincial commissions.

The proposed project team will utilize a team of experts supported by experienced regulatory research analysts, selected for their specific knowledge of IR plans and related regulatory context across multiple jurisdictions. Specifically, Mr. Coyne led a series of workshops on behalf of Vermont Gas and the Vermont Public Service Board to research and identify potential incentive regulation programs, their specific program features, and assist the company and Board with reaching agreement on a recommended IR formulation for Vermont Gas, including the appropriate "X factor", and then supported this proposal with expert testimony and supporting documentation. He has also worked directly with the OEB, staff and stakeholders, and has provided direct testimony before the Board and was recently invited by the Board to speak on "Presenting Expert Evidence" to Board and CAMPUT members at this past summer's Queens University regulatory program. Mr. Simpson has directed studies on the estimation of utility productivity factors and provided expert testimony on these matters. His recent testimony filed on behalf of WMECO before the Massachusetts Department of Public Utilities is provided as Attachment E as an example of our work on these matters. Additional members of the proposed team have a broad understanding of alternative regulation models, and will be used selectively for their insights and contribution to specific questions and issues as they arise. Ms. Bartos is an experienced regulatory researcher and quantitative expert who will be responsible for supporting research and analysis. Ms. O'Neill has recently completed a national study on incentive regulation plans and will bring this experience to the project. Mr. Trogonoski has conducted significant research on a variety of regulatory issues for presentation to the OEB and other regulators. Short biographies for the project team are provided below, and resumes are provided as Attachment A.

James M. Coyne, Senior Vice President, is an industry expert who provides financial, regulatory, strategic, and litigation support services to clients in the power and utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, and matters pertaining to rate and regulatory policy, capital costs, valuation, fuels, and power markets. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. He has authored numerous articles on the energy industry, is a regular speaker before both Canadian and U.S. regulatory audiences, and has provided testimony before the Federal Energy Regulatory Commission and jurisdictions in Alberta, California, Connecticut, New Jersey, Ontario, Maine, Texas, Vermont, and Wisconsin. Mr. Coyne holds a B.S. in Business from Georgetown University with honors and an M.S. in Resource Economics from the University of New Hampshire.

James D. Simpson, Senior Vice President, has over 25 years of experience with regulatory relations, regulated pricing and business strategy; he has held senior executive positions at a natural gas utility and an entrepreneurial company providing a proprietary service to generating companies. As Chief

Operating Officer for a major New England gas company, Mr. Simpson was responsible for all regulated business activities including Gas Supply, Operations, Engineering, Marketing and Sales, and Planning. His responsibilities in other positions have included business development, pricing strategy, regulatory affairs, analysis and planning. Mr. Simpson also held staff and director level positions at the Wisconsin Public Service Commission and the Massachusetts Department of Public Utilities; he has an M.S. in Economics from the University of Wisconsin and a B.A. in Economics from the University of Minnesota.

Lisa M. Quilici, Senior Vice President, is a financial and economic consultant with more than 15 years of experience in the energy industry. She has provided advisory services in rate and regulatory matters to clients across North America. Ms. Quilici has extensive experience in the development of regulatory strategies for a variety of clients throughout North America. Ms. Quilici has provided expert testimony regarding transaction and ratemaking matters before state utility commissions. She has previously served in managerial and executive positions for a regulatory commission and for major energy consulting firms, acting as an assistant director of the Massachusetts Department of Telecommunications and Energy, a Vice President of Reed Consulting Group, and, most recently, a Managing Director of Navigant Consulting, Inc. Ms. Quilici is a graduate of Purdue University and was awarded an M.B.A. from Northeastern University.

Ronald J. Amen, Vice President, provides financial, regulatory, strategic, operation and litigation support to his energy clients. Mr. Amen has over thirty-two years of combined experience in utility management and consulting in the areas of regulatory affairs, resource planning, organizational development, distribution operations and customer service, marketing and sales, and systems administration. He has particular expertise in the following areas: cost allocation and pricing issues; regulatory strategy; resource strategy, planning and financial analysis; and expert witness testimony. Prior to joining Concentric, Mr. Amen was a Director with Navigant Consulting, Inc. His prior utility experience includes Manager of Federal Regulatory Affairs at Puget Sound Energy, Inc., Director of Rates at Washington Natural Gas Company, Regional Director - Operations for Indiana Energy (now Vectren), and Data Processing Manager at Ohio Valley Gas Corporation. Mr. Amen is a graduate of the University of Nebraska. Mr. Amen is an Associate Member of the American Gas Association and a past member of the former Pacific Coast Gas Association and past Chairman – Rate Committee of the Indiana Gas Association.

Melissa F. Bartos, Assistant Vice President, is a financial and economic consultant with more than ten years of experience in the energy industry. She has conducted comprehensive demand forecast analyses including data collection and validation, model building using various statistical and econometric approaches, and developing presentations, reports and testimony to communicate results. Ms. Bartos has also designed, built, and enhanced numerous financial and statistical models to support clients in asset-based transactions, energy contract negotiations, reliability studies, asset and business valuations, rate and regulatory matters, cost-of-service analysis, and risk management. Her modeling experience includes building Monte-Carlo simulation models, designing an allocated cost-of-service model, statistical modeling using SPSS, and programming using Visual Basic for Applications (VBA). Ms. Bartos consulted with Reed Consulting Group and most recently served as Senior Consultant for Navigant Consulting, Inc. Ms. Bartos has an M.S. in Mathematics (Statistics) from the University of Massachusetts at Lowell, a B.A. from the College of the Holy Cross in Worcester, MA, and is a member of the American Statistical Association.

Caroline O'Neill, Project Manager, has more than ten years of analytical, management and policy experience in the energy industry. She has experience in corporate and asset-based transactions, litigation support, regulatory analysis, cost of service analysis, due diligence analyses, energy market assessment, business unit valuation, and business unit strategy. Ms. O'Neill had extensive involvement in divestiture and acquisition transactions for fossil, nuclear, hydro electric and renewable assets including offering memorandum development, marketing management, due diligence, work force matters and negotiations of purchase and sale agreements. Ms. O'Neill has performed a variety of economic analyses, extensive regulatory research, and has assisted in the preparation of regulatory testimony on the topics of Cost of Capital and Return on Equity. She has also assisted in the preparation of testimony in litigation and other non-regulatory legal proceedings. Ms. O'Neill has served as Senior Consultant for Navigant Consulting and is a graduate of LeMoyne College of Syracuse, NY and was awarded an M.L.S. from the University at Buffalo.

John Trogonoski, Project Manager, is a project manager with recognized expertise in rate of return, cost of equity, and capital structure issues for public utilities. He has over fifteen years of experience in financial analysis, business valuation, utility regulation, property taxation, and program administration. He has filed expert testimony on rate of return, revenue requirement, cost allocation, rate design, incentive regulation, and policy development. He has a Master's degree in Business Administration and an undergraduate degree in Marketing from the University of Colorado at Denver.

The staff cited for this assignment will be available to meet all deliverables proposed, according to the project schedule. Mr. Coyne, Mr. Simpson, Ms. Bartos, and Mr. Trogonoski will provide the majority of the work. Concentric will also draw upon the remainder of this team for their additional expertise, and its experienced regulatory research staff to complete this assignment.

IV. RELEVANT EXPERIENCE

Concentric understands that Enbridge requires an independent consultant to develop quantitative recommendations for the productivity (X-Factor) for EGD's next IR proposal. We also understand that the recommendations must be consistent with the regulatory trends across North America as well as with effective incentive mechanisms. Our research and perspectives on incentive regulation are very current, as we recently completed a similar study for a U.S. utility client, and recently completed a study of comparable scope for another client. The following are representative examples of Concentric's work in this area. Where key team members were involved in these projects and proposed for this assignment, they are noted in brackets.

Incentive Regulation

Xcel Energy – Concentric is assisting with the development and support of a multi-year rate ("MYR") plan for Xcel's Minnesota electric business. Concentric has prepared a presentation which depicts Xcel's proposed MYR for interveners and other market participants. Concentric has also worked with the Company to research other utility MYR plans as well as alternative rate plans throughout the US. [O'Neill, Amen]

Western Massachusetts Electric Company ("WMECO") – Concentric supported WMECO in its decoupling proposal for the Company's General Rate Case. Concentric's work included: (1) research on the financial implications of decoupling; (2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; (3) identification of rate adjustment mechanisms that would work together with the Company's proposed decoupling mechanism; and (4) preparing pre-filed testimony and testifying at hearings in support of the Company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism, which is based on Concentric statistical analyses, and a capital spending mechanism to recover the costs associated with capital plant investment that is targeted to improving service reliability. [Simpson, Bartos]

TXU Corp – Concentric conducted extensive research into various forms of performance based or alternative ratemaking, including price caps, revenue caps, earnings sharing mechanisms, various cost trackers, targeted incentives (e.g., service quality measures). Concentric prepared report which explained the purpose and functionality of the various measures. Concentric conducted a general nationwide survey of mechanisms that were in place at that time, summarizing and discussing such mechanisms in the report and then facilitated a multi-hour session with senior management to review report, educate the team regarding performance based rates ("PBR"), consider what form of PBR if any would be beneficial to TXU. The end result was the company decided not to pursue PBR at that time. [Quilici, Simpson]

Confidential Client – Concentric was retained by a confidential client to assess, on behalf of its senior executive team, the potential of various forms of alternative ratemaking, including performance based ratemaking. As part of this engagement, Concentric researched various alternative ratemaking mechanisms ("ARMs") and PBRs adopted or considered across the U.S., developed possible ARMs or PBRs which might be considered by the client and, using a financial model and other tools developed by Concentric, assessed how these approaches would impact the client's rates, financials and regulatory strategy under various scenarios (e.g., declining per customer usage, recovery of anomalous investments). As part of this assignment, Concentric prepared and facilitated a strategic planning session with the client's senior executive team. [Quilici, Trogonoski]

Arkansas Oklahoma Gas Corp – Concentric prepared and supported comments filed with the Arkansas Public Service Commission related to innovative approaches to rate base and rate of return regulation. Specifically, Concentric:

1. Held scoping meeting with AOG personnel
2. Conducted research regarding proposed and/or existing regulatory initiatives
3. Met with AOG personnel to establish direction of comments
4. Prepared written comments to Commission
5. Supported AOG's position(s) throughout docket

[Amen, Trogonoski]

CenterPoint Energy Resources Corp – Concentric provided expert testimony in connection with CenterPoint Energy's March 15, 2009 Performance Based Rate Change filing with the Oklahoma Corporation Commission. [Trogonoski]

Vermont Gas Systems Inc – Concentric prepared a presentation regarding decoupling for the Strategy Subcommittee of Vermont Gas Systems Board of Directors in February 2009. [Simpson, Bartos]

Xcel Energy – Concentric conducted comprehensive research on alternative ratemaking mechanisms used by electric utilities and developed a summary matrix describing mechanisms and their results. Concentric then worked with the client to facilitate their consideration of the appropriate ARM for them, providing regulatory support as necessary and appropriate. [Quilici, Simpson, Trogonoski]

Edison Electric Institute – Conducted a survey of incentive mechanisms for electric utilities. The research included various incentives such as earnings sharing, load factors, productivity and performance measures.

Vermont Department of Public Service and Vermont Gas Systems – Facilitated the development of an Alternative Regulation Plan with the Department of Public Service and Vermont Gas Systems providing research and advice leading to a rate proposal for the Vermont Public Service Board. Conducted several workshops including utility staff and regulatory agencies to develop solutions satisfying both public policy and utility objectives. Research provided included: incentive rate programs in use across U.S. jurisdictions, estimation of productivity factors, earnings sharing mechanisms and, purchased gas adjustment mechanisms (including incentivized programs). [Coyne]

New England Gas Company - Concentric assisted New England Gas in filing a rate increase case at the Massachusetts Department of Public Utilities, based on a Test Year of 12 months ending December 31, 2009. The scope of the cost study project consists of providing expert assistance to New England Gas in: Developing and supporting an allocated or accounting cost of service study ("ACOSS"); preparing an update to the MCS filed with the Company's 2008 rate case, D.P.U. 08-35; developing a revenue-decoupling mechanism; and related cost tracker mechanisms; developing proposed rate design including inverted rate structures; developing and support for all rate tariffs; and additional rate-related tasks including a throughput forecast, administrative fees and an Excel model to be used in the preparation of GAF filings. [Simpson, Bartos]

Multi-Jurisdictional Research Experience

Concentric's staff has also prepared numerous studies incorporating multi-jurisdictional reviews of a broad range of relevant topics. As shown below, a significant portion of our studies were prepared for submission before regulatory bodies, many of which are Canadian regulators. Specific examples of Concentric's experience in preparing multi-jurisdictional reviews include:

ATCO – Concentric is currently engaged by ATCO to provide a study on behalf of ATCO, AltaLink and Fortis Alberta pertaining to the comparability of Canadian and U.S. utilities for purposes of establishing the fair return on equity for Alberta's utilities. This research focuses on operational, financial and regulatory risk, with detailed analysis of rate and regulatory policies in use in both the U.S. and Canada. [Coyne, Trogonoski]

New Brunswick Power – Concentric has recently completed a study for NB Power with a multi-jurisdictional review of economic development and retention incentives for industrial customers in the U.S. and Canada. This research identified specific program features and rate incentives targeted to retain or expand industrial load, and was designed to facilitate discussions with stakeholders on alternative program elements. [Coyne]

Ontario Energy Board – Concentric was retained by the Ontario Energy Board in November, 2009 to critically review, compare, and assess the Ontario DSM framework for natural gas distributors with respect to best practices in selected North American and other jurisdictions and to make recommendations on what changes, if any, should be made to the DSM framework for 2011 and beyond. Concentric drafted a report which made many specific recommendations for changes to the DSM framework in Ontario, including adopting a different cost effectiveness test, considering different methods for measuring program success, adopting a different approach to recovering lost revenues, revising the incentive structure for achieving program targets, and increasing the budget for DSM programs as a percentage of distribution revenues. This report was presented during a stakeholder meeting in Toronto in April 2010. [Coyne, Trogonoski]

Terasen Gas – Pursuant to the British Columbia Utilities Commission's Return on Equity and Capital Structure Decision dated December 16, 2009, Terasen engaged Concentric to assist with the completion of a study of alterative formulae for determining the cost of capital. Concentric compiled research on all U.S. and Canadian jurisdictions where automatic adjustment mechanisms are in effect, analyzed the performance of these mechanisms over time, and evaluated their attributes and input parameters. This research was summarized in a detailed report that will be filed with the BCUC this fall. [Coyne, Trogonoski]

Ontario Energy Board – Concentric prepared a report, titled "A Review of Low Income Energy Assistance Measures Adopted in Other Jurisdictions" for the Board that summarized the policies, programs, and measures that have been implemented by regulators in other jurisdictions to assist low-income energy consumers. Concentric's research indicated that low-income energy assistance programs have been established and implemented in many different jurisdictions. This report examines programs that have been adopted in Canada, the United States, the United Kingdom, Australia, New Zealand, France, Spain, and Finland. [Coyne, Trogonoski]

Ontario Energy Board – Concentric was engaged by the OEB to conduct a detailed analysis of differences between ROEs for Ontario's gas utilities and those elsewhere in Canada, the U.S. and select foreign countries. The report examined methods of determining ROEs, relating the differences in ROE awards, the competition for capital between Canada and the U.S. utilities, and the treatment of affiliates from an ROE perspective. [Coyne]

Enbridge, Hydro One and the Coalition of Large Distributors – Concentric provided written comments to the Ontario Energy Board ("OEB") in response to the Board's invitation to interested stakeholders to provide comments to help the Board better understand whether current economic and financial market conditions have an impact on the reasonableness of the Cost of Capital parameter values calculated in accordance with the Board's established Cost of Capital methodology; and to help the Board determine if, when, and how to make any appropriate adjustments to those parameter values. Concentric also represented the Company, the Coalition of Large Distributors and Enbridge in the provision of oral evidence at the stakeholder conference, and the submission of a detailed written response and recommendations to the Board prior to its decision in EB-2009-0084 on the Cost of Capital for Ontario's Regulated Utilities (December 11, 2009). [Coyne]

Hydro One and the Coalition of Large Distributors – Concentric undertook a review of the Return on Equity ("ROE") of electricity utilities in Ontario in comparison to awarded returns of electric utilities in other jurisdictions, and prepared a report titled "A Comparative Analysis of Return on Equity For Electric Utilities", prepared for The Coalition of Large Distributors and Hydro One Networks in June 2008. [Coyne]

Southern Connecticut Gas Company – Concentric prepared a study regarding the cost effectiveness of energy efficiency, conservation and demand side management measures to produce a substantial reduction in peak day natural gas demand by 2021. As part of this study Concentric reviewed (1) natural gas energy efficiency activities of various Canadian and U.S. LDCs; (2) potential achievable peak day natural gas demand reductions and costs through expansion of energy efficiency programs, conversions to renewable energy sources, and dynamic pricing; and (3) possible barriers to achieving natural gas demand reductions. [Bartos, Simpson]

ATCO Utilities Group – Concentric was engaged by ATCO to recommend a generic ROE and capital structure for each of the four utility sectors operating in Alberta: gas transmission, gas distribution, electric transmission, and electric distribution. ROE estimates were developed using DCF, CAPM, risk premium and comparable earnings methodologies; including comparisons with recently allowed ROEs from other jurisdictions and pipeline settlements in Canada. Concentric's recommendations were supported by detailed financial, operating, and regulatory risk comparisons between U.S., Canadian, and Alberta utilities. Concentric reviewed relative economic conditions, regulatory processes, rate structures, financial and operating metrics, credit rating practices, and the competitive environment, for each sector, to draw conclusions on the riskiness of Alberta utilities relative to other Canadian and U.S. counterparts. [Coyne, Trogonoski]

Climate Change Central of Alberta – Concentric was retained to assist Climate Change Central of Alberta (a grant-funded not-for-profit, aligned with the Alberta Office of Energy Efficiency) with its effort to identify a regulatory path to sustainable funding for third party administered DSM and energy efficiency programs. Concentric reviewed pertinent Alberta Legislation and DSM funding mechanisms in place in other jurisdictions that could impact rate base funding for DSM and renewable energy programs in the Province. [Coyne]

Related Experience Before Provincial and State Regulatory Bodies

Below are highlights of our additional related experience before provincial and state regulatory commissions. In addition to the engagements shown below, a testimony listing for our firm is provided as Attachment D.

New Brunswick Power – Concentric performed nine rate related studies ordered by the Board of Commissioners of Public Utilities of New Brunswick in its December 2005 Cost Allocation and Rate Design Ruling, and as reconfirmed in the Board's Decision of May 31, 2007. [Simpson]

Nova Scotia Power – Concentric provided Nova Scotia Power ("NSPI") with the following consulting services pertaining to the Board's hearing into the proper method of calculating NSPI's return on equity: Review and comment on the positions and evidence drafted by the Company and its expert witness on capital structure; Review and comment on positions taken by intervenors, and draft rebuttal evidence as requested; Support to the Company during the Oral Hearing in Halifax, Nova Scotia. [Coyne]

Ontario Power Generation – Concentric provided a report that established a range of cost of capital estimates, including the respective costs of equity and debt and the associated capital structure, relating to investments in new nuclear generation by Ontario Power Generation with a particular emphasis focus on the cost of equity. [Trogonoski]

Repsol Energy Canada, Ltd – Concentric assisted Repsol with its preparation of an import/export license application before the National Energy Board for the Canaport LNG project. As part of the application, Repsol required an update to the market demand analysis that Concentric previously prepared and submitted in May 2006 before the NEB in the Brunswick Pipeline certificate proceeding. Specifically, Concentric presented Repsol with a brief report presenting its findings in a determination regarding whether the natural gas demand Concentric projected in the 2006 Brunswick Report had materially changed since that report was submitted. Concentric focused on updating three key demand drivers - KeySpan demand; ISO New England demand; and NYISO demand.

Central Vermont Public Service – Concentric provided rate of return testimony on behalf of Central Vermont Public Service in their 2010 Alternative Regulation proceeding.

Confidential Client – Concentric supported the client in evaluating various applications filed with the AEUB to transfer retail gas sales service from ATCO Gas to Direct Energy. The client retained Concentric to provide testimony in opposition to a proposal to allow the local gas utility to contract with a corporate affiliate to provide gas sales service. In developing testimony, Concentric researched similar arrangements including regulatory prohibitions/restrictions in other jurisdictions.

Xcel Energy – Concentric supported all aspects of Northern States Power- Minnesota's cost of capital testimony before the Minnesota Public Utilities Commission including pre-filed direct testimony, preparing written responses to information requests, providing rebuttal testimony, assisting in the preparation of cross-examination of opposing witnesses, and the preparation for and appearance to testify before the Commission, as necessary.

Ameren – Concentric prepared rate of return and capital structure testimony for the gas rate case filed in Missouri on behalf of AmerenUE in April, 2010. [Trogonoski]

Maritimes & Northeast Pipeline – Concentric provided a market assessment of Atlantic Canada and New England for M&NP's Phase IV expansion project, including the evaluation of electric and natural gas supply issues, development of projected electric and natural gas demand in the market, and the viability/feasibility of infrastructure projects.

Maritimes & Northeast Pipeline – On behalf of Maritimes and Northeast Pipeline, Concentric prepared and submitted testimony to the NEB, assisted with the preparation of pleadings, data requests and responses to data requests, and appeared at the Escrow Application hearing as an expert witness with respect to appropriate regulatory treatment of escrow balances for ratemaking purposes. [Quilici]

Maritimes & Northeast Pipeline – Concentric prepared a study to assess the market demand for gas to be transported on the Brunswick Pipeline. Specifically, Concentric assessed the adequacy of the Canadian and U.S. gas markets for the incremental volumes available to the marketplace as a result of the applied for facilities, including an assessment of the physical capability of the upstream and downstream facilities to accept those incremental volumes. Concentric concluded that there would be sufficient market demand for natural gas such that the Brunswick Pipeline would be used at reasonable load factors over its economic life.

PNM Resources – Concentric provided cost of equity analysis and testimony filed on June 1, 2010 with the New Mexico Public Regulation Commission.

NSTAR – In 2010, Concentric provided expert testimony on the subject of incremental costs, how they are defined, and how they might be measured. [Quilici]

Canadian Energy Pipeline Association – Concentric prepared pipeline-specific indices of rate of return and demonstrated a significant increase in risk premia between mid-1990's and 2006.

Northern Indiana Public Service Company – Concentric provided expert testimony as to the fair value of NIPSCO's generation segment (using the DCF approach) for purposes of NIPSCO's 2010 electric rate case. The Project approach included data collection and review of inputs and assumptions; construction of a DCF model; expert testimony and regulatory support.

Bennett Jones LLP (on behalf of Market Hub Partners) – Concentric provided a market power assessment of client's proposed storage facility in Ontario. The market power review was filed with the Ontario Energy Board, and the client ultimately received market-based rate authority. Concentric also assisted the client through the OEB's regulatory policy proceeding, filing both direct and rebuttal testimony, as well as testifying at hearing, that storage rates in Ontario should be established as market-based, as there did not exist market power for storage. The OEB ultimately ruled that storage for most customers should be based on market-based rates.

TransCanada – Concentric provided advice on Pipeline Cost Allocation and Rate Design for Nova Gas Transmission Ltd. (NGTL) Rate Proceeding.

TransCanada – Concentric supported TransCanada's consideration and development of securitization proposals.

Unocal Canada LTD – Concentric provided a market power study to Unocal, a division of Chevron, regarding the ability of Aitken Creek storage to exercise market power in the relevant market. Markets analyzed included British Columbia, Alberta, Pacific Northwest, and California. The study was submitted to the BCUC in support of an exemption from rate regulation. [Bartos]

TransCanada – Concentric provided rebuttal testimony on behalf of Ventures Pipeline, an unregulated pipeline of TransCanada Pipelines located in Alberta, regarding the request by a customer for the Alberta Utilities Commission to regulate the pipeline as a cost-based pipeline. Currently, Ventures Pipeline has negotiated long-term contracts with its customers.

Baltimore Gas & Electric – Concentric provided expert testimony for Baltimore Gas & Electric pertaining to the allocation of costs associated with shared services provided by the parent company to the regulated utility. The testimony was filed in the Company's rate case.

V. References

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VI. BUDGET AND TERMS

Budget

Concentric proposes to perform this work according to an estimated budget for professional fees. For the first 10 tasks including filing of draft evidence we estimate the following budget based on our experience in similar engagements, the specified scope of work and estimated hours for each member of the consulting team. It is more difficult to estimate with accuracy the cost of the actual hearings process, as it is dependent on the degree on intervention, number and extent of interrogatories, days of hearings, etc. We therefore incorporate these services into the proposal on a time and materials basis. We estimate the professional fees for this work through completion of the filing of evidence (Tasks 1-10) to be $395,186 CDN.

Project Budget by Task
(Canadian dollars)

	Task/Deliverable	Budget
1	Preparation & Kick-off	
2	Complete Study Outline	
3	Research & Draft Report	
4	Strategy Session	
5	1st Draft Study	
6	Incorporate Feedback	
7	Final Draft	
8	Meet with Stakeholders	
9	Incorporate Feedback	
10	Draft Evidence	
11	Case Support	T&M
	Total Professional Fees (USD)	
	Total Professional Fees (CAD)	

Key assumptions underlying this estimate include:

- A 10 month project schedule, culminating with completion of Draft Final Evidence in October 2011
- Monthly in-person meetings with Enbridge, including the project kick-off, presentation of results and draft evidence review, and the strategy session
- Stakeholder meetings lasting 2-3 days, with advance preparation
- Total consulting time of 1,106 hours, from a combination of senior experts, a project manager, with supporting researchers & analysts.

We would be pleased to refine our estimate with the benefit of any additional input from the Enbridge team. In fairness, we believe it is likely that the process will have some uncertainty and require responsiveness to Enbridge feedback, the regulatory and stakeholder process. We would therefore commit to monthly updates on budget status over the course of the engagement to both prevent any surprises and work together to effectively allocate resources. Our Standard Hourly Rates incorporated into the estimate and Standard Terms and Conditions are provided as Attachments B and C, respectively.

Travel time is generally not billed to clients unless that time is spent productively working on the engagement (e.g., document review, meeting preparations, etc.). That time is included in the above budget. Travel and related out-of-pocket expenses if necessary, are billed at cost, and are in addition to the above budget for professional fees. Based on the project schedule and anticipated travel, we estimate the following travel and expense budget:

Estimated Travel Costs

(Canadian dollars)

Month	Travel Days	# Consultants	Avg Trip Cost	Total Cost
Jan	1	2	810	1,620
Feb	1	2	810	1,620
Mar	1	2	810	1,620
Apr	3	2	1,010	2,020
May	3	2	1,010	2,020
Jun	3	2	1,010	2,020
Jul	1	2	810	1,620
Aug	1	2	810	1,620
Sep	3	2	1,010	2,020
Oct	3	2	1,010	2,020
Misc. printing, phone, postage				1,000
Total (USD)				$ 19,200
Total (CAD)				$ 19,335

Assumptions underlying this estimate include:

- Per guidance from the Company, a meeting day once a month in the earlier months, increased to 2-3 days per month in April - June for the remainder of the project through filing evidence
- Two of the Concentric senior team traveling
- Current airfare booked one week out for Boston-Toronto is $940, two weeks out is $580, three weeks out is $380 (all nonstop, American Airlines)
- Advanced planning so trips are booked two weeks out
- The nearest hotels are the Radisson Hotel Toronto East at 55 Hallcrown Place, Toronto ($140 plus tax) and the Yorkland Hotel at 185 Yorkland Blvd., Toronto ($110 plus tax).
- Meals at $60/day ($10 breakfast, $15 lunch, $25 dinner, $10 coffee, snacks)
- Factors affecting this budget would be the actual number of travel days, the ability to book lower-cost fares in advance, and duration of stays.

Concentric would work with Enbridge to ensure a cost-effective utilization of travel time while meeting the needs of project deliverables and good communications.

As in prior engagements for Enbridge, Concentric is willing to provide proof of commercial and professional liability insurance and WSIB standing prior to contract execution.

Conflict with Prior Positions

Concentric does not believe that this project would present any conflict with positions taken in prior cases, nor would we be limited in our ability to provide the requested research and analysis.

Requirements of Enbridge Resources

We would anticipate a cooperative team effort with the Enbridge regulatory team. Concentric only requires access to the Enbridge regulatory team for the kickoff call, interim reporting and feedback on research and preliminary results, and review of the draft study and final reports and evidence.

SCHEDULE A

Scope of Work

This Schedule is made under the above referenced consulting agreement (the "**Agreement**") between ENBRIDGE GAS DISTRIBUTION INC. ("**Enbridge**") and LONDON ECONOMICS INTERNATIONAL LLC (the "**Consultant**").

All terms not defined herein take the meaning ascribed to them in the Agreement.

1. SCOPE OF SERVICES AND DELIVERABLE

The Consultant will provide Enbridge with an independent written evaluation (the "**Independent Evaluation**") of the impact of rate making mechanisms on Enbridge's business. In particular, the Consultant will undertake the following:

- Identify conceptually why a revenue cap per customer (rather than price cap model) would be a reasonable regulatory model and possibly the preferred methodology given Enbridge's circumstances, including its customer mix and consumption trends, as well as capital expenditure and depreciation profiles. This would involve:
    - setting out the theory behind revenue and price cap regulation and the strengths/weaknesses of each approach in the context of a high growth business, with growing capital needs relative to historical, cost accounting based depreciation profiles;
    - identifying the theory behind the design of different revenue cap methodologies, for example revenue per customer;
    - case study analysis of approaches used in North America for regulation of gas distribution utilities;
    - assuming various customer growth scenarios, quantify the revenue and implied customer growth capital that the revenue cap per customer method produces and supports; and
    - summarizing the findings.
- Discuss impacts of applying incentive (I-X) revenue cap regulation on Enbridge's opportunity to earn a reasonable commercial ROE and fund needed capital investment particularly in the context of the fair return standard. This would involve:
    - setting out the basic theory behind incentive (I-X) regulation, notably the efficiency of I-X theory assumes a steady state environment;
    - explaining the practical implications (and limitations) of I-X regime for: different utility business environments (e.g. high growth versus low growth); high operating efficiency versus low operating efficiency levels; and high investment versus low investment (as measured by the asset base, inclusive of capital expenditure and depreciation profiles);
    - case study analysis of approaches used in North America for regulation of gas distribution utilities, specifically with heavy capital expenditure needs;
    - case study analysis of Ontario and other Canadian regulators approach to applying the fair return standard, particularly in the context of (I-X) regulation;
    - illustrative quantitative analysis demonstrating practical shortcomings of the I-X regime and revenue sufficiency problem against various trends in capital investment, using reasonable projections supplied by Enbridge including;
    - analysis of Basic 'I-X' revenue growth versus expected growth in depreciation, discussing:
        - Why does depreciation growth outpace I-X revenue growth?
        - For utilities that continue with base level capital, challenge caused by incremental depreciation
        - Historical and NA precedents to deal with the issue of depreciation expense growth outpacing I-X

  - Discuss and analyze rate base impacts due to depreciation (existing and incremental rate base additions), retirements and capital additions; and

- o summarizing the findings in the context of the application of the Fair Return Standard in Ontario.

The Consultant aims to complete a draft of the Independent Evaluation within four weeks of the start of the Term.

2. INSTRUCTIONS

The Consultant acknowledges and agrees that the Rule 13A.03(c) of the Ontario Energy Board (the "**Board**") Rules of Practice and Procedure (last revision, January 17, 2013) (the "**Board Rules**") requires Enbridge to disclose the instructions (the "**Expert Instructions**") it has provided to the Consultant, for the purpose of Enbridge submitting the Independent Evaluation to the Board as a form of expert evidence to support an application before the Board.

The Expert Instructions are included at Attachment 1 to this Schedule A.

3. TERM AND COMMENCEMENT AND COMPLETION DATES

Notwithstanding the date of execution, this Schedule shall be effective as of the execution date of the Agreement, and shall expire on December 31, 2013, or such other date as the parties may mutually agree in writing.

4. STATUTORY DECLARATION

The Consultant acknowledges and agrees that the Independent Evaluation will be prepared for the purpose of providing expert evidence before the Board, and further acknowledges and agrees that the Independent Evaluation, and any other oral or written testimony it may provide in relation to same, shall be prepared impartially, be fair and be objective, as required by the Board Rules. Owing to the importance this requirement to Enbridge, the Consultant will execute a statutory declaration attached to the Schedule at Attachment 2, in order to solemnly affirm the foregoing. An executive or senior manager of the Consultant shall swear the statutory declaration on behalf of the Consultant.

5. FEES AND PAYMENT TERMS

The Consultant shall prepare the Independent Evaluation in accordance with the discounted hourly fee rates as set out in the table below:

Staff	Standard Hourly Fee Rate (US$)	Discounted Hourly Fee Rate (US$)
Principal/Managing Director		
Managing Consultant		
Senior Consultant		
Consultant		
Research Associate		
Admin		

CCC INTERROGATORY #2

INTERROGATORY

Issue A1 – Is Enbridge's proposal for a Customized IR plan for a 5-year term covering its 2014 through 2018 fiscal years appropriate?

Please provide copies of all correspondence including presentations, reports etc. presented to EGD's Board of Directors and senior management throughout the process whereby approval for the 5-year plan was being sought and obtained.

RESPONSE

Attached are copies of the memoranda provided to EGD's Board of Directors in connection with the approval of the Customized IR plan.

Witnesses: K. Culbert
R. Fischer
A. Kacicnik
M. Lister

ENBRIDGE

April 30, 2013

CONFIDENTIAL

ENBRIDGE GAS DISTRIBUTION INC.
AUDIT, FINANCE & RISK COMMITTEE
BOARD OF DIRECTORS

Re: Enbridge Gas Distribution (EGD or the Company) 2nd Generation Incentive Regulation (IR) Plan

Management is seeking approval to file a 2nd Generation IR Plan with the Ontario Energy Board (OEB) before the end of Q2 2013. The OEB has the authority to use any method or technique they consider appropriate to set "just and reasonable" rates, and has made it clear that it expects all utilities, both natural gas and electric in Ontario, to submit rate applications that are designed using IR principles. Recently the OEB established a formal framework for electric utilities that established three alternative IR models that can be used: i) Base year plus 4 Year Price Cap; ii) Annual Index applied to existing rates and no set term, and iii) 5 Year Custom IR determined in a multi-year application review. As a gas utility EGD is not required to abide by the specific IR framework the OEB established for electric utilities. However, this framework represents the most current thinking of the OEB and the Company's IR design has been guided by this framework.

The OEB's application Hearing process includes an Alternative Dispute Resolution process involving registered Intervenors, where some or all of the elements of the application can be negotiated and settled. While the Company will attempt to settle as much of this application as possible, there is no assurance that it will be successful in doing so. Once the settlement process is concluded, the process then continues by way of formal oral Hearing before an OEB panel of Board members which adjudicates and issues a formal Board Decision on all matters. The OEB final Decision on the application is expected by the end of Q1 2014.

1st Generation IR Plan

The 1st Generation IR Plan, which was in effect from 2008 to 2012, was structured as a "Revenue Cap per Customer" model. This model inflated the Company's annual revenues at an agreed-to inflation index less a productivity factor. These revenues were then adjusted annually to take into account actual "customer growth" and forecast volume throughput. This annual adjustment mechanism combined with an average use true up account (which is also being proposed in the 2nd generation plan) provided a level of throughput protection. The model incented the Company by allowing the shareholder to keep a portion of annual earnings in excess of the OEB allowed Return on Equity ("ROE"). Specifically, the shareholder was allowed to retain 100% of annual over-earnings for the first 100 basis points above the allowed ROE and 50% of over-earnings after that.

It is widely viewed that customers and the shareholder both benefited from this plan. In each year of this plan, weather normalized earnings after “earnings sharing” exceeded the allowed ROE by an average of 131 basis points ($18.3 M), while the average annual customer rate after “earnings sharing” decreased by 0.77%. Although cost efficiency was an element in producing those favourable results, most of the excess earnings were derived from reductions in debt interest rates and tax rates, neither of which is expected to be repeated in the near future.

Proposed 2nd Generation IR Plan

EGD has designed its 2nd Generation IR Plan using a “custom model” approach which will cover the period from 2014 to 2016. The “custom model” by its nature has been established for utilities that are facing significantly large multi-year variable investment commitments that exceed historical levels. EGD’s 2nd Generation IR Plan is structured to respond to the forecast business needs which includes significant increased capital investments for safety, system integrity and reliability initiatives.

Most notable of these is the fact that EGD is planning to increase its capital investment program over the next 3 years as result of numerous Operational Risk Management initiatives, the GTA and Ottawa Reinforcement projects and the need for a renewed Work and Asset Management System. In fact, EGD’s total capital expenditures over the IR term are forecast to be $2.1 billion which represents a 60% increase over the total capital spent during the previous 3 years.

This significant increase in capital spending, translates directly into a higher rate base and annual depreciation expense, which in turn results in an annual revenue requirement that is much higher than what a traditional “inflation less productivity” inflator methodology would provide.

In addition, given that there is uncertainty around the outcome of a number of important integrity studies currently underway and their impact on capital spending requirements beyond 2016, Management concluded that it is appropriate to pursue a 3 year term versus the 5 year term of the 1st Generation IR Plan. The new Plan will also include the tracking of productivity initiatives and operational performance, which is now a mandatory requirement for all electric utilities in Ontario.

Other major elements of the Plan are described below:

1. The 2nd Generation IR Plan establishes the annual revenue requirement for each year of the term based on a “bottom up” forecast of O&M and capital costs, depreciation, debt interest rates, tax rates and ROE. Therefore, aside from the GTA Reinforcement Project where a true-up mechanism is being proposed, the Company will be at risk for any overspending in these areas during the term.

2. An equity to debt ratio of 36/64 will be locked-in for the term, as would the forecast return on equity based on the OEB’s existing ROE methodology.

3. Over the course of many years EGD has been setting aside as a future liability or "reserve" on its Balance Sheet, a depreciation expense to cover the cost of "site restoration of retired gas distribution assets". Currently, EGD collects approximately $56 million annually from its customers to fund this reserve which in total now stands at approximately $894 million. History has shown that the actual annual costs incurred and charged against this reserve are significantly less than the rate at which this reserve is growing.

   Management has reviewed this situation with its depreciation consultant and determined that the reserve balance and the annual contribution to this reserve are not required, at the same level, for the future needs of the business. As a result, Management will be proposing that the annual collection of approximately $56 million be reduced to approximately $30 million, and in addition, the accumulated reserve account be drawn down by $294 million to $600 million over a period of 5 years.

   These reductions will buffer the customer rate increases that would otherwise have occurred, beginning in 2014.

4. The Plan will include a proposed mechanism for earnings sharing that is identical to the sharing mechanism adopted in the 1st Generation IR along with an "off-ramp" having a symmetrical 300 basis point collar around the annual allowed ROE.

Risks and Mitigants

Given the significance of this application and EGD's historical overearning on its allowed ROE, it is expected that the Company's forecasts and position on issues will be carefully scrutinized and challenged by Intervenors and Board Staff. The primary defense the Company has in this regard is putting together strong evidence and an experienced witness team to support the Company's application. With that being said, Management's assessment is that some elements of the 2nd Generation IR Plan are subject to a greater risk of acceptance by Intervenors or approval by the OEB, than others. Elements of the Plan that are at an elevated regulatory risk of modification or OEB approval are identified below:

Cost Disallowances: The Company's forecast of capital costs and O&M expense will be carefully scrutinized and some portion of these may be disallowed for revenue recovery purposes. The forecast for ROE and debt rates will also likely be challenged. The Company intends to minimize disallowances by ensuring that compelling evidence is provided in the application supporting these expenditures, including full explanations of how prioritization and risk tolerance assessments were applied, supported by benchmarking against peer group utilities and independent econometric evidence. The evidence will also demonstrate that productivity is embedded in the Company's forecast of O&M and capital costs.

Process and Model Construct: Aside from the specific costs, there are procedural and certain design elements of the IR model construct being proposed that may be subject to rejection or adjustment by the OEB. There are four procedural or design element issues in particular that are expected to be contentious during the Hearing: the 3 year term, rate retroactivity from the time of the OEB Decision back to January 1, 2014; the earnings sharing mechanism; and the risk of incremental productivity being imposed on the annual Allowed Revenue amounts.

With respect to the term, there is some risk that the OEB may reject the 3 year term since 5 years is now the standard for electric utilities in the province. Having said that, Management believes it has a strong argument to support a 3 year term since expanding the term further would require the Company to present cost forecasts with tolerances of uncertainty that would be unacceptable to our customers.

The potential for disallowance of rate retroactivity is deemed to be low if the application is accepted as filed, as the OEB has ruled favourably in similar situations in the past.

Changes to the proposed earnings sharing mechanism are possible but are expected to be modest if they do occur since the OEB is committed to incentive mechanisms for all of the utilities which it regulates.

Finally, there is some risk that the OEB may impose incremental productivity. Management believes it will be able to clearly demonstrate that productivity is already addressed through the process used to develop its cost forecasts. This will also be supported by the Company's 3rd party expert evidence that demonstrates that the appropriate productivity factor, based on a peer group of North American utilities, should be zero.

Financial Summary

The proposed IR model sets out the forecast cost of service inclusive of productivity and efficiency. In addition, Management plans to make every effort to find further efficiency opportunities and by taking this into account has set a "stretch" objective of achieving earnings modestly above the allowed ROE on average of 60 bps per year.

Over the next IR term customer rate increases will be offset by customers experiencing a decrease in gas commodity costs as a result of the GTA Reinforcement and an annual adjustment from the drawdown of the accumulated depreciation liability which will further reduce customer bills and overall result in an average annual customer bill decrease of approximately 1%.

Financial Summary

$ Millions	2013F	2014	2015	2016	2014-2016
Capital Expenditure	470	716	887	473	2,076
Rate Base	4,162	4,467	4,907	5,695	5,023
Utility Earnings	155	159	184	220	563
Return on Deemed Equity - Utility	10.3%	9.9%	10.4%	10.7%	10.3%
Allowed ROE	8.9%	9.3%	9.7%	10.1%	9.7%
Bill Impact		-4.2%	1.4%	-0.2%	-1.0%

From a sensitivity analysis perspective and assuming Management is unable to mitigate, the impact of higher than forecast spending or regulatory disallowances in capital, O&M and ROE are illustrated below:

Sensitivity Analysis

$ Millions	2014	2015	2016	2014-2016
1 Capex variance $10 M/year				
Earnings impact	$ (0.3)	$ (0.7)	$ (1.0)	$ (2.0)
Resulting ROE	9.87%	10.37%	10.67%	10.30%
2 O&M variance of $5 M/year				
Earnings impact	$ (3.7)	$ (3.7)	$ (3.7)	$ (11.0)
Resulting ROE	9.7%	10.2%	10.5%	10.1%
3 ROE (-50 bps)				
Earnings impact	(8.0)	(9.0)	(10.0)	$ (27.0)
Resulting ROE	9.4%	9.9%	10.2%	9.8%

Recommendation

Management recommends that the Board of Directors (i) approve the filing of EGD's 2nd Generation IR Plan with the Ontario Energy Board as outlined above and (ii) authorize the Chair of the Board of Directors of Enbridge Gas Distribution Inc., upon the recommendation of the President of the Company, to approve any related settlement with Interveners that may be negotiated by the Company.

ENBRIDGE

July 2, 2013

CONFIDENTIAL

ENBRIDGE GAS DISTRIBUTION INC.
AUDIT, FINANCE & RISK COMMITTEE
BOARD OF DIRECTORS

Re: Enbridge Gas Distribution (EGD or the Company) 2nd Generation Incentive Regulation(IR) Plan Update

Based on continuing stakeholder consultation, Management has amended the 2nd Generation IR Plan to be filed with the Ontario Energy Board (OEB) from that outlined in the memo dated April 30, 2013. The amendment is to extend the term of the IR from 3 years to 5 years, for the period 2014 to 2018.

EGD had previously identified the risk that the OEB may reject the 3 year term since 5 years is now the standard for electric utilities in the province. Though EGD, as a gas utility, is not required to adhere to those specific requirements, this more recently established requirement for electric utilities signals a clear preference by the OEB for IR terms greater than the 3 years originally contemplated. This preference was reinforced duringindividual and group stakeholder consultations that occurred after the EGD AF&RC meeting in May, which included OEB staff. As a result, Management's assessment is that the risk of rejection by the OEB has increased since the Plan was finalized and presented for Board approval.

Given that there is uncertainty around the outcome of a number of important integrity studies currently underway and their impact on capital spending requirements beyond 2016, Management had concluded that it was appropriate to pursue a 3-year term versus the 5-year term. Moving to a 5-year term to reduce the risk of rejection by the OEB introduces a need to address the uncertainty associated with the final two years of the 5-year term. As a result, EGD's 2nd Generation IR Plan now incorporates a mechanism that would allow for a complete reforecasting of capital for 2017 and 2018 in 2016.This mechanism substantially addresses Management's concern around capital forecast risk in the latter years of a 5 year IR plan and reduces the risk of rejection by the OEB. The remaining cost elements, mainly operating and maintenance expense, would be inflated in 2017 and 2018 at the same rate as forecast for 2014 to 2016.

Recommendation

Management recommends that the Board of Directors approve the filing of the revised and updated 2nd Generation IR Plan, as described above.

CCC INTERROGATORY #3

INTERROGATORY

Issue A1 – Is Enbridge's proposal for a Customized IR plan for a 5-year term covering its 2014 through 2018 fiscal years appropriate?

Did EGD seriously consider other rate-making models for the years 2014-2018? If so, please explain what models were considered and why those models were rejected.

RESPONSE

Yes. Enbridge did consider an Incentive Regulation Model ("IRM") similar to that which existed for the 1st Generation IR. Specifically, EGD considered a plan including elements such as a 5 year term, a revenue cap per customer model, Composite I-Factor, X-Factor, Y-Factors, Z-Factor, ESM and Off-ramps. New plan elements that were considered included Capital Trackers, an ROE Factor and Performance Measurement reporting.

The Company presented a variety of analyses explaining the Company's decision to reject these 'I-X' formulations at Exhibit A2, Tab 1, Schedule 3. Specifically, at page 18, paragraph 37 the Company states:

> The analyses also show that, the escalation factor that is required to allow for capital recovery and the opportunity to earn a Fair Return is well in excess of traditional values for I and X. This condition has arisen as a result of significantly higher reinforcement requirements, and safety, integrity, and reliability drivers. EGD does not believe that the introduction of additional adders to the formula could accommodate the total required increase in capital spending, as the inevitable result would include many more Y factors and capital trackers, adding further complexity to the IR model framework. This would cause the IR framework to become too unwieldy and invite criticism of a model that includes too much patchwork and complexity.

Witnesses: R. Fischer
M. Lister

CCC INTERROGATORY #4

INTERROGATORY

Issue A1 – Is Enbridge's proposal for a Customized IR plan for a 5-year term covering its 2014 through 2018 fiscal years appropriate?

Please comment on the applicability of the Union Gas Limited, Board-approved IRM model to EGD (EB-2013-0202). If not applicable, please explain, in detail, why that model could not be applied to EGD.

RESPONSE

Union's Board-approved IRM model can be described as an I-X framework with provision for Y-factors, including new Y-factors for major capital projects that meet certain criteria. The IRM model includes other parameters such as a Z-factor, 5-year term and earnings sharing mechanism, similar to that proposed by Enbridge in its Customized IR plan.

Union's IRM model would not accommodate Enbridge's operating requirements over the 2014 to 2018 period. Enbridge demonstrated in its evidence (Exhibit A2, Tab 1, Schedule 3) that an I-X IR framework, even assuming new Y-factors for the GTA and Ottawa major reinforcement projects, and a revenue cap per customer model, would require an I-X escalator in excess of the 2.5% estimated by Concentric Energy Advisors, Inc., and clearly well in excess of the approximate 0.7% approved for Union. Scenario 3, which determines the breakeven I-X escalation factor assuming new Y-factors for the GTA and Ottawa major reinforcement projects, described in Exhibit A2, Tab1, Schedule 3, page 11, Paragraph 25, calculated a required 3-year I-X escalation factor of 3.4%. Therefore, applying Union's IRM model to Enbridge's circumstances would not allow Enbridge a reasonable opportunity to finance its much need capital program and fund its O&M and still earn a fair return.

Witness: R. Fischer

CCC INTERROGATORY #5

INTERROGATORY

Issue A1 – Is Enbridge's proposal for a Customized IR plan for a 5-year term covering its 2014 through 2018 fiscal years appropriate?

Assuming EGD's plan is approved by the Board, please estimate the total dollar amount EGD is requesting to recover from customers over and above the 2013 revenue requirement, over the five-year period. In providing this amount please include all assumptions.

RESPONSE

Please see the response to Board Staff Interrogatory #68 found at Exhibit I.C29.EGDI.STAFF.68.

Witness: K. Culbert

CME INTERROGATORY #2

INTERROGATORY

Issue: A1

Reference: Exhibit Al, Tab 2, Schedule 1
Exhibit A2, Tab 1, Schedule 1, page 40, para.12

CME is interested in determining the proportion of the revenue requirement in each of the years 2014 to 2018 inclusive which will not be subject to adjustment in future years. The evidence indicates that revenue requirements in 2015, 2016, and 2018 will be adjusted for updated volumes and gas costs, and amounts related to pension, DSM and customer care costs. The same items will be the subject matter of adjustments in 2017 and in addition, the revenue requirements for 2017 and 2018 will be adjusted for updated forecasts of capital spending, cost of capital, taxes and depreciation. For example, the evidence at Exhibit Al, Tab 2, Schedule 1, page 22 in paragraph 63 indicates that the categories of OM&A expenses that will be subject to adjustment in future years ranges between 45% to 48% of total OM&A expenses in the years 2014 to 2016 inclusive. In addition to all of these adjustments, the company will benefit from the protection provided by the 24 deferral accounts listed in Exhibit D1, Tab 8. In connection with this information, please provide the following:

(a) List the line items of the revenue requirement calculation for 2014 and then show, in a column opposite each of those line items, the amounts that will not be subject to adjustment in the ensuing year or to variance account protection under the auspices of the deferral accounts.

(b) Express the total of the non-adjustable items as a percentage of the total revenue requirement.

(c) Do the same exercise for each of the revenue requirements presented in this proceeding for 2015, 2016, 2017 and 2018.

RESPONSE

The Company has filed evidence at Exhibit A2, Tab 1, Schedule 1, and Exhibit A2, Tab 3, Schedule 1, explaining an update to its Customized IR plan which proposes to set now the 2017 and 2018 capital spends and related rate base amounts contained within the original evidence which previously EGD had requested to be re-set through a capital re-fresh process to occur in 2016. EGD is no longer proposing such a 2017 and 2018 capital spend and related rate base/allowed revenue re-fresh. Instead, Allowed Revenue amounts for 2014 to 2018 are to be set in this proceeding.

As a result and as explained in Exhibit A2, Tab 3, Schedule 1, the items which will change from those currently shown as forecasts within each of the years 2014 to 2018 are revenues, gas cost and income tax related forecasts in relation to annual volume updates and Board required gas commodity pricing pass through, CIS/Customer Care related Board pre-approved amounts, separately viewed DSM program related costs and Pension related costs. Additionally, as within any ratemaking construct, some amounts are subject to deferral and variance treatments.

While amounts for the above noted items will be updated in future years for inclusion in rates from the current placeholders, all of these items with the exception of Pension related costs, were previously treated the same way within EGD's 1st generation IR model such that they were updated annually for inclusion in rates in the same manner as being proposed in this 2nd generation Customized IR model. The proposal to update Pension related costs is in recognition of the EB-2011-0354 Board-approved Settlement Agreement.

While rates in future years will change and include different amounts annually for all of such other amounts, this is no different in concept from EGD's 1st Generation IR model where rates changed annually from an "I-X" type formula being representative of expected changes annually in required costs.

The result is that other than those elements which would change annually either within EGD's Customized IR model proposal or any alternate "I-X" model, the remaining Allowed Revenue amounts for all five years to be used to set rates will not change from those to be approved in this proceeding.

With that context, EGD does not believe that the requested calculation of % of items that are subject to annual change is meaningful.

Witness: K. Culbert

CME INTERROGATORY #3

INTERROGATORY

Issue: A1

Reference: Exhibit A2, Tab 1, Schedule 1, page 8
Exhibit A2, Tab 2, Schedule 2, page 1

The evidence indicates that the annual bill impacts under EGDI's proposal for 2014, 2015 and 2016 for the average residential customer will be -0.7%, 1.7% and 2.1% respectively. Such evidence suggests that an annual escalator of 2.1% in each of those years be more than adequate to protect EGDI. However, the I—X calculations in Exhibit A2, Tab 1, Schedule 3 at page 11 indicate that escalator factors of 4.3% for 2014, 2.0% for 2015 and 4.0% for 2016 are needed to enable the company to earn its allowed return. In connection with this evidence:

(a) Please explain why escalators of 4.3%, 2.0% and 4.0% in 2014, 2015 and 2016 respectively are insufficient to produce rates for the average residential customer more favourable than those EGDI is asking the Board to approve in each of those years.

RESPONSE

(a) The interrogatory asks the Company to look at escalations of Allowed Revenue for 2014 to 2016 in comparison to bill impacts. These are not the same thing. Escalation of Allowed Revenue is an adjustment to the amounts EGD is allowed to recover in distribution costs through rates. Bill impacts take into account the change in Allowed Revenue, as well as the impact from the Site Restoration Cost ("SRC") credits to be passed on to ratepayers.

The forecast bill impacts are set out at Exhibit A2, Tab 1, Schedule 1, page 8 and show that for 2014, 2015, and 2016 average residential customer bills are forecast to change by -3.5%, 1.4%, and 1.5%, respectively. This includes the impacts of the depreciation rate change, SRC credits, and the GTA project.

The equivalent illustration of the required changes to the Allowed Revenue that would enable EGD to earn Board Allowed ROE is set out a Scenario 5 of Exhibit A2, Tab 1, Schedule 3. It shows that an escalation to Allowed Revenue of 5.6% per year is required to allow EGD to earn the Board Approved ROE.

Witnesses: R. Fischer
M. Lister

The reason why the change to the Allowed Revenue is different from Bill impact changes include:

- Bill Impacts include the SRC credit
- Bill impacts includes changes from volume due to weather and other items
- Bill impacts include the impact of lower depreciation rates in 2014.

Witnesses: R. Fischer
M. Lister

CME INTERROGATORY #10

INTERROGATORY

Issue: A1

Reference: Exhibit A2, Tab 9, Schedule 1
Exhibit A2, Tab 10, Schedule 1

In connection with the expert reports from CEA and LEI, please provide the following information:

(a) Were each of these experts retained pursuant to a RFP? If so, please provide copies.

(b) Please provide copies of any further instructing communications provided to CEA and LEI.

(c) Please produce the retainer agreements.

(d) What costs have been incurred to date for each expert and what costs are being forecasted for these experts to the end of this proceeding?

RESPONSE

(a) Please see response to CCC Interrogatory #1 at Exhibit I.A1.EGDI.CCC.1.

(b) Please see response to CCC Interrogatory #1 at Exhibit I.A1.EGDI.CCC.1.

(c) Please see response to CCC Interrogatory #1 at Exhibit I.A1.EGDI.CCC.1.

(d) Please see response to CCC Interrogatory #1 at Exhibit I.A1.EGDI.CCC.1.

Witnesses: R. Fischer
M. Lister

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

Ref: Exhibit A2, Tab 3, Schedule 1

a) Please explain why the Board needs to approve preliminary allowed revenue amounts for 2017 and 2018 as part of this proceeding.

b) Could the Board only approve the components of the 2017 and 2018 allowed revenue that will not change (OM&A, other revenues, municipal taxes, income tax rates, debt rates, return on equity rates, equity ratio)?

c) Please explain why the volume forecasts for 2015 and 2016 should not be considered final as part of this application, eliminating the need to review the forecasts in the setting of 2015 and 2016 rates.

d) Please explain why the volumetric forecasts would be updated on an annual basis while the other revenue forecast would not.

RESPONSE

a) Please see the Company's updated evidence filed at Exhibit A2, Tab 1, Schedule 1. That evidence explains EGD's updated proposal for the approval of Allowed Revenue amounts for 2017 and 2018 within this proceeding.

b) The Company is revising its proposal with respect to a "capital refresh" in 2016 for Capital budgets in 2017 and 2018. The Company is proposing to pre-set all the components and the corresponding Allowed Revenues for each of the years 2014 through to 2018. Please see Exhibit A2, Tab 1, Schedule 1 and Exhibit A2, Tab 3, Schedule 1. Therefore, the Company is requesting within this proceeding that the Board approve Allowed Revenues for the period of 2014 to 2018.

c) Similar to the 1st Generation IR plan, EGD is proposing to annually adjust volumes for the determination of final rates. More information on the annual adjustment process can be found at Exhibit A2, Tab 3, Schedule 1. Specifically paragraph 20 states:

Witnesses: K. Culbert
R. Fischer
A. Kacicnik
M. Lister

> Under this approach, risks for ratepayers and shareholders are reduced by annually reviewing volume forecasts. Specifically, since the volume forecast depends on the forecast annual degree days, an annual review and update will ensure that rates are set using the most up to date information using the Board Approved methodology for degree days. This will minimize the probability that volumes, and therefore rates, are set on an irrelevant weather basis.

Including a provision for the annual updating of volumes addresses several salient issues:

Average Use declines – there is a well-documented situation of declining average use consumption in EGD's franchise area. To provide an order of magnitude, the Company has added almost 1 million customers since 2000, while its total volumes have remained relatively stable. For both the Company and ratepayers, having the most up to date volumetric profile in advance of a test year limits the risk exposure and the likelihood that one party would gain at the other's expense due to conditions that neither controls.

The Company had a variance account in the 1st generation IR related to average use variances from annual budget. This variance account should not be considered an alternative to an annual volume re-forecast, however. The variance account triggers off variances from the forecast ensuring that rates are set and collected according to forecast average uses and no more or less. If this variance account were triggered off of forecasts set now for the next 5 years, then the trigger would effectively be the average use forecast established today. However, forecasts may change over time due to weather, gas prices, or economic circumstances. In other words, the average use variance account cannot be used in place of volumetric update.

Large volumes – Large volumes may also change from year to year or over time due to circumstances unrelated to the EGD's business. For example, economic or currency swings could affect manufacturing activity, which could impact volumes or volumes may increase (decrease) significantly if there is a decrease (increase) in gas costs. Again, for both the Company and ratepayers, having the most up to date volumetric profile in advance of a test year limits the risk exposure and the likelihood that one party would gain at the other's expense due to conditions that neither controls.

Weather unpredictability – Another reason to update the volumetric forecast on an annual basis is due to the unpredictability of annual weather conditions in the Company's franchise area. Weather significantly impacts the volume forecast and without a process to reset the degree day (weather) forecast, the approved volume profile may be stale to the detriment of either the Company's revenues, or customer's rates.

d) Within the updated Customized IR plan, the Company proposes to pre-set Allowed Revenue for 2014 to 2018, which includes an amount for Other Revenues, and update annually for volumes for collection of those amounts. For the purposes of establishing its Customized IR plan, Enbridge believes there are two distinct differences between Other Revenues and volumes that warrant or necessitate different treatments.

The first is that Other Revenues are used in the determination of Allowed Revenue (as an offset to cost). Volumes, on the other hand, are used to collect those revenue amounts. In other words, the volumes are not used to determine Allowed Revenue.

Secondly, the Company has little control over the conditions that drive changes in volumes (such as weather, economic activity, gas costs, legislation impacting efficiency mandates, etc.), whereas Other Revenues are part of the Company's daily operations.

Witnesses: K. Culbert
R. Fischer
A. Kacicnik
M. Lister

SEC INTERROGATORY #1

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Please provide the Applicant's most recent Strategic Plan or similar document.

RESPONSE

The Strategic Plan is not relevant to this Customized IR plan application. Further, it contains confidential and commercially sensitive information which is not appropriately disclosed in a public forum.

Witnesses: R. Fischer
M. Lister

SEC INTERROGATORY #2

INTERROGATORY

Issue A1: Is Enbridge’s proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Please file the materials the Applicant provided to stakeholders in its December 7, 2012 stakeholder meeting on 2014-2018 rates.

RESPONSE

Please see attachment.

Witnesses: R. Fischer
M. Lister

Enbridge Gas Distribution Inc.

STAKEHOLDER CONFERENCE

Incentive Rate Application for 2014 Rates

December 7, 2012

- Introduction: Facilitator, Bob Betts
- Meeting Facilities and Safety Review
- Participant Introductions
- Review of the Agenda

- Mobile phones “Off” or “Silenced”
- All questions are good ones
- All comments are appreciated

Agenda

9:00 AM	**Welcome and Housekeeping Items** • Bob Betts, Facilitator
9:10 AM	**Introductory Remarks and Application Status Update** • Ralph Fischer, Director, Regulatory Special Projects
9:20 AM	**Review of the Asset Plan including Major Reinforcement Projects** • Lloyd Chiotti, Senior Director, Distribution Asset Management • Edith Chin, Senior Manager, Upstream Regulatory Strategy
10:00 AM	**Challenges of [I-X] for Capital Investments** • Sagar Kancharla, Director, Business Performance
10:45 AM	**Break**
11:00 AM	**Capital Trackers** • Jim Simpson, Concentric Energy Advisors
11:30 AM	**Enbridge's Proposed IR Plan** • Ralph Fischer, Director, Regulatory Special Projects
12:00 PM	**Lunch**
12:30 PM	**Update on Performance Measurement** • Sagar Kancharla, Director, Business Performance
1:00 PM	**Wrap-up and Adjourn** • Ralph Fischer, Director, Regulatory Special Projects

Objectives for Today:

1. Share with stakeholders our current high level assessment of the drivers and preliminary thinking for a 2nd Generation IR plan for EGD

2. To receive stakeholder feed-back on the potential plan elements

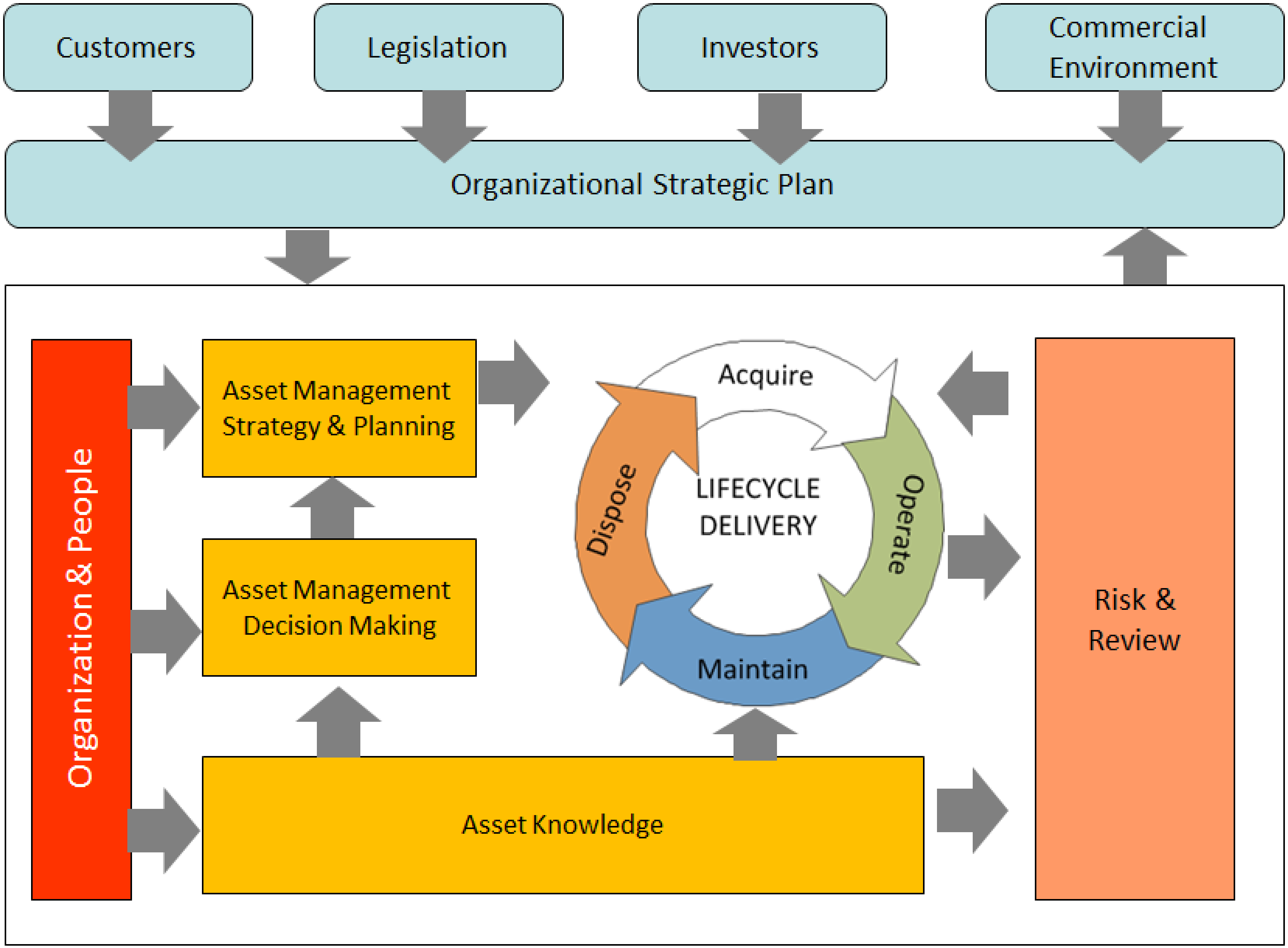
IR Status

- 2nd Generation IRM will be an evolution of the current IRM with most elements expected to be carried forward
- The 2nd Generation IRM will need to consider the growing need for capital and macroeconomic outlook
- Expected Filing date in Q1 2013

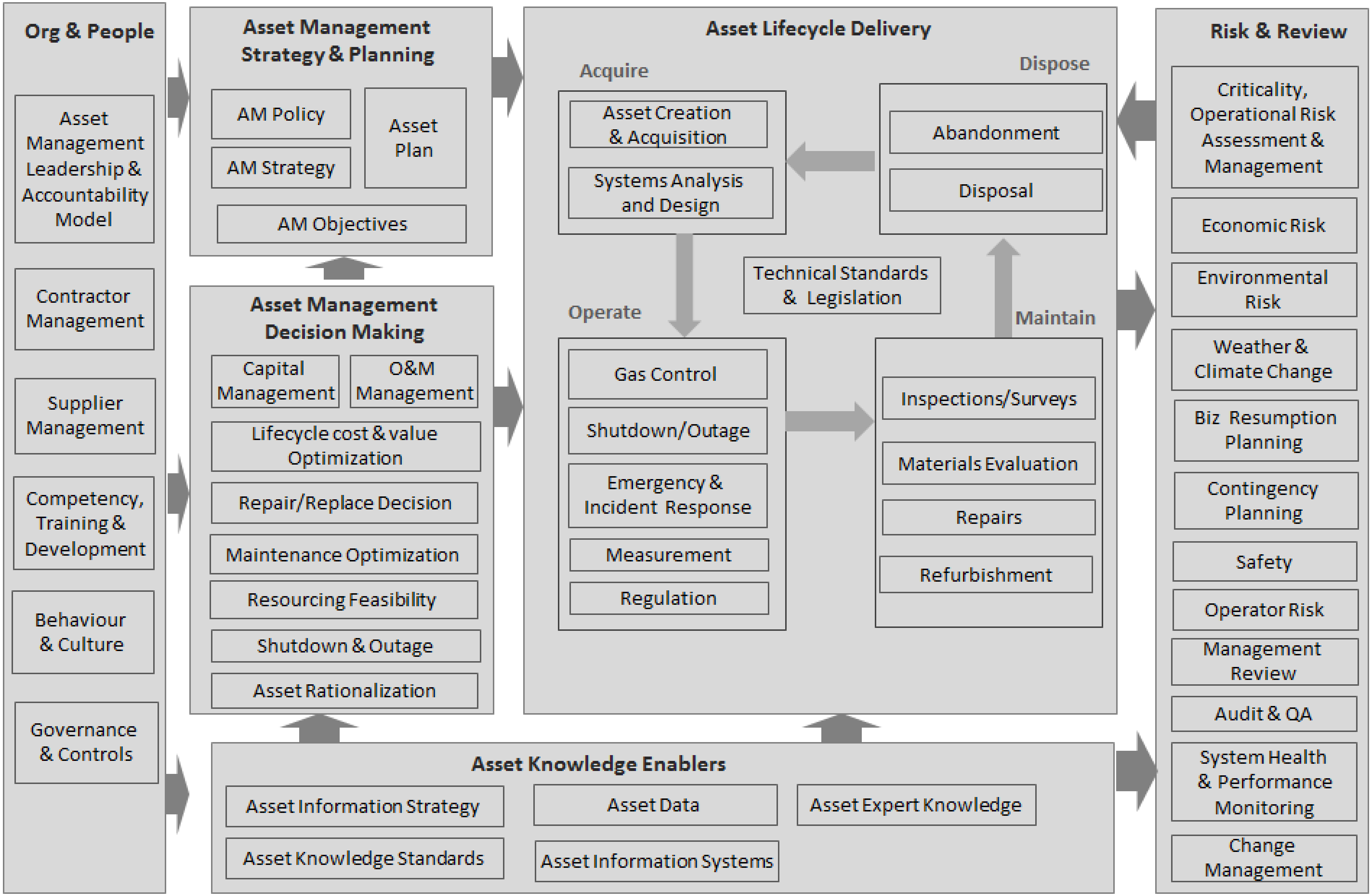
Asset Management

ENBRIDGE

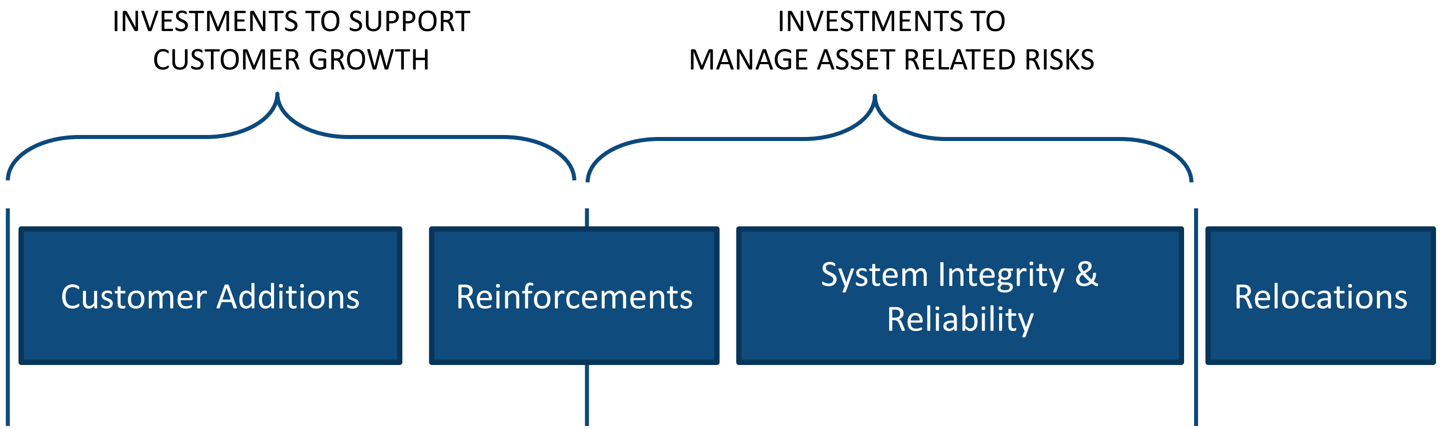
Context
The IAM Framework



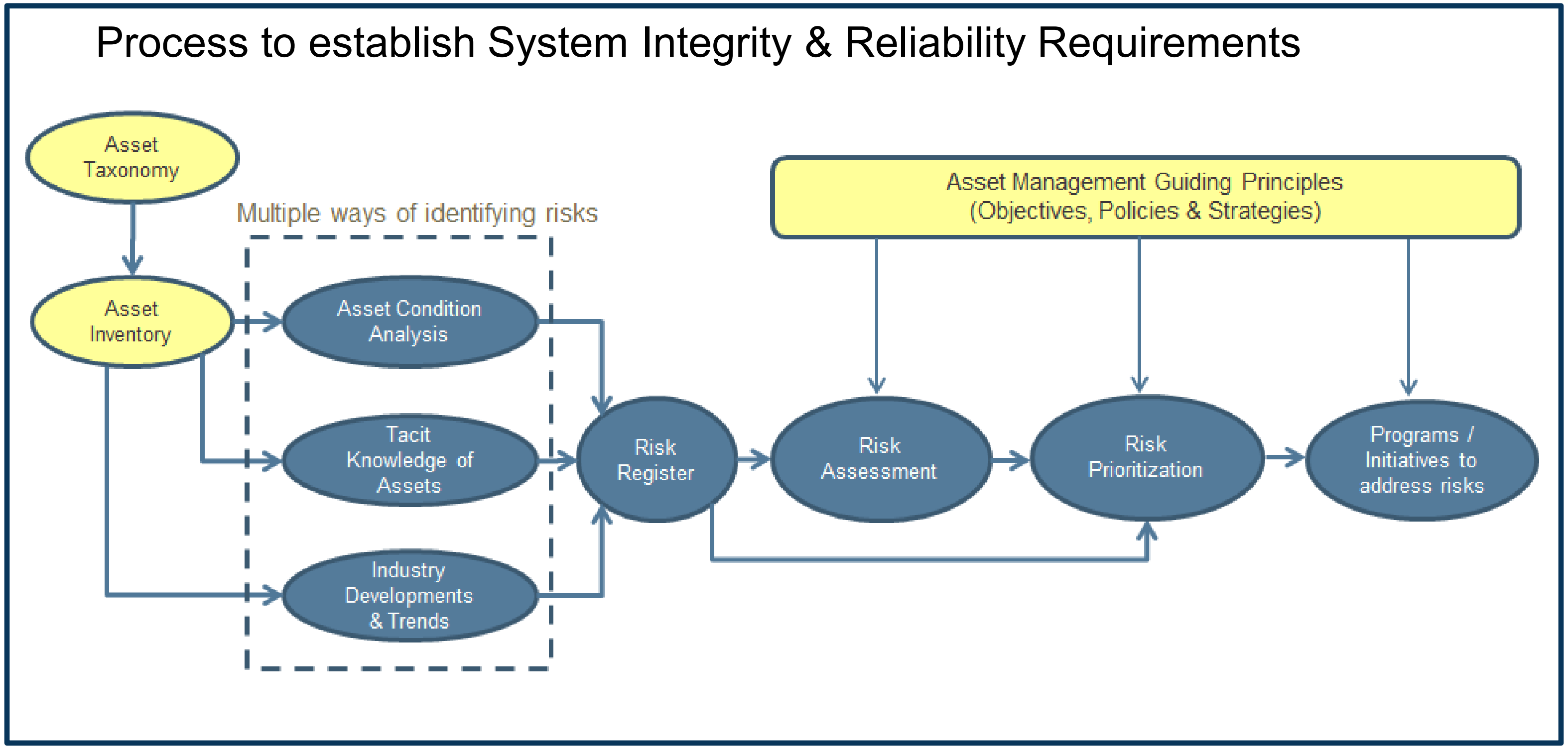
Context
IAM Framework – Adapted for EGD



Asset Requirements
Overview



Asset Requirements
System Integrity & Reliability - Process



Risk Analysis :

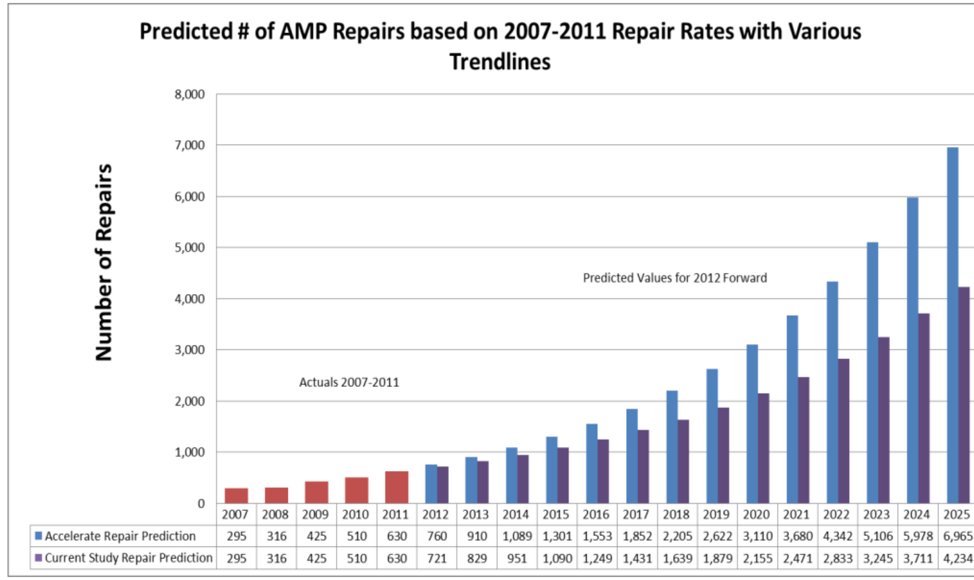
		Impact					
	Value	Minor	Moderate	Major	Severe	Worst Case	
Daily to monthly	5	P3	P2	P1	P1	P1	**Likelihood**
Monthly to yearly	4	P3	P2	P2	P1	P1	
Once in 1 to 10 years	3	P3	P3	P2	P2	P1	
Once in 10 to 100 years	2	P4	P3	P3	P2	P2	
Once in > 100 years	1	P4	P4	P3	P3	P3	
		1	2	3	4	5	

STUDY EXAMPLE – AMP Fittings

AMP fittings (underground fittings located outside customer homes) have been failing at an increasing rate over the past number of years, due to corrosion of the copper risers connected to plastic services. The potential is for the underground leak to enter into homes and cause a safety event.

Approx. 400,000 Services with AMP Fittings

Increasing failure rates are anticipated as infrastructure ages and contributors accelerate corrosion and reduce residual life.



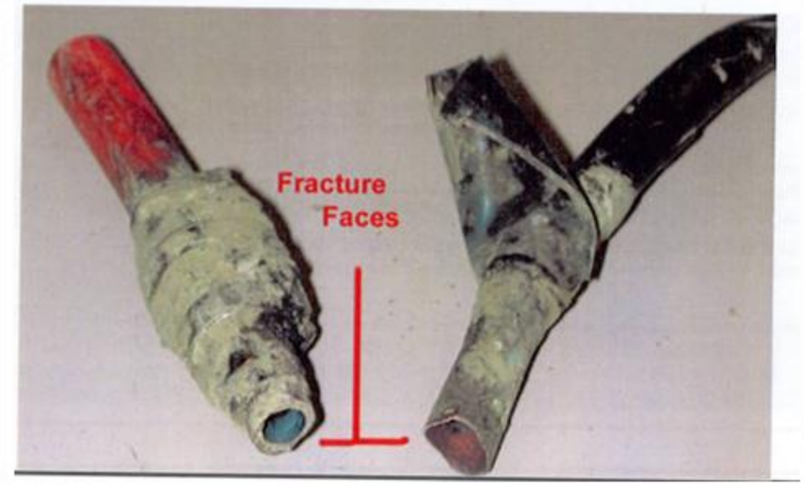
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Accelerate Repair Prediction	295	316	425	510	630	760	910	1,089	1,301	1,553	1,852	2,205	2,622	3,110	3,680	4,342	5,106	5,978	6,965
Current Study Repair Prediction	295	316	425	510	630	721	829	951	1,090	1,249	1,431	1,639	1,879	2,155	2,471	2,833	3,245	3,711	4,234

Study Plan:

- Comprehensive lab analysis of statistically valid sample
- Confirm population of services with AMP fittings
- Develop a targeted mitigation program including increased condition monitoring and condition based replacement

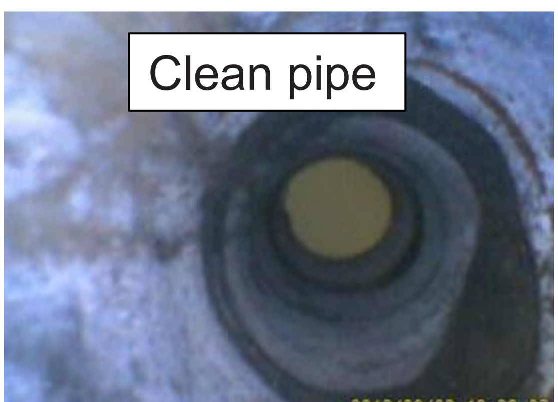
STUDY EXAMPLE – AMP Fittings

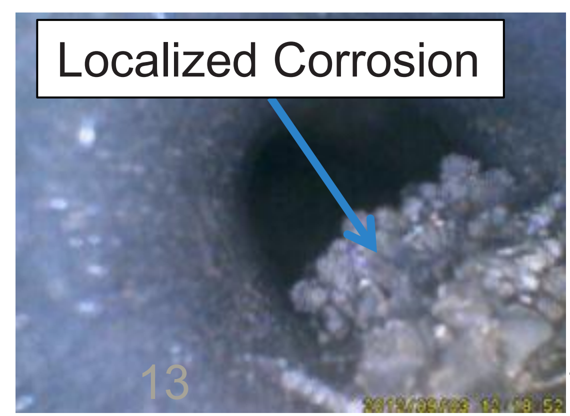
- 700 Samples analyzed
- All Samples have some degree of corrosion



Overall Leakage Rate (%)			
Historical Repair Data	Historical Leak Survey	2012 Leak Survey	2012 Sampling
0.2	0.2	1.1	2.2

	Percentage Range of Average Wall Thickness Loss									
	> 0% and ≤ 10%	> 10% and ≤ 20%	> 20% and ≤ 30%	> 30% and ≤ 40%	> 40% and ≤ 50%	> 50% and ≤ 60%	> 60% and ≤ 70%	> 70% and ≤ 80%	> 80% and ≤ 90%	> 90% and ≤ 100%
Top	3%	14%	20%	16%	19%	10%	9%	7%	1%	1%
Bottom	11%	11%	10%	23%	17%	17%	7%	3%	0%	0%





Major Reinforcements
GTA and Ottawa

GTA Reinforcement - Timing and Costs

- **LTC filing December, 2012**
- **Proposed construction schedule:**
  - **Construction start Summer 2014**
  - **Segment B and associated facilities in service by end of 2014**
  - **Segment A and associated facilities in service by mid-2015**
- **Total Project Cost ~$600M**

GTA Reinforcement - Proposed Facilities

Facilities include:

- **2 Large Spans of Pipeline**
- **1 Parkway West Tie-in**
- **1 New Gate Station**
- **2 New Regulation Stations**
- **3 Modifications to Existing Stations**

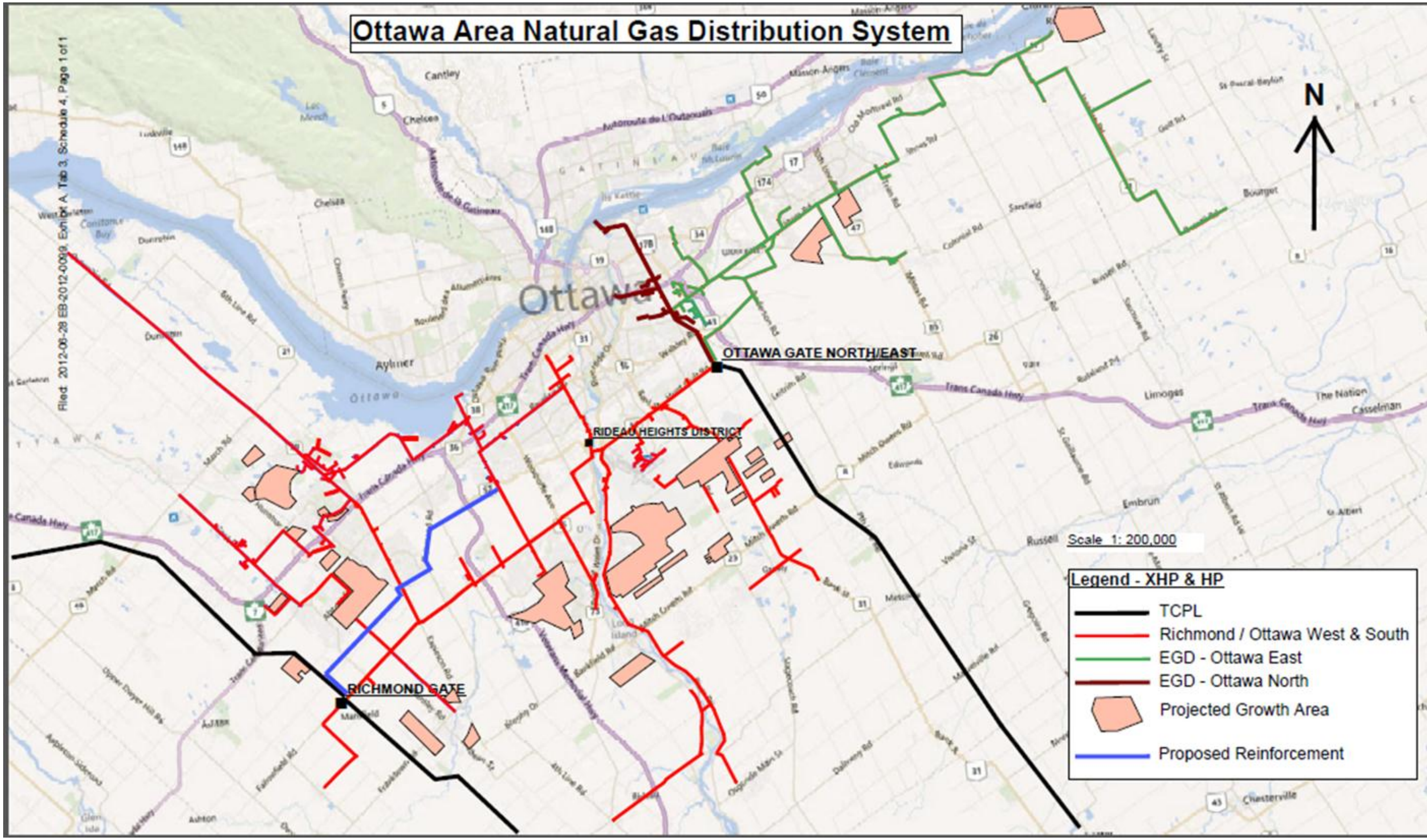
Ottawa Reinforcement

ENBRIDGE

- **19 km of 24 inch steel to be located in west Ottawa**
- **Cost approx. $51 million**
- **To be completed in 2013***
- **Leave To Construct application filed June 28, 2012 and approved Nov 29 2012.**

*If there are permit delays, ~85% will be completed in 2013, the rest in early 2014.

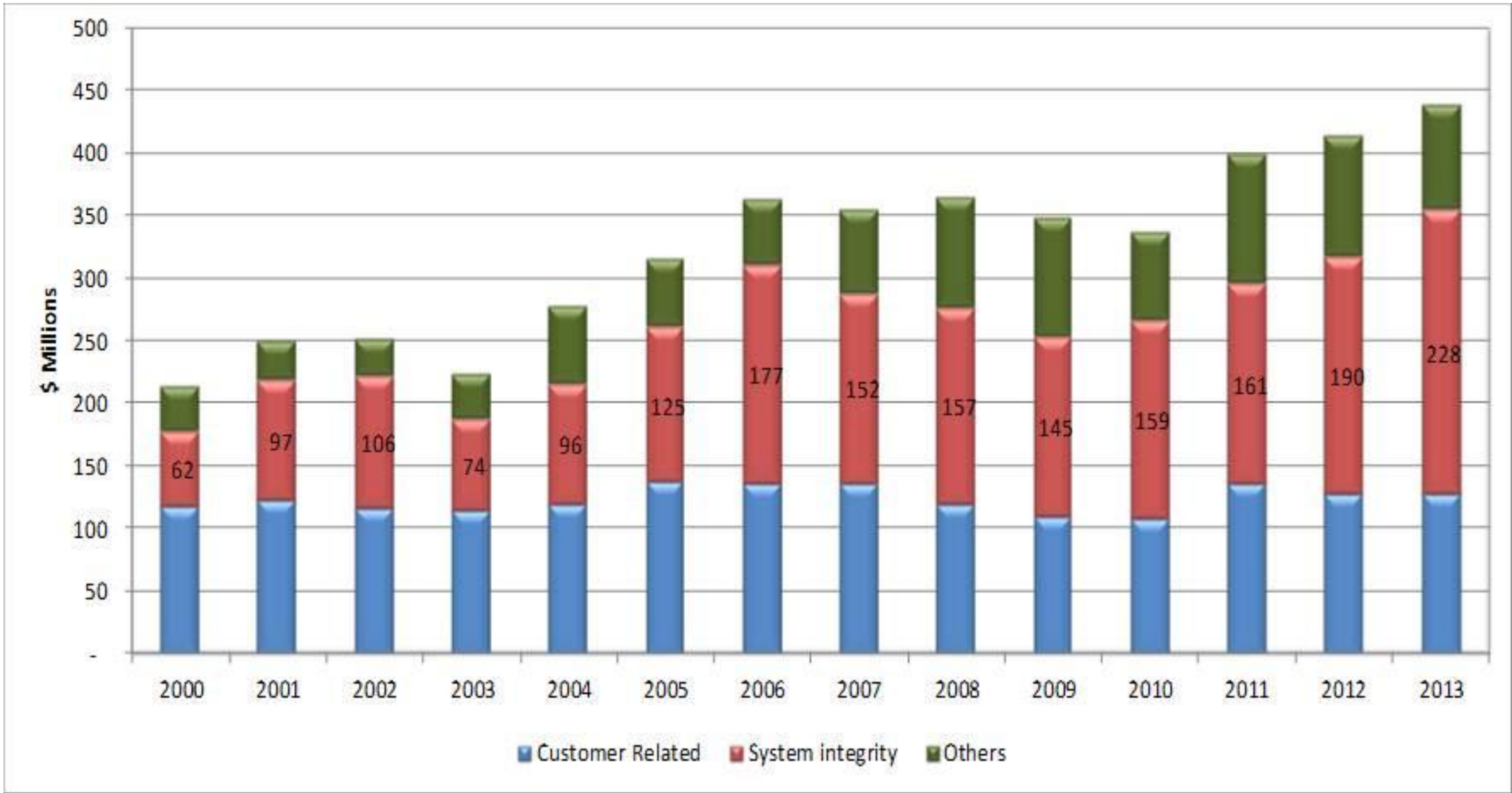
Ottawa Reinforcement



Challenges of [I-X] for Capital Investments

Focus on Operational Safety & Reliability

Changing Capital Profile



Increasing System Integrity Spend

Illustration 1: Earnings Impact

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Key Assumptions

- $100m annual system integrity capex
- Incremental to depreciation levels
- Debt/Equity:64/36; Cost of debt 6%
- Depreciation rate: 4%
- Tax rate: 27%
- Effectivity not considered

No Y Factor (Non-Revenue Generating Capital)

$ Millions	**Year 1**
Revenues	-
Opex	-
EBITDA	-
Depreciation	(4)
Interest Expense	(4)
EBT	(8)
Taxes	2
Earnings	(6)

Impact of Depreciation and Interest expense

Illustration 2: Multi-year Earnings Impact

Earnings Profile - $100M annual spending Non-Revenue Generating Capital

$ Millions	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Revenues	-	-	-	-	-
Opex	-	-	-	-	-
EBITDA	-	-	-	-	-
Depreciation	(4)	(8)	(12)	(16)	(20)
Interest Expense	(4)	(8)	(11)	(15)	(19)
EBT	(8)	(16)	(23)	(31)	(39)
Taxes	2	4	6	8	10
Earnings	(6)	(11)	(17)	(23)	(29)

Cumulative Impact of Depreciation and Interest expense

Illustration 3: Multi-year Earnings Impact

ENBRIDGE

Earnings Profile - $100M annual spending Non-Revenue Generating Capital

$ Millions	Year 1	Year 2	Year 3	Year 4	Year 5
Revenues	-	-	-	-	-
Opex	-	-	-	-	-
EBITDA	-	-	-	-	-
Depreciation	(4)	(8)	(12)	(16)	(20)
Interest Expense	(4)	(8)	(11)	(15)	(19)
EBT	(8)	(16)	(23)	(31)	(39)
Taxes	2	4	6	8	10
Earnings	(6)	(11)	(17)	(23)	(29)

Y Factor (Non-Revenue Generating Capital)

	Year 1	Year 2	Year 3	Year 4	Year 5
Ratebase	98	196	294	392	490
Allowed ROE	9%	9%	9%	9%	9%
Earnings	3	6	10	13	16

Earnings gain/loss not symmetrical between "with Y " and "without Y".
Recognizing rate impacts are different.
(Depreciation + Interest) vs. Allowed ROE

Assumptions for the Next Two Illustrations

	2014	2015	2016	2017	2018
Capital Structure					
Debt	64%	64%	64%	64%	64%
Equity	36%	36%	36%	36%	36%
Cost of Capital					
Cost of Debt	6%	6%	6%	6%	6%
Allowed ROE	9%	9%	9%	9%	9%
Depreciation Rate	4%	4%	4%	4%	4%
Tax Rate	27%	27%	27%	27%	27%
IR - Revenue Cap per Customer					
Customer growth	1.3%	1.3%	1.3%	1.3%	1.3%
Inflation	1.7%	1.7%	1.7%	1.7%	1.7%
X factor	0.0%	0.0%	0.0%	0.0%	0.0%
IR Escalation	3.0%	3.0%	3.0%	3.0%	3.0%
$ millions					
O&M	422	429	437	444	452
Capex	668	688	400	400	400
RateBase ($ Billions)					
Gross PPE	7.2	7.8	8.5	8.9	9.2
Depreciation	(3.0)	(3.3)	(3.6)	(3.9)	(4.2)
Net PPE	4.2	4.5	4.9	5.0	5.0
Allowance for working capital	0.2	0.2	0.2	0.2	0.2
Net ratebase	4.4	4.7	5.2	5.2	5.3

Annual capital expenditure of $400 m + GTA & Ottawa reinforcements

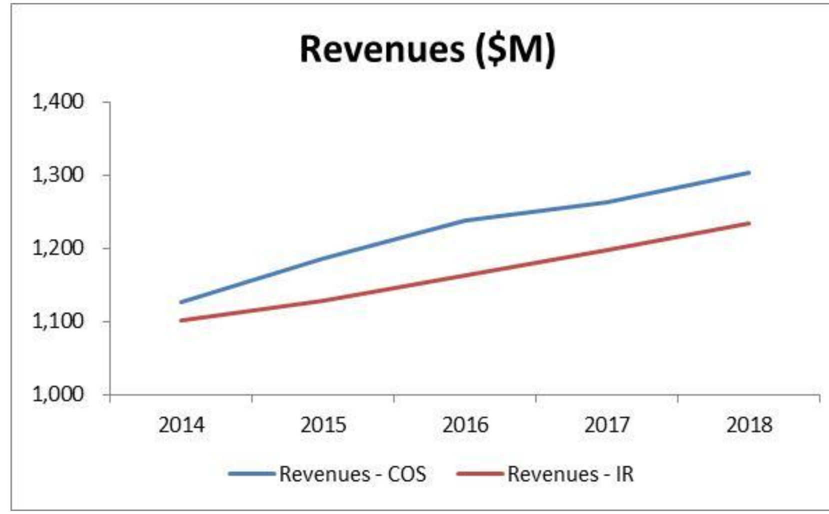
Revenue Requirement on Existing Capital

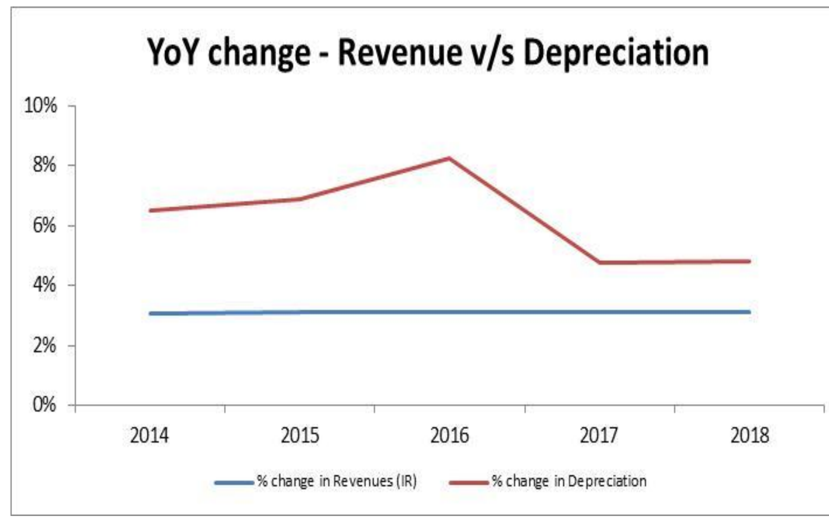
($millions)	2013	2014	2015	2016	2017	2018
Gross PP&E	6,749	6,948	6,900	6,846	6,807	6,744
Accumulated Depreciation	(2,804)	(3,042)	(3,269)	(3,475)	(3,672)	(3,851)
PP&E RateBase	3,945	3,905	3,631	3,371	3,135	2,893
Gross Return on RateBase	320	320	304	291	277	258
Existing Capital Annual Depreciation	279	283	275	265	259	248
Revenue Requirement in Rates	599	602	578	556	536	506
YOY Revenue Requirement change in Rates		3	(24)	(22)	(20)	(30)

Depreciating existing rate base helps, but not adequate

Illustration 4: IR Financial Impact

IR - First Generation IR treatment	2014	2015	2016	2017	2018
Revenues - IR	1,101	1,128	1,163	1,198	1,235
Opex	422	429	437	444	452
Depreciation	297	318	344	361	378
Interest Expense	154	166	185	189	188
Taxes & Others	102	101	83	81	95
Earnings - IR	125	113	113	124	122
Return on Equity (%)	8%	7%	6%	7%	6%
	-	-	-	0	(0)
Cost of Service - Incl. GTA & Ottawa					
Earnings - Cost of Service	142	153	168	170	171
Return on Equity (%)	9%	9%	9%	9%	9%
Earnings - Gap					
Earnings	(17)	(40)	(54)	(46)	(49)
Return on Equity (%)	-1%	-2%	-3%	-2%	-3%





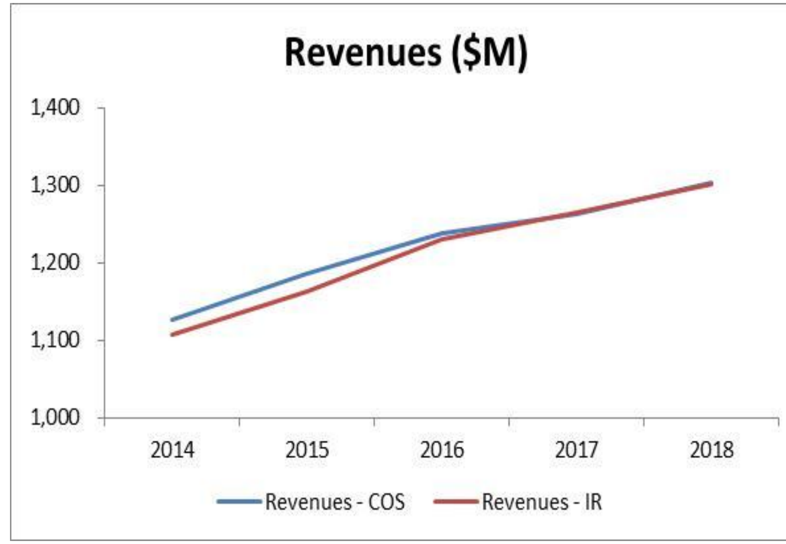
Depreciation expense growing faster than Revenue

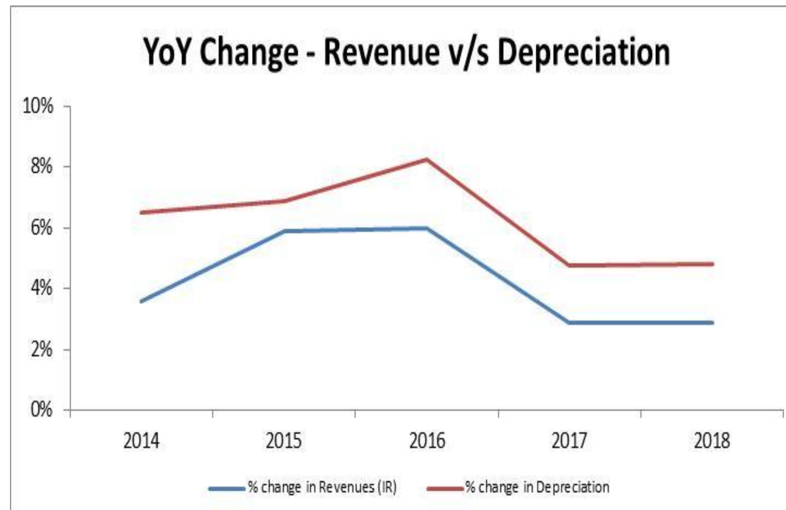
Illustration 5: IR Financial Impact
(Y factor for GTA & Ottawa Reinforcements)

IR - First Generation IR Treament incl. Y factor for GTA & Ottawa	2014	2015	2016	2017	2018
Revenues	1,106	1,163	1,231	1,265	1,301
Opex	422	429	437	444	452
Depreciation	297	318	344	361	378
Interest Expense	154	166	185	189	188
Taxes & Others	104	111	101	101	113
Earnings - IR	129	139	163	170	170
Return on Equity (%)	8%	8%	9%	9%	9%
	-	-	-	-	-

Cost of Service - Including GTA & Ottawa					
Earnings - Cost of Service	142	153	168	170	171
Return on Equity (%)	9%	9%	9%	9%	9%

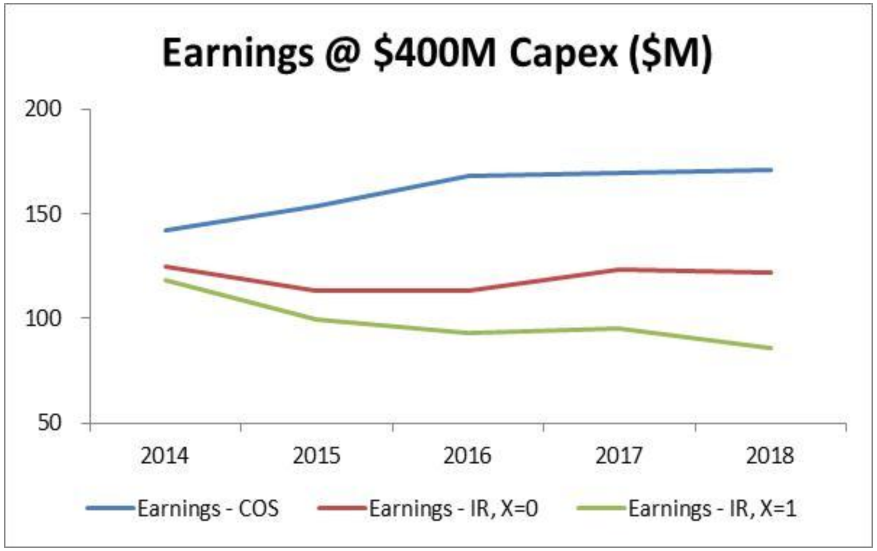
Earnings - Gap					
Earnings	(13)	(15)	(5)	1	(1)
Return on Equity (%)	-1%	-1%	0%	0%	0%

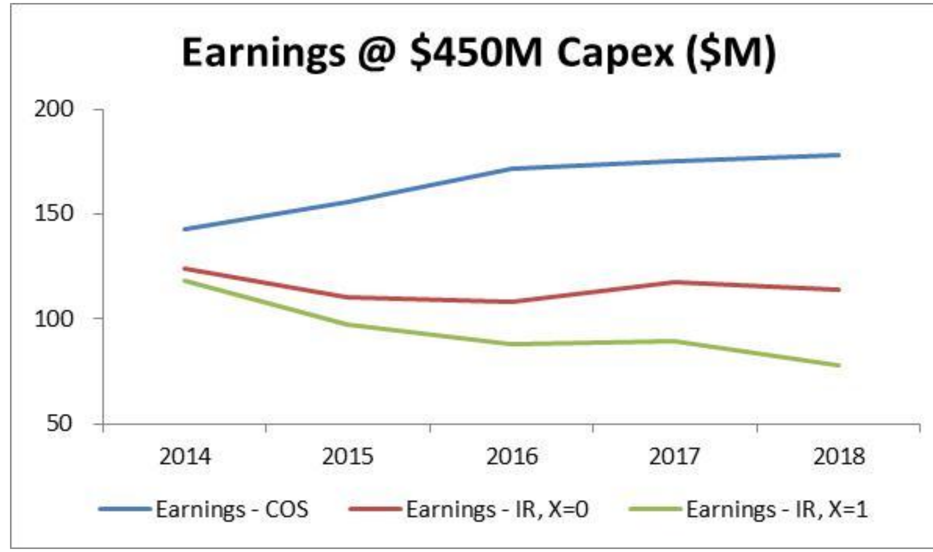


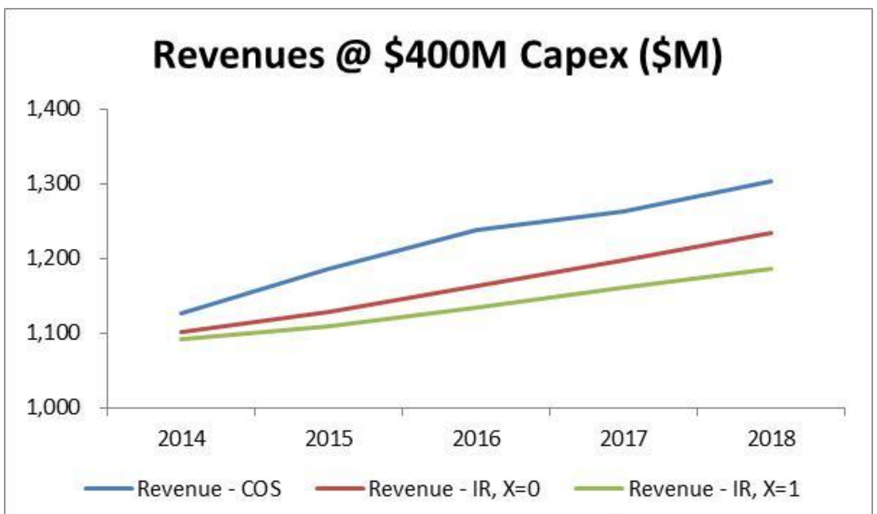


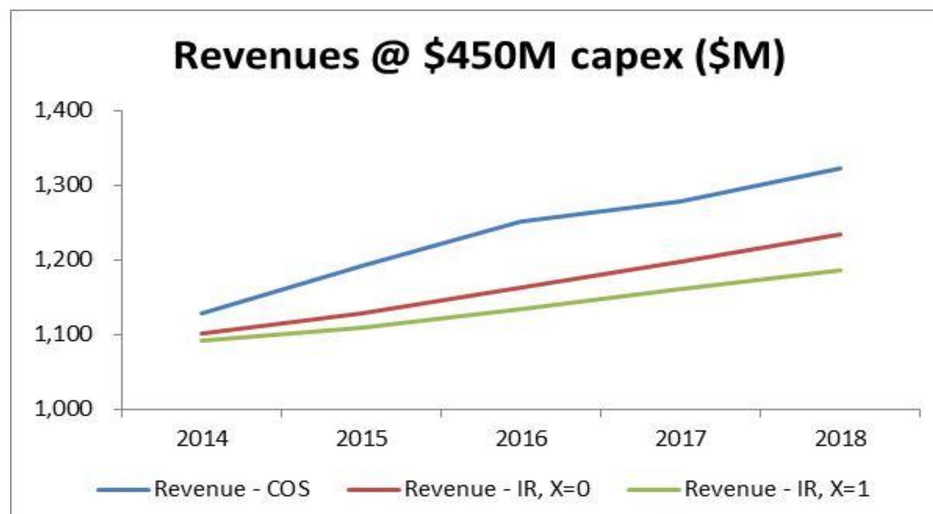
Y Factor for major reinforcements still doesn't solve the issue completely

Illustration 6: IR Earnings Sensitivity
(No Y factors for GTA and Ottawa Reinforcements)

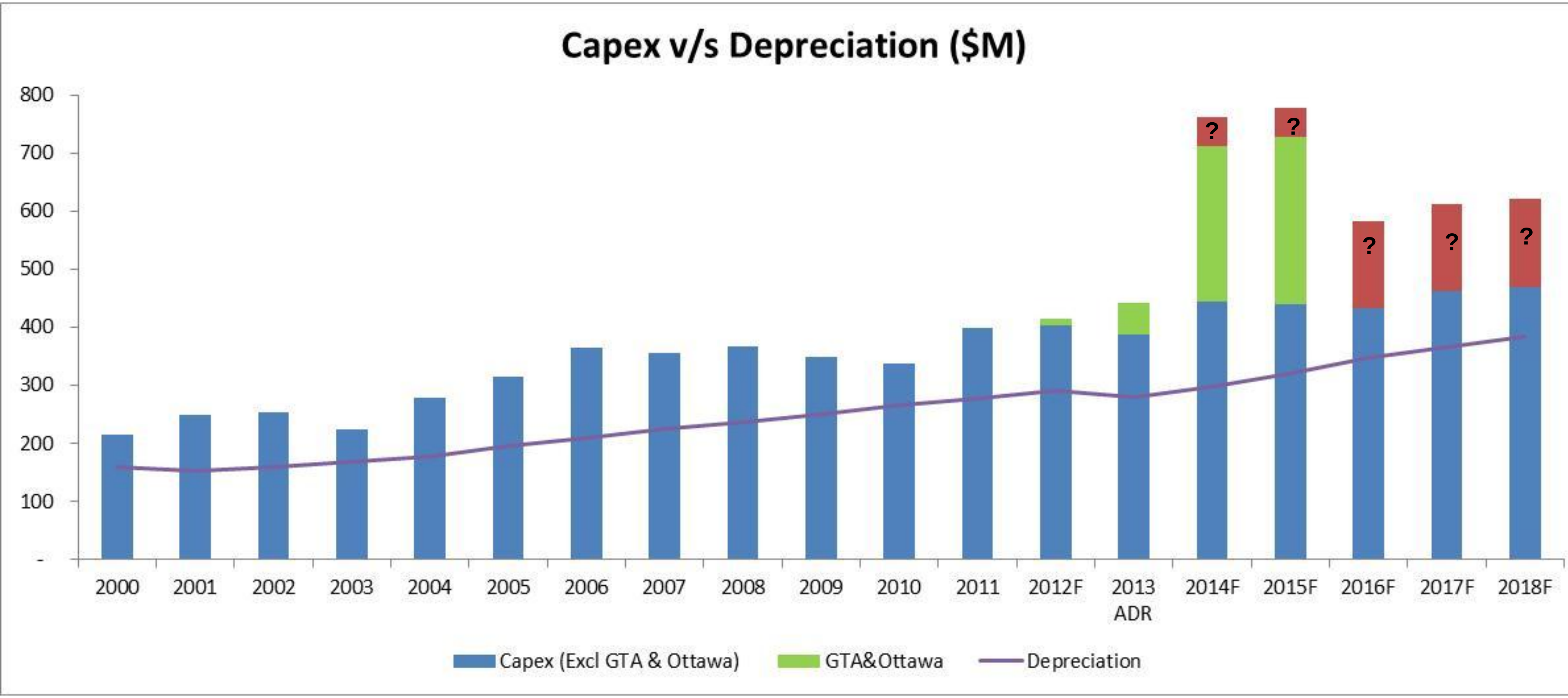








Increasing Depreciation



Challenges in the Next Regulatory Framework

Investments required for:

- System Expansion
- Major Reinforcements
- Normal Reinforcements
- System Integrity
- Replacements
- Relocations

- Increased capital expenditures

[I-X] framework doesn’t provide timely recovery

Potential solutions ?

Break

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Capital Trackers

Basis for Capital Cost Recovery Mechanisms

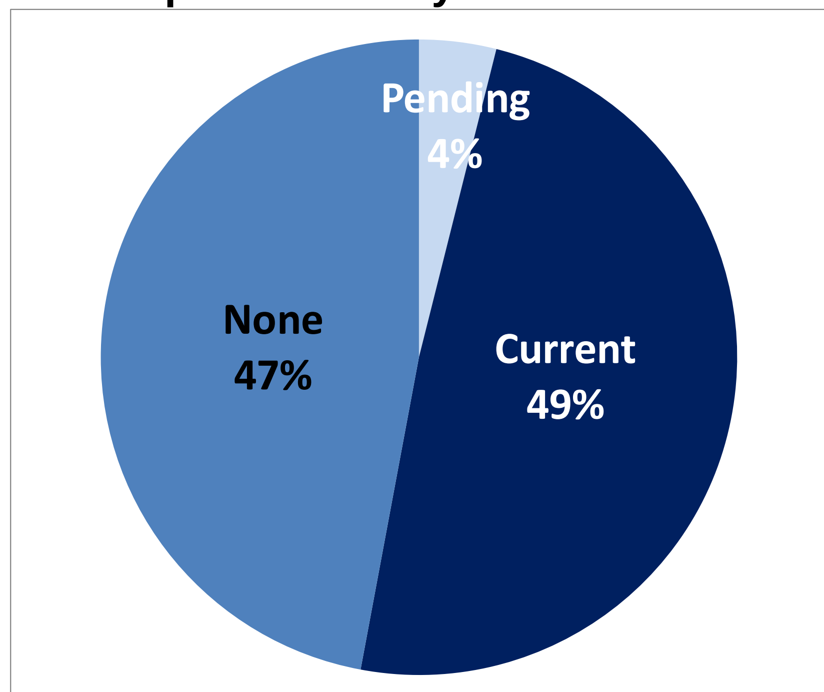
- Over the past decade there has been growing acceptance among regulators in Canada and US that traditional ratemaking does not "work" in current conditions – electric and gas utilities do not have a reasonable opportunity to earn a fair rate of return and make necessary investments in infrastructure.
  - Key factors of infrastructure investments
    - Gas and electric utilities are faced with growing needs to make significant investments in non revenue producing infrastructure
      - Infrastructure replacement, reinforcement, "hardening"
  - Key factors of "current conditions"
    - Slowed growth in revenues due to conservation, recession, and/or effect of IR price adjustments and decoupling mechanisms

Capital Cost Recovery Mechanisms in the U.S. and Canada

- Capital cost recovery mechanisms are common in Canada and the United States.

  - More than half of US states have some form of natural gas distribution capital cost recovery mechanism, or have cases pending.
  - More than a quarter of US states have electric distribution capital cost recovery mechanisms.
  - Canadian capital cost recovery mechanisms:
    - Alberta: The AUC determined in September 2012 that a Capital Tracking mechanism - in addition to an I-X mechanism - was necessary for gas and electric utilities to recover certain capital-related costs.
    - British Columbia: capital tracker mechanisms were available to gas utilities until 2009.

States with Gas Distribution Capital Recovery Mechanisms



Capital Recovery Mechanism Categories

The three general categories of Capital Recovery Mechanisms:

Category	Types of Eligible Assets	Examples of Eligible Assets	Prevalence
Special Purpose Projects	• Typically non-revenue generating • Targeted • Out of the ordinary	• Cast iron/ bare steel replacement programs • Smart metering/ AMI investments • Emission controls on power plants • Reliability enhancement projects	• Very common
Large Projects	• Very large • Defined, specific projects • May include revenue generating projects	• Specific system expansion/ system growth areas • Electric generation plants	• Common
Comprehensive	• All capital spending		• Less common

Eligibility Criteria

- General eligibility criteria for capital cost recovery mechanisms are common. Examples:
  - Outside of the normal course of ongoing operations
  - Replacement of existing capital assets
  - Required by an external party
  - Has a material effect on finances
  - Planned and managed prudently
  - No direct increase revenues by directly connecting new customers
  - Compliance with environmental mandates

Eligibility Criteria

- Specific eligibility criteria for capital cost recovery mechanisms should be clear and unambiguous
  - Utilities must be confident that they can recover legitimate costs that meet the criteria as they are expressed; new mid-program criteria create uncertainty and result in contentious proceedings
  - Regulators must be assured that costs are for eligible projects only and that costs and project are prudent

Special Purpose Project Example

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Targeted Infrastructure Recovery Mechanism (New England Gas Company)

Issue	Detail
Eligible TIR assets	Replacement of non-cathodically protected steel mains and services, small diameter (less than 8 inches) cast/wrought iron distribution mains and services, and any connected facilities
Eligible TIR asset costs	Capital costs of TIR plant investments including cost of removal and applicable overhead and burden costs
Revenue Requirement	Depreciation, property taxes, and return based on pre-tax cost of capital.
Cap	Annual incremental increase in TIR Revenue Requirements cannot exceed 1% of total revenues (distribution plus gas revenues, including imputed gas revenues from transportation customers)

Large Project Example

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Nuclear Power Plant Cost Recovery (Florida Power & Light)

Issue	Detail
Eligible assets	Nuclear power plants
Eligible asset costs	Costs incurred in the siting, design, licensing, and construction of eligible assets
Revenue Requirement	Rate of return, any applicable taxes and all expenses, including operation and maintenance expenses, related to or resulting from the siting, licensing, design, construction, or operation of eligible assets
Termination	Cost recovery through the Nuclear Power Plant Cost Recovery Clause ends when eligible asset is included in base rates
Other	Filings include true-ups for previous, current and remaining project years; projections for current and remaining project years

Comprehensive Capital Recovery Example

Capital Recovery Mechanism; included in RDM (Massachusetts Electric Company d/b/a National Grid)

Issue	Detail
Eligible Capital Spending	Annual plant additions less the annual allowance for depreciation expense in base rates, subject to Limit.
Revenue Requirement	Return on year-end average cumulative incremental rate base, at approved pre-tax weighted average cost of capital plus the annual depreciation on Cumulative Net CapEx.
Limit	Average of last 3 years annual plant additions ($170 million)
Cap	Annual incremental increase in rates from CRM and RDM shall not exceed 3% of total revenues. Increase above cap is recoverable (with interest) in following years.

Enbridge’s Proposed IR Plan

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Enbridge's Proposed IR Plan

- The 2nd Generation IRM is seen as evolving from the 1st Generation IRM

- Common Plan Elements:
  - 5 year term (2014-2018)
  - Revenue Cap per Customer
  - I Factor
  - X Factor
  - Y Factors
  - Z Factor
  - ESM and Off-ramps

- Possible New Plan Elements:
  - Capital Trackers
  - ROE Factor
  - Performance Measurement

Lunch

Performance Measurement : Preliminary Considerations

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Topics for Discussion

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- Performance Measurement
- Overview of Techniques
- Feedback

Performance Measurement

- Objective
  - Enhance visibility and transparency around performance management
- Factors impacting performance
  - Actions of management
  - Events beyond the control of management

Preliminary Considerations

- Formula driven
- Productivity tracking
- Scorecard
- Benchmarking

Objectives of Productivity Tracking and Reporting

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1. Simple and Transparent

2. Minimal Administrative Burden – Consistent with Efficient and Cost Effective Objectives

3. Focus on Materiality to Optimize the Resources and Time Spent on Tracking and Reporting

4. Transparent Linkages (Drivers) between Initiatives and Outcomes

5. Emphasize Results rather than Activities

Productivity Definition

= Efficient and Effective Use of Resources

= Doing Things Right + Doing the Right Things

= Optimal Balance between Effort and Outcomes that are Valued by all Stakeholders

= Reliable Energy Supply at a Reasonable Cost

Productivity Initiatives Tracking and Reporting

1. Tracking and Reporting will typically relate to:

   - Cost Savings, Revenue Generation, Avoided Costs, Cost Pressure Mitigation Savings, and Qualitative Benefits* resulting from any given Productivity Initiative

2. Reporting

   - Productivity Benefits will be Tracked by Major Initiatives

   - Results will be Reported to OEB under the subsequent Rebasing Application

* Qualitative Outcomes e.g., Customer Satisfaction, Reliable Energy Supply, Employee Engagement, Risk Management, etc.

Scorecard

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- Multi-dimensions
  - Financial perspective
  - Safety & Reliability perspective
  - Customer perspective
- SQRs incorporated

Benchmarking

- Peer group comparison
- Trend analysis
- Reporting at rebasing time

Feedback

Wrap-up

SEC INTERROGATORY #3

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Please provide a summary of the major reasons why Enbridge changed from a revenue cap approach to a Customized IR approach, including any reports, memoranda, or other such documents relating in whole or in part to this change in strategy prepared in the period December 2012 to and including April 2013.

RESPONSE

Please see responses to CCC Interrogatory #2 and #3 found at Exhibit I.A1.EGDI.CCC.2 and Exhibit I.A1.EGDI.CCC.3.

Witnesses: R. Fischer
M. Lister

SEC INTERROGATORY #4

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

(A2/1/1, p. 3 and A2/1/2, p. 12) "Enbridge's proposed Customized IR plan meets the Board's (and the Company's) objectives for an IR plan." Please explain how the Applicant's proposal decouples rates and costs, if at all, in a manner different from cost of service on a forward test year.

RESPONSE

Enbridge's plan establishes a revenue cap. A revenue cap decouples rates and costs because the actual costs that are experienced over time occur independently of the ability to request revenue relief, which is the typical manner that a cost of service on a forward test year operates (i.e., with a one-year lag).

Allowed Revenue in Enbridge's Application is determined by forecasting cost elements, building in productivity, and making a determination of where Enbridge will or can take risk (for example managing costs with no increase for FTE expenses, managing "variable" costs, managing O&M costs within inflation, etc.). These are the same activities that occur in an I-X framework; the difference lies in the determination of 'I' and 'X' where the 'I' and 'X' terms are used to approximate growth in costs and productivity. Enbridge believes it cannot operate within these approximations and therefore seeks to embed the 'I' and 'X' through forecasts in a Customized approach.

Therefore, the Customized IR plan achieves the decoupling of costs from revenues just as a revenue cap does, which is different from a traditional cost of service on a forward test year. A typical cost of service application resets the "bridge" year based on a current forecast. In the case of the Customized IR proposal, operating costs are built off the rebase year with no reset for 2013.

In their report filed at Exhibit A2, Tab 10, Schedule 1, page 24, LEI concludes:

> In short, Enbridge's Customized IR plan:
> - builds in strong productivity measures by virtue of the limits it puts on the rates that Enbridge can charge its customers. The forward-looking determination of a set allowed revenue amount for each year of the term of

Witnesses: R. Fischer
S. Kancharla
M. Lister

> the Customized IR plan commits Enbridge to safely and effectively operating its utility business under a very specific and firm "cost envelope," as described in Enbridge in its own application. The Customized IR plan also embeds a forward looking commitment on Enbridge to meet its own cost and productivity goals, as the actual expenditures made during the term of the Customized IR plan will be open for review when Enbridge prepares its next IR plan. Most impressively this process has resulted in other real O&M costs per customer (just over 50% of the O&M budget and excluding costs already reviewed by the OEB) continuing to decline over the regulatory period. This is occurring at a time when customer numbers are projected to further increase, demonstrating that Enbridge has embedded not only commitments for overall productivity improvements but also economies of scale efficiency gains; Enbridge is taking on real risks and challenges to contain costs over the term of the Customized IR plan. If, for example, variable capital costs come to be realized during the term of the Customized IR plan, Enbridge will need to fund those during the term through its pre-set allowed revenue amounts;

Furthermore, the most obvious difference between Enbridge's proposed plan and a traditional cost of service on a forward test year is that Enbridge's proposal is a five-year plan (see updates provided at Exhibit A2, Tab 1, Schedule 1), where a traditional cost of service on a forward test year is typically a one-year plan. That is, a traditional cost of service on a forward test year decouples rates (revenues) from costs for one year, where Enbridge's proposal decouples rates (revenues) from costs for five years.

Witnesses: R. Fischer
S. Kancharla
M. Lister

SEC INTERROGATORY #5

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Please provide a table that sets out forecasts of the Applicant's allowed distribution revenues, deficiency or sufficiency, and percentage rate increase/decrease for each year from 2014 to 2018, calculated on the assumption that rates are set on the basis set out for Union Gas in EB-2013-0202, Exhibit A, Tab 2, as approved by the Board. Please state explicitly any assumptions used by the Applicant (e.g. inflation rates) in calculating the amounts requested.

RESPONSE

The Assumptions used to generate the scenario described in the question above include the following:

Assumptions for 'Approximation of Union IRM':
- Escalation factor assuming GDPIPI of 1.7%, with 60% productivity factor
- Revenue cap Model
- Y factor treatment for GTA and Ottawa project
- DSM, CIS/Customer Care, Pension cost and carrying cost of Gas In Storage as flow through items
- 2013 Depreciation rate

Using these assumptions, EGD has calculated the resulting revenues that would be generated for each year over the 2014 to 2018 period. The table below sets out these revenues, as well as the Allowed Revenues excluding the depreciation rate changes and SRC credit impacts and calculates the difference between them as the resulting implied deficiency for each year.

Witnesses: K. Culbert
R. Fischer
A. Kacicnik
M. Lister

Revenue Requirement (Net of Gas Cost)						
$ Millions	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
	Board Approved					
Customized IR (Excluding Depreciation & SRC)	1,021	1,073	1,114	1,223	1,271	1,314
Approximation of Union IRM	1,021	1,031	1,046	1,107	1,117	1,126
Difference (Implied Deficiency)	-	(41)	(68)	(116)	(154)	(187)
Cumulative Difference		(41)	(110)	(184)	(271)	(342)

Finally, the estimated rate impacts associated with the revenues calculated above for "Approximation of Union IRM" are depicted below.

Estimated T-Service Rate Impact for the 2014 to 2018 period:

Rate Class	**Col. 1 2014**	**Col. 2 2015**	**Col. 3 2016**	**Col. 4 2017**	**Col. 5 2018**
1	-0.4%	1.5%	3.3%	0.3%	0.3%
6	-1.0%	1.1%	3.2%	0.2%	0.2%
100	0.0%	0.0%	0.0%	0.0%	0.0%
110	-0.7%	-1.2%	1.4%	0.2%	0.1%
115	0.0%	-1.7%	1.6%	0.2%	0.2%
135	0.3%	-2.0%	1.5%	0.2%	0.2%
145	-0.1%	-1.3%	1.6%	0.0%	0.0%
170	-0.1%	-2.2%	1.4%	0.3%	0.2%
200	-2.1%	-1.4%	0.8%	0.3%	0.2%

Witnesses: K. Culbert
R. Fischer
A. Kacicnik
M. Lister

SEC INTERROGATORY #6

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Please provide details of all material differences between the Applicant and Union Gas that would justify higher rates for the Applicant in the years 2014 through 2018.

RESPONSE

As explained in the pre-filed evidence, EGD's Customized IR application has been prepared to meet the specific circumstances facing EGD over the next five years. Thus, EGD's application is focused on its operations. EGD notes, however, that the rates for EGD and Union Gas have never been identical, and that Union Gas rates are different even within its own different operating areas.

EGD is not able to provide a detailed account of all material differences between EGD and Union Gas that influence the rates of each utility as EGD does not have detailed information regarding Union Gas' assets or operations. Further, EGD does not have any insight into the management strategy that resulted in the Union Gas 2014 to 2018 rate settlement agreement. Enbridge was not an active participant in the Union Gas 2014 to 2018 rate case settlement discussions.

EGD does understand, though, that there are differences between the two utilities. The following are some examples.

- Most obvious are the relative geographies of the different franchises and the higher level of urbanization in EGD's franchise area. This influences many items, including operations, relocations requirements and labour costs.
- With different customer mixes, as well as the different customer growth rates, each utility has a mix of assets being at differing points in their life cycle. This influences where the companies are in their respective asset renewal cycles.
- In addition to where in the asset renewal cycle the companies are, there may also exist different management philosophies guiding their operations and decision making.
- Also, different growth rates, especially within concentrated urban areas, may drive different reinforcement requirements.

Witnesses: R. Fischer
M. Lister
J. Sanders

Another difference between the two companies arises from Union Gas's Storage and Transportation ("S&T") business, both regulated and unregulated. Representing some 40 percent of Union Gas's investment, S&T has different drivers and different revenue and costs saving opportunities. This may influence the form of Incentive Regulation plan that will function effectively for Union Gas, as compared to Enbridge.

Finally, the benchmarking study produced by Concentric in the 2013 rebasing case (EB-2011-0354) provided a comparison on Customer, volumes, O&M, and Plant profiles for EGD and peer group utilities, inclusive of Union Gas up to and including 2009. That report generally showed EGD was a more efficient operator than Union Gas, which may also have implications for how the two utilities may differ in looking forward into the IR period. Specifically that report showed:

- Residential volumes as a % of Total – A greater proportion of EGD's system relates to residential usage; total costs for EGD would be expected to be higher.
- Total Natural Gas Volumes per Customer – Union has fewer customers taking more volumes; total costs would be expected to be higher for EGD.
- Natural Gas Customers per Kilometer Main – EGD has more customers per km of main (and more services); total costs would be expected to be higher for EGD
- Measures that show EGD's relatively greater efficiency include:

    - Total Net Plant per Customer
    - Total O&M Expense per Customer
    - Labour Costs per Customer (excluding and including capitalized amounts)
    - Labour Costs per Employee (excluding and including capitalized amounts)

Witnesses: R. Fischer
M. Lister
J. Sanders

SEC INTERROGATORY #7

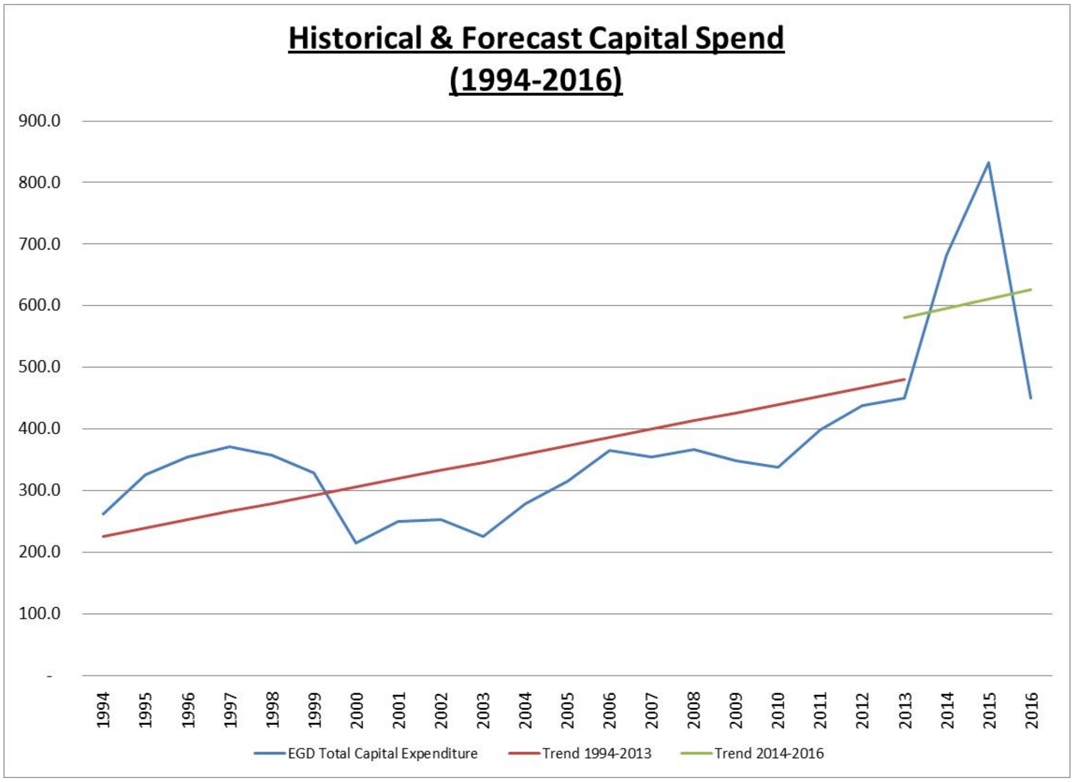
INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

(A2/1/1, p. 11) Please identify which of the Applicant's planned capital expenditures during the period 2014 through 2018 are "lumpy in nature", and the impact of that subset of capital expenditures on the capital spending for each year.

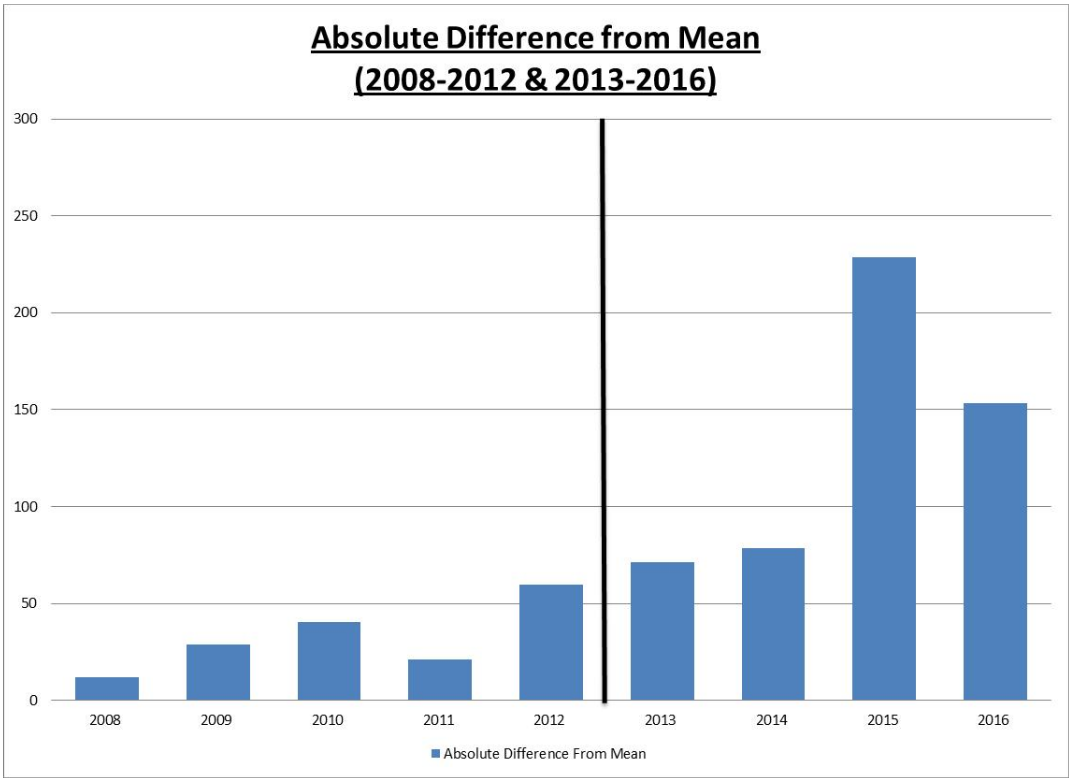
RESPONSE

Enbridge's total capital profile going forward is "lumpier" than it has been historically. The graph below shows capital spending over the period 1994 to 2016 forecast. It is evident that the projected capital amounts are greater and expected to be more volatile, particularly in 2014 and 2015, than historically.



Witnesses: R. Fischer
L. Lawler
M. Lister
J. Sanders

The graph below shows the “lumpiness” as the difference over the mean for two distinct periods, 2008 to 2012 and 2013 to 2016. By using the “absolute difference” from the mean for each period, it is evident that the dispersion of the annual total capital amounts is greater, or lumpier, in the projected period, relative to recent history.



As can be seen in the pre-filed evidence (Exhibit B2, Tab1, Schedule 1, Table 13), the major contributors to the increased dispersion of annual capital spending amounts are: 1) major reinforcements and 2) system improvements and upgrades.

Major Reinforcements

Both the Ottawa and GTA major reinforcement projects are discrete, new projects for which there was no comparable historical spend and are major contributors to the lumpiness. The contributions to the capital budget are $202 million in 2014 and

Witnesses: R. Fischer
L. Lawler
M. Lister
J. Sanders

$359.7 million in 2015, as shown below. More information regarding major reinforcements can be found at Exhibit B2, Tab 3, Schedule 2.

Leave to Construct	2013	2014	2015	2016
Ottawa Reinforcement	44.0	5.1	-	-
GTA Reinforcement	19.3	197.1	359.7	-
Total	63.3	202.2	359.7	-

System Improvements & Upgrades

As shown below, the contributions to the capital budget are $243.2 million in 2014, $247.8 million in 2015, and $242.2 million in 2016.

System Improvements and Upgrades	2008	2009	2010	2011	2012	2013	2014	2015	2016
Mains - Relocations	14.8	8.0	13.2	15.5	13.0	27.5	28.6	24.9	26.0
- Replacement	58.8	49.9	55.7	54.6	49.1	71.0	105.6	94.2	82.5
- Reinforcement	16.7	16.8	14.0	9.8	37.5	27.0	21.3	31.6	18.1
Total Improvement Mains	90.3	74.7	82.9	79.8	99.6	125.5	155.5	150.7	126.6
Services - Relays	30.4	37.0	45.8	45.9	48.1	17.3	29.8	34.5	52.1
Regulators - Refits	3.5	7.7	6.4	5.6	11.3	9.7	9.8	10.0	10.1
Measurement and Regulation	13.4	9.2	10.3	11.4	17.1	24.3	31.5	34.1	32.6
Meters	18.9	15.9	13.1	17.8	20.0	16.0	16.6	18.5	20.8
Total	156.5	144.5	158.5	160.5	196.1	192.8	243.2	247.8	242.2

More detailed information on the system improvements and upgrades portion of the capital budget can be found at Exhibit B2, Tab 5, Schedules 1 through 6.

Among other items within the capital budget, some are at higher levels than historical, and some are at lower levels. The combination of all of the line items within the capital budget, however, results in the increased “lumpiness” referenced in the pre-filed evidence.

Witnesses: R. Fischer
L. Lawler
M. Lister
J. Sanders

SEC INTERROGATORY #8

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

(A2/1/1, p. 11) Please provide a table, over as long a period as is available, but at a minimum 50 years, showing the Applicant's capital expenditures by asset class, and identify in that table which asset classes have a pattern of past "lumpy" spending.

RESPONSE

Please see the following table for capital expenditures by asset class from 1994 to 2012. Patterns of spending by asset class can be seen in the table on the following page. The requested information (capital expenditures by asset class) is not readily available for years prior to 1994.

Witnesses: L. Au
T. Knight

COMPARISON OF CAPITAL EXPENDITURES
1994 THROUGH 2012 ACTUAL
($M)

Item No.		Col. 1 Actual 1994	Col. 2 Actual 1995	Col. 3 Actual 1996	Col. 4 Actual 1997	Col. 5 Actual 1998	Col. 6 Actual 1999	Col. 7 Actual 2000	Col. 8 Actual 2001	Col. 9 Actual 2002	Col.10 Actual 2003	Col. 11 Actual 2004	Col. 12 Actual 2005	Col. 13 Actual 2006	Col. 14 Actual 2007	Col. 15 Actual 2008	Col. 16 Actual 2009	Col. 17 Actual 2010	Col. 18 Actual 2011	Col. 19 Actual 2012
A.	Customer Related																			
1.1.1	Sales Mains **	23.8	35.1	41.2	40.7	48.6	60.8	44.7	51.7	48.0	37.5	52.4	74.2	71.2	83.9	60.6	48.2	46.7	72.1	65.3
1.1.2	Services	41.4	42.6	46.1	53.0	50.4	51.7	53.7	50.9	49.7	59.3	54.4	47.4	52.3	40.9	49.3	48.7	52.6	55.9	71.8
1.1.3	Meters and Regulation	19.9	21.0	21.5	22.1	20.5	20.0	18.3	19.7	18.2	17.6	12.5	14.9	11.3	11.4	9.7	11.9	8.3	7.6	14.7
1.1.4	Customer Related Distribution Plant	85.1	98.7	108.8	115.8	119.5	132.5	116.7	122.3	115.9	114.4	119.3	136.5	134.8	136.2	119.6	108.8	107.6	135.6	151.8
1.1.5	NGV Rental Equipment ***	72.8	82.2	80.2	99.1	99.4	98.9	0.6	0.3	0.2	0.2	0.3	0.1	0.2	0.1	0.3	0.2	0.2	-	0.2
1.1	TOTAL CUSTOMER RELATED CAPITAL	157.9	180.9	189.0	214.9	218.9	231.4	117.3	122.6	116.1	114.6	119.6	136.6	135.0	136.3	119.9	109.0	107.8	135.6	152.0
B.	System Improvements and Upgrades																			
1.2.1	Mains - Relocations	7.4	4.8	3.0	4.8	3.7	1.7	5.8	3.4	5.3	4.5	11.0	6.5	9.8	11.2	14.8	8.0	13.2	15.5	13.0
1.2.2	- Replacement	21.6	22.3	22.4	20.9	19.5	13.3	18.9	28.3	25.6	28.9	21.5	49.1	82.1	49.7	58.8	49.9	55.7	54.6	49.1
1.2.3	- Reinforcement	4.2	5.8	8.3	6.2	9.7	3.1	3.4	9.7	22.7	12.2	12.2	4.2	19.0	17.1	16.7	16.8	14.0	9.8	37.5
1.2.4	Total Improvement Mains	33.2	32.9	33.7	31.9	32.9	18.1	28.1	41.4	53.6	45.6	44.7	59.8	110.9	78.0	90.3	74.7	82.9	79.8	99.6
1.2.5	Services - Relays	16.6	24.2	26.7	21.2	19.2	17.9	21.8	41.6	26.5	16.1	30.1	38.1	37.5	35.8	30.4	37.0	45.8	45.9	48.1
1.2.6	Regulators - Refits	2.1	3.6	5.0	4.0	3.1	3.2	1.4	1.5	7.8	3.1	1.7	8.4	2.4	3.1	3.5	7.7	6.4	5.6	11.3
1.2.7	Measurement and Regulation	5.8	7.2	6.8	6.7	8.1	8.0	6.8	9.0	15.2	6.8	9.0	5.9	9.4	15.6	13.4	9.2	10.3	11.4	17.1
1.2.8	Meters	1.5	5.0	6.2	6.1	5.1	4.6	3.6	3.9	3.1	2.5	10.7	13.1	16.5	19.3	18.9	15.9	13.1	17.8	20.0
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	59.2	72.9	78.4	69.9	68.4	51.8	61.7	97.4	106.2	74.1	96.2	125.3	176.7	151.8	156.5	144.5	158.5	160.5	196.1
C.	General and Other Plant																			
1.3.1	Land, Structures and Improvements	2.3	5.3	6.4	5.4	7.9	7.8	6.0	3.7	2.4	3.3	4.4	4.6	3.1	2.7	3.4	2.9	14.0	20.9	18.0
1.3.2	Office Furniture and Equipment	0.6	2.1	1.7	2.5	0.6	0.3	0.2	0.5	0.2	0.1	0.5	0.9	0.3	0.9	1.0	0.9	1.9	5.1	1.4
1.3.3	Transp/Heavy Work/NGV Compressor Equipment	1.9	2.4	2.6	2.9	2.8	2.2	2.3	1.8	1.9	1.9	4.0	2.6	9.8	7.4	11.0	11.4	6.5	7.4	3.1
1.3.4	Tools and Work Equipment	1.2	1.3	1.3	1.3	1.6	1.3	1.1	1.3	1.3	1.2	1.9	1.5	2.0	1.4	3.6	2.3	2.5	1.9	2.0
1.3.5	Computers and Communication Equipment	20.1	20.7	33.5	43.3	37.1	22.1	11.6	11.9	14.7	23.4	45.4	37.6	25.0	17.5	18.3	24.8	32.0	37.7	42.9
1.3	TOTAL GENERAL AND OTHER PLANT	26.1	31.8	45.5	55.4	50.0	33.7	21.2	19.2	20.5	29.9	56.2	47.2	40.2	29.9	37.3	42.3	56.9	73.0	67.4
D.	Underground Storage Plant	1.6	19.0	12.1	17.5	19.7	11.7	15.0	10.6	10.1	6.2	6.4	6.4	8.1	4.5	5.9	4.6	14.7	30.1	22.4
E.	Sub total "CORE" CAPITAL EXPENDITURES	244.8	304.6	325.0	357.7	357.0	328.6	215.2	249.8	252.9	224.8	278.4	315.5	360.0	322.5	319.6	300.4	337.9	399.2	437.9
F.	Customer Information System (CIS) /WAMS ****	17.4	20.8	29.3	13.5	-	-	-	-					4.5	32.4	46.4	48.7	(0.3)		
G.	Leave to Construct																			
1.7.1	Ottawa Reinforcement																			
1.7.2	GTA Reinforcement																			
1.7	TOTAL LEAVE TO CONSTRUCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H.	TOTAL CAPITAL EXPENDITURES	262.2	325.4	354.3	371.2	357.0	328.6	215.2	249.8	252.9	224.8	278.4	315.5	364.5	354.9	366.0	349.1	337.6	399.2	437.9
**	Power Generation Projects Included in Sales Mains														21.1	13.0	5.7	4.6	19.8	0.3
***	Pre- 2000 includes Water Heater Rentals																			
****	1994-1997 Strategic Information System																			

Witnesses: L. Au
T. Knight

SEC INTERROGATORY #9

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

(A2/1/1, p. 12 and A2/1/2) Please provide a table, in the same format as provided in Table 2 of Exhibit B1, Tab 2, Schedule 1, showing the capital expenditures of the Applicant by category before taking into account "the inclusion of anticipated productivity savings in the forecast cost elements".

RESPONSE

The response to SEC Interrogatory #11(Exhibit I.A1.EGDI.SEC.11) contains a tabular view of each capital budget review stage during the capital planning process, by category. From this table, one can see which program areas were reduced, and by how much. Productivity opportunities was one of several criteria used to reduce the capital budget for 2014 to 2016, as outlined in Exhibit B2, Tab 1, Schedule 1, pages 21 to 24.

In many cases, the capital budget reductions between review stages represented the net effect of multiple adjustments, and productivity is not explicitly quantifiable. In some cases, however, productivity opportunities can be more clearly identified and/or quantified. For example:

- Capitalized departmental labour costs have been held below 2013 levels through to 2016, to reflect the Company's intention to manage labour costs through attrition and operating efficiencies (see Exhibit B2, Tab 1, Schedule 1, pars. 21 to 22). These productivity savings are set out in Table 3 of Exhibit B2, Tab 1, Schedule 1, and are included and allocated across the major accounts set out within Table 2 of Exhibit B2, Tab 1, Schedule 1.

- Productivity improvements are implicit in the assumptions for direct cost per customer addition forecast for 2014 to 2016, captured in Exhibit B2, Tab 2, Schedule 1, Table 3, page 3. Despite a number of new and emerging cost pressures affecting customer additions capital outlined in Exhibit B2, Tab 2 Schedule 1, the Company has committed to holding these costs below at the budgeted 2013 level of $2,487 and increasing them only by inflation in 2014, 2015, and 2016. Given that the current (9+3) forecast of 2013 direct cost per customer addition is $2,665, the 2014 budget assumes productivity savings of

Witnesses: J. Sanders
P. Squires

around $180 per customer addition (around $6.5 million in total). That challenge will continue for 2015 to 2018.

- Productivity opportunities have been captured in the General and Other Plant categories such as fleet costs, for which expected increases in fleet units over the forecast period will be absorbed through fleet management efficiencies. Other productivity opportunities in this category are outlined in Exhibit B2, Tab 9, Schedule 1, pages 15 and 16.

Witnesses: J. Sanders
P. Squires

SEC INTERROGATORY #10

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

(A2/1/1, p. 12 and A2/1/2) Please provide a table, in the same format as provided in Table 10 of Exhibit D1, Tab 3, Schedule 1, showing the Operations and Maintenance Expense of the Applicant by Department before taking into account "the inclusion of anticipated productivity savings in the forecast cost elements".

RESPONSE

To the extent that the anticipated productivity savings embedded in the budget are anticipated at the overall Company level, the allocation of savings by department would be arbitrary in some elements.

The overall O&M forecasts excluding the savings are provided in the response to CCC Interrogatory #21, found at Exhibit I.B17.EGDI.CCC.21.

Individual productivity items are quantified in the response to Board Staff Interrogatory #19, found at Exhibit I.A2.EGDI.STAFF.19.

Witnesses: S. Kancharla
M. Torriano

SEC INTERROGATORY #11

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

(A2/1/1, p. 18) *"Enbridge's forecast capital spending requirements for 2014 to 2016 were determined through a rigorous process that examined all proposed areas of capital spending, and then prioritized and paced the associated spending."* Please provide all reports, memoranda, analyses, and other such documents, including without limitation draft capital budgets, that support this statement.

RESPONSE

Throughout the capital budgeting process, several artifacts were reviewed by the Capital Owner Committee. The Capital Owner Committee utilized a set of central or consolidated spreadsheets as the repositories to record outcomes of each review. The capital budget process also produced management presentations.

The following attachments are provided in response to the request for information that supports Enbridge's statement that a rigorous process examined all proposed areas of capital spending:

- Attachment 1 - Draft Capital Budgets Repository 1: Spreadsheet view of the Capital Budget review database. This spreadsheet provides by year and for each review the budgeted amounts for each of the proposed programs or projects.
    a. The spreadsheet view provides a numerical listing of variations through the six reviews for each of the project budgets.
- Attachment 2 - Management Presentation 1: Presentation to management outlining Review 3 findings and decisions.
    b. Major reductions to Customer Related capital were implemented and approved.

Witnesses: S. Kancharla
J. Sanders
P. Squires

- Attachment 3 - Management Presentation 2: Presentation to management outlining Review 5 findings and decisions.
    a. Reductions of Customer Related capital and Overheads (Direct Labour Cost, Administrative and General and Interest During Construction) are reconfirmed.
    b. Proposal to move to a 3 year Customized IR model with Capital refresh were approved.
- Attachment 4 - Management Presentation 3: Presentation of spreadsheet with comments outlining Review 6 findings and recommendations.
    c. Reductions proposed to a variety of capital programs or projects as a result of review of detailed program evidence.

Witnesses: S. Kancharla
J. Sanders
P. Squires

CONTINUITY OF DRAFT CAPITAL BUDGET DETAILS FROM REVIEW 1 TO REVIEW 6
($Ks)

		2014 FIRM COSTS						2014 VARIABLE COSTS				2015 FIRM COSTS						2015 VARIABLE COSTS				2016 FIRM COSTS						2016 VARIABLE COSTS			
PL CATG	Project Name or Blanket Program	Review 1	Review 2	Review 3	Review 4	Review 5	Review 6	Review 3	Review 4	Review 5	Review 6	Review 1	Review 2	Review 3	Review 4	Review 5	Review 6	Review 3	Review 4	Review 5	Review 6	Review 1	Review 2	Review 3	Review 4	Review 5	Review 6	Review 3	Review 4	Review 5	Review 6
1. CUST REL	cust related (473 direct)			58,358	58,358	58,358	58,358							62,518	62,518	62,518	62,518							65,683	65,683	65,683	65,683				
	cust related (475 direct)			20,842	20,842	20,842	20,842							22,328	22,328	22,328	22,328							23,458	23,458	23,458	23,458				
	Customer Attachment	90,883	90,883									97,922	97,922									104,960	104,960								
	Customer Attachment Overhead - BDCS	3,035	3,035	3,035	3,035	3,035	3,035					3,107	3,107	3,107	3,107	3,107	3,107					3,179	3,179	3,179	3,179	3,179	3,179				
	Customer related 477		5,719	4,168	4,168	4,168	4,168						6,162	4,466	4,466	4,466	4,466						6,604	4,692	4,692	4,692	4,692				
	Meter Costs		5,461	4,466	4,466	4,466	4,466						5,884	4,784	4,784	4,784	4,784						6,307	5,026	5,026	5,026	5,026				
	system expansion - bdcs		285	285	285	285	285						293	293	293	293	293						302	302	302	302	302				
1. CUST REL Total		**93,919**	**105,384**	**91,156**	**91,156**	**91,156**	**91,156**					**101,028**	**113,367**	**97,495**	**97,495**	**97,495**	**97,495**					**108,139**	**121,352**	**102,340**	**102,340**	**102,340**	**102,340**				
2. SYS IMPR	1" Steel Mains (Study)			-	-	-								-	-	-								-	-	-					
	2.5 km of NPS 16" HP from Node 1803363 to 1900043 fr	-	50	-	-	-						-	50	-	-	-						-	50	-	-	-					
	20-Inch Lakeshore Line Replacement	5,610	5,610	5,610	5,610	5,610						-	750	-	-	-						-	-	-	-	-					
	3.5 km of NPS 16" HP Steel Main from New Bayview Stat	-	-	-	-	-						-	-	-	-	-						-	-	-	-	-					
	4.0 km of NPS 12" HP from Node 1802294 to 1802241 to	-	-	-	-	-						-	-	-	-	-						-	-	-	-	-					
	4.2 km of HP on Bathurst from Steeles to Sheppard & 3	-	-	-	-	-						-	-	-	-	-						-	-	-	-	-					
	4.5 km of NPS 12" HP from Node 1803252 to 1890057, (	-		-	-	-						-		-	-	-						-	500	-	-	-					
	AC Corrosion (Anderson Road)		-	-	-	-							2,081	(0)	(0)	(0)							-	-	-	-					
	AC Corrosion (Remediation work)		102	102	102	102	102						52	52	52	52	52						27	27	27	27	27				
	Alliston Reinforcement Phase 2, 1.5 km NPS 8	1,020	1,020	-	-	-	-					-	-	1,040	1,040	1,040	1,040					-	-	-	-	-	-				
	Alliston Reinforcement Phase 3, 2.8 km NPS 8	-	-	-	-	-	-					2,069	2,069	-	-	-	-					-	-	2,111	2,111	2,111	2,111				
	Alliston Reinforcement Phase 4, 3 km NPS 6	-	-	-	-	-						-	-	-	-	-						-	-	-	-	-					
	AMP Fitting Replacement	10,200	9,272	9,272	9,272	9,272	8,543	27,387				31,212	37,951	10,564	37,951	24,257	13,100		-	13,814	13,814	31,836	38,965	11,337	38,965	25,151	30,046	27,628	-	13,694	13,694
	Anodeless Riser Replacement	275		-	-	-						281		-	-	-						669		-	-	-					
	Approx. 6700m of NPS 20 ST HP pipe from Greenbank to	-	-	-	-	-						-	-	-	-	-						-	-	-	-	-					
	Bare Steel Drips (study & removal program)		255	255	255	255	255	2,289					312	-	-	-	-		2,289	2,335	2,335		318	-	-	-	-	2,335	2,335	2,289	2,289
	Bare Steel Services Replace		510	-	-	-	-	208					520	0	0	0	0		208				531	0	0	0	0			208	208
	Bare Steel Services Study	-										208										-									
	Cambrian Road Phase 2	408	408	408	408	408	408					-	-	-	-	-	-					-	-	-	-	-	-				
	Casing Study & Program	510	510	510	510	510	510	520				520	520	-	-	-	-		520	531	531	531	531	-	-	-	-	531	531	520	520
	Central East	5,406	5,406	5,406	5,406	5,406	5,406					5,514	5,514	5,514	5,514	5,514	5,514					5,624	5,624	5,624	5,624	5,624	5,624				
	Central West	2,856	2,856	2,856	2,856	2,856	2,856					2,913	2,913	2,913	2,913	2,913	2,913					2,971	5,000	2,971	2,971	2,971	2,971				
	Chicago Fitting Study	204	204	204	204	204	204					-	-	-	-	-	-					-	-	-	-	-	-				
	Chippawa Creek Road Reinforcement, Replace approx. 4	408	408	408	408	408	408					-	-	-	-	-	-					-	-	-	-	-	-				
	Coated Steel Program (Mains & Services)	367	367	362	362	362	362	375				375	375	-	-	-	-		375	382	382	-	382	-	-	-	-	382	382	375	375
	Collingwood RNF -apr 18					7,750										-										-					
	Compliance of Integrity Programs	1,224	1,248	0	0	0						1,248	1,299	(0)	(0)	(0)						1,273	1,351	0	0	0					
	Compression Outlet Service Tee Study	-	1,275	2,866	2,866	2,866	2,866	2,924				-	1,301	-	2,924	2,924	2,924		-	-	-	-	1,327	-	2,982	2,982	2,982	2,982	-	-	-
	Contingency to account for additional Reinforcement re	2,805	2,805	2,805	2,805	2,805	2,805					2,861	2,861	2,861	2,861	2,861	2,861					2,918	2,918	2,918	2,918	2,918	2,918				
	Damages to Steel Mains (develop Damage Prevention technology, c		255	-	-	-							260	0	0	0							265	0	0	0					
	Distribution Integrity Technology			1,597	1,597	1,597	1,597							1,934	1,934	1,934	1,934							2,063	2,063	2,063	2,063				
	Distribution Records Management Program	8,160	8,160	8,160	8,160	8,160	9,639					7,283	7,283	7,283	7,283	7,283	8,740					6,367	6,367	6,367	6,367	6,367	7,695				
	District Station Equipment Replacement	2,550	6,477									2,601	10,078									2,653	10,984								
	District/Header Station Equipment Replacement			2,907	6,477	6,477	6,477	6,763	-	-	-			2,965	9,728	9,728	9,728	3,570	(0)	(0)	(0)			4,086	10,984	10,984	10,984	6,898	(0)	(0)	(0)
	Don River Bridge Crossing Replacement	9,700	9,700	9,700	9,700	9,700	-					(0)	(0)	(0)	(0)	(0)	(0)					0	0	0	0	0	0				
	Eastern	1,087	1,087	1,087	1,087	1,087	1,087					1,199	1,199	1,199	1,199	1,199	1,199					1,325	1,325	1,325	1,325	1,325	1,325				
	EFV Program	1,530	2,754	-	-	500	500	2,809	2,754	2,254	2,254	-	7,023	-	-	1,404	604	2,754	2,809	1,432	1,432	-	7,163	-	-	1,433	733	2,865	2,865	1,405	1,405
	Encased Bridge Crossings Study	-	-	-	-	-	-					208	-	208	208	208	208					-	212	0	0	0	0				
	Expansion Joint Study	-	-	-	-	-						-	-	-	-	-						-	-	-	-	-					
	Failure of Bonnet Bolts on Valves Study	-		-	-	-	-					-		-	-	-	-			212	212	212	212	-	-	-	-	212	212		
	Farm Tap Study	-	-	-	-	-	-					208	208	208	208	208	208					-	265	265	265	265	265				
	Field Applied Coatings Study	-		-	-	-						-		-	-	-						-		-	-	-					
	Gate Station Equipment Replacement	5,100	8,160	6,630	11,730	13,230	12,160	2,601	-	-	-	5,202	8,323	6,242	8,843	11,444	10,440	5,100	-	0	0	5,306	8,490	6,367	9,020	11,673	7,060	2,653	0	-	-
	Green Bank Reinforcment	51	51	51	51	51	51					-	-	-	-	-	-					-	-	-	-	-	-				
	Growth Related M&R	5,719										6,162										6,604									
	Header Stations	1,000	5,300	1,500	1,500	1,500	1,500					1,020	5,300	1,537	1,537	1,537	1,537					1,040	5,300	1,576	1,576	1,576	1,576				
	ILI for pipelines over 20% SMYS	10,200	10,200	-	-			10,404	10,200			10,404	10,404	-	-			10,200	10,404			10,612	10,612	-	-			10,612	10,612		
	ILI for pipelines over 20% SMYS plus HCA					4,000	4,000			6,200	6,200					4,080	4,080			6,450	6,450					4,162	4,162			6,324	6,324
	ILI for pipelines over 30% SMYS					1,000	7,000									1,020	4,820									1,040	4,340				
	Innes and Orleans Station	92	92	92	92	92	92					-	-	-	-	-						-	-	-	-	-					
	Inside Regulator Replacement	-	82	36	36	36	36					-	83	5	5	5	5					-	85	5	5	5	5				
	Install 1050m of NPS 4 on 6th Concession, from Silver Sp	-	-	-	-	-						-	-	-	-	-						424	424	-	-	-					
	Install 1200m NPS 12 HP main in new development to a	918	918	1,530	1,530	1,530	1,530					-	50	-	-	-	-					-	50	-	-	-	-				
	Install 1200m of NPS 8 on Hwy 7, from stn# 33027 to We	-	25	-	-	-						-	25	-	-	-						-	25	-	-	-					
	Install 2.5km of NPS 8 ST XHP westerly on HWY 35/7 from ex. NPS 8 ST XHP so			-	-	-	-							1,665	1,665	1,665	1,665							-	-	-	-				
	Install 2.8 km of NPS 8 ST HP main from ex NPS 8 HP ma	-	2,500	-	-	-	-					-	2,500	-	-	-	-					-	2,500	-	-	-	-				
	Install 200m of NPS 4 on Holburn, from Leslie to Woodbine (NOT NEEDED)			-	-	-								-	-	-								-	-	-					
	Install 2200m of NPS 8 on 19th Ave, from 9th Line to Rec	-	20	-	-	-						-	20	-	-	-						-	20	-	-	-					
	Install 253.7m NPS 6 connect 21820195 to NPS 24 PineV	-	-	-	-	-						-	-	-	-	-						-	-	-	-	-					
	Install 300m of NPS 4 ST HP on Whites from south of HW	-	-	-	-	-	-					208	208	208	208	208	208					-	-	-	-	-	-				
	Install 400m of NPS 4 on Hwy 27, from Hwy 9 south, with XHP to HP station Sc			-	-	-								-	-	-								-	-	-					

CONTINUITY OF DRAFT CAPITAL BUDGET DETAILS FROM REVIEW 1 TO REVIEW 6

($Ks)

		2014 FIRM COSTS						2014 VARIABLE COSTS				2015 FIRM COSTS						2015 VARIABLE COSTS				2016 FIRM COSTS						2016 VARIABLE COSTS			
PL CATG	Project Name or Blanket Program	Review 1	Review 2	Review 3	Review 4	Review 5	Review 6	Review 3	Review 4	Review 5	Review 6	Review 1	Review 2	Review 3	Review 4	Review 5	Review 6	Review 3	Review 4	Review 5	Review 6	Review 1	Review 2	Review 3	Review 4	Review 5	Review 6	Review 3	Review 4	Review 5	Review 6
2. SYS IMPR	Install 570m of NPS 8 on 16th Ave, from Granton to Spa	-	250	-	-	-						-	-	-	-	-						-	-	-	-	-					
	Install 6500m of NPS 16 on Woodbine, from Bloomingto	-	100	-	-	-						-	100	-	-	-						-	200	-	-	-					
	Install 6800m of NPS 8 on Glenwoods/Warden, from Woodbine to Bethel Sdrc			-	-	-								-	-	-								-	-	-					
	Install 7400m of NPS 16 on Woodbine, from Victoria Squ	510	510									10,404	10,404									-	20								
	Install approximately 1000m of NPS 6 ST HP on Hurontai	765	765	-	-	-	-					-		780	780	780	780					-		-	-	-	-				
	Isolated Steel Mains (Study)		82										83										85								
	Isolated Steel Mains CP Program			82	82	82	82	83						-	-	-	-		83	85	85			-	-	-	-	85	85	83	83
	Isolated Steel Remediation Program			1,326	1,326	1,326	1,326							1,353	1,353	1,353	1,353							-	-	-	-				
	Isolated Steel Study	1,326	1,326									1,353	1,353									-	-								
	Isolation Valve Study & Installation (RCV / ASV)	3,060	3,060									3,121	3,121									3,184	3,184								
	Jumper and Service Extension Study	102	102	408	408	408	408					104	104	208	208	208	208					106	106	212	212	212	212				
	Jumpers (Remediation program)		306	-	-	-							104	0	0	0							106	0	0	0					
	Kingston Road Reinforcement, install 2.4 km of NPS 4 ST	918	2,918	918	918	918	918					-	17,850	-	-	-	-					-		-	-	-	-				
	Lansdowne Park NPS 12 ST IP			1,224	1,224	1,224	1,224							-	-	-	-							-	-	-	-				
	Lisgar Gate Station Rebuild			-	-	-								-	-	-								-	-	-					
	Load Research Program	548	548	0	0	0	0	560	548	548	548	560	560	0	0	0	0	548	560	572	572	572	572	0	0	0	0	572	572	560	560
	Load Shed Zone			2,295	2,295	2,295	1,145	2,341						-	-	1,171	1,171		2,341	1,194	1,194			-	-	1,194	1,194	2,388	2,388	1,170	1,170
	Low Pressure Delivery Meter Set Program	3,060	3,060	-	-	1,530	1,530	4,682	3,060	1,530	1,530	5,202	5,202	-	-	2,341	2,341	3,060	4,682	2,387	2,387	5,306	5,306	-	-	2,388	2,388	4,775	4,775	2,341	2,341
	Meter Barrier Study & Program	-		-	-	-						-	-	-	-	-						-	50	-	-	-					
	Meter boxes		179	-	-	-	-	182	179	179	179		182	-	-	-	-	179	182	186	186		186	-	-	-	-	186	186	182	182
	Meter Costs	5,461										5,884										6,307									
	Meters (MXGI)	18,452	18,821	18,821	18,821							19,906	20,710	20,710	20,710							21,645	22,970	22,970	22,970						
	Meters (MXGI) - replacement 478 at apr18					14,355	14,355									15,926	15,926									17,944	17,944				
	Miscellaneous Replacement Mains	4,080	4,080	4,080	4,080	4,080	5,388					4,162	4,162	4,162	4,162	4,162	5,866					4,245	4,245	4,245	4,245	4,245	5,058				
	N-1 reliability of supply for Single source networks		-	-	-	-	-						1,040	520	520	520	520			-	-		1,061	0	0	0	0	-	-		
	Network OPS/ORM M&R LEAK	1,758		1,758	1,758	1,758	1,758					1,794		1,794	1,794	1,794	1,794					1,830		1,830	1,830	1,830	1,830				
	Niagara	632	632	632	632	632	632					645	645	645	645	645	645					658	658	658	658	658	658				
	Operate Gas Network - SMART System	3,570	-	-	-	-						6,763	-	-	-	-						6,898	35	-	-	-					
	Peterborough Reinforcement Phase 2 - Install approxima	1,530	1,530	1,530	1,530	1,530	1,530					-	-	-	-	-	-					-	-	-	-	-	-				
	Peterborough Reinforcement Phase 3 - Install 1.9 km of	-	-	-	-	-						-	-	-	-	-						-	-	-	-	-					
	Pipeline Markers	-	100	10	10	10	10					-	100	10	10	10	10					-	100	11	11	11	11				
	Plastic Mains & Services Technology (further develop pipe locator	-	102										104																		
	Plastic Mains (Incl Services) Study	-	-	-	-	-	-	10,925	-	-	-	12,485	9,364	-	-	-	-	-	10,925	11,143	11,143	21,224	15,918	-	-	-	-	11,143	11,143	10,925	10,925
	Platic Mains & Services (w/ EFV) (Enhanced Education Program)			-	-	-								-	-	-								-	-	-					
	Pressure elevate HP network 6597 feeding Richmond to	-	-	1,020	1,020	1,020	1,020					1,040	1,040	-	-	-	-					-	-	-	-	-	-				
	Reg Refits	8,914	8,914	8,914	8,914	8,914	9,814					9,285	9,285	9,285	9,285	9,285	9,985					9,671	9,671	9,671	9,671	9,671	10,171				
	Relays	9,473	4,737	4,737	4,737	4,737	4,737					10,097	5,049	5,049	5,049	5,049	5,049					10,763	5,381	5,381	5,381	5,381	5,381				
	Remote Control Valve Study & Installation			765	765	765	565	7,803						-	-	3,902	602		7,803	3,979	3,979			-	-	3,980	680	7,959	7,959	3,901	3,901
	Remotely operated Valves (ASV's)		765										780										7,959								
	Replace 1.8 km of NPS 12 XHP main with 1.8km of NPS 1	-	-	-	-	-	-					-	-	-	-	-	-					3,714	3,714	3,714	3,714	3,714	3,714				
	Replace 1181.5m of NPS 4 with NPS 8 on Hurontario, frc	-	-	-	-	-						-	-	-	-	-						-	-	-	-	-					
	Replace 1279.9m NPS 4 with NPS 8 from 1803184 to 18(	-	-	-	-	-						-	-	-	-	-						-	-	-	-	-					
	Residential Meter Sets Study (incl. SMART system)	204		-	-	-						-		-	-	-						-		-	-	-					
	Sewer Safety Program	706	1,530	1,530	1,530	1,530	1,530					720	1,561	1,561	1,561	1,561	1,561					734	1,592	1,592	1,592	1,592	1,592				
	smoothing of Reinforcements per Asset plan -Erik revisions			-	-	-								-	-	-								-	-	-					
	Sombra Tecumseh Redundancy	2,000	2,000	-	-	-	-	17,850	2,000	2,000	2,000	17,850	17,850	-	-	-	-	2,000	17,850			-		-	-	-	-			17,850	17,850
	Targeted Compression Couplings Pressure Containment	2,040	2,040	1,122	1,122	1,122	1,622	2,081				2,081	2,081	-	-	1,040	2,040		2,081	1,061	1,061	2,122	2,122	-	-	1,061	2,061	2,122	2,122	1,041	1,041
	Thorton Gate pressure elevation (includes Baxter and Inissville beach road)			765	765	765	765							-	-	-	-							-	-	-	-				
	Toronto	5,355	5,355	5,355	5,355	5,355	5,255					5,514	5,514	5,514	5,514	5,514	3,114					5,624	5,624	5,624	5,624	5,624	2,024				
	Vanjumar Pressure Elevation	133	133	133	133	133	133					-	-	-	-	-	-					-	-	-	-	-	-				
	Verification of MAOP	14,426	19,380	7,140	7,140	12,444	3,296	9,572	10,608	5,304	5,304	8,000	19,768	7,282	7,282	12,068	3,397	10,608	9,572	4,881	4,881	8,000	20,163	7,429	7,429	12,311	3,195	9,763	9,763	4,786	4,786
	WingLock Valve Study & Replacement	3,060	204	204	204	204	204	832				3,121	832	-	-	-	-		832	849	849	3,184	849	-	-	-	-	849	849	832	832
	XHP/HP Services at Buildings (Study)			-	-	-							104	0	0	0							106	0	0	0					
	york region rapid transit ph1 -apr 18					3,000										-										-					
	york region rapid transit ph2 - apr 18					2,000										-										-					
	York Region Reinforcement Phase 1 - 6.5km of NPS16 XHP. Install on Bathurst			510	510	510	510							10,404	10,404	10,404	10,404							-	-	-	-				
2. SYS IMPR Total		**169,483**	**171,614**	**129,632**	**138,302**	**160,421**	**130,150**	**113,190**	**29,349**	**18,015**	**18,015**	**211,786**	**250,583**	**115,675**	**155,349**	**159,216**	**140,546**	**38,019**	**73,515**	**51,494**	**51,494**	**196,155**	**223,808**	**110,382**	**150,542**	**154,495**	**145,001**	**96,940**	**56,780**	**68,485**	**68,485**
3. ALLOC	AG	36,523	36,523	35,434	35,434	35,434	35,500					37,072	37,072	35,555	35,555	35,555	36,440					37,664	37,664	35,823	35,823	35,823	37,140				
	Distribution Operations	37,625	37,625	38,697	38,697	33,839	33,839					38,378	38,378	38,142	38,142	33,728	33,728					39,145	39,145	38,524	38,524	34,022	34,022				
	Governance & Control	4,217	4,217	2,952	2,952	2,952	2,952					4,302	4,302	3,011	3,011	3,011	3,011					4,388	4,388	3,071	3,071	3,071	3,071				
	IDC - core	7,435	7,435	7,800	7,800	7,800	7,800					8,981	8,981	7,251	7,251	7,251	7,251					9,825	9,825	6,999	6,999	6,999	6,999				
	Operations	296	296	296	296	296	296					302	302	302	302	302	302					308	308	308	308	308	308				
	Safety	745	745	745	745	745	745					220	220	220	220	220	220					224	224	224	224	224	224				
	System Operations	14,085	14,085	14,260	14,260	14,260	14,260					12,545	12,545	12,725	12,725	12,725	12,725					13,753	13,753	13,936	13,936	13,936	13,936				
	System Measurement - Indirect	624	624	624	624	624	624					645	645	645	645	645	645					666	666	666	666	666	666				
	Ops-Eng Admin	1,355	1,355	1,355	1,355	1,355	1,355					1,400	1,400	1,400	1,400	1,400	1,400					1,446	1,446	1,446	1,446	1,446	1,446				
	Engineering Material Miscellaneous	986	986	986	986	986	986					1,019	1,019	1,019	1,019	1,019	1,019					1,052	1,052	1,052	1,052	1,052	1,052				
	Toronto -Leak Survey	447	447	447	447	447	447					461	461	461	461	461	461					477	477	477	477	477	477				
	Engineering Distribution Planning	14,377	14,377	14,377	14,377	14,377	14,377					14,731	14,731	14,731	14,731	14,731	14,731					15,093	15,093	15,093	15,093	15,093	15,093				

CONTINUITY OF DRAFT CAPITAL BUDGET DETAILS FROM REVIEW 1 TO REVIEW 6
($Ks)

		2014 FIRM COSTS						2014 VARIABLE COSTS			
PL CATG	Project Name or Blanket Program	Review 1	Review 2	Review 3	Review 4	Review 5	Review 6	Review 3	Review 4	Review 5	Review 6
3. ALLOC	Distribution Technology Miscellaneous	105	105	105	105	105	105				
	Engineering System Reliability Miscellaneous	635	635	635	635	635	635				
	Engineering Admin	516	516	516	516	516	516				
	Quality and Training Administration	381	381	381	381	381	381				
	Engineering Quality Assurance Miscellaneous	611	611	611	611	611	611				
	Technical Training Miscellaneous	2,714	2,714	2,714	2,714	2,714	2,714				
	Engineering System Regulation Miscellaneous	1,347	1,347								
3. ALLOC Total		**125,025**	**125,025**	**122,935**	**122,935**	**118,077**	**118,143**				
3.1 DIRECT SYS	ASM - DAM GIS Records	1,042	1,042	1,042	1,042	1,042	1,042				
	ASM - DAM GIS Records Incremental Addition			150	150	150	150				
	Distribution Operations - DIRECT ohd					4,858	4,858				
	Fixed Oh to EA contractors	5,628		5,628	5,628	5,628	5,628				
	PSR REDUCTION TO OFFSET ENVISION AND AMP FITTINGS						(1,000)				
	Ops- Eng Admin Incremental			130	130	130	130				
	Engineering Distribution Planning -Incremental			1,195	1,195	1,195	1,195				
	Engineering Damage Prevention	2,875	2,875	2,875	2,875	2,875	2,875				
	Engineering Damage Prevention -incremental			90	90	90	90				
	Engineering Integrity Management	3,707	3,707	3,707	3,707	3,707	3,707				
	Engineering Integrity Management - incremental			140	140	140	140				
	Engineering Admin - incremental			100	100	100	100				
	Engineering System Regulation Miscellaneous -Increment			260	260	260	260				
	Engineering Quality Assurance Miscellaneous -Incremental			35	35	35	35				
	Technical Training Miscellaneous - incremental			255	255	255	255				
	Engineering System Regulation Miscellaneous			1,347	1,347	1,347	1,347				
3.1 DIRECT SYS IMPR OHD Total		**13,252**	**7,624**	**16,955**	**16,955**	**21,813**	**20,813**				
3.2 Envision Ex	ENVISION EXTENSION						8,000				
3.2 Envision Extension Total							**8,000**				
4. GENL	Building Improvements	3,475	2,000	2,000	2,000	5,090	5,090				
	Central Region West Operations Depot		1,000	1,000	1,000						
	Community events requirements - vehicles, vehicle wrapping, BBQ's, tents, etc			25	25	25	25				
	Convert Vacated Meter Shop space at VPC into 200 offices					-	-				
	Fleet	7,800	7,800	5,300	5,300	5,300	5,300	2,500	2,500	2,500	2,500
	Fleet Garage Relocation to a New Leased Property					-	-				
	Meter Shop Addition to the Toronto Ops Depot		4,000	4,000	4,000						
	Meter Shop Relocation to Markland Leased Property					3,000	3,000				
	Natural Gas Transportation - Customer Compressor Stat	7,612	7,612	5,000	5,000	5,000	2,000	2,612	2,612	2,612	2,612
	Natural Gas Transportation - Rental Cylinders	69	69	69	69	69	69				
	Natural Gas Transportation - Rental VRA's	1,412	1,412	1,412	1,412	1,412	1,412				
	Natural Gas Transportation - Utility Compressor Station	105	105	105	105	105	105				
	Natural Gas Transportation - Utility Fleet Cyliners	51	51	51	51	51	51				
	Natural Gas Transportation - Utility Fleet Vehicle Conver	458	458	458	458	458	458				
	New Office / Conference / Space Alterations	3,315	2,000	3,000	3,000	4,830	4,830				
	Office Furniture and Equipment	3,630	2,550	3,550	3,550	4,630	4,630				
	Tools and Work Equipment	125	125	125	125	125	125				
	Toronto Operations Depot and Fleet Garage		3,000	3,000	3,000						
4. GENL Total		**28,052**	**32,182**	**29,095**	**29,095**	**30,095**	**27,095**	**5,112**	**5,112**	**5,112**	**5,112**
5. IT	Altra GMS / SCADA / GDMS	300	300	300	300	300	300				
	Capital & OM Analytics Upgr						200				
	CIS	4,800	4,800	4,800	4,800	4,800	6,800				
	Clarity	-	-	-	-	-					
	COMMS	500	500	500	500	500	300				
	Customer Care Improvement Initiative						6,500				
	Data Centre Operations	2,900	2,100	2,100	2,100	2,100	2,100				
	Datapak / iViewer	200	200	200	200	200	200				
	DSM DARTs	-	-	-	-	-					
	eBridge upgrade			-	-	-					
	EDMS	200	200	200	200	200	200				
	EHS	100	100	100	100	100	100				
	eInvoice	100	100	100	100	100	100				
	eLMS	200	200	200	200	200	200				
	EnMAR	100	100	100	100	100	100				
	Enterprise GIS	500	500	500	500	500	500				
	EnTRAC	-	-	-	-	-	-				
	EQAT			-	-	-					
	ESM / SRM	400	400	400	400	400	400				
	Extranet	1,000	1,000	1,000	1,000	1,000					
	Gas Molecule	1,000	1,000	1,000	1,000	1,000	1,000				
	Gas Storage	800		-	-	-					
	Gas Storage - GIS	1,000	1,000	1,000	1,000	1,000	1,000				

		2015 FIRM COSTS						2015 VARIABLE COSTS			
PL CATG	Project Name or Blanket Program	Review 1	Review 2	Review 3	Review 4	Review 5	Review 6	Review 3	Review 4	Review 5	Review 6
3. ALLOC	Distribution Technology Miscellaneous	108	108	108	108	108	108				
	Engineering System Reliability Miscellaneous	656	656	656	656	656	656				
	Engineering Admin	533	533	533	533	533	533				
	Quality and Training Administration	394	394	394	394	394	394				
	Engineering Quality Assurance Miscellaneous	629	629	629	629	629	629				
	Technical Training Miscellaneous	2,788	2,788	2,788	2,788	2,788	2,788				
	Engineering System Regulation Miscellaneous	1,392	1,392								
3. ALLOC Total		**126,554**	**126,554**	**120,568**	**120,568**	**116,154**	**117,039**				
3.1 DIRECT SYS	ASM - DAM GIS Records	1,077	1,077	1,077	1,077	1,077	1,077				
	ASM - DAM GIS Records Incremental Addition			153	153	153	153				
	Distribution Operations - DIRECT ohd					4,414	4,414				
	Fixed Oh to EA contractors	5,740		5,740	5,740	5,740	5,740				
	PSR REDUCTION TO OFFSET ENVISION AND AMP FITTINGS						(5,000)				
	Ops- Eng Admin Incremental			133	133	133	133				
	Engineering Distribution Planning -Incremental			1,219	1,219	1,219	1,219				
	Engineering Damage Prevention	2,946	2,946	2,946	2,946	2,946	2,946				
	Engineering Damage Prevention -incremental			92	92	92	92				
	Engineering Integrity Management	3,819	3,819	3,819	3,819	3,819	3,819				
	Engineering Integrity Management - incremental			143	143	143	143				
	Engineering Admin - incremental			102	102	102	102				
	Engineering System Regulation Miscellaneous -Increment			265	265	265	265				
	Engineering Quality Assurance Miscellaneous -Incremental			71	71	71	71				
	Technical Training Miscellaneous - incremental			360	360	360	360				
	Engineering System Regulation Miscellaneous			1,392	1,392	1,392	1,392				
3.1 DIRECT SYS IMPR OHD Total		**13,582**	**7,842**	**17,511**	**17,511**	**21,925**	**16,925**				
3.2 Envision Ex	ENVISION EXTENSION						8,000				
3.2 Envision Extension Total							**8,000**				
4. GENL	Building Improvements	1,550	2,000	2,000	2,000	2,600	2,600				
	Central Region West Operations Depot		1,000	1,000	1,000						
	Community events requirements - vehicles, vehicle wrapping, BBQ's, tents, etc			25	25	25	25				
	Convert Vacated Meter Shop space at VPC into 200 offices					2,100	2,100				
	Fleet	7,800	7,800	5,300	5,300	5,300	5,300	2,500	2,500	2,500	2,500
	Fleet Garage Relocation to a New Leased Property					3,000	3,000				
	Meter Shop Addition to the Toronto Ops Depot		5,300	5,300	5,300						
	Meter Shop Relocation to Markland Leased Property					-	-				
	Natural Gas Transportation - Customer Compressor Stat	7,712	7,712	5,100	5,100	5,100	2,100	2,612	2,612	2,612	2,612
	Natural Gas Transportation - Rental Cylinders	71	71	71	71	71	71				
	Natural Gas Transportation - Rental VRA's	1,415	1,415	1,415	1,415	1,415	1,415				
	Natural Gas Transportation - Utility Compressor Station	107	107	107	107	107	107				
	Natural Gas Transportation - Utility Fleet Cyliners	103	103	103	103	103	103				
	Natural Gas Transportation - Utility Fleet Vehicle Conver	468	468	468	468	468	468				
	New Office / Conference / Space Alterations	3,870	2,000	3,000	3,000	3,520	3,520				
	Office Furniture and Equipment	6,380	2,800	3,800	3,800	4,680	4,680				
	Tools and Work Equipment	125	125	125	125	125	125				
	Toronto Operations Depot and Fleet Garage		3,000	3,000	3,000						
4. GENL Total		**29,601**	**33,901**	**30,814**	**30,814**	**28,614**	**25,614**	**5,112**	**5,112**	**5,112**	**5,112**
5. IT	Altra GMS / SCADA / GDMS	300	300	300	300	300	300				
	Capital & OM Analytics Upgr						400				
	CIS	4,800	4,800	4,800	4,800	4,800	4,800				
	Clarity	-	-	-	-	-					
	COMMS	1,000	1,000	1,000	1,000	1,000	600				
	Customer Care Improvement Initiative						4,000				
	Data Centre Operations	3,000	2,100	2,100	2,100	2,100	2,100				
	Datapak / iViewer	-	-	-	-	-	-				
	DSM DARTs	-	-	-	-	-					
	eBridge upgrade			-	-	-					
	EDMS	-	-	-	-	-	-				
	EHS	-	-	-	-	-	-				
	eInvoice	100	100	100	100	100	100				
	eLMS	-	-	-	-	-	-				
	EnMAR	100	100	100	100	100	100				
	Enterprise GIS	500	500	500	500	500	500				
	EnTRAC	2,000	2,000	2,000	2,000	2,000	2,000				
	EQAT			-	-	-					
	ESM / SRM	400	400	400	400	400	400				
	Extranet	1,500	1,500	1,500	1,500	1,500					
	Gas Molecule	300	300	300	300	300	300				
	Gas Storage	300		-	-	-					
	Gas Storage - GIS	200	200	200	200	200	200				

		2016 FIRM COSTS						2016 VARIABLE COSTS			
PL CATG	Project Name or Blanket Program	Review 1	Review 2	Review 3	Review 4	Review 5	Review 6	Review 3	Review 4	Review 5	Review 6
3. ALLOC	Distribution Technology Miscellaneous	112	112	112	112	112	112				
	Engineering System Reliability Miscellaneous	677	677	677	677	677	677				
	Engineering Admin	551	551	551	551	551	551				
	Quality and Training Administration	407	407	407	407	407	407				
	Engineering Quality Assurance Miscellaneous	647	647	647	647	647	647				
	Technical Training Miscellaneous	2,864	2,864	2,864	2,864	2,864	2,864				
	Engineering System Regulation Miscellaneous	1,438	1,438								
3. ALLOC Total		**130,736**	**130,736**	**122,876**	**122,876**	**118,374**	**119,691**				
3.1 DIRECT SYS	ASM - DAM GIS Records	1,112	1,112	1,112	1,112	1,112	1,112				
	ASM - DAM GIS Records Incremental Addition			156	156	156	156				
	Distribution Operations - DIRECT ohd					4,502	4,502				
	Fixed Oh to EA contractors	5,855		5,855	5,855	5,855	5,855				
	PSR REDUCTION TO OFFSET ENVISION AND AMP FITTINGS						(5,000)				
	Ops- Eng Admin Incremental			135	135	135	135				
	Engineering Distribution Planning -Incremental			1,243	1,243	1,243	1,243				
	Engineering Damage Prevention	3,019	3,019	3,019	3,019	3,019	3,019				
	Engineering Damage Prevention -incremental			94	94	94	94				
	Engineering Integrity Management	3,934	3,934	3,934	3,934	3,934	3,934				
	Engineering Integrity Management - incremental			146	146	146	146				
	Engineering Admin - incremental			104	104	104	104				
	Engineering System Regulation Miscellaneous -Increment			271	271	271	271				
	Engineering Quality Assurance Miscellaneous -Incremental			72	72	72	72				
	Technical Training Miscellaneous - incremental			367	367	367	367				
	Engineering System Regulation Miscellaneous			1,438	1,438	1,438	1,438				
3.1 DIRECT SYS IMPR OHD Total		**13,921**	**8,066**	**17,947**	**17,947**	**22,449**	**17,449**				
3.2 Envision Ex	ENVISION EXTENSION						-				
3.2 Envision Extension Total							**-**				
4. GENL	Building Improvements	1,600	2,000	2,000	2,000	2,910	2,910				
	Central Region West Operations Depot		1,000	1,000	1,000						
	Community events requirements - vehicles, vehicle wrapping, BBQ's, tents, etc			25	25	25	25				
	Convert Vacated Meter Shop space at VPC into 200 offices					-	-				
	Fleet	7,800	7,800	5,300	5,300	5,300	5,300	2,500	2,500	2,500	2,500
	Fleet Garage Relocation to a New Leased Property					-	-				
	Meter Shop Addition to the Toronto Ops Depot		-	-	-						
	Meter Shop Relocation to Markland Leased Property					-	-				
	Natural Gas Transportation - Customer Compressor Stat	7,814	7,814	5,202	5,202	5,202	2,202	2,612	2,612	2,612	2,612
	Natural Gas Transportation - Rental Cylinders	73	73	73	73	73	73				
	Natural Gas Transportation - Rental VRA's	1,418	1,418	1,418	1,418	1,418	1,418				
	Natural Gas Transportation - Utility Compressor Station	110	110	110	110	110	110				
	Natural Gas Transportation - Utility Fleet Cyliners	105	105	105	105	105	105				
	Natural Gas Transportation - Utility Fleet Vehicle Conver	479	479	479	479	479	479				
	New Office / Conference / Space Alterations	2,830	2,000	2,500	2,500	3,860	3,860				
	Office Furniture and Equipment	5,130	2,800	3,800	3,800	4,380	4,380				
	Tools and Work Equipment	125	125	125	125	125	125				
	Toronto Operations Depot and Fleet Garage		-	-	-						
4. GENL Total		**27,483**	**25,723**	**22,136**	**22,136**	**23,986**	**20,986**	**5,112**	**5,112**	**5,112**	**5,112**
5. IT	Altra GMS / SCADA / GDMS	300	300	300	300	300	300				
	Capital & OM Analytics Upgr						400				
	CIS	6,800	6,800	6,800	6,800	6,800	6,800				
	Clarity	-	-	-	-	-					
	COMMS	1,000	1,000	1,000	1,000	1,000	600				
	Customer Care Improvement Initiative						1,000				
	Data Centre Operations	1,400	2,100	2,100	2,100	2,100	2,600				
	Datapak / iViewer	-	-	-	-	-	-				
	DSM DARTs	-	-	-	-	-					
	eBridge upgrade			-	-	-					
	EDMS	-	-	-	-	-	-				
	EHS	100	100	100	100	100	100				
	eInvoice	100	100	100	100	100	100				
	eLMS	-	-	-	-	-	-				
	EnMAR	100	100	100	100	100	100				
	Enterprise GIS	500	500	500	500	500	500				
	EnTRAC	2,000	2,000	2,000	2,000	2,000	2,000				
	EQAT			-	-	-					
	ESM / SRM	1,000	1,000	1,000	1,000	1,000	1,000				
	Extranet	1,000	1,000	1,000	1,000	1,000					
	Gas Molecule	200	200	200	200	200	200				
	Gas Storage	300		-	-	-					
	Gas Storage - GIS	200	200	200	200	200	200				

CONTINUITY OF DRAFT CAPITAL BUDGET DETAILS FROM REVIEW 1 TO REVIEW 6

($Ks)

PL CATG	Project Name or Blanket Program	2014 FIRM COSTS						2014 VARIABLE COSTS			
		Review 1	Review 2	Review 3	Review 4	Review 5	Review 6	Review 3	Review 4	Review 5	Review 6
5. IT	Information & Productivity Services	3,000	3,000	3,000	3,000	3,000	3,000				
	Integrated Training Environment	200	200	200	200	200	200				
	IT Risk Management	400	400	400	400	400	400				
	IT Service Management/ Desktop Replacement	2,100	2,100	2,100	2,100	2,100	2,100				
	Lakeside Services GPS						150				
	MVRS	900	900	900	900	900	900				
	Network Services	400	400	400	400	400	400				
	Orm Facilities Integrity SW						200				
	Orm IDP IVE Continuation Project						200				
	Orm Knowledge Management						1,100				
	Orm Leak Survey Mgt Sys Repl						350				
	ORMs Projects	2,000	2,000	2,000	2,000	2,000					
	Pressure Monitor/Customer connection			-	-	-					
	RAVE	300	300	300	300	300	300				
	Records Management (iiewer/dp replacement)			-	-	-					
	Risk Management	900	900	-	-	-	-	300	900	900	900
	STB - Best Customers Initiatives			7,500	7,500	7,500					
	Sustainment	-	-	-	-	-	-				
	WAMS (Post Implementation Enhancements)	-	-	-	-	-					
5. IT Total		**24,300**	**22,700**	**29,300**	**29,300**	**29,300**	**29,300**	**300**	**900**	**900**	**900**
6. STOR	Acid Program	300	300	300	300	300					
	Base Gas	18	18	18	18	18					
	C of A (Stack Height, Turbo and Noise Attenuation)	250	250	750	750	750					
	Compressor Engine Overhaul						250				
	Compressor Overhaul (valve replacement)	100	100	100	100	100	100				
	Corunna Compressor Plan						9,680				
	Crowland Plant Automation	50	50	30	30	30	-	20	20	20	20
	Crowland Plant Upgrades	200	200	200	200	200	200				
	Drawing Upgrades	100	100	100	100	100	100				
	DSA Boundary changes (purchase leases)	1,000	1,000	(500)	250	250	-	750	-	-	-
	Engine Compressor Analyzer Automation (Ingenuity)	100	100	50	50	50	-	50	50	50	50
	Engine Overhaul	250	250		250	250					
	Farm Purchase (C of A)		-	-	-	-	-				
	Gas Chromatograph at Chatham D										
	High Deliverability Well Erosion	60	60	60	60	60	-	-	-	-	-
	Horizontal Well replacement program		-	-	-	-	-				
	Integrity of Pools (abandoned wells)		-	-	-	-		400			
	Integrity Records	150	150	150	150	150					
	K711 Suction Scrubber Door			-	-	-					
	MCC#1 Generator and Boiler	2,500	2,500	2,000	2,000	2,000	-		500	500	500
	Misc Structures	100	100	(50)	-	-	-	100	50	50	50
	Misc Field Lines	100	100	50	50	50	-	50	50	50	50
	Misc. Compresssor	100	100	75	75	75	433	25	25	25	25
	Misc. Meas and Reg	250	250	-	50	50	-	100	50	50	50
	Misc. Wells	100	100	50	50	50	-	125	50	50	50
	MOE C of A						3,000				
	Observation Wells						1,850				
	OEB Hearing and Observation Wells	3,500	1,750	1,600	1,600	1,600					
	Pipe Spec Standard (Engineering standards integration)	100	100	100	100	100	100				
	Pipeline Integrity Records						150				
	Plant Roadways and Culverts		-	-	-	-	-				
	Press Test/log/wellhead & fence replace	1,825	1,825	825	825	825					
	Remote Operations Control	600	600	350	350	350	350		250	250	250
	Replacement Lines to Horizontal Wells		-	-	-	-	-				
	Road Purchase (Tecumseh Road)			-	-	-					
	Roads	70	70	20	20	20	-	50	50	50	50
	SCADA Upgrade and Automation	50	50	30	30	30	-	20	20	20	20
	Tecumseh Fence, Hydrant, and Oil Tank			-	-	-					
	Tecumseh New Building		9,000	9,000	9,000	9,000					
	Tecumseh New Building ORM	9,000									
	Warehouse / Layout Change						-				
	Warehouse retrofit/Johnson barn abandonment		-	-	-	-		350			
	Well Acid Program						300				
	Well Casing Replacement	678	678	678	678	678					
	Well Integrity						2,530				
	Well Loops	555	555	555	555	555					
	Wellhead Emergency Shutdown						125				
	Wellhead ESD	125	125	125	125	125					
6. STOR Total		**22,231**	**20,481**	**16,666**	**17,766**	**17,766**	**19,168**	**2,040**	**1,115**	**1,115**	**1,115**

PL CATG	Project Name or Blanket Program	2015 FIRM COSTS						2015 VARIABLE COSTS			
		Review 1	Review 2	Review 3	Review 4	Review 5	Review 6	Review 3	Review 4	Review 5	Review 6
5. IT	Information & Productivity Services	6,000	6,000	6,000	6,000	6,000	6,000				
	Integrated Training Environment	-	-	-	-	-	-				
	IT Risk Management	700	700	700	700	700	400				
	IT Service Management/ Desktop Replacement	2,300	2,300	2,300	2,300	2,300	2,600				
	Lakeside Services GPS						100				
	MVRS	300	300	300	300	300	300				
	Network Services	900	900	900	900	900	900				
	Orm Facilities Integrity SW						100				
	Orm IDP IVE Continuation Project						200				
	Orm Knowledge Management						500				
	Orm Leak Survey Mgt Sys Repl						100				
	ORMs Projects	1,000	1,000	1,000	1,000	1,000					
	Pressure Monitor/Customer connection			-	-	-					
	RAVE	200	200	200	200	200	200				
	Records Management (iiewer/dp replacement)			-	-	-					
	Risk Management	300	300	-	-	-	-	900	300	100	100
	STB - Best Customers Initiatives			2,500	2,500	2,500					
	Sustainment	-	-	-	-	-	-				
	WAMS (Post Implementation Enhancements)	-	-	-	-	-					
5. IT Total		**26,200**	**25,000**	**27,200**	**27,200**	**27,200**	**27,200**	**900**	**300**	**100**	**100**
6. STOR	Acid Program			-	-	-					
	Base Gas	18	18	18	18	18					
	C of A (Stack Height, Turbo and Noise Attenuation)			-	-	-					
	Compressor Engine Overhaul						250				
	Compressor Overhaul (valve replacement)	100	100	100	100	100	225				
	Corunna Compressor Plan						4,620				
	Crowland Plant Automation	50	50	30	30	30	-	20	20	20	20
	Crowland Plant Upgrades	200	200	200	200	200	200				
	Drawing Upgrades	100	100	100	100	100	100				
	DSA Boundary changes (purchase leases)	1,000	1,000	250	250	250	-	750	750		
	Engine Compressor Analyzer Automation (Ingenuity)	100	100	50	50	50	-	50	50	50	50
	Engine Overhaul	250	250		250	250					
	Farm Purchase (C of A)		-	-	-	-	-			100	100
	Gas Chromatograph at Chatham D						400				
	High Deliverability Well Erosion	60	60	60	60	60	-	-	-	35	35
	Horizontal Well replacement program	2,500	2,500	2,500	2,500	2,500	-			5,000	5,000
	Integrity of Pools (abandoned wells)	1,000	1,000	600	600	600			400		
	Integrity Records			-	-	-					
	K711 Suction Scrubber Door			-	-	-					
	MCC#1 Generator and Boiler		-	-	-	-	-	500			
	Misc Structures	100	100	(50)	(50)	(50)	-	100	100	100	100
	Misc Field Lines	100	100	50	50	50	-	50	50	50	50
	Misc. Compresssor	100	100	75	75	75	388	25	25	25	25
	Misc. Meas and Reg	250	250	-	-	-	-	100	100	200	200
	Misc. Wells	250	250	(25)	(25)	(25)	-	50	125	125	125
	MOE C of A						-				
	Observation Wells						2,450				
	OEB Hearing and Observation Wells	3,500	1,750	1,600	1,600	1,600					
	Pipe Spec Standard (Engineering standards integration)	100	100	100	100	100	100				
	Pipeline Integrity Records						-				
	Plant Roadways and Culverts	50	50	50	50	50	-			50	50
	Press Test/log/wellhead & fence replace	1,150	1,150	1,150	1,150	1,150					
	Remote Operations Control		-	-	-	-	-	250			
	Replacement Lines to Horizontal Wells		-	-	-	-	-			500	500
	Road Purchase (Tecumseh Road)			-	-	-					
	Roads	75	75	25	25	25	-	50	50	50	50
	SCADA Upgrade and Automation	50	50	30	30	30	-	20	20	20	20
	Tecumseh Fence, Hydrant, and Oil Tank			500	500	500					
	Tecumseh New Building		2,000	2,000	2,000	2,000					
	Tecumseh New Building ORM	2,000									
	Warehouse / Layout Change						150				
	Warehouse retrofit/Johnson barn abandonment	500	500	150	150	150			350		
	Well Acid Program						-				
	Well Casing Replacement	698	698	698	698	698					
	Well Integrity						4,800				
	Well Loops	390	390	390	390	390					
	Wellhead Emergency Shutdown						125				
	Wellhead ESD	125	125	125	125	125					
6. STOR Total		**14,816**	**13,066**	**10,776**	**11,026**	**11,026**	**13,808**	**1,965**	**2,040**	**6,325**	**6,325**

PL CATG	Project Name or Blanket Program	2016 FIRM COSTS						2016 VARIABLE COSTS			
		Review 1	Review 2	Review 3	Review 4	Review 5	Review 6	Review 3	Review 4	Review 5	Review 6
5. IT	Information & Productivity Services	3,800	3,800	3,800	3,800	3,800	3,800				
	Integrated Training Environment	-	-	-	-	-	-				
	IT Risk Management	900	900	900	900	900	900				
	IT Service Management/ Desktop Replacement	4,300	4,300	4,300	4,300	4,300	4,300				
	Lakeside Services GPS						150				
	MVRS	-	-	-	-	-	-				
	Network Services	900	900	900	900	900	400				
	Orm Facilities Integrity SW										
	Orm IDP IVE Continuation Project						50				
	Orm Knowledge Management						200				
	Orm Leak Survey Mgt Sys Repl						100				
	ORMs Projects	500	500	500	500	500					
	Pressure Monitor/Customer connection			-	-	-					
	RAVE	200	200	200	200	200	200				
	Records Management (iiewer/dp replacement)			-	-	-					
	Risk Management	100	100	-	-	-	-	100	100	300	300
	STB - Best Customers Initiatives			-	-	-					
	Sustainment	1,500	1,500	1,500	1,500	1,500	1,500				
	WAMS (Post Implementation Enhancements)	-	-	-	-	-					
5. IT Total		**27,200**	**27,600**	**27,500**	**27,500**	**27,500**	**27,500**	**100**	**100**	**300**	**300**
6. STOR	Acid Program	325	325	325	325	325					
	Base Gas			-	-	-					
	C of A (Stack Height, Turbo and Noise Attenuation)			-	-	-					
	Compressor Engine Overhaul						500				
	Compressor Overhaul (valve replacement)	100	100	100	100	100	100				
	Corunna Compressor Plan										
	Crowland Plant Automation	50	50	30	30	30	-	20	20	20	20
	Crowland Plant Upgrades			-	-	-	-				
	Drawing Upgrades	100	100	100	100	100	100				
	DSA Boundary changes (purchase leases)		-	-	-	-	-			750	750
	Engine Compressor Analyzer Automation (Ingenuity)	100	100	50	50	50	-	50	50	50	50
	Engine Overhaul	500	500		500	500					
	Farm Purchase (C of A)	1,000	1,000	(100)	(100)	(100)	-	100	100		
	Gas Chromatograph at Chatham D										
	High Deliverability Well Erosion	70	70	35	35	35	-	35	35	-	-
	Horizontal Well replacement program	7,500	7,500	2,500	2,500	2,500	-	5,000	5,000		
	Integrity of Pools (abandoned wells)		-	-	-	-				400	
	Integrity Records			-	-	-					
	K711 Suction Scrubber Door			-	-	-					
	MCC#1 Generator and Boiler		-	-	-	-	-				
	Misc Structures	100	100	-	-	-	-	100	100	100	100
	Misc Field Lines	100	100	50	50	50	-	50	50	50	50
	Misc. Compresssor	100	100	75	75	75	425	25	25	25	25
	Misc. Meas and Reg	500	500	50	50	50	-	200	200	100	100
	Misc. Wells	250	250	125	125	125	-	125	125	125	125
	MOE C of A						-				
	Observation Wells						1,600				
	OEB Hearing and Observation Wells		1,750	1,700	1,700	1,700					
	Pipe Spec Standard (Engineering standards integration)	100	100	100	100	100	100				
	Pipeline Integrity Records						-				
	Plant Roadways and Culverts	50	50	-	-	-	-	50	50		
	Press Test/log/wellhead & fence replace	1,300	1,300	1,300	1,300	1,300					
	Remote Operations Control		-	-	-	-	-				
	Replacement Lines to Horizontal Wells	1,000	1,000	500	500	500	-	500	500		
	Road Purchase (Tecumseh Road)			-	-	-					
	Roads	80	80	30	30	30	-	50	50	50	50
	SCADA Upgrade and Automation	50	50	30	30	30	-	20	20	20	20
	Tecumseh Fence, Hydrant, and Oil Tank			-	-	-					
	Tecumseh New Building			-	-	-					
	Tecumseh New Building ORM										
	Warehouse / Layout Change						-				350
	Warehouse retrofit/Johnson barn abandonment		-	-	-	-				350	
	Well Acid Program						325				
	Well Casing Replacement	720	720	720	720	720					
	Well Integrity						5,760				400
	Well Loops	690	690	690	690	690					
	Wellhead Emergency Shutdown						-				
	Wellhead ESD			-	-	-					
6. STOR Total		**14,785**	**16,535**	**8,410**	**8,910**	**8,910**	**8,910**	**6,325**	**6,325**	**2,040**	**2,040**

CONTINUITY OF DRAFT CAPITAL BUDGET DETAILS FROM REVIEW 1 TO REVIEW 6

($Ks)

		2014 FIRM COSTS						2014 VARIABLE COSTS				2015 FIRM COSTS						2015 VARIABLE COSTS				2016 FIRM COSTS						2016 VARIABLE COSTS			
PL CATG	Project Name or Blanket Program	Review 1	Review 2	Review 3	Review 4	Review 5	Review 6	Review 3	Review 4	Review 5	Review 6	Review 1	Review 2	Review 3	Review 4	Review 5	Review 6	Review 3	Review 4	Review 5	Review 6	Review 1	Review 2	Review 3	Review 4	Review 5	Review 6	Review 3	Review 4	Review 5	Review 6
Grand Total		476,262	485,010	435,739	445,509	468,627	443,825	120,642	36,476	25,142	25,142	523,568	570,313	420,039	459,964	461,631	446,627	45,996	80,967	63,031	63,031	518,419	553,820	411,591	452,251	458,054	441,877	108,477	68,317	75,937	75,937

Enbridge Gas Distribution Inc.

Capital Plan Refresh [2014 to 2018] – Executive Update (Review 3)

March 26, 2013

Capital Plan – Review 3 Findings

- Customer Related budget decrease of $14 M annually from 2013 – 2018
  - Drivers:
    - Operations prudence review: reduced Unit Cost to $2082 per attachment (2013 – 2018)
    - Sales Stations budget alignment between System Improvement and Customer Related – reduction of $5.7 M
- WAMS capital moved to Y-Factor after regulatory review
  - 2014 - $36 M, 2015 - $24 M, 2016 - $8 M

ENBRIDGE

Capital Plan – Review 3 Findings

Overheads(DLC, IDC, A&G) Analysis to date (Ongoing as part of Review):

- With respect to capital overheads, the 2013 Capital budget of $387 M has cost pressures of which $26 M is overheads. The 2012 actual capital spend was $420 M with $113 M of overheads. Finance and capital owners are in the process of finalizing the 2013 capital budget prioritization process so that both the program budget and overheads meet the budget of $387 M. The following table is a breakdown of the additional overheads:

Additional Overheads for 2013 vs. 2012 Actual - $26M	OPS	PIE	Other EGD	Total
MAOP		0.6		0.6
TT initiative		0.5		0.5
integrity management		0.7		0.7
planning/records GPS/special projects		12.1		12.1
incremental adds	4.0	1.3	1.8	7.1
merit increase	1.5			1.5
increased capitalization	1.5			1.5
material cost adjustment ($1M credit in 2012)	1.0			1.0
Outside consulting- Envision, M&R network ops	1.0			1.0
Total	9.0	15.2	1.8	26.0

Review 3: 2014 Prioritized

2014 "Core" Budget (Millions)				
Priority	**Probability of Spend**			
	High	**Medium**	**Low**	**Totals**
Tier 1a	$ 124	$ 15		$ 139
Tier 1b	$ 237	$ 17		$ 254
Tier 2	$ 33	$ 9		$ 42
Tier 3	$ 1	$ 0		$ 1
Totals	$ 395	$ 41	$ -	
				$ 436

Tier 1a- Mandatory: Legislated, OEB mandated

Tier 1b - Prudence, Due-Diligence, capital deemed necessary and align to business objectives

Tier 2 - Discretionary: Capital deemed necessary and align to business objectives and needs (e.g. equipment replacement, productivity projects, revenue generating

Tier 3 – General: Capital of less priority than Tier 2 and aligns to business objectives and needs (e.g. studies, projects where costs are not fully finalized, projects with lesser benefits than Tier 2 projects)

High Probability - 80% to 100% probability of spending in that year
Medium Probability - 50% to 80% probability of spending in that year
Low Probability - 0% to 50% probability of spending in that year

Review 3: 2015 Prioritized

2015 "Core" Budget (Millions)				
Priority	**Probability of Spend**			
	High	**Medium**	**Low**	**Totals**
Tier 1a	$ 131	$ 16		$ 147
Tier 1b	$ 227	$ 5		$ 232
Tier 2	$ 29	$ 11		$ 40
Tier 3	$ 0.2	$ 1		$ 1
Totals	$ 387	$ 33	$ -	
				$ 420

Tier 1a- Mandatory: Legislated, OEB mandated

Tier 1b - Prudence, Due-Diligence, capital deemed necessary and align to business objectives

Tier 2 - Discretionary: Capital deemed necessary and align to business objectives and needs (e.g. equipment replacement, productivity projects, revenue generating

Tier 3 – General: Capital of less priority than Tier 2 and aligns to business objectives and needs (e.g. studies, projects where costs are not fully finalized, projects with lesser benefits than Tier 2 projects)

High Probability - 80% to 100% probability of spending in that year
Medium Probability - 50% to 80% probability of spending in that year
Low Probability - 0% to 50% probability of spending in that year

ENBRIDGE

Review 3: 2016 Prioritized

2016 "Core" Budget (Millions)				
Priority	Probability of Spend			
	High	Medium	Low	Totals
Tier 1a	$ 137	$ 16		$ 153
Tier 1b	$ 219	$ 3		$ 222
Tier 2	$ 24	$ 12		$ 36
Tier 3	1	$ 1		$ 2
Totals	$ 381	$ 32	$ -	
				$ 413

Tier 1a- Mandatory: Legislated, OEB mandated

Tier 1b - Prudence, Due-Diligence, capital deemed necessary and align to business objectives

Tier 2 - Discretionary: Capital deemed necessary and align to business objectives and needs (e.g. equipment replacement, productivity projects, revenue generating

Tier 3 – General: Capital of less priority than Tier 2 and aligns to business objectives and needs (e.g. studies, projects where costs are not fully finalized, projects with lesser benefits than Tier 2 projects)

High Probability - 80% to 100% probability of spending in that year
Medium Probability - 50% to 80% probability of spending in that year
Low Probability - 0% to 50% probability of spending in that year

ENBRIDGE

Enbridge Gas Distribution Inc.

Capital Plan Refresh [2014 to 2018] – Executive Update (Final)

April 19 2013

Capital Plan – Process (Completed Steps)

Task	Due Date
Capital Plan Refresh – Kickoff	Completed
Capital Plan 2014 – 2018 Update and Ranking	Completed
Capital Owners Prioritize: Review 2 *(Probability of spend and Priority)*	Completed
Executive Update: Review 2 *(Awareness and guidance on direction)*	Completed
Capital Owners Prioritize: Review 3 *(Priority segmentation: 1a &1b)*	Completed
Executive Update: Review 3	Completed
Capital Owners Prioritize: Review 4 *(Customer Additions)*	Completed
Executive Update: Review 4	Completed
Capital Owners Prioritize: Review 5 *(Update on Overheads)*	Completed
Executive Update: Review 5	Completed
	Completed
Finalize IR Model / Approach	Completed
Finalize Capital Budget *(with forecasts 2014 to 2016)*	Completed

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Capital Plan – Key Changes from last update

- Regulatory model finalized: 3 Year Custom IR Model
  - Last generation IR model does not support higher capital needs
    - Significant capital projects from 2014 to 2016
      - GTA Reinforcement, WAMS Replacement
    - Legislation on safety and reliability in US driving step increases to System Reliability budgets

- Modified Capital Refresh Budget process:
  - Reduced to 3 year term
  - Removed Capital Trackers: Revisited budgets for approved capital projects

- Maintained budgeted efficiencies: e.g. Customer Additions and Overheads

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Capital Plan - Regulatory Approach

- Custom IR with 3 Year Term: Finalize forecast capital costs with robust detail

- Budget Process has defined 3 years of Capital Forecasts:
  - Customer Related
  - System Reliability/Improvement
  - Operations, IT, Facilities and Storage
  - Large projects: GTA, Ottawa and WAMS

- Extend budgeting process rigor (prioritization and management review) to produce detailed program briefs as evidence

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Capital Plan – Process Next Steps

Task	Due Date
Capital Program/Area Briefs Completed (Capital Overview and Program/Area Briefs)	April 22 – April 29
Regulatory Legal Review (Asset Plan, Capital Overviews and Program/Area Briefs)	April 22 – May 10
Finalize Capital Evidence *(with forecasts to 2018)*	May 10 – May 17
File Next Generation IR Model	May 31

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Review 6: Final “Core” and “Project” Capital

($ millions)	2012 Act	2013 2+10	2014 LRP	2015 LRP	2016 LRP
Customer Related Capital	101.9	95.8	91.2	97.5	102.3
System Improvements and Upgrades	91.4	140.8	180.9	179.7	175.5
Overheads	112.9	114.7	119.4	117.5	119.8
IT Capital	38.7	25.9	29.3	27.2	27.5
General Plant	24.6	18.3	30.1	28.6	24.0
Underground Storage Plant	19.2	22.0	17.8	11.0	8.9
Maintenance Capital	**388.7**	**417.5**	**468.6**	**461.6**	**458.1**
Cast Iron Repl (relays/mains)	34.6				
Maintenance Capital with Cast Iron	**423.3**	**417.5**	**468.6**	**461.6**	**458.1**
Power Generation	3.1	0.1	9.0	-	2.3
Ottawa Reinforcement	1.0	43.6	5.1		
GTA Reinforcement	7.7	19.3	205.3	394.1	
WAMS		7.0	35.7	23.7	7.7
IDC specific to special projects			1.0	2.7	-
Special Utility Projects	**11.8**	**70.0**	**256.1**	**420.4**	**10.0**
Total Utility Capital	**435.1**	**487.6**	**724.7**	**882.1**	**468.0**

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Review 6: Final "Overheads"

Plant Group	Detail	2010	2011	2012	2013B	2013 (2+10)F REV	2014	2015	2016
3. Allocation	Capitalized Admin and General	24	24	32	34	36	35	36	36
	Designated Overheads	65	66	75	89	73	76	75	77
	capital efficiency				-				
	Interest During Construction	3	5	6	6	6	8	7	7
3. Allocation Total		**92**	**95**	**113**	**129**	**115**	**119**	**118**	**120**

Review 6: Final 2014 Prioritized

2014 "Core" Budget (Millions)				
Priority	Probability of Spend			
	High	Medium	Low	Totals
Tier 1a	$ 126	$ 21	$ -	$ 147
Tier 1b	$ 256	$ 15	$ 3	$ 274
Tier 2	$ 31	$ 16	$ -	$ 47
Tier 3	$ 0.1	$ 1	$ -	$ 1
Totals	$ 413	$ 53	$ 3	
				$ 469

Tier 1a- Mandatory: Legislated, OEB mandated

Tier 1b - Prudence, Due-Diligence, capital deemed necessary and align to business objectives

Tier 2 - Discretionary: Capital deemed necessary and align to business objectives and needs (e.g. equipment replacement, productivity projects, revenue generating

Tier 3 – General: Capital of less priority than Tier 2 and aligns to business objectives and needs (e.g. studies, projects where costs are not fully finalized, projects with lesser benefits than Tier 2 projects)

High Probability - 80% to 100% probability of spending in that year
Medium Probability - 50% to 80% probability of spending in that year
Low Probability - 0% to 50% probability of spending in that year

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Review 6: Final 2015 Prioritized

2015 "Core" Budget (Millions)				
Priority	Probability of Spend			
	High	Medium	Low	Totals
Tier 1a	$ 132	$ 16	$ -	$ 148
Tier 1b	$ 260	$ 4	$ 3	$ 267
Tier 2	$ 29	$ 14	$ 3	$ 46
Tier 3	$ 0.2	$ 1	$ -	$ 1
Totals	$ 421	$ 35	$ 6	
				$ 462

Tier 1a- Mandatory: Legislated, OEB mandated

Tier 1b - Prudence, Due-Diligence, capital deemed necessary and align to business objectives

Tier 2 - Discretionary: Capital deemed necessary and align to business objectives and needs (e.g. equipment replacement, productivity projects, revenue generating

Tier 3 – General: Capital of less priority than Tier 2 and aligns to business objectives and needs (e.g. studies, projects where costs are not fully finalized, projects with lesser benefits than Tier 2 projects)

High Probability - 80% to 100% probability of spending in that year
Medium Probability - 50% to 80% probability of spending in that year
Low Probability - 0% to 50% probability of spending in that year

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Review 6: Final 2016 Prioritized

2016 "Core" Budget (Millions)				
Priority	**Probability of Spend**			
	High	**Medium**	**Low**	**Totals**
Tier 1a	$ 138	$ 16	$ -	$ 154
Tier 1b	$ 254	$ 5	$ 3	$ 262
Tier 2	$ 27	$ 15	$ -	$ 42
Tier 3	$ 0.1	$ 0.2	$ -	$ 0
Totals	$ 419	$ 36	$ 3	
				$ 458

Tier 1a- Mandatory: Legislated, OEB mandated

Tier 1b - Prudence, Due-Diligence, capital deemed necessary and align to business objectives

Tier 2 - Discretionary: Capital deemed necessary and align to business objectives and needs (e.g. equipment replacement, productivity projects, revenue generating

Tier 3 – General: Capital of less priority than Tier 2 and aligns to business objectives and needs (e.g. studies, projects where costs are not fully finalized, projects with lesser benefits than Tier 2 projects)

High Probability - 80% to 100% probability of spending in that year
Medium Probability - 50% to 80% probability of spending in that year
Low Probability - 0% to 50% probability of spending in that year

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Additional Slides

Review 3: 2014 Prioritized

2014 "Core" Budget (Millions)				
Priority	Probability of Spend			
	High	Medium	Low	Totals
Tier 1a	$ 124	$ 15		$ 139
Tier 1b	$ 237	$ 17		$ 254
Tier 2	$ 33	$ 9		$ 42
Tier 3	$ 1	$ 1		$ 1
Totals	$ 394,013	$ 41,726	$ -	
				$ 436

Tier 1a- Mandatory: Legislated, OEB mandated

Tier 1b - Prudence, Due-Diligence, capital deemed necessary and align to business objectives

Tier 2 - Discretionary: Capital deemed necessary and align to business objectives and needs (e.g. equipment replacement, productivity projects, revenue generating

Tier 3 – General: Capital of less priority than Tier 2 and aligns to business objectives and needs (e.g. studies, projects where costs are not fully finalized, projects with lesser benefits than Tier 2 projects)

High Probability - 80% to 100% probability of spending in that year
Medium Probability - 50% to 80% probability of spending in that year
Low Probability - 0% to 50% probability of spending in that year

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Review 4: 2014 Prioritized

2014 "Core" Budget (Millions)				
Priority	Probability of Spend			
	High	Medium	Low	Totals
Tier 1a	$ 130	$ 16		$ 146
Tier 1b	$ 239	$ 17		$ 256
Tier 2	$ 35	$ 9		$ 44
Tier 3	$ 1.0	$ 1		$ 2
Totals	$ 405	$ 43	$ -	
				$ 448

Tier 1a- Mandatory: Legislated, OEB mandated

Tier 1b - Prudence, Due-Diligence, capital deemed necessary and align to business objectives

Tier 2 - Discretionary: Capital deemed necessary and align to business objectives and needs (e.g. equipment replacement, productivity projects, revenue generating

Tier 3 – General: Capital of less priority than Tier 2 and aligns to business objectives and needs (e.g. studies, projects where costs are not fully finalized, projects with lesser benefits than Tier 2 projects)

High Probability - 80% to 100% probability of spending in that year
Medium Probability - 50% to 80% probability of spending in that year
Low Probability - 0% to 50% probability of spending in that year

ENBRIDGE

Review 5: 2014 Prioritized

2014 "Core" Budget (Millions)				
Priority	Probability of Spend			
	High	Medium	Low	Totals
Tier 1a	$ 126	$ 21		$ 147
Tier 1b	$ 256	$ 18		$ 274
Tier 2	$ 31	$ 16		$ 47
Tier 3	$ 1	$ 1		$ 2
Totals	$ 414	$ 56	$ -	
				$ 470

Tier 1a- Mandatory: Legislated, OEB mandated

Tier 1b - Prudence, Due-Diligence, capital deemed necessary and align to business objectives

Tier 2 - Discretionary: Capital deemed necessary and align to business objectives and needs (e.g. equipment replacement, productivity projects, revenue generating

Tier 3 – General: Capital of less priority than Tier 2 and aligns to business objectives and needs (e.g. studies, projects where costs are not fully finalized, projects with lesser benefits than Tier 2 projects)

High Probability - 80% to 100% probability of spending in that year
Medium Probability - 50% to 80% probability of spending in that year
Low Probability - 0% to 50% probability of spending in that year

ENBRIDGE

Potential changes to Baseline Capital Forecast - Results of Capital Evidence Scrub Meetings

Program Description	Plant Catg	Major Acct	2013	2014	2015	2016		Comments
Don River Bridge	Repl/Integrity	475 mains		(9.70)				Removed: Original TRCA justification and request no longer valid
Lakeshore 20 inch	Repl/Integrity	475 mains		(5.60)				Removed: Original TRCA justification and request no longer valid
Reg Refits	Repl/Integrity	474 refits		0.90	0.70	0.50		MXGI refit component understated (firmed up May 16)
Network Ops	Repl/Integrity	477 M&R						Renamed to: Paper chart recorder replacement project.
Sewer Lateral	Repl/Integrity	473 svc						No change.
Excess Flow Valve	Repl/Integrity	473 svc			(0.80)	(0.70)		Anticipated volumes not supported - a study is required
Targeted Compression Couplings	Repl/Integrity	475 mains		0.46	1.00	1.00		Additional Cost and Combined with Main Replacements
AMP fittings	Repl/Integrity	473 svc		(0.73)	(11.15)	(3.10)		Revised to reflect final consultant report and direction from Operations on ability to execute as a self-contained project
Remove Control Valves	Repl/Integrity	475 mains		(0.16)	(3.30)	(3.30)		Replaced: Changed to one valve each year $600K per year
Gate Stations: Heat Exchange Replacement	Repl/Integrity	477 M&R		2.40	(1.20)	(5.60)		Reduction: Heat Exchanger program revamped to a pilot examination.
Load Shed Program	Repl/Integrity	475 mains	1.50	(1.15)				Require expenditure in 2013 to support proposed 2014 to 2016 activities. Future years dependant on studies.
Replacement mains	Repl/Integrity	475 mains			(0.20)	(0.30)		
ILI retrofits	Repl/Integrity	475 mains		6.00	3.80	3.30		Proposed pipeline replacement amount subject to ILI inspection. Final amounts increased
Verification of Maop	Repl/Integrity	475 mains		(5.80)	(5.10)	(5.70)		per Bruce Parent may 21st
Collingwood Replacement				(7.75)				dependant on ILI studies
Keele and Finch	Reloc	475 mains						Claim with TTC pending. Propose to inform Board and inform them of a potential future recovery amount of potentially $11M -NEED GUIDANCE FROM REGULATORY ON PROCESS
YRTCC Reloc	Reloc	475 mains	5.00	(5.00)				Activities in 2014 moved to 2013
Relocations	Reloc	475 mains		(0.10)	(2.40)	(3.60)		Potential increase of $8.0M b/w 2014-16 to account for YRTCC and other Transit decisions (Firmed up May 16PM)
Capitalized Admin and Genl Ohd	ovhd	475 mains		0.07	0.89	1.32		True up with most recent estimate
Storage increases	storage	various		1.40	2.80			Regroup from oil and gas
sum of changes			**6.5**	**(24.8)**	**(15.0)**	**(16.2)**		**Recommended Final Increases/(Reductions) to Baseline Capital Forecast**

Current Capital Budget				**468.6**	**461.6**	**458.1**		Baseline forecasts as per Review 5
Revised Capital Budget: After Detailed Reviews				**443.9**	**446.7**	**441.9**		Proposed Capital Forecasts after applying recommended increases/(Reductions)
Potential Capital Budget: After At Risk reduction				**443.9**	**446.7**	**441.9**		Awareness Item: Potential Capital Budget given At Risk amounts identified via Scrub

At Risk Amounts								
At Risk Total				**0.00**	**0.00**	**0.00**		

NON CORE CHANGES								
Power generation - remove all	cust related	475 mains		(9.0)		(2.3)		Probabilities of projects moving ahead are too low

SEC INTERROGATORY #12

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/1/2, p. 8] Please confirm that the (-) sign in the two tables refers to negative productivity, i.e. that costs rose faster than inflation.

RESPONSE

The negative sign in the tables on page 8 of Exhibit A2, Tab 1, Schedule 2 refer to negative productivity, which means that input quantities grew faster than output quantities.

Witnesses: J. Coyne – Concentric
J. Simpson – Concentric
M. Bartos – Concentric

SEC INTERROGATORY #13

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p. 2] Please provide a list of all subject areas in which each of Mr. Coyne, Mr. Simpson and Ms. Bartos has filed an expert report, claimed expert qualifications, or been qualified as an expert, in the period 2001 to date.

RESPONSE

The areas in which Mr. Coyne has filed an expert report, claimed expert qualifications or has been qualified as an expert include: cost of capital, valuation, business risk, demand forecasting, industry benchmarking, incentive regulation, stranded cost recovery, low income programs, demand side management programs, and rate policy.

The areas in which Mr. Simpson has filed an expert report, claimed expert qualifications or has been qualified as an expert include: utility demand forecasting, analysis of cost mitigation efforts, cost of gas filings, inflation adjustment factors, industry benchmarking, incentive regulation, marginal cost of service studies, customer usage trends, decoupling policy considerations, revenue decoupling mechanisms, capital cost tracking mechanisms, rate design, consolidation of service classifications, tariffs, test year billing determinants, and marginal cost of service studies.

The areas in which Ms. Bartos has filed an expert report, claimed expert qualifications or has been qualified as an expert include: gas utility demand forecasting, capacity planning, planning standards, and industry benchmarking.

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #14

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p. 5] Please explain why the performance of the Applicant was not benchmarked to Union Gas.

RESPONSE

As noted in Concentric's evidence (Exhibit A2, Tab 9, Schedule 1, p. 76):

> Canadian companies were included in the original benchmarking analysis for 2009; however, due to the difficulty [of] obtaining consistent, reliable data Canadian companies were not included in the 2011 update.

The report referenced is Concentric's January 27, 2012 Benchmarking Study which included data on six Canadian companies, including Union Gas.

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #15

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p. 6] Please confirm that, prior to its 1st Generation IRM plan, Enbridge, according to Concentric, underperformed on both TFP and PFP relative to both the whole industry study group and the seven company group. Please comment on whether, in Concentric's opinion, that underperformance was influenced in whole or in part by the fact that Enbridge was, for most of that period, on cost of service ratemaking.

RESPONSE

EGD's PFP growth rate was comparable to the Industry Study Group growth rate (0.44 vs. 0.47, respectively) over the 2000 to 2007 period, but below the TFP growth rate (-0.06 vs. 0.19, respectively) as highlighted below from Figure 1:

Figure 1: TFP and PFP Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Average Annual Growth Rates					
		Industry Study Group		Seven Company Sub-Group		EGD	
		TFP Growth Rate	PFP Growth Rate	TFP Growth Rate	PFP Growth Rate	TFP Growth Rate	PFP Growth Rate
Whole Period	2000-2011	-0.32%	-0.25%	-0.01%	-0.02%	-0.28%	0.50%
Pre-IR	2000-2007	0.19%	0.47%	0.43%	0.74%	-0.06%	0.44%
During IR	2007-2011	-1.22%	-1.52%	-0.78%	-1.33%	-0.66%	0.60%

We note that EGD's predecessor company, Consumers Gas, was on a targeted PBR program over the 2000 to 2002 period, so the Company was not on a cost of service basis for the entire 2000 to 2007 period.

Witnesses: M. Bartos - Concentric
J. Coyne – Concentric
J. Simpson – Concentric

Pertaining to the issue of this performance differential, and the change in EGD's performance post 1st Generation IR, Concentric observed on page 7 of its report: EGD's TFP and PFP improvement between 2000 to 2007 and 2007 to 2011 may be attributable to (a) the incentives for efficiency improvements that resulted from EGD's 1st Generation IR, and (b) EGD's relatively high output growth rate from 2007 to 2011, compared to industry study group or seven company sub-group companies.

So we attribute the shift in productivity both to company specific service area trends and the incentives under 1st Generation IR.

Witnesses: M. Bartos - Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #16

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p. 7, 30] Please provide whatever evidence Concentric has that "efficiency and productivity improvement opportunities [will be] more difficult for EGD to find" during the 2014 to 2018 period. In addition, if Concentric has studies or other such information showing that 2nd generation IRM plans generally show reduced productivity and efficiency, please provide.

RESPONSE

Concentric's observation is based on the benchmarking analysis that shows Enbridge is among the most efficient of its industry peers measured on a total O&M cost per customer basis (Figure 7, p. 23). It stands to reason that incremental productivity gains become more challenging as companies become more efficient. PEG makes this point in its testimony filed on behalf of Central Maine Power requesting a new Alternative Rate Plan:

> A third important source of productivity growth is change in X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology allows. Productivity growth will increase (decrease) to the extent that X inefficiency diminishes (increases). The potential of a company for productivity growth from this source is greater the lower is its current efficiency level. (Mark Lowry, Productivity Offset Factor, report filed on behalf of Central Maine Power Company before the Maine Public Utilities Commission, May 1, 2013, p. 12.)

The Board has recognized the relationship between the efficiency of a distributor and the attainment of subsequent gains through assignment of "stretch factors" for electric distributors which vary from 0% for the most efficient to 0.60% for the least efficient. (EB-2010-0379, Draft Report of the Board on Empirical Research to Support Incentive Rate-setting for Ontario's Electric Distributors, September 6, 2013, pages 27 to 28.)

Witnesses: M. Bartos - Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #17

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p. 8] Please confirm that Concentric did not do any independent review of the Applicant's capital spending plans, nor is Concentric providing any opinion on whether those plans are reasonable. Please confirm that Concentric is not able to provide any opinion on whether, under an I-X escalation formula, Enbridge would be able to operate the distribution system in a safe and reliable manner.

RESPONSE

It is correct that (a) Concentric did not do any independent review of the Applicant's capital spending plans, and (b) Concentric is not providing any opinion on whether those plans are reasonable.

Although Concentric is not able to provide an opinion on whether, under an I-X escalation formula, Enbridge would be able to operate the distribution system in a safe and reliable manner, Concentric did prepare an analysis, which is summarized in Figure 30 (Exhibit A2, Tab 9, Schedule 1, p. 61), that demonstrates that an I-X escalation formula would not provide adequate recovery of Enbridge's planned capital-related costs during the 2014 to 2016 period. The cumulative three year capital-related revenue deficiency under an I-X escalation formula would be $141.5 million.

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #18

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p. 14] *"It is our understanding that stakeholders were generally satisfied with Enbridge's 1st Generation IR Plan, as was the Company, suggesting a balance of interests achieved in the end result."* Please confirm, based on footnote 7 cited for the above statement, that Enbridge has advised Concentric that the discussions at the stakeholder conference on December 7, 2012 were neither "off the record" nor confidential or privileged in any way.

RESPONSE

Concentric never understood the December 7th, 2012 meeting to be confidential or off-the-record, and was never advised otherwise by Enbridge.

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #19

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p. 15] Please provide Concentric's evidence for its conclusion that the Enbridge capital plan shows a lumpy capital spending path.

RESPONSE

Concentric concluded that the Enbridge capital spending plan shows a lumpy capital spending path based on our review of the Enbridge 2014 to 2016 utility capital spending forecast, and specifically, the Ottawa and GTA reinforcement projects. The Enbridge 2014 to 2016 utility capital spending forecast is summarized in Exhibit A2, Tab 1, Schedule 3, page 2.

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #20

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p. 16] Please describe what analysis, if any, Concentric did to determine if, based on its actual bond maturities and new borrowing needs over the 2014-2018 period, the costs of debt for Enbridge would follow a similar pattern of increase over that period.

RESPONSE

Concentric considered both the cost of capital and growth in ratebase in its analysis provided in Section VII of its report (beginning on p. 54). The costs of capital included in the analysis (for medium and long term debt, short term debt, preference shares and common equity) were provided by Enbridge. The debt costs included the Company's projections for maturing debt and new debt at market rates. The table below summarizes those inputs. As can be seen, despite the projected increase in debt rates, the average cost rate for medium and long term debt is actually declining over the 2013 to 2016 period as older more expensive securities are replaced with lower cost securities, but due to the substantial growth in rate base, the revenue requirement impact grows by 26% over this period (from $142.8 MM to $179.6 MM). It is the increase in capital investment that creates the mismatch between revenues and costs under a standard I-X program for EGD over the period, more so than the changes in the cost rates for each capital component.

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

	2013	2014	2015	2016
	($000,000)			
Rate base excluding CIS	4,091.5	4,384.3	4,752.6	5,492.0
Medium and Long Term Debt (net)	2,461.9	2,596.9	2,918.4	3,367.0
Component % of Rate Base	60.17%	59.23%	61.41%	61.31%
Cost Rate	5.80%	5.57%	5.39%	5.33%
Return Component LTD	3.49%	3.30%	3.31%	3.27%
Medium and Long Term Debt Cost	142.8	144.7	157.3	179.6
Short Term Debt	$ 56.7	$ 109.0	$ 23.2	$ 47.9
Component % of Rate Base	1.39%	2.49%	0.49%	0.87%
Cost Rate	2.00%	1.78%	2.75%	3.35%
Return Component STD	0.03%	0.04%	0.01%	0.03%
Short Term Debt Cost	$1.2	$1.8	$ 0.5	$ 1.6
Preference Shares (net)	100	100	100	100
Component % of Rate Base	2.44%	2.28%	2.10%	1.82%
Cost Rate	3.20%	2.96%	3.68%	4.32%
Return Component Pref Shares	0.08%	0.07%	0.08%	0.08%
Preference Shares (net) Cost	3.3	3.1	3.8	4.4
Common Equity	$ 1,473.0	$ 1,578.3	$ 1,710.9	$ 1,977.1
Component % of Rate Base	36.00%	36.00%	36.00%	36.00%
Cost Rate	8.93%	9.27%	9.72%	10.12%
Return Component Common Equity	3.21%	3.34%	3.50%	3.64%
Common Equity Cost	131.5	146.3	166.3	200.0

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #21

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p. 18] Please provide evidence to support Concentric's statement that in recent years there has been a trend away from I-X plans.

RESPONSE

The Pacific Economics Group Research LLC published the attached survey of utility rate plans, "Alternative Regulation for Evolving Utility Challenges: An Updated Survey", for the Edison Electric Institute in January 2013. The report presents a discussion of Multi-Year Rate Plans beginning on page 31 and includes summary tables of current and historical precedents (Table 8 beginning on p. 33). A comparison of these tables indicates that stairsteps and rate freezes are more prevalent today as compared to the historical experience in which price cap indices were more common than they are today.

The following table contains the current and historical count of rate escalation provisions from Table 8 beginning on page 33 of the report:

Rate Escalation Provisions[1]	Current Count (% of Total)	Historical Count (% of Total)
Stairsteps	7 (28%)	17 (40%)
Rate Freeze	8 (32%)	5[2] (12%)
Index (Price Cap, Revenue Cap, Revenue Per Customer)	9 (36%)	19 (44%)
Hybrid	1 (4%)	2 (5%)

[1] Page 31 of "Alternative Regulation for Evolving Utility Challenges: An Updated Survey" defines the rate escalation provisions as follows: Stairsteps provide predetermined increases in rates (or revenue) which often reflect forecasts of cost growth. Indexing escalates rates (or revenue) automatically for inflation and sometimes also for growth in the number of customers served and/or industry productivity trends. Hybrid ARMs typically involve indexing of budgets for O&M expenses and stairsteps for capital cost budgets.
[2] National Grid, MA had a rate freeze between 2000 and 2005, and a Price Cap Index from 2006-2010.

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

Edison Electric Institute

Alternative Regulation for Evolving Utility Challenges:

An Updated Survey

Prepared by:
Pacific Economics Group Research LLC

Mark Newton Lowry, PhD

Matthew Makos

Gretchen Waschbusch, MBA

Prepared for:
Edison Electric Institute

January 2013

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Published by:
Edison Electric Institute
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I. Introduction: The Problem of Financial Attrition Under Traditional Cost of Service Regulation

Many utilities are exploring alternatives to traditional rate regulation today. The underlying problem they face is a tendency of cost to grow more rapidly than the billing determinants (*e.g.* kWh of use) that determine revenue growth between rate cases. On the cost side, some utilities need large new generation or transmission investments. Others are engaged in accelerated distribution system modernization. Even without accelerated modernization, "wireco utilities" tend to experience more rate base growth than was the norm in the last years before they sold or spun off their generation. On the revenue side, growth in energy usage per customer ("average use") helped finance utility cost growth before 1980 because it bolstered revenue appreciably more than cost. Arguably, this was a feature of the Regulatory Compact which allowed utilities to finance needed new capacity.[1] Growth in average use has been much slower since then. Few utilities have experienced much bounceback in average use since the recession thanks to sluggish economic growth, increased energy efficiency, and the spread of distributed generation ("DG"). Some utilities are experiencing declining average use.

Traditional approaches to utility regulation can fail to provide timely rate relief for such conditions. The frequency of rate cases has increased. Utilities facing a pronounced gap between cost and billing determinant growth can experience chronic underearning even with annual rate cases. Financial attrition undoubtedly has been a factor in the long-term decline of average credit ratings among investor-owned electric utilities. This is illustrated in Figure 1. Higher risk raises financing costs and can discourage needed investments.

Alternative approaches to regulation have been developed which handle today's business conditions better. Some, such as multiyear rate plans, formula rates, and fully-forecasted test years, are comprehensive in character but involve large-scale departures from traditional regulation. Others, such as revenue decoupling and cost trackers, target cost and revenue problem areas that cause cost and revenue growth to differ. Judicious use of targeted approaches can bring revenue and cost growth into better balance and reduce the frequency of rate cases.

This survey, now updated to include precedents through late 2012, briefly explains salient alternative regulation ("Altreg") options and details precedents for electric and natural gas utilities. A summary of states that currently use these approaches is featured in Table 1. Natural gas precedents are included because of their relevance to "wires only" utilities.

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[1] See Cost of Service Regulation in the Investor-Owned Electric Utility Industry: A History of Adaptation, by Karl McDermott, June 2012. Prepared for the Edison Electric Institute.

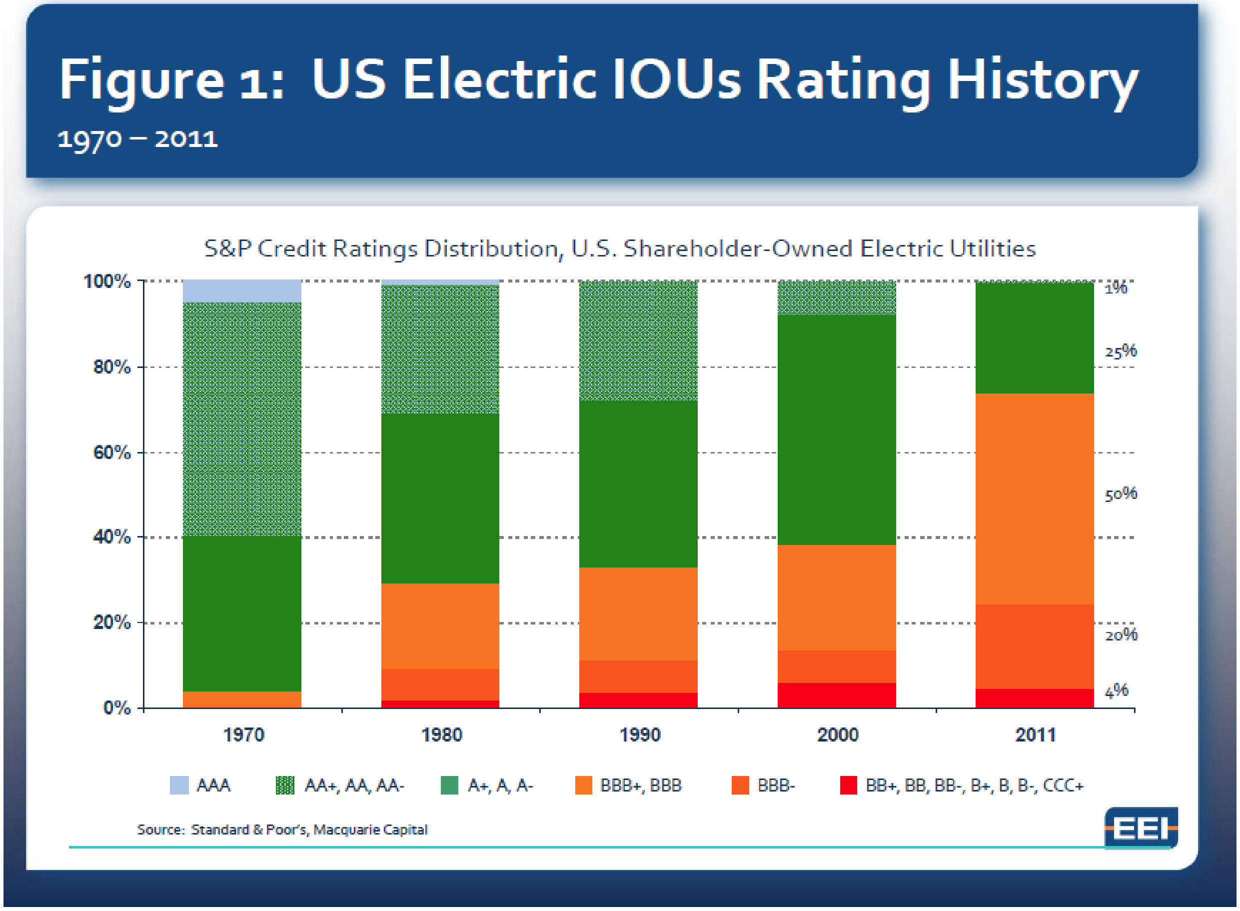


Figure 1: US Electric IOUs Rating History
1970 – 2011
S&P Credit Ratings Distribution, U.S. Shareholder-Owned Electric Utilities
100%
80%
60%
40%
20%
0%
1970
1980
1990
2000
2011
1%
25%
50%
20%
4%
AAA
AA+, AA, AA-
A+, A, A-
BBB+, BBB
BBB-
BB+, BB, BB-, B+, B, B-, CCC+
Source: Standard & Poor's, Macquarie Capital
EEI

Table 1
Innovations to Reduce Regulatory Lag: An Overview of Current Precedents

State	Capex Cost Tracker	CWIP in Rate Base[1]	Multiyear Rate Plan[2]	Revenue Decoupling			Retail Formula Rate Plans	Forward Test Years
				Decoupling True Up Plans	Lost Revenue Adjustment Mechanisms	Fixed Variable Retail Pricing		
Alabama	Yes						Yes	Yes
Arizona	Yes		Yes (electric only)	Yes (gas only)	Yes			
Arkansas	Yes			Yes (gas only)	Yes			
California	Yes		Yes	Yes				Yes
Colorado	Yes	Yes	Yes (electric only)					
Connecticut	Yes (electric only)			Yes (electric only)	Yes (gas only)	Yes		Yes
Delaware	Pending							
District of Columbia				Yes (electric only)				
Florida	Yes	Yes	Yes (electric only)			Yes (gas only)		Yes
Georgia	Yes	Yes	Yes (electric only)	Yes (gas only)		Yes (gas only)	Yes (gas only)	Yes
Hawaii	Yes (electric only)		Yes (electric only)	Yes (electric only)				Yes
Idaho				Yes (electric only)				
Illinois				Yes (gas only)		Yes	Yes (electric only)	Yes
Indiana	Yes (electric only)	Yes		Yes (gas only)	Yes (electric only)			
Iowa	Yes (electric only)		Yes (electric only)					
Kansas	Yes	Pending			Yes (electric only)			
Kentucky	Yes				Yes	Yes (gas only)		Yes
Louisiana	Yes (electric only)	Yes	Yes (electric only)		Yes (electric only)		Yes	Yes (electric only)
Maine	Yes (electric only)		Yes (electric only)					Yes
Maryland				Yes				
Massachusetts	Yes			Yes	Yes			
Michigan	Yes (gas only)	Pending		Yes (gas only)				Yes

Table 1 (continued)
Innovations to Reduce Regulatory Lag: An Overview of Current Precedent

State	Capex Cost Tracker	CWIP in Rate Base[1]	Multiyear Rate Cap[2]	Revenue Decoupling			Retail Formula Rate Plans	Forward Test Years
				Decoupling True Up Plans	Lost Revenue Adjustment Mechanisms	Fixed Variable Retail Pricing		
Minnesota	Yes	Yes		Yes (gas only)				Yes
Mississippi	Yes (electric only)	Yes				Yes (electric only)	Yes	Yes
Missouri	Yes (gas only)					Yes (gas only)		
Montana	Yes				Yes			
Nebraska								
Nevada				Yes (gas only)	Yes (electric only)			
New Hampshire	Yes		Yes (electric only)		Yes (electric only)			
New Jersey	Yes			Yes (gas only)				
New Mexico		Pending						Pending
New York	Yes (electric only)		Yes	Yes	Yes			Yes
North Carolina		Yes		Yes (gas only)	Yes (electric only)			
North Dakota		Pending				Yes (gas only)		Yes
Ohio	Yes	Pending	Yes (electric only)	Yes (electric only)	Yes (electric only)	Yes (gas only)		
Oklahoma	Yes (electric only)	Pending			Yes (electric only)	Yes (gas only)	Yes (gas only)	
Oregon	Yes			Yes	Yes			Yes
Pennsylvania	Yes (electric only)							Pending
Rhode Island	Yes			Yes				Yes
South Carolina	Yes (electric only)	Yes			Yes (electric only)		Yes (gas only)	
South Dakota	Yes (electric only)	Pending						
Tennessee				Yes (gas only)				Yes
Texas	Yes	Yes					Yes (gas only)	
Utah	Yes (gas only)			Yes (gas only)				Yes
Vermont	Yes (electric only)		Yes					
Virginia	Yes	Yes	Yes (electric only)	Yes (gas only)				
Washington	Pending			Yes (gas only)				
West Virginia	Yes (electric only)	Yes						
Wisconsin		Yes		Yes				Yes
Wyoming	Yes (electric only)	Yes		Yes (gas only)	Yes			Yes (electric only)

[1] This column pertains only to electric utilities.
[2] This column excludes plans involving rate freezes without extensive supplemental funding from trackers.

II. Cost Trackers and CWIP in Rate Base

A cost tracker is a mechanism for expedited recovery of specific utility costs. Balancing accounts are typically used to track unrecovered allowances. Cost recovery is often implemented using tariff sheet provisions called riders.

Trackers are used in various situations where they are a more practical means of adjusting rates for particular business conditions. Utilities usually recover fuel and purchased power costs via trackers because the volatility and substantial size of these costs would otherwise lead to frequent general rate cases and high risk. Other volatile expenses that are sometimes addressed using trackers include those for pension contributions and uncollectible bills.

A second common use of trackers is for costs that must be incurred because they are required by government agencies. Examples here include franchise fees and certain taxes. Tracking costs like these is fair to utilities and encourages government agents to moderate policies that are apt to raise customer bills.

Trackers are also widely used to compensate utilities for costs that are rapidly rising and don't produce much revenue, whether or not they are volatile or mandated. This can facilitate the targeted expenditures and reduce operating risk and rate case frequency. Examples of operation and maintenance ("O&M") expenses that are sometimes tracked due in whole or part to their rapid growth include those for health care and demand side management ("DSM").

Trackers for the costs of plant additions are sometimes called capital expenditure ("capex") trackers. The costs that are recovered typically include the accumulating depreciation, return on asset value, and taxes that the capex gives rise to. Recovery is sometimes achieved by keeping a rate case open beyond the date of a final decision for the limited purpose of adding assets to the revenue requirement.

Capex costs can qualify for expedited recovery using either or both of the second or third reasons just discussed. A utility might, for example, be compelled to make capital expenditures due to highway relocations or changes in government safety or reliability standards or conductor undergrounding requirements. Capex costs might also be tracked because they are large enough to cause material growth in assets that would otherwise occasion frequent rate cases.

The construction of base load generating capacity is a common source of major plant additions for VIEUs. This kind of capacity can take years to construct, especially when it is powered by solid fuels or hydroelectric resources. An allowance in rates for funds used during construction was traditionally not permitted until assets were used and useful and a rate case was filed. Deferred recovery can strain utility cash flow, involve extra financing expenses, and induce rate "shock" when the value of the plant and construction financing is finally added to the rate base. This is particularly true if the utility is not experiencing growth in average use during the years of construction. Many commissions address these problems by making a return on construction work in progress ("CWIP") eligible for immediate recovery. Capital cost trackers are often used in lieu of frequent rate cases to obtain CWIP recovery.

The capex costs of distribution system modernization are sometimes recovered using trackers for somewhat different reasons. The annual expenditure may not be as large as that for solid-fuel generation capacity, and construction of specific assets usually takes less than a year. However, the expenditures can still be sizable and, unlike new generation or customer connections, don't automatically trigger new revenue when construction is finished. A tracker for the cost of the new investment can help a company modernize its grid and improve its services without frequent rate cases.

The capex costs of generation emissions controls are often accorded expedited recovery for a combination of the reasons just discussed. The controls are occasioned by the emissions policies of state and federal agencies. Additionally, the facilities do not produce revenue and some facilities often become used and useful each year over a series of years.

There are varied treatments of costs in approved capex trackers. Plant addition budgets are usually set in advance and commission review of these budgets can be extensive. Once a budget is established, treatment of variances from the budget becomes an issue. Some trackers permit conventional prudence review treatment of cost overruns. In other cases, no adjustments are subsequently made if cost exceeds the budget. In between these extremes are mechanisms in which deviations, of prescribed magnitude, from budgeted amounts are shared formulaically (*e.g.* 50-50) between the utility and its customers.

Recent precedents for capital cost trackers are listed in Table 2 and Figures 2 and 3. It can be seen that the precedents are quite numerous and continue to grow. This is one of the most widespread approaches to Altreg. On the electric side, trackers for emissions controls, generation capacity, and advanced metering infrastructure have been especially common in recent years. Trackers for gas utilities often focus on the cost of replacing old cast iron and bare steel mains. Trackers for water utilities, sometimes called distribution system improvement charges ("DSICs"), are also common for accelerated modernization. Recent electric utility precedents for CWIP in rate base are listed in Table 3 and Figure 4. It can be seen that most involve investments in generating plant.

Figure 2: Recent Capex Tracker Precedents by State: Energy Utilities

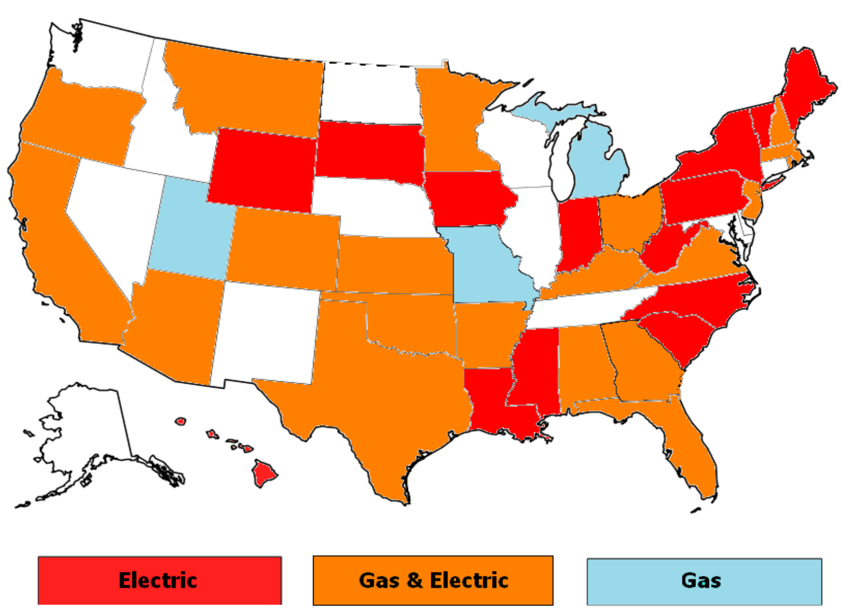


Table 2
Recent Capex Tracker Precedents

Current

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
AL	Alabama Power	Electric	Rate Certificated New Plant	Any approved by Commission through CPCN	Dockets 18117 and 18416 (November 1982)
AL	Mobile Gas Service	Gas	Cast Iron Replacement Factor	Replacement of cast iron mains	Docket 24794 (November 1995)
AR	CenterPoint Energy Arkla	Gas	Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket 06-161-U (October 2007)
AR	CenterPoint Energy Arkla	Gas	Government Mandated Expenditure Surcharge Rider	Replacements resulting from highway and street rebuilding	Docket No. 10-108-U (March 2011)
AR	Oklahoma Gas & Electric	Electric	Smart Grid Rider	Systemwide smart grid implementation	Docket No. 10-109-U (August 2011)
AR	SWEPCO	Electric	Generation Recovery Rider	New generation	Docket No. 09-008-U (November 2009)
AZ	Arizona Public Service	Electric	Environmental Improvement Surcharge	Environmental improvement projects	Docket No. E-01345A-11-024
AZ	Arizona Public Service	Electric	Renewable Energy Standard Adjustment Schedule	Renewables not recovered in base rates	Docket No. E-01345A-08-0172
AZ	Southwest Gas	Gas	Customer Owned Yard Line Cost Recovery Mechanism	Replacement and ownership of customer-owned yard lines that have been shown to be leaking	Docket No. G-01551A-10-0458 (January 2012)
CA	Pacific Gas & Electric	Electric & Gas	Smart Meter Balancing Accounts	AMI	Decision 06-07-027 (July 2006)
CA	Pacific Gas & Electric	Electric	Cornerstone Improvement Project Balancing Account	Capital and O&M expenses to improve the reliability of the electric distribution system	Decision 10-06-048 (June 2010)
CA	Pacific Gas & Electric	Gas Transmission	Pipeline Safety Implementation Plan	Pipeline replacement, automated valve installation, and upgrades to pipeline	Decision 12-12-030 (December 2012)
CA	San Diego Gas & Electric	Electric & Gas	Advanced Metering Infrastructure Balancing Account	AMI	Decision 07-04-043 (April 2007)
CA	San Diego Gas & Electric	Electric	SONGS Major Additions Adjustment Clause	Steam generator replacement for San Onofre Nuclear Generating Station	Decision 06-11-026 (November 2006)
CA	Southern California Edison	Electric	Steam Generator Replacement Project	Steam generator replacement for San Onofre Nuclear Generating Station	Decision 05-12-040 (December 2005)
CA	Southern California Edison	Electric	SmartConnect Balancing Account	Advanced Metering Infrastructure Project	Decision No. 08-09-039 (September 2008)
CA	Southern California Edison	Electric	Solar PV Balancing Account	Solar generation	Decision No. 09-06-049 (June 2009)
CA	Southern California Gas	Gas	Advanced Metering Infrastructure Balancing Account	AMI	Decision 10-04-027 (April 2010)
CO	Atmos Energy	Gas	AMI Surcharge	AMI pilot deployment	Docket No. 10A-189G (May 2010)
CO	Public Service Company of Colorado	Electric	Transmission Cost Adjustment	Transmission projects	Docket No. 07A-339E, Decision No. C07-1085 (December 2007)
CO	Public Service Company of Colorado	Gas	Pipeline Safety Integrity Adjustment	Gas distribution and transmission integrity management programs, main replacement, partial recovery of two large pipeline replacements	Docket No. 10-AL-963G (August 2011)
CT	Connecticut Light & Power	Electric	System Resiliency Plan	Structural hardening	Docket No. 12-07-06 (January 2013)
DE	All utilities may file	Electric & Gas	Utility Facility Relocation Charge	Replacements due to mandated relocations that are not otherwise reimbursed	PSC Regulation Docket No. 63 (April 2012)
FL	Chesapeake Utilities	Gas	Gas Reliability Infrastructure Program Tariff	Replacement of bare steel mains and services	Docket No. 120036-GU (September 2012)
FL	Florida Public Utilities	Gas	Gas Reliability Infrastructure Program Tariff	Replacement of bare steel mains and services	Docket No. 120036-GU (September 2012)
FL	Gulf Power	Electric	Environmental Cost Recovery Clause	Environmental	Docket No. 930613-EI (January 1994)
FL	Florida Power and Light	Electric	Environmental Cost Recovery Clause	Environmental	Docket No. 080281-EI (August 2008)
FL	Florida Power and Light	Electric	Generation Base Rate Adjustment	Generation	Docket No. 120015-EI (December 2012)
FL	Florida Power and Light	Electric	Capacity Cost Recovery Clause	Nuclear power	Docket No. 090009-EI (November 2009)
FL	Peoples Gas System	Gas	Cast Iron/Bare Steel Replacement Rider	Replacement of bare steel and cast iron pipes	Docket No. 110320-GU (September 2012)
FL	Progress Energy Florida	Electric	Capacity Cost Recovery Clause	Nuclear power	Docket No. 090009-EI (November 2009)
FL	Progress Energy Florida	Electric	Environmental Cost Recovery Clause	Environmental	Docket No. 050078-EI (September 2005)
FL	Tampa Electric	Electric	Environmental Cost Recovery Clause	Environmental	Docket No. 960688-EI (August 1996)
GA	Atmos Energy	Gas	Pipe Replacement Surcharge	Replace cast iron and bare steel pipe	Docket No. 12509-U (December 2000)
GA	Atlanta Gas Light	Gas	Strategic Infrastructure Development and Enhancement Program	Infrastructure improvements that sustain reliability and operational flexibility	Docket No. 8516-U (October 2009)
GA	Georgia Power Company	Electric	Environmental Compliance Cost Recovery	Environmental	Docket No. 25060-U (December 2007)
GA	Georgia Power Company	Electric	Nuclear Construction Cost Recovery	Nuclear generation	Docket No. 27800, Senate Bill 31

Table 2 (continued)
Recent Capex Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
HI	Hawaii Electric Light	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket No. 2007-0416 (December 2009)
HI	Hawaiian Electric Company	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket No. 2007-0416 (December 2009)
HI	Maui Electric	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket No. 2007-0416 (December 2009)
IA	MidAmerican Energy	Electric	Cooper Tracking Mechanism	Nuclear plant	Docket APP-96-1 (June 1997), Docket No. TF-02-154 (APP-96-1, RPU-96-8) (May 2002)
IN	Duke Energy Indiana	Electric	Qualified Pollution Control Property	Environmental	Cause No. 41744 (February 2001)
IN	Duke Energy Indiana	Electric	Integrated Coal Gasification Combined Cycle Generating Facility Cost Recovery Adjustment	Integrated gasification combined cycle generating plant	Docket No. 43114 (November 2007)
IN	Indianapolis Power & Light	Electric	Environmental Compliance Cost Recovery	Environmental	Cause 42170 (November 2002)
IN	Indiana Michigan Power	Electric	Clean Coal Technology Rider	Environmental	Cause No. 43636 (June 2009)
IN	Northern Indiana Public Service	Electric	Environmental Cost Recovery Mechanism	Environmental	Cause No. 42150 (November 2002)
KS	Atmos Energy	Gas	Gas System Reliability Surcharge	Infrastructure system replacements	Docket No. 10-ATMG-133-TAR (December 2009)
KS	Black Hills Energy (Aquila)	Gas	Gas System Reliability Surcharge	Infrastructure system replacements	Docket No. 07-AQLG-431-RTS (May 2007)
KS	Kansas Gas Service	Gas	Gas System Reliability Surcharge	Infrastructure system replacements	Docket 10-KGSG-155-TAR (December 2009)
KS	Kansas Gas & Electric	Electric	Environmental Cost Recovery Rider	Environmental	Docket No. 05-WSEE-981-RTS (October 2005)
KS	Midwest Energy	Gas	Gas System Reliability Surcharge	Infrastructure system replacements	Docket 09-MDWE-722-TAR (May 2009)
KS	Westar Energy Inc.	Electric	Environmental Cost Recovery Rider	Environmental	Docket No. 05-WSEE-981-RTS (October 2005)
KY	Atmos Energy	Gas	Pipe Replacement Program Rider	Replacement of bare steel service lines, curb valves, meter loops, and mandated relocates	Docket No. 2009-00354 (May 2010)
KY	Columbia Gas	Gas	Advanced Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket No. 2009-00141 (September 2009)
KY	Delta Natural Gas	Gas	Pipe Replacement Program Surcharge	Replacement of bare steel pipe, service lines, curb valves, meter loops, and mandated pipe relocations	Case No. 2010-00116 (October 2010)
KY	Kentucky Power	Electric	Environmental Cost Recovery Surcharge	Environmental	Docket No. 2002-00169 (March 2003)
KY	Kentucky Utilities	Electric	Environmental Cost Recovery Surcharge	Environmental	Case No. 93-465 (July 1994)
KY	Louisville Gas & Electric	Electric	Environmental Cost Recovery Surcharge	Environmental	Case No. 94-332 (April 1995)
KY	Louisville Gas & Electric	Gas	Gas Line Tracker	Replacement and transfer of ownership of customer owned service risers	Case No. 2012-00222 (December 2012)
LA	Cleco Power	Electric	Infrastructure and Incremental Costs Recovery	Generation, Transmission, environmental, other projects to be determined	Docket U-30689 (October 2010)
MA	Bay State Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel mains and services	DPU 09-30
MA	Massachusetts Electric	Electric	Net CapEx Factor	All distribution above depreciation expense	DPU 09-39
MA	Massachusetts Electric	Electric	Solar Cost Adjustment Provision	Solar generation	DPU 09-38
MA	Nantucket Electric	Electric	Solar Cost Adjustment Provision	Solar generation	DPU 09-38
MA	National Grid (Boston-Essex Gas and Colonial Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel, cast iron, and wrought iron mains, services, meters, meter installations, and house regulators	DPU 10-55
MA	New England Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of non-cathodically protected steel mains and services and small diameter cast-iron and wrought iron	DPU 10-114
MA	NSTAR Electric	Electric	Capital Projects Scheduling List	Stray voltage inspection survey and remediation program; double pole inspections, replacements, and restorations; and manhole inspection, repair, and upgrade	DTE 05-85 and DPU 10-70-B
MA	NSTAR Electric	Electric	NA	Smart grid pilot	DPU-09-33
MA	Western Massachusetts Electric	Electric	Solar Program Cost Adjustment	Solar generation	DPU 09-05
MN	Minnesota Power	Electric	Arrowhead Regional Emission Abatement Rider	Environmental	M-05-1678 (June 2006)
MN	Minnesota Power	Electric	Renewable Resource Rider	Renewable generation	Docket M-10-273 (July 2010)
MN	Minnesota Power	Electric	Transmission Cost Recovery Rider	Incremental transmission investment	Docket M-07-965 (December 2007)
MN	Northern States Power (Xcel Energy)	Electric	Renewable Energy Standard Cost Recovery Rider	Renewable generation	M-07-872 (March 2008)
MN	Northern States Power (Xcel Energy)	Electric	Metropolitan Emissions Reduction Project (later called Environmental Improvement Rider)	Environmental	Docket M-02-633 (March 2004)
MN	Northern States Power (Xcel Energy)	Electric	Mercury Cost Recovery Rider	Environmental	Docket No. M-09-847 (November 2009)
MN	Northern States Power (Xcel Energy)	Gas	State Energy Policy Rider	Cast iron replacements	Docket No. M-08-261 (November 2008)

Table 2 (continued)
Recent Capex Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
ME	Central Maine Power	Electric	NA	AMI	Docket No. 2007-215(II) (February 2010)
MI	SEMCO Gas	Gas	Main Replacement Rider	Replacement of cast iron and unprotected steel mains and service lines	Case U-16169 (January 2011)
MO	AmerenUE	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components	Case No. GT-2008-0184 (February 2008)
MO	Atmos Energy	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components	Docket No. GO-2009-0046 (October 2008)
MO	Laclede Gas	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components	Docket No. GR-2007-0208 (July 2007)
MO	Missouri Gas Energy	Gas	Infrastructure System Replacement Surcharge	Natural gas line replacements and relocations	Docket No. GR-2009-0355 (February 2010)
MS	Mississippi Power	Electric	Enviromental Compliance Overview Plan Rate	Environmental	Docket No. 92-UA-0058 and 92-UN-0059 (July 1992)
MT	Northwestern Energy	Electric	NA - Amounts recovered through electric supply service rates	Generation	Docket D.2008.6.69 (November 2008)
MT	Northwestern Energy	Gas	Natural Gas Supply Tracker	Battle Creek natural gas production resources	Docket No. D2012.3.25 (November 2012)
NH	Energy North	Gas	Cast Iron/Bare Steel Replacement Program	Replacement of cast iron and bare steel pipe	Docket DG-107 (June 2007)
NH	Granite State Electric	Electric	Reliability Enhancement Plan Capital Investment Allowance	Feeder hardening and asset replacement	Docket DG-107 (June 2007)
NH	Public Service Company of New Hampshire	Electric	Energy Service	Environmental	DE 11-250 (April 2012)
NJ	Elizabethtown Gas	Gas	Utility Infrastructure Enhancement Rate	Projects to enhance reliability and reinforce infrastructure	Docket No. GO09010053 (April 2009)
NJ	Elizabethtown Gas	Gas	Utility Infrastructure Enhancement Rate II	Projects to enhance reliability and reinforce infrastructure	Docket No. GO10120969 (May 2011)
NJ	New Jersey Natural Gas	Gas	Compressed Natural Gas Pilot Program	Compressed natural gas infrastructure	Docket No. GR11060361 (June 2012)
NJ	Public Service Electric and Gas	Electric & Gas	Capital Infrastructure Investment Program	Electric: reliability upgrades & feeder replacement, Gas: replacement of cast iron & bare steel mains and services	Docket No. GO09010050 (April 2009)
NJ	Public Service Electric and Gas	Electric & Gas	Capital Infrastructure Investment Program II	Electric: reliability upgrades & feeder replacement, Gas: replacement of cast iron & bare steel mains and services	Docket No. EO11020088, GO10110862 (July 2011)
NJ	Public Service Electric and Gas	Electric	Solar Generation Investment Program	Solar generation	Docket No., EO09020125 (August 2009)
NJ	Rockland Electric	Electric	Smart Grid Surcharge	Smart Grid pilot	Docket No. EO09060459 (April 2010)
NJ	South Jersey Gas	Gas	Capital Investment Recovery Tracker	Bare steel replacement, expand key distribution mains for reliability	Docket No. GO09010051 (April 2009)
NJ	South Jersey Gas	Gas	Capital Investment Recovery Tracker II	Bare steel replacement, expand key distribution mains for reliability	Docket No. GO10100765 (March 2011)
NJ	South Jersey Gas	Gas	Capital Investment Recovery Tracker III	Accelerated Main Replacement Program	Docket No. GO11100632 (May 2012)
NY	Consolidated Edison	Electric	Monthly Adjustment Clause	AMI, SCADA, undergrounding	Case 09-E-0310 (October 2010)
OH	Cleveland Electric Illuminating	Electric	Rider AMI	Ohio Site Deployment	Case Nos. 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Cleveland Electric Illuminating	Electric	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case	Case No. 10-388-EL-SSO (August 2010)
OH	Columbia Gas of Ohio	Gas	Infrastructure Replacement Program Rider	Replacement of cast iron and bare steel mains & services, AMI	Case No. 08-0072-GA-AIR, 08-0073-GA-ALT, 08-0074-GA-AAM, and 08-0075-GA-AAM (December 2008); Case No. 09-1036-GA-RDR (April 2010)
OH	Columbus Southern Power	Electric	Distribution Investment Rider	Net capital additions since the date certain of most recent rate case not recovered through other riders	Case 11-346-EL-SSO
OH	Columbus Southern Power	Electric	GridSMART Rider (Phase I)	Smart grid	Case No. 08-917-EL-SSO and 08-918-EL-SSO (March 2009)
OH	Dayton Power and Light	Electric	Environmental Investment Rider	Environmental	Case No. 05-276-EL-AIR (December 2005)
OH	East Ohio Gas d/b/a Dominion East Ohio	Gas	Pipeline Infrastructure Replacement Rider	Pipelines & faulty riser replacements	Case No. 09-458-GA-RDR (December 2009)
OH	East Ohio Gas d/b/a Dominion East Ohio	Gas	Automated Meter Reading Charge	AMI	Case No. 07-0829-GA-AIR, 07-0830-GA-ALT, 07-0831-GA-AAM, 08-0169-GA-ALT, and 06-1453-GA-UNC (October 2008); Case No. 09-38-GA-UNC (May 2009); Case No. 09-1875-GA-RDR (May 2010)

Table 2 (continued)
Recent Capex Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
OH	Duke Energy Ohio	Gas	Accelerated Main Replacement Program Rider	Replacement of bare steel and cast iron mains and services	Case No. 01-1228-GA-AIR, and 01-1478-GA-ALT, and 01-1539-GA-AAM (May 2002); 07-0589-GA-AIR 07-0590-GA-ALT 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Gas	Advanced Utility Rider	Gas AMI	Case No. 07-0589-GA-AIR 07-0590-GA-ALT 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Electric	Infrastructure Modernization Distribution Rider	Electric AMI	Case No. 08-920-EL-SSO and 08-921-EL-AAM and 08-922-EL-UNC and 08-923-EL-ATA (December 2008)
OH	Ohio Edison	Electric	Rider AMI	Ohio Site Deployment	Case Nos. 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Ohio Edison	Electric	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case No. 10-388-EL-SSO (August 2010)
OH	Ohio Power	Electric	Distribution Investment Rider	Net capital additions since the date certain of most recent rate case not recovered through other riders	Case 11-346-EL-SSO
OH	Ohio Power	Electric	GridSMART Rider (Phase I)	Smart grid	Case No. 08-917-EL-SSO and 08-918-EL-SSO (March 2009)
OH	Toledo Edison	Electric	Rider AMI	Ohio Site Deployment	Case Nos. 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Toledo Edison	Electric	Delivery Capital Recovery Rider	Power Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case No. 10-388-EL-SSO (August 2010)
OH	Vectren Energy Delivery	Gas	Distribution Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket No. 07-1081-GA-ALT, 07-1080-GA-AIR and 08-0632-GA-AAM (January 2009)
OK	Oklahoma Gas & Electric	Electric	Smart Grid Rider	Smart grid	Cause No. PUD 201000029 (July 2010)
OK	Oklahoma Gas & Electric	Electric	System Hardening Recovery Rider	Undergrounding and other circuit hardening	Cause No. PUD 20080387, Order No. 567670 (May 2009)
OK	Oklahoma Gas & Electric	Electric	Crossroads Rider	Crossroads Wind Farm	Cause No. PUD 201000037 (July 2010)
OK	Public Service Company of Oklahoma	Electric	Reliability Vegetation/Undergrounding Rider	Conversion of overhead to underground customer service lines	Cause No. PUD 200800144 (January 2009)
OR	Northwest Natural Gas	Gas	System Integrity Program	Bare steel replacement, Transmission integrity management program, distribution integrity management program	Docket UM 1406, Order No. 09-067 (March 2009)
OR	PacifiCorp	Electric	Renewable Adjustment Clause	Renewable generation	Docket UM 1330 (December 2007)
OR	PacifiCorp	Electric	NA	Mona to Oquirrh transmission line only if line is placed into service within 6 months of May 31, 2013	Docket UE 246, Order 12-493 (December 2012)
OR	Portland General Electric	Electric	Renewable Adjustment Clause	Renewable generation	Docket UM 1330 (December 2007)
PA	All utilities may file	Electric & Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects	Docket No. M-2012-2293611 (August 2012)
PA	PPL Electric Utilities	Electric	Act 129 Compliance Rider	AMI	Docket No. M-2009-2123945 (January 2010)
PA	PECO	Electric	Smart Meter Cost Recovery Rider	AMI	Docket No. M-2009-2123944 (April 2010)
PA	Metropolitan Edison	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania Electric	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania Power	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Duquesne Light	Electric	Smart Meter Charge Rider	AMI	Docket No. M-2009-2123948 (April 2010)
PA	West Penn Power	Electric	Smart Meter Surcharge	AMI	Docket No. M-2009-2123951 (June 2011)
RI	Narragansett Electric (electric operations)	Electric	Electric Infrastructure, Safety, and Reliability Plan Factor	Replacements and load growth	Docket No. 4218 (December 2011)
RI	Narragansett Electric (gas operations)	Gas	Gas Infrastructure, Safety, and Reliability Plan Factor	Replacement investment	Docket No. 4219 (September 2011)
SC	South Carolina Electric & Gas	Electric	NA	Nuclear generation	Docket 2008-196-E (March 2009)
SD	Black Hills Power	Electric	Environmental Improvement Adjustment tariff	Environmental	Docket EL11-001
SD	Northern States Power- MN	Electric	Environmental Cost Recovery Tariff	Environmental	Docket EL07-026 (January 2009)

Table 2 (continued)
Recent Capex Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
TX	All Electric Utilities	Electric	Distribution Cost Recovery Factor	Any distribution	Docket 39465
TX	AEP Texas Central	Electric	Advanced Metering System Surcharge	AMI	Docket No. 36928
TX	AEP Texas North	Electric	Advanced Metering System Surcharge	AMI	Docket No. 36928
TX	Atmos Energy Mid Tex	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity	Texas Utilities Code 104.301 and Gas Utilities Docket 9615
TX	Atmos Energy Pipelines	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity	Texas Utilities Code 104.301 and Gas Utilities Docket 9615
TX	Atmos Energy West Texas Division	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity	Texas Utilities Code 104.301 and Gas Utilities Docket 9608
TX	Centerpoint Energy Entex - Houston Division	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity	Texas Utilities Code 104.301 and Gas Utilities Docket 10067
TX	Centerpoint Energy Houston Electric	Electric	Advanced Metering System Surcharge	AMI	Docket No. 35620 (August 2008)
TX	Oncor Electric Delivery	Electric	Advanced Metering System Surcharge	AMI	Docket No. 35718 (August 2008)
TX	Texas-New Mexico Power	Electric	Advanced Metering System Surcharge	AMI	Docket No. 38306 (July 2011)
UT	Questar Gas	Gas	Infrastructure Rate Adjustment Tracker	Replacement of aging high-pressure feeder lines	Docket 09-057-16 (June 2010)
VA	Appalachian Power	Electric	Environmental & Reliability Cost Recovery Surcharge	Environmental & reliability	Docket No. PUE-2007-00069 (December 2007)
VA	Appalachian Power	Electric	Environmental Rate Adjustment Clause	Environmental	Case No. PUE-2011-00035 (November 2011)
VA	Appalachian Power	Electric	Generation Rate Adjustment Clause	Dresden plant	Docket No. PUE-2011-00036 (January 2012)
VA	Atmos Energy	Gas	Infrastructure Reliability and Replacement Adjustment	Replacement of first generation plastic pipe and service lines and bare steel mains and services	Case No. PUE-2012-00049 (August 2012)
VA	Columbia Gas of Virginia	Gas	SAVE Rider	Replacement of bare steel and cast iron mains, some early plastic pipe, isolated bare steel services, and risers prone to failure	Case No. PUE-2011-00049 (November 2011)
VA	Virginia Electric Power	Electric	Rider R	Bear Garden Generating Station	Case No. PUE-2009-00017 (March 2010)
VA	Virginia Electric Power	Electric	Rider S	Virginia City Hybrid Energy Center	Case No. PUE-2007-00066 (March 2008)
VA	Virginia Electric Power	Electric	Rider W	Warren County Power Station	Case No. PUE-2011-00042 (February 2012)
VA	Virginia Electric Power	Electric	Rider B	Biomass conversions	Case No. PUE-2011-00073 (March 2012)
VA	Washington Gas Light	Gas	SAVE Rider	Replacement of bare and unprotected steel services and mains, mechanically coupled pipe, copper services, cast iron main, and plastic services	Case No. PUE-2010-00087 (April 2011)
VT	Central Vermont Public Service	Electric	New Initiatives Adder	AMI	Dockets 7586 and 7612
WA	All gas utilities may file	Gas	Special Pipe Replacement Program Cost Recovery Mechanism	Replacement of pipe that is at an elevated risk of failure	Docket UG-120715 (December 2012)
WV	Appalachian Power	Electric	Construction/765kW Surcharge	Generation, Environmental	Case No. 11-0274-E-GI (June 2011)
WV	Wheeling Power	Electric	Construction/765kW Surcharge	Generation, Environmental	Case No. 11-0274-E-GI (June 2011)
WY	Black Hills Power	Electric	Cheyenne Prairie Generating Station rate rider tariff	Construction of Cheyenne Prairie Generating Station	Docket No. 20002-84-ET-12 (November 2012)
WY	Cheyenne Light, Fuel, & Power	Electric	Cheyenne Prairie Generating Station rate rider tariff	Construction of Cheyenne Prairie Generating Station	Docket No. 20003-123-ET-12 (November 2012)

Table 2 (continued)
Recent Capex Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
			Historic		
CA	San Diego Gas & Electric	Electric & Gas	Advanced Metering Infrastructure Balancing Account	AMI	Application 05-03-015 (March 2005)
CA	Southern California Edison	Electric	Advanced Metering Infrastructure Balancing Account	AMI	Docket No. 07-07-042 (July 2007)
CO	Public Service Company of Colorado	Electric	Air Quality Improvement Rider	Environmental	Docket 98A-511E
GA	Atlanta Gas Light	Gas	Pipeline Replacement Program Cost Recovery Rider	Replacement of cast iron and bare steel pipe	Docket 8516-U later updated in Docket No. 29950 as STRIDE tracker in 2009
IL	Commonwealth Edison	Electric	Rider Systems Modernization Projects, renamed Rider Advanced Metering Pilot	AMI	Case 07-0566, Case 09-0263
IL	Peoples Gas Light & Coke	Gas	Rider Incremental Cost Recovery	Replacement of cast iron and bare steel pipe	Docket No. 09-0167 (January 2010)
KY	Union Light, Heat and Power (Duke Energy Kentucky)	Gas	Advanced Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket No. 2001-00092 (January 2002)
NJ	Atlantic City Electric	Electric	Infrastructure Investment Surcharge	Replacements	Docket No. EO09010049 and GO09010054 (April 2009)
NJ	New Jersey Natural Gas	Gas	Accelerated Infrastructure Projects	Replace bare steel mains, reinforce distribution system & transmission mains	Docket No. GO09010052 and GR07110889 (April 2009)
NJ	New Jersey Natural Gas	Gas	Accelerated Infrastructure Projects II	Replace bare steel mains, reinforce distribution system & transmission mains	Docket No. GR10100793 (March 2011)
NY	Corning Natural Gas	Gas	Delivery Rate Adjustment	Incremental additions	Docket No. 08-G-1137 (March 2009)
NY	NYSEG	Gas	Gas Cost Savings Incentive Mechanism	Infrastructure that reduces the cost of gas supply	Docket No. 01-G-1668 (November 2002)
OH	Cleveland Electric Illuminating	Electric	Delivery Service Improvement Rider	Distribution reliability	0021-EL-ATA, 09-0022-EL-AEM, and 09-0023-EL-AAM (March 2009)
OH	Columbus Southern Power	Electric	IGCC Surcharge (Phase I only)	Early IGCC development	Case No. 05-376-EL-UNC (April 2006)
OH	Columbus Southern Power	Electric	IGCC Surchage (Phase II) IGCC Recovery Factor (Phase III)	IGCC	Case No. 05-376-EL-UNC (June 2006)
OH	Columbus Southern Power	Electric	Generation Cost Recovery Rider	Environmental	Case No. 07-63-EL-UNC (October 2007)
OH	Columbus Southern Power	Electric	Environmental Investment Carrying Charges (applies only to standard offer service customers)	Environmental	Case 08-917-EL-SSO (October 2011)
OH	Ohio Edison	Electric	Delivery Service Improvement Rider	Distribution reliability	Case No. 08-0935-EL-SSO, 09-0021-EL-ATA, 09-0022-EL-AEM, and 09-0023-EL-AAM (March 2009)
OH	Ohio Power	Electric	Environmental Investment Carrying Charges (applies only to standard offer service customers)	Environmental	Case 08-917-EL-SSO (October 2011)
OH	Ohio Power	Electric	Generation Cost Recovery Rider	Environmental	Case No. 07-63-EL-UNC (October 2007)
OH	Ohio Power	Electric	IGCC Surcharge (Phase I only)	Early IGCC development	Case No. 05-376-EL-UNC (April 2006)
OH	Ohio Power	Electric	IGCC Surchage (Phase II) IGCC Recovery Factor (Phase III)	IGCC	Case No. 05-376-EL-UNC (June 2006)
OH	Toledo Edison	Electric	Delivery Service Improvement Rider	Distribution reliability	Case No. 08-0935-EL-SSO, 09-0021-EL-ATA, 09-0022-EL-AEM, and 09-0023-EL-AAM (March 2009)
OK	Empire District Electric	Electric	Capital Recovery Rider	All incremental investment between rate cases	Cause No. PUD 201000033, Order 577904 (August 2010)
OK	Oklahoma Gas & Electric	Electric	OU Spirit Rider	OU Spirit Wind Farm	Cause No. 200900167, Order No. 571788 (October 2009)
OK	Oklahoma Gas & Electric	Electric	Smart Power Rider	Norman, Oklahoma pilot smart grid program	Cause No. 200800398
OK	Public Service Company of Oklahoma	Electric	Capital Investment Rider (CIR)	All incremental investment between rate cases	Cause No. 200900181 (August 2009)
OR	Northwest Natural Gas	Gas	NA	AMI	Docket UM 1413, Order 09-105 (March 2009)
OR	Northwest Natural Gas	Gas	Bare steel replacement program	Replacement of bare steel	Docket No. UM 1030, Order No. 01-843 (September 2001)
OR	Portland General Electric	Electric	NA	AMI	Docket UE 189, Order No. 08-245 (May 2008)
PA	PPL Electric Utilities	Electric	Energy Development Rider	Renewable interconnections	Docket No. M-00031715 F0003 (August 2006); Previously R-00973954 (May 14, 1998)
RI	Narragansett Electric (gas operations)	Gas	Accelerated Capital Replacement Program	Replacement of high pressure bare steel services inside customer premises	Docket No. 3943 (January 2009)
WV	Appalachian Power	Electric	NA: tracker included in the Expanded Net Energy Cost Mechanism	Transmission line, Environmental	Case No. 05-1278-E-PC-PW-42T (July 2006)

Figure 3: Recent Capex Tracker Precedents by State: Water Utilities

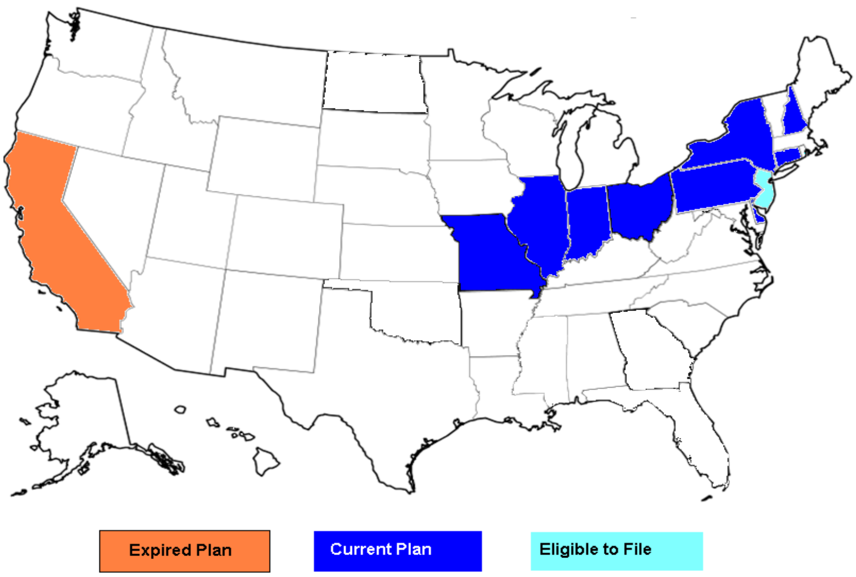


Figure 4: Recent Electric Precedents for CWIP In Rate Base

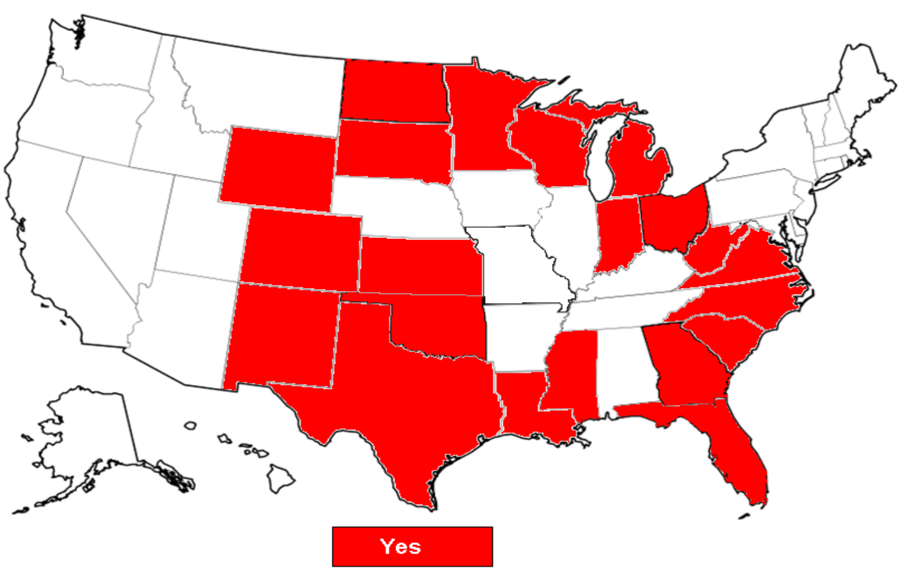


Table 3
CWIP in Rate Base: Recent Electric Retail Precedents

Jurisdiction	Company	Year Approved	Type of Project	Reference
Colorado	Public Service of Colorado	2006	Transmission, generation	Docket No. 06S-234EG
Colorado	Legislation	2007	Transmission	Senate Bill 07-100
Florida	Rulemaking	2007	Nuclear and IGCC generation	Docket 060508-EL
Florida	Florida Power & Light	2008	Nuclear generation	Docket 080650-EL
Florida	Progress Energy Florida	2008	Nuclear generation	Docket 080148-EI
Georgia	Georgia Power	2009	Nuclear generation	Docket 27800
Indiana	General Policy		Environmental	
Indiana	Duke Energy Indiana	2007	IGCC generation	Docket No. 43114
Kansas	Legislation	2008	Nuclear generation	Senate Bill 586
Louisiana	Rulemaking	2007	Nuclear generation	Docket R-29712
Louisiana	Cleco Power	2006	Generation	Docket U-28765
Michigan	Legislation	2008	Significant capital projects	House Bill 5524
Minnesota	Northern States Power- MN	2004	Environmental	Docket No. M-02-633
Minnesota	Minnesota Power	2007	Transmission	Docket M-07-965
Mississippi	Mississippi Power	2001	All projects within 1 year of completion	Docket No. 01-UN-0548
New Mexico	Legislation	2009	All	Senate Bill 477
North Carolina	Duke Energy Carolinas	2009	Generation	Docket No. E-7, Sub 909
North Carolina	Legislation	2007	Generation	Senate Bill 3
North Dakota	Legislation	2007	Transmission, federally mandated environmental	Senate Bill 2031 & House Bill 1221
Ohio	Legislation	2008	New Generation, Environmental	SB 221
Oklahoma	Legislation	2005	Environmental, transmission	House Bill 1910
South Carolina	South Carolina Electric & Gas	2003	Generation	Docket No. 2002-223-E
South Carolina	South Carolina Electric & Gas	2009	Nuclear generation	Docket 2009-211-E
South Dakota	Legislation	2006/2007	Transmission, environmental	
Texas	Rulemaking	2005	All Transmission within ERCOT (conditional)	Project 28884
Virginia	Legislation	2007	Reliability-related, nuclear, renewables, new generation using Virginia coal	Senate Bill 1416
Virginia	Virginia Electric Power	2008	New generation using Virginia coal	PUE-2007-00066
West Virginia	Appalachian Power	2006	Transmission, environmental, IGCC generation	Case No. 05-1278-E-PC-PW-42T
West Virginia	Monongahela Power	2007	Environmental	Case No. 05-0750-E-PC
Wisconsin	Wisconsin Public Service	2000	Nuclear generation, transmission	Docket 6690-UR-112
Wisconsin	Wisconsin Public Service	2005	Generation	Docket 6690-UR-117
Wisconsin	Wisconsin Power & Light	2012	All Commission approved projects	Docket 6680-UR-118
Wisconsin	General Policy		Diverse operations	
Wyoming	Black Hills Power	2012	Generation	Docket 20002-84-ET-12
Wyoming	Cheyenne Light, Fuel, & Power	2012	Generation	Docket 20003-123-ET-12

III. Revenue Decoupling

We use the term revenue decoupling to describe a diverse set of rate treatments designed to facilitate recovery of allowed revenue. The link between a utility's revenue and its sales is thereby weakened. This reduces the utility's disincentive to promote energy efficiency and can alleviate the financial stress caused by DSM programs and declining average use. DSM programs to encourage energy efficiency and discourage load peakedness can yield large cost savings for customers. Three approaches to decoupling are well established: decoupling true up plans, lost revenue adjustment mechanisms ("LRAMs"), and fixed variable pricing.

A. Decoupling True Up Plans

Decoupling true up plans adjust rates periodically to ensure that a utility's actual revenue tracks the revenue allowed by regulators. Most decoupling true up plans have two basic components: a revenue decoupling mechanism ("RDM") and an allowed revenue adjustment mechanism ("RAM"). The RDM tracks variances between actual and allowed revenue and makes periodic true ups. To the extent that recovery of allowed revenue is achieved, utilities can use rate designs more aggressively to promote DSM goals.

Decoupling true ups may be made annually or more frequently. More frequent adjustments cause actual and allowed revenue each year to correlate better so that rates fluctuate less from year to year. The size of the true up that is permitted in a given year is sometimes capped. A "soft" cap permits utilities to defer for later recovery any account balances that cannot be recovered immediately.

RDMs vary in the scope of utility services to which they apply. Quite commonly, only revenues from residential and commercial business customers are decoupled. These customers account for a high share of distribution base rate revenue and are usually the primary focus of DSM programs. RDMs also vary in terms of the service classes for which revenues are pooled for true up purposes. In some plans all service classes are placed in the same "basket". Other plans have multiple baskets. These insulate customers of services in each basket from changes in demands for services in other baskets.

Some RDMs are "partial" in the sense that they exclude from decoupling the revenue impact of certain kinds of demand fluctuations. For example, true ups are sometimes allowed only for the difference between weather normalized revenue and allowed revenue. An RDM that instead accounts for *all* sources of demand variance is called a "full" decoupling mechanism. Full decoupling provides more encouragement for rate design experimentation.

The RAM component of a decoupling true up plan escalates allowed revenue between rate cases. Virtually all decoupling true up plans have some kind of RAM because if allowed revenue is static the utility will experience financial attrition as its costs rise. Utilities that do not have RAMs in their decoupling true up plans often file annual rate cases.

Some RAMs are "broad-based" in the sense that they provide enough revenue growth to compensate the utility for several kinds of cost pressures. Broad-based RAMs are essentially the same thing as the revenue cap escalators that we discuss below in the section on multiyear rate plans. When RAMs are not broad-based, utilities usually retain the right to file rate cases during the decoupling plan and frequently do file. The revenue per customer ("RPC") freeze is a popular approach to RAM design. Allowed revenue grows at the same gradual pace as customer growth. An RPC freeze is not a broad-based RAM and will enhance expected revenue growth only when average use is expected to decline.

True up plans are the most popular approach to revenue decoupling in the United States. States that have tried gas and electric decoupling true up plans are indicated on the maps below in Figures 5a and 5b, respectively. Decoupling true up plan precedents in the United States and Canada are detailed in Table 4. It can be seen that there are more plans for gas utilities than for electric utilities. This reflects the fact that gas distributors have been much more likely to experience declining average use. Decoupling true up plans are nonetheless operative for a number of electric utilities in states with large DSM programs. Note also that RAMs for electric utilities are frequently broad-based, whereas most RAMs for gas distributors are revenue per customer freezes.

Figure 5a: Electric Decoupling True up Plans by State

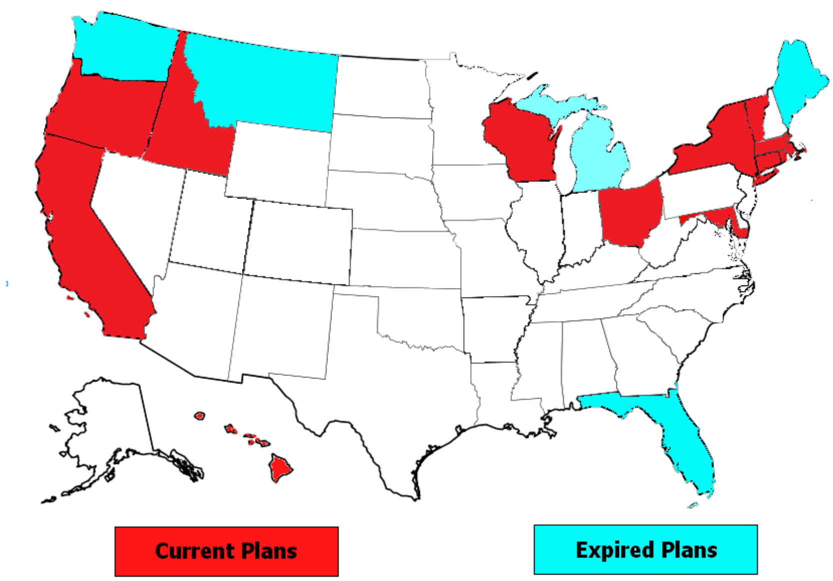


Figure 5b: Gas Decoupling True up Plans by State

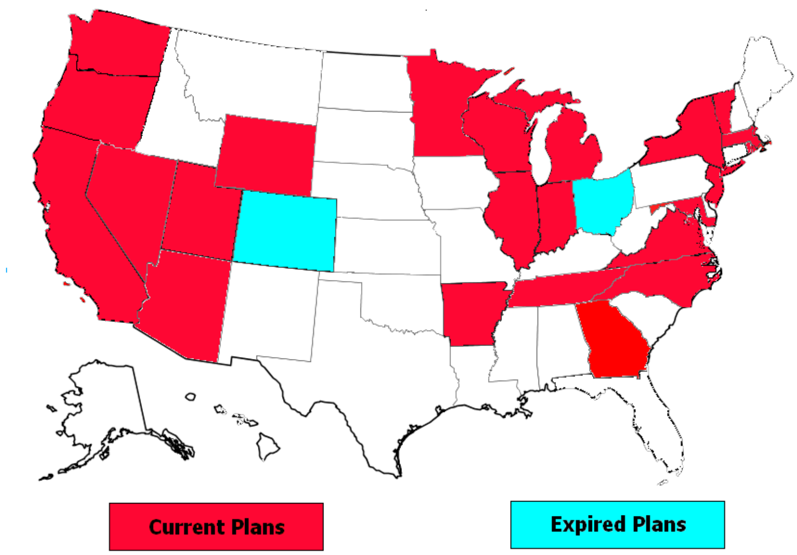


Table 4
Decoupling True Up Plan Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
			Current		
Canada					
AB	Altagas Utilities	Gas	2013-2017	RPC Index	Decision 2012-237
AB	ATCO Gas	Gas	2013-2017	RPC Index	Decision 2012-237
BC	BC Hydro	Electric	2012-2014	Stairstep	Order G-77-12A
BC	FortisBC	Electric	2012-2013	Stairstep	Order G 110-12
BC	Terasen Gas	Gas	2012-2013	Stairstep	Order G-44-12
BC	Pacific Northern Gas	Gas	2003-open	RPC Freeze	N/A
ON	Union Gas	Gas	2008-2012, extended through 2013	RPC Index through 2012, RPC Freeze for 2013	Docket EB-2007-0606
United States					
AR	CenterPoint Energy	Gas	2008-2015	No RAM but broad-based capex tracker	Dockets 06-161-U, 11-088-U
AR	Arkansas Oklahoma Gas	Gas	2007-2013	No RAM	Dockets 07-026-U, 07-077-TF
AR	Arkansas Western	Gas	2007-2013	No RAM	Docket 07-078-TF
AZ	Southwest Gas	Gas	2012-open	RPC Freeze	Docket No. G-01551A-10-0458
CA	California Pacific Electric	Electric	2013-2015	Indexing	Decision 12-11-030
CA	Pacific Gas & Electric	Gas & Electric	2011-2013	Stairstep	Decision 11-05-018
CA	Southwest Gas	Gas	2009-2013	Stairstep	Decision 08-11-048
CA	Southern California Edison	Electric	2012-2014	Hybrid	Decision 12-11-051
CA	Southern California Gas	Gas	2008-2011	Stairstep	Decision 08-07-046
CA	San Diego Gas & Electric	Gas & Electric	2008-2011	Stairstep	Decision 08-07-046
CT	United Illuminating	Electric	2009-open	Stairstep until 2011/No RAM for 2011 onwards	Docket No. 08-07-04
DC	Potomac Electric Power	Electric	2010-open	RPC Freeze	Order 15556
GA	Atmos Energy	Gas	2012-open	No RAM but FRP type mechanism also in effect	Docket No. 34734
HI	Hawaiian Electric Company	Electric	2011-open	Hybrid	0083
HI	Hawaiian Electric Light Company	Electric	2012-open	Hybrid	Docket No. 2008-0274, 2009-
HI	Maui Electric	Electric	2012-open	Hybrid	Dockets 2008-0274, 2009-0163
ID	Idaho Power	Electric	2012-open	RPC Freeze	Case No. IPC-E-11-19
IL	North Shore Gas	Gas	2012-open	No RAM	Case 11-0280
IL	Peoples Gas Light & Coke	Gas	2012-open	No RAM	Case 11-0281
IN	Indiana Gas	Gas	2011-2015	RPC Freeze	Cause No. 44019
IN	Vectren Southern Indiana	Gas	2011-2015	RPC Freeze	Cause No. 44019
IN	Citizens Gas	Gas	2007-open	RPC Freeze	Cause No. 42767
MA	Fitchburg Gas & Electric	Gas	2011-open	RPC Freeze	DPU 11-02
MA	Fitchburg Gas & Electric	Electric	2011-open	No RAM	DPU 11-01
MA	New England Gas	Gas	2011-open	RPC Freeze	DPU-10-114
MA	Western Massachusetts Electric	Electric	2011-open	No RAM	DPU 10-70
MA	Massachusetts Electric	Electric	2010-open	No RAM but broad-based capex tracker	DPU 09-39
MA	Bay State Gas	Gas	2009-open	RPC Freeze	DPU 09-30
MA	Boston-Essex Gas	Gas	2010-open	RPC Freeze	DPU 10-55
MA	Colonial Gas	Gas	2010-open	RPC Freeze	DPU 10-55
MD	Baltimore Gas & Electric	Electric	2008-open	RPC Freeze	Letter Orders ML 108069, 108061
MD	Delmarva Power & Light	Electric	2007-open	RPC Freeze	Order No. 81518
MD	Potomac Electric Power	Electric	2007-open	RPC Freeze	Order No. 81517
MD	Chesapeake Utilities	Gas	2006-open	RPC Freeze	Order No. 81054
MD	Washington Gas Light	Gas	2005-open	RPC Freeze	Order No. 80130
MD	Baltimore Gas & Electric	Gas	1998-open	RPC Freeze	Case No. 8780
MI	Michigan Consolidated Gas	Gas	2013-open	No RAM	Case No. U-16999
MI	Michigan Gas Utilities	Gas	2010-open	RPC Freeze	Case No. U-15990
MN	Minnesota Energy Resources	Gas	2012-2015	RPC Freeze	GR-10-977
MN	CenterPoint Energy	Gas	2010-2013	RPC Freeze	GR-08-1075
NC	Public Service Co of NC	Gas	2008-open	RPC Freeze	Docket No. G-5, Sub 495
NC	Piedmont Natural Gas	Gas	2008-open	RPC Freeze	Docket No. G-9, Sub 550
NJ	New Jersey Natural Gas	Gas	2010-2013	RPC Freeze	Docket GR05121020
NJ	South Jersey Gas	Gas	2010-2013	RPC Freeze	Docket GR05121019
NV	Southwest Gas	Gas	2009-open	RPC Freeze	D-09-04003
NY	Orange & Rockland Utilities	Gas	2012-open	RPC Freeze	Case 08-G-1398
NY	Corning Natural Gas	Gas	2012-2015	RPC Stairstep	Case 11-G-0280
NY	Orange & Rockland Utilities	Electric	2012-2015	Stairstep	Case 11-E-0408
NY	Niagara Mohawk	Electric	2011-open	No RAM	Case 10-E-0050
NY	New York State Electric & Gas	Gas & Electric	2010-2013	RPC Stairstep for Gas, Stairstep for Electric	Case 09-E-0715
NY	Rochester Gas & Electric	Gas & Electric	2010-2013	RPC Stairstep for Gas, Stairstep for Electric	Case 09-E-0717

Table 4 (continued)
Decoupling True Up Plan Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
NY	Consolidated Edison	Gas	2010-2013	RPC Stairstep	Case 09-G-0795
NY	Consolidated Edison	Electric	2010-2013	Stairstep	Case 09-E-0428
NY	Central Hudson G&E	Gas & Electric	2010-2013	RPC Stairstep for Gas, Stairstep for Electric	Case 09-E-0588
NY	Keyspan Energy Delivery - Long Island	Gas	2010-open	RPC Stairstep through 2012, RPC Freeze After 2012	Case 06-G-1186
NY	Keyspan Energy Delivery - New York	Gas	2010-open	RPC Stairstep through 2012, RPC Freeze After 2012	Case 06-G-1185
NY	Niagara Mohawk	Gas	2009-open	RPC Freeze	Case 08-G-0609
NY	National Fuel Gas	Gas	2008-open	RPC Freeze	Case 07-G-0141
OH	AEP Ohio	Electric	2012-2015	RPC Freeze	Case 11-351-EL-AIR
OH	Duke Energy Ohio	Electric	2012-2014	RPC Freeze	Case 11-5905-EL-RDR
OR	Northwest Natural Gas	Gas	2012-open	RPC Freeze	Order No. 12-408
OR	Portland General Electric	Electric	2011-2013	RPC Freeze	Order No. 10-478
OR	Cascade Natural Gas	Gas	2007-2012	RPC Freeze	Order No. 06-191
RI	Narragansett Electric	Electric	2012-open	No RAM but broad-based capex tracker	Docket 4206
RI	Narragansett Electric	Gas	2012-open	RPC Freeze	Docket 4206
TN	Chattanooga Gas	Gas	2010-2013	RPC Freeze	Docket 09-0183
UT	Questar Gas	Gas	2010-open	RPC Freeze	Docket No. 09-057-16
VA	Washington Gas Light	Gas	2010-2013	RPC Freeze	Case No. PUE-2009-00064
VA	Columbia Gas of Virginia	Gas	2013-2015	RPC Freeze	Case No. PUE-2012-00013
WA	Avista	Gas	2013-2014	Stairstep	Docket UG-120437
WI	Wisconsin Public Service	Gas & Electric	2013-open	No RAM	Docket 6690-UR-121
WY	Questar Gas	Gas	2012-open	RPC Freeze	Docket 30010-113-GR-11
WY	SourceGas Distribution	Gas	2011-open	RPC Freeze	Docket 30022-148-GR-10
			Historic		
Canada					
BC	BC Hydro	Electric	2011	No RAM	Order G-180-10
BC	BC Hydro	Electric	2009-2010	Stairstep	Order G-16-09
BC	Terasen Gas	Gas	2010-2011	Stairstep	Order G-141-09
BC	Terasen Gas	Gas	2008-2009	Hybrid	Order G-33-07
BC	Terasen Gas	Gas	2004-2007	Hybrid	Order G-51-03
BC	BC Gas	Gas	2000-2001	Hybrid	Order G-48-00
BC	BC Gas	Gas	1998-2000	Hybrid	Order G-85-97
ON	Enbridge Gas Distribution	Gas	2008-2012	RPC Index	Docket EB-2007-0615
United States					
CA	Pacific Gas & Electric	Gas & Electric	2007-2010	Stairstep	Decision 07-03-044
CA	Pacific Gas & Electric	Gas & Electric	2004-2006	Indexing	Decision 04-05-055
CA	Pacific Gas & Electric	Gas & Electric	1993-1995	Hybrid	Decision 92-12-057
CA	Pacific Gas & Electric	Electric	1990-1992	Hybrid	Decision 89-12-057
CA	Pacific Gas & Electric	Electric	1986-1989	Hybrid	Decision 85-12-076
CA	Pacific Gas & Electric	Electric	1984-1985	Hybrid	Decision 83-12-068
CA	Pacific Gas & Electric	Gas & Electric	1982-1983	Hybrid	Decision 93887
CA	Pacific Gas & Electric	Gas	1978-1981	No RAM	Decisions 89316, 91107
CA	PacifiCorp	Electric	1984-1985	Stairstep	Decision 89-09-034
CA	San Diego Gas & Electric	Gas & Electric	2005-2007	Indexing	Decision 05-03-025
CA	San Diego Gas & Electric	Gas & Electric	1994-1999	Hybrid	Decision 94-08-023
CA	San Diego Gas & Electric	Electric	1989-1993	Hybrid	Decision 89-11-068
CA	San Diego Gas & Electric	Gas & Electric	1986-1988	Hybrid	Decision 85-12-108
CA	San Diego Gas & Electric	Gas & Electric	1982-1983	Hybrid	Decision 93892
CA	Southern California Edison	Electric	2009-2011	Stairstep	Decision 09-03-025
CA	Southern California Edison	Electric	2006-2008	Hybrid	Decision 06-05-016
CA	Southern California Edison	Electric	2004-2006	Hybrid	Decision 04-07-022
CA	Southern California Edison	Electric	2001-2003	Indexing	Decision 02-04-055
CA	Southern California Edison	Electric	1986-1991	Hybrid	Decision 85-12-076
CA	Southern California Edison	Electric	1983-1984	Hybrid	Decision 82-12-055
CA	Southern California Gas	Gas	2005-2007	Indexing	Decision 05-03-025
CA	Southern California Gas	Gas	1998-2002	Indexing	Decision 97-07-054
CA	Southern California Gas	Gas	1986-1989	Hybrid	Decision 85-12-076
CA	Southern California Gas	Gas	1990-1993	Hybrid	Decision 90-01-016
CA	Southern California Gas	Gas	1981-1982	Stairstep	Decision 92497
CA	Southern California Gas	Gas	1979-1980	Stairstep	Decision 89710

Table 4 (continued)
Decoupling True Up Plan Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
CO	Public Service Company of Colorado	Gas	2008-2011	RPC Freeze	Decision C07-0568
FL	Florida Power Corporation	Electric	1995-1997	RPC Freeze	Docket 930444
ID	Idaho Power	Electric	2007-2009	RPC Freeze	Case No. IPC-E-04-15
ID	Idaho Power	Electric	2010-2012	RPC Freeze	Case No. IPC-E-09-28
IL	North Shore Gas	Gas	2008-2012	RPC Freeze	Case 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-2012	RPC Freeze	Case 07-0242
IN	Vectren Energy	Gas	2007-2011	RPC Freeze	Cause No. 43046
IN	Vectren Southern Indiana	Gas	2007-2011	RPC Freeze	Cause No. 43046
IN	Citizens Gas	Gas	2007-2011	RPC Freeze	Cause No. 42767
ME	Central Maine Power	Electric	1991-1993	RPC Freeze	Docket No. 90-085
MI	Consumers Energy	Electric	2009-2011	RPC Freeze	Case No. U-15645
MI	Consumers Energy	Gas	2010-2012	RPC Freeze	Case No. U-15986
MI	Detroit Edison	Electric	2010-2011	RPC Freeze	Case No. U-15768
MI	Upper Peninsula Power	Electric	2010-2011	RPC Freeze	Case No. U-15988
MI	Michigan Consolidated Gas	Gas	2010-2012	RPC Freeze	Case No. U-15985
MT	Montana Power Company	Electric	1994-1998	RPC Freeze	Docket No. 93.6.24
NC	Piedmont Natural Gas	Gas	2005-2008	RPC Freeze	Docket G-44 Sub 15
NJ	New Jersey Gas Natural	Gas	2007-2010	RPC Freeze	Docket GR05121020
NJ	South Jersey Gas	Gas	2007-2010	RPC Freeze	Docket GR05121019
NY	Central Hudson G&E	Gas	2009-open	RPC Freeze	Case 08-E-0888
NY	Central Hudson G&E	Electric	2009-open	No RAM	Case 08-E-0887
NY	Consolidated Edison	Electric	2008-open	No RAM	Case 07-E-0523
NY	Consolidated Edison	Gas	2007-2010	Stairstep	Case 06-G-1332
NY	Consolidated Edison	Electric	1992-1995	Stairstep	Opinion No. 92-8
NY	Long Island Lighting Company	Electric	1992-1994	Stairstep	Opinion No. 92-8
NY	New York State Electric & Gas	Electric	1993-1995	Stairstep	Opinion No. 93-22
NY	Niagara Mohawk	Electric	1990-1992	Stairstep	Case 94-E-0098
NY	Orange & Rockland Utilities	Gas	2009-2012	RPC Stairstep	Case 08-G-1398
NY	Orange & Rockland Utilities	Electric	2011-2012	No RAM	Case 10-E-0362
NY	Orange & Rockland Utilities	Electric	2008-2011	Stairstep	Case 07-E-0949
NY	Orange & Rockland Utilities	Electric	1991-1993	Stairstep	Case 89-E-175
NY	Rochester Gas & Electric	Electric	1993-1996	Stairstep	Opinion No. 93-19
OH	Vectren Energy	Gas	2007-2009	RPC Freeze	Case 05-1444-GA-UNC
OR	Northwest Natural Gas	Gas	2009-2012	RPC Freeze	Order No. 07-426
OR	Northwest Natural Gas	Gas	2005-2009	RPC Freeze	Order No. 05-934
OR	Northwest Natural Gas	Gas	2002-2005	RPC Freeze	Order No. 02-634
OR	PacifiCorp	Electric	1998-2001	Indexing	Order No. 98-191
OR	Portland General Electric	Electric	2009-2010	RPC Freeze	Order No. 09-020
OR	Portland General Electric	Electric	1995-1996	Stairstep	Order No. 95-0322
UT	Questar Gas	Gas	2006-2010	RPC Freeze	Docket No. 05-057-T01
VA	Virginia Natural Gas	Gas	2009-2012	RPC Freeze	Case No. PUE-2008-00060
WA	Avista	Gas	2009-2012	RPC Freeze	Docket UG-060518
WA	Avista	Gas	2007-2009	RPC Freeze	Docket UG-060518
WA	Cascade Natural Gas	Gas	2005-2010	RPC Freeze	Docket UG-060256
WA	Puget Sound & Power	Electric	1991-1995	RPC Freeze	Docket UE-901184-P
WI	Wisconsin Public Service	Gas & Electric	2009-2012	RPC Freeze	D-6690-UR-119
WY	Questar Gas	Gas	2009-2012	RPC Freeze	Docket 30010-94-GR-08

B. Lost Revenue Adjustment Mechanisms

An LRAM explicitly compensates a utility for base rate revenues that are estimated to be lost due to its DSM programs, distributed generation ("DG"), or other specific causes. Compensation for lost margins is usually effected through a rate rider. Estimates of energy (and sometimes also peak load) savings are needed for LRAM calculations. The utility remains at risk for fluctuations in volumes and peak load due to weather, local economic activity, power market prices, and other volatile demand drivers. The utility is usually kept whole for the full revenue impact of its DSM (and possibly also DG) programs and not just for the incremental effort that causes average use to decline.[2] This is desirable because a program to promote DSM and DG increases the gap between cost and billing determinant growth and thereby increase potential attrition and the need for more frequent rate cases even if average use does not decline. Precedents for LRAMs are detailed in Table 5 and Figure 6 below.[3] It can be seen that, while LRAMs are less widely used than decoupling true up plans today, they have experienced a rebound in recent years and are more popular for electric than for gas utilities. For example, they are featured in Duke Energy's "Save a Watt" approach to DSM regulation and are also popular in the Intermountain West states. Some utilities have LRAMs and decoupling true up plans.

[2] For an example of an LRAM that covers DG as well as DSM programs, see Decision 73183 of the Arizona Corporation Commission in the 2012 rate case for Arizona Public Service. A multiyear rate plan was also approved in the decision.
[3] Some mechanisms similar to LRAMs are excluded from this survey.

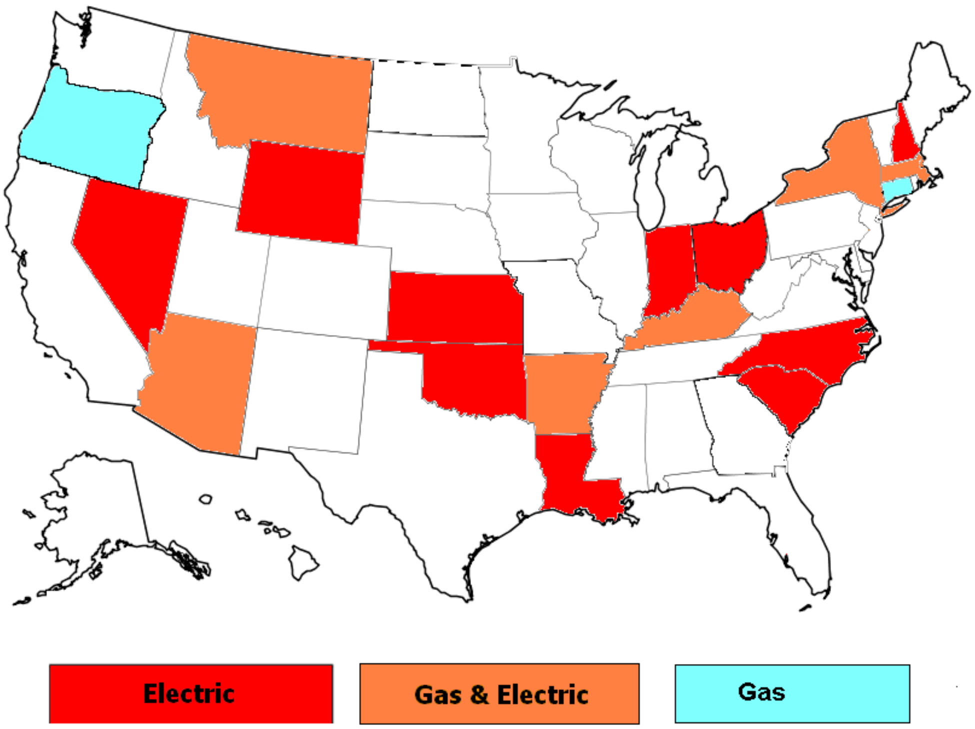
Table 5
Current LRAM Precedents

State	Company	Services	Approval Date	Case Reference
AR	Arkansas Oklahoma Gas	Gas	June 2011	Docket No. 07-077-TF, Order Number 30
AR	Centerpoint Energy Arkla	Gas	June 2011	Docket No. 07-081-TF, Order Number 31
AR	Entergy Arkansas	Electric	June 2011	Docket No. 07-085-TF, Order Number 40
AR	Oklahoma Gas & Electric	Electric	June 2011	Docket No. 07-075-TF, Order No. 26
AR	SourceGas Arkansas	Gas	June 2011	Docket No. 07-078-TF, Order No. 26
AR	Southwestern Electric Power	Electric	June 2011	Docket No. 07-082-TF, Order Nos. 35 and 36
AZ	Arizona Public Service	Electric	May 2012	Docket No. E-01345A-11-0224, Decision No. 73l83
AZ	UNS Gas	Gas	May 2012	Docket No. G-04204A-11-0158 Decision No. 73142
CT	Connecticut Natural Gas	Gas	August 1995	Docket No. 93-02-04
CT	Southern Connecticut Gas	Gas	August 1995	Docket No. 93-03-09
CT	Yankee Gas Service	Gas	January 2012	Docket No. 11-10-03
IN	Duke Energy Indiana (PSI)	Electric	February 2010	Cause No. 43374
IN	Indiana-Michigan Power	Electric	September 2010	Cause 43827
IN	Northern Indiana Public Service	Electric	May 2011	Cause 43618
IN	Southern Indiana Gas & Electric	Electric	August 2011 (large commercial and industrials), June 2012 (residential and small commercial)	Cause Nos. 43938 and 43405 DSMA 9 S1
KS	Kansas Gas & Electric	Electric	January 2011	Docket No. 10-WSEE-775-TAR
KS	Westar Energy	Electric	January 2011	Docket No. 10-WSEE-775-TAR
KY	Atmos Energy	Gas	September 2009	Case No. 2008-00499
KY	Columbia Gas of Kentucky	Gas	October 2009	Case No. 2009-00141
KY	Delta Natural Gas	Gas	July 2008	Docket No. 2008-00062
KY	Duke Energy Kentucky	Electric	December 1995 and February 2005	Case Nos. 95-321 and 2004-00389
KY	Duke Energy Kentucky	Gas	February 2005	Case No. 2004-00389
KY	Louisville Gas & Electric	Electric & Gas	November 1993	Case No. 93-150
KY	Kentucky Power	Electric	December 1995	Case No. 95-427
KY	Kentucky Utilities	Electric	May 2001	Case No. 2000-0459
LA	Entergy New Orleans	Electric	April 2009	New Orleans Resolution R-09-136
MA	All Electric distributors	Electric	July 2012	D.P.U. 12-01A
MA	Berkshire Gas	Gas	October 1992	D.P.U. 91-154
MA	NSTAR Electric	Electric	April 1992, June 1994, and June 2010	D.P.U. 90-335, D.P.U. 94-2/3-CC, and D.P.U. 10-06
MA	Commonwealth Gas d/b/a NSTAR Gas	Gas	November 1994	D.P.U. 94-128
MT	Northwestern Energy	Gas	February 2009	Docket No. D2008.5.44
MT	Northwestern Energy	Electric	December 2005	Docket No. D2004.6.90
MT	Montana-Dakota Utilities	Gas	October 2006	Docket No. D2005.10.156; Order No. 6697c

Table 5 (continued)
Current LRAM Precedents

State	Company	Services	Approval Date	Case Reference
NY	Central Hudson Gas & Electric	Electric	July 2006	Case No. 05-E-0934
NY	Consolidated Edison of New York	Electric	March 2005	Case No. 04-E-0572
NY	Consolidated Edison of New York	Gas	April 2002	Case No.00-G-1456
NY	Keyspan Long Island	Gas	December 2009	Case No. 06-G-1186; Currently effective for all customers not in RDM
NY	Keyspan New York	Gas	December 2009	Case No. 06-G-1185; Currently effective for all customers not in RDM
NC	Duke Energy Carolinas	Electric	February 2010	Docket No. E-7, Sub 831
NC	Progress Energy Carolinas (Carolina Power & Light)	Electric	November 2009	Docket No. E-2, Sub 931
NC	Virginia Electric Power	Electric	October 2011	Docket No. E-22, Sub 464
NH	Unitil Energy Services	Electric	June 2010	DE 09-137, Order No. 25,111
NV	Nevada Energy	Electric	May 2011	Docket 10-10024
NV	Sierra Pacific Power	Electric	May 2011	Docket 10-10025
OH	Duke Energy Ohio (Cincinnati Gas & Electric)	Electric	July 2007	Docket No. 06-0091-EL-UNC
OH	First Energy Ohio (Cleveland Electric Illuminating, Toledo Edison, Ohio Edison)	Electric	March 2009	Docket No. 08-935-EL-SSO
OH	American Electric Power (Ohio Power, Columbus Southern Power)	Electric	May 2010	Docket No. 09-1089-EL-POR; Effective for classes not included in RDM
OH	Dayton Power & Light	Electric	June 2009	Docket No. 08-1094-EL-SSO
OK	Empire District Electric	Electric	November 2009	Cause No. 200900146 Order 571326
OK	Oklahoma Gas & Electric	Electric	July 2008	Cause No. 200800059 Order 556179
OK	Public Service of Oklahoma	Electric	January 2010	Cause No. PUD 200900196; Order 572836
ON	Union Gas	Gas	January 2008	EB-2007-0606
ON	Enbridge Gas Distribution	Gas	February 2008	EB-2007-0615
ON	Toronto Hydro-Electric	Electric	September 2007	EB-2007-0096
OR	Portland General Electric	Electric	September 2001	Order No. 01-836; UE 79 (Approved 2001 LRAM) Currently non-residential customers only
OR	Cascade Natural Gas	Gas	April 2006	Order No. 06-191; UG 167 excludes classes under RDM
OR	Avista Utilities	Gas	December 1993	Order 93-1881
SC	Progress Energy Carolinas	Electric	June 2009	Docket No. 2008-251-E Order 2009-373
SC	Duke Energy Carolinas	Electric	January 2010	Docket No. 2009-226-E Order No. 2010-79
SC	South Carolina Electric & Gas	Electric	July 2010	Docket No. 2009-261-E, Order No. 2010-472
WY	Cheyenne Light, Fuel, and Power	Electric & Gas	September 2011	Docket Nos. 20003-108-EA-10 and 30005-140-GA-10
WY	Montana-Dakota Utilities	Electric	January 2007	Docket No. 20004-65-ET-06

Figure 6: Current LRAMs by State



C. Fixed Variable Pricing

Fixed variable pricing is an approach to the design of base rates that uses fixed charges (charges that do not vary with the sales volume or peak demand) to recover a high percentage of fixed costs. A *straight* fixed variable ("SFV") rate design recovers *all* fixed costs through fixed charges. A rate design that recovers a substantial but smaller share of fixed costs through fixed charges is sometimes called *modified* fixed variable pricing. Most fixed variable rate designs implemented to date have involved the same fixed charge for all customers in a service class. However, "sliding scale" rate designs have been developed which assign lower fixed charges to customers who are likely to have lower volumes.

The lion's share of base rate revenue from residential and commercial customers is typically raised using customer charges under fixed variable pricing. Revenue thus tends to grow at the gradual pace of customer growth.

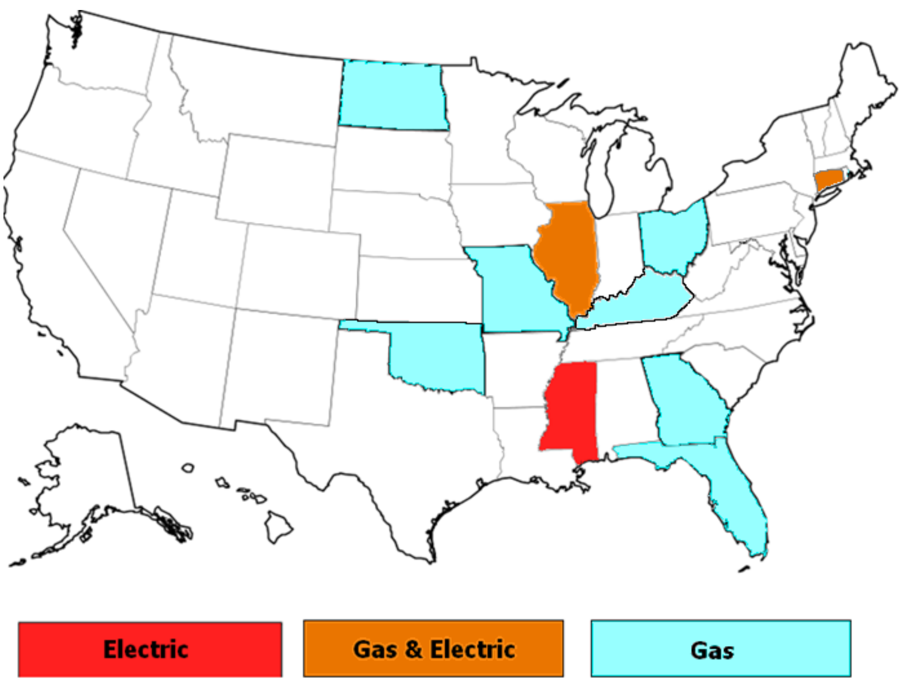
SFV pricing has been used on a large scale by interstate gas transmission companies since the early 1990s. Precedents for fixed variable pricing in retail ratemaking are listed below on Table 6 and Figure 7. It can be seen that fixed variable retail pricing has to date been more common for gas distributors than electric utilities. This again reflects the greater problem of declining average use that gas distributors have faced. Ohio is noteworthy for having recently switched from decoupling true up plans to fixed variable pricing for its gas distributors.

Table 6
Fixed Variable Retail Pricing Precedents

Jurisdiction	Company Name	Services	Years in Place	Case Reference
CT	Connecticut Light & Power	Electric	2007-open	Docket 07-07-01
CT	Yankee Gas System	Gas	2011-open	Docket 10-12-02
FL	Peoples Gas System	Gas	2009-open	Docket 080318-GU
GA	Altanta Gas Light	Gas	1998-open	Docket No. 8390-U
IL	Ameren CILCO	Gas	2008-2012	Case 07-0588
IL	Ameren CIPS	Gas	2008-2012	Case 07-0589
IL	Ameren IP	Gas	2008-2012	Case 07-0590
IL	Ameren Illinois	Gas	2012-open	Case 11-0282
IL	Commonwealth Edison	Electric	2011-open	Case 10-0467
IL	Nicor Gas	Gas	2009-open	Docket No. 08-0363
IL	North Shore Gas	Gas	2008-open	Case No. 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-open	Case No. 07-0242
KY	Delta Natural Gas	Gas	2007-open	Case No. 2007-00089
KY	Duke Energy Kentucky	Gas	2010-open	Case No. 2009-00202
MO	AmerenUE	Gas	2007-open	Case No. GR-2007-0003
MO	Atmos Energy	Gas	2007-2010	Case GR-2006-0387
MO	Atmos Energy	Gas	2010-open	Case No. GR-2010-0192
MO	Empire District Gas	Gas	2010-open	Case GR-2009-0434
MO	Missouri Gas Energy	Gas	2007-open	Case GR-2006-0422
MO	Laclede Gas	Gas	2002-open	Case GR-2002-356
MS	Mississippi Power	Electric	Occurred over period of years	No specific case
ND	Xcel Energy	Gas	2005-open	Case PU-04-578
OH	Duke Energy Ohio (CG&E)	Gas	2008-open	Case 07-590-GA-ALT
OH	Dominion East Ohio	Gas	2008-2010	Case 07-830-GA-ALT
OH	Columbia Gas	Gas	2008-open	Case 08-0072-GA-AIR
OH	Vectren Energy Delivery of Ohio	Gas	2009-open	Case 07-1080-GA-AIR
OK	Oklahoma Natural Gas	Gas	2004-open	Cause Nos. PUD 200400610, PUD 201000048, PUD 200900110
OK	Centerpoint Energy	Gas	2010-open	Cause No. PUD 201000030

In addition to the precedents listed here, some other states have in recent years made sizable steps in the direction of fixed variable pricing by redesigning rates for small volume customers to raise customer charges and lower volumetric charges substantially. Investor-owned utilities in Canada are typically permitted to raise a much higher portion of their revenue through fixed charges than in the United States. Most fixed variable rate designs feature uniform fixed charges within service classes, but gas utilities in Florida, Georgia, and Oklahoma have fixed charges that vary in some fashion with long term consumption patterns.

Figure 7: Fixed Variable Pricing Precedents by State



IV. Forward Test Years

General rate cases involve "test years" in which revenue requirements and billing determinants are jointly considered in setting new rates. An historic test year ends before the rate case is filed. A fully-forecasted (a/k/a "forward") test year ("FTY") is a twelve month period that begins after the rate case is filed. An FTY typically begins about the time that the rate case is expected to end. Two-year forecasts are therefore required to span both the rate case year and the year that rates take effect.[4] In between FTYs and historic test years is the option of a "partially forecasted" test year in which some months of historic data on utility operations are combined with some months of forecasted data. Under this approach, actual data for all months usually become available during the course of the rate case.

Historic test years are chronically uncompensatory when cost grows materially faster than billing determinants. Annual rate cases can alleviate but not eliminate underearning. Where historic test years are used in rate cases there are thus added advantages to implementing other Altreg innovations discussed in this paper.

Forward test years can compensate utilities for a tendency of cost growth to exceed billing determinant growth.[5] If this tendency is chronic, however, it does not eliminate the problem of frequent rate cases. It is therefore not unusual for regulators to combine FTYs with other Altreg remedies, as is the case in California and New York.

Diverse approaches are used to forecast costs in FTY rate cases. Some companies rely on their budgeting process to make cost projections. Others normalized data for an historical reference period and adjust for known and measurable changes and then use indexing and other statistical methods to extend projections. Mixes of these two approaches are common.

Forward test years were adopted in many jurisdictions during the 1970s and 1980s when rapid price inflation and major plant additions coincided with slowing growth in average use. This approach to Altreg was therefore one of the earliest implemented. Several additional states have recently moved in the direction of FTYs. Many of these states are in the West, where comparatively rapid economic growth has required more rapid build out of utility infrastructure. FTYs were recently sanctioned legislatively in Pennsylvania.

Current state policies concerning test years are summarized below in Figure 8 and Table 7. The ranks of US jurisdictions that allow the use of alternatives to historic test years have swollen and now encompass well over half of the total. The "other" category in Figure 8 includes states where utilities can file FTYs but many do not (*e.g.* Illinois), states where FTYs may be approved on a case by case basis (*e.g.* New Mexico, Utah, and Wyoming), and states where partially forecasted test years are the norm (*e.g.* Ohio and New Jersey). Forward test years are the norm in Canada and several jurisdictions have permitted two forward test years.

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[4] A forward test year can be the rate case year, and thereby not require two-year forecasts, if rates are allowed to be changed as proposed on an interim basis shortly after the filing.

[5] The effect on credit metrics can be material. For evidence see "Forward Test Years for US Electric Utilities" by Mark Newton Lowry, David Hovde, Lullit Getachew, and Matt Makos, August 2010. Prepared for the Edison Electric Institute.

Figure 8: Test Year Policy by State

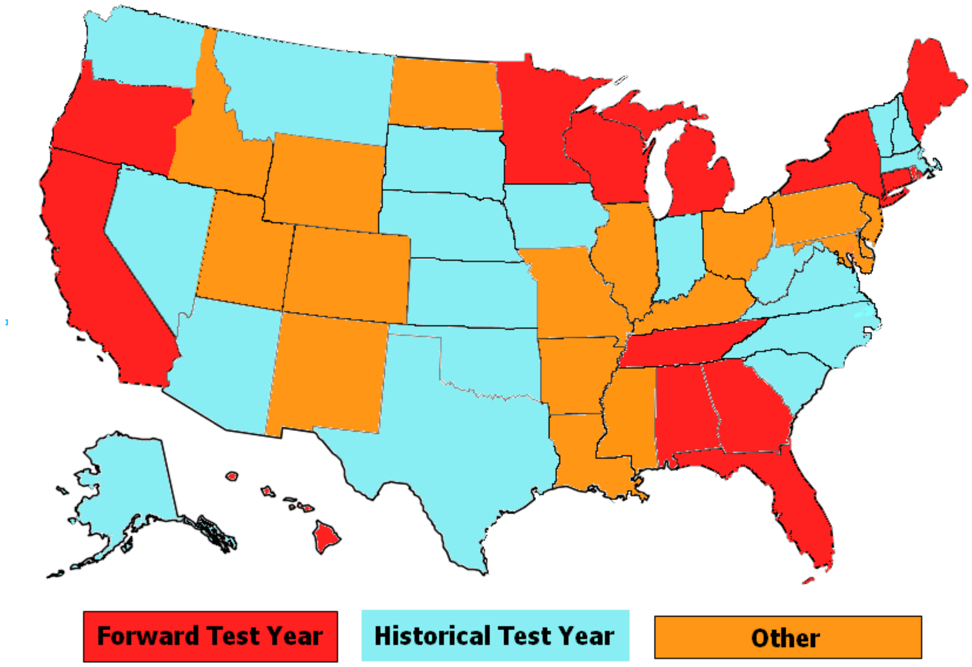


Table 7
Test Year Approaches of US Jurisdictions

Jurisdiction	Notes
Fully-Forecasted (15)	
Alabama	Utilities operate under forward-looking formula rate plans
California	
Connecticut	
FERC	Rate cases use forward test years but some formula rate plans use HTYs
Florida	
Georgia	
Hawaii	
Maine	
Michigan	
Minnesota	
New York	
Oregon	
Rhode Island	
Tennessee	
Wisconsin	
Partially-Forecasted (3)	
Arkansas	
Ohio	
New Jersey	
Transitional/Varying (14)	
District of Columbia	PEPCO has filed rate cases using both hybrid and historical test years recently
Delaware	Before restructuring FTY filings were common, but companies have used a mix of HTYs and partially-forecasted test years in recent filings
Idaho	
Illinois	Utilities use various test years including FTYs
Kentucky	Utilities use various test years including FTYs
Louisiana	Utilities use various test years including FTYs
Maryland	Utilities use various test years excluding FTYs
Mississippi	One electric utility operates under a forward-looking formula rate plan
Missouri	Utilities have the option to file partially-forecasted test years
New Mexico	A recently passed law allows for use of FTYs, but no rate increase based on FTY evidence has yet been approved
North Dakota	Utilities use various test years including FTYs
Pennsylvania	Partially-forecasted test years have been the norm. Law allowing fully-forecasted test years passed in 2012. First FTY case is pending.
Utah	Test year selection is part of the rate case and can be contested. Several recent rate cases have used FTYs.
Wyoming	Rocky Mountain Power has recently used FTYs
Historic (20)	
Alaska	
Arizona	
Colorado	Utilities can file FTY evidence. No FTY rates have yet been approved but a recent case made extraordinary HTY adjustments.
Indiana	
Iowa	
Kansas	
Massachusetts	
Montana	
Nebraska	Nebraska has no electric IOUs. Gas companies are legally authorized to use FTYs but commonly use HTYs.
Nevada	
New Hampshire	
North Carolina	
Oklahoma	
South Carolina	
South Dakota	
Texas	
Vermont	
Virginia	
Washington	
West Virginia	

V. Multiyear Rate Plans

Multiyear rate plans ("MRPs") are designed to compensate a utility for changing business conditions without frequent, full true ups to its actual cost of service. Rate cases are held infrequently, most often at three to five year intervals. Any rate escalations that are made between rate cases are based in whole or in part on automatic attrition relief mechanisms ("ARMs"). The rate adjustments provided by ARMs are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* growth. The "externalization" of ratemaking that these two features of MRPs achieve can strengthen utility performance incentives despite a reduction in regulatory cost. Benefits of better performance can be shared between the utility and its customers. Lower regulatory cost has special appeal in jurisdictions where numerous utilities must be regulated.

ARMs typically cap the growth in either rates (*e.g.* customer charges and cents per kWh) or allowed revenue. Rate caps are favored when and where utilities are encouraged to bolster system use since they strengthen incentives to promote use and facilitate marketing flexibility by reducing concerns about cross-subsidies. Revenue caps are usually combined with decoupling true ups, and are often favored where utilities must cope with declining average use and/or large-scale DSM programs.

Several approaches to the design of ARMs are well-established. These approaches include stairsteps, indexing, and hybrids. Stairsteps provide predetermined increases in rates (or revenue) which often reflect forecasts of cost growth. Indexing escalates rates (or revenue) automatically for inflation and sometimes also for growth in the number of customers served and/or industry productivity trends. Hybrid ARMs typically involve indexing of budgets for O&M expenses and stairsteps for capital cost budgets.

The indexing approach to ARM design is more common for distribution charges because distribution cost growth is relatively gradual and predictable. Hybrid and stairstep ARMs are more adaptable to the cost growth trajectories of VIEUs, which are more uneven due to occasional major plant additions. Some VIEUs operating under MRPs have separate ratemaking treatments for generation and distribution.

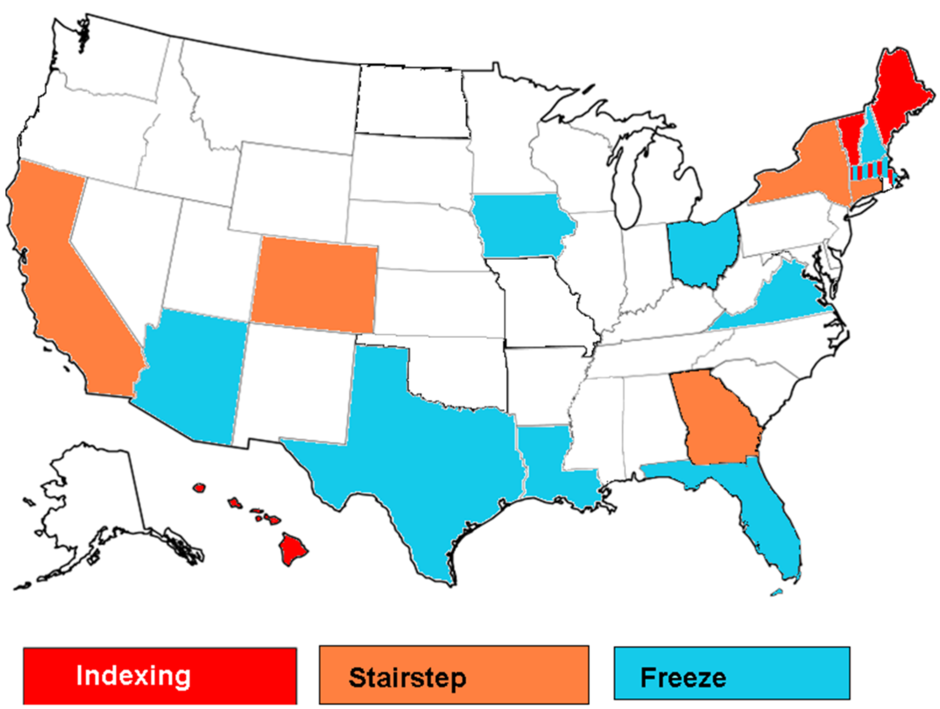
Supplemental rate adjustments are usually allowed for changes in business conditions that are especially difficult to address using ARMs. A tracker that recovers a large portion of a utility's capex cost can, for example, sometimes permit the company to operate under a multiyear freeze on rates for other non-energy costs. This is so because the value of the residual rate base is more likely to be static or decline. Trackers may also address *force majeure* events such as severe storms and changes in tax rates and other government policies that affect costs.

Some multiyear rate and revenue caps feature earnings sharing mechanisms ("ESMs") that automatically share earnings surpluses and/or deficits that result when the rate of return on equity ("ROE") deviates from its regulated target. Some feature "off-ramps" that permit plan suspension when earnings are unusually high or low. Plans often feature award and/or penalty mechanisms that are linked to the utility's service quality.

MRPs were first widely used in the railroad, telecommunications, and oil pipeline industries. A major attraction was the ability of price caps to afford utilities flexibility in serving markets with diverse competitive pressures from a consolidated set of assets. The use of MRPs in the regulation of gas and electric utilities has been chiefly motivated by other advantages such as stronger performance incentives and lower regulatory cost.

Current US and Canadian precedents for MRPs are indicated in Table 8 and Figures 9a and 9b.[6] In the US, multiyear rate plans are most common in California and the Northeast. MRPs with ARMs that escalate rate or revenue automatically are more common for energy distributors than for VIEUs. Canada is moving towards MRPs with index-based ARMs for pipe and wire utilities in all four populous provinces. MRPs with index-based ARMs are more the rule than the exception for pipe and wire utilities overseas. ARMs used in MRPs for VIEUs typically have a stairstep or hybrid form. Other VIEUs operate under a combination of a rate freeze and one or more trackers to compensate the utility for specific causes of potential attrition.

Figure 9a: Recent US Electric Multiyear Rate Cap Precedents by State



[6] The table considers only MRPs that weren't listed in Table 4 on decoupling true up precedents. Figures 9a and 9b cover all MRPs. Rate freezes without extensive supplemental funding from trackers are excluded from Table 8 and Figures 9a and 9b.

Table 8
Multiyear Price Cap Precedents[1,2]

Jurisdiction	Company Name	Plan Term	Services Covered	Rate Escalation Provisions	Case Reference
Current					
AZ	Arizona Public Service	2012-2016	Bundled power service	Rate freeze with an adjustment to account for purchase of SCE's share of Four Corners generating facility, additional capex and other cost trackers, LRAM	Decision No. 73183, May 2012
CA	PacifiCorp	2011-2013	Bundled power service	Price Cap Index: Rates escalated by Global Insight forecast of CPI, less 0.5% productivity factor; supplemental funding for major plant additions can be requested in annual filings.	Decision 10-09-010; September 2, 2010
CO	Public Service Company of Colorado	2012-2014	Bundled power service	Stairstep	Decision No. C12-0494
FL	Florida Power & Light	2013-2016	Bundled power service	Rate freeze with multiple capex and other cost trackers	Docket No. 120015-EI, December 2012
FL	Progress Energy Florida	2012-2016	Bundled power service	Rate Freeze with one step plus capex and other cost trackers	Docket No. 120022-EI
GA	Georgia Power	2011-2013	Bundled power service	Stairstep: Rate increases permitted for DSM and major generation plant additions	Docket 31958
IA	MidAmerican Energy	2001 - 2005, extended to 2013	Bundled power service	Rate Freeze with nuclear capex and other cost trackers	Dockets RPU-01-3 and RPU-2012-0001
LA	Cleco	2009-2014	Bundled power service	Rate freeze with capex tracker	Order No. U-30689
ME	Central Maine Power (III)	2009-2013	Power distribution	Price Cap Index: GDPPI - 1%, separate AMI tracker	Docket 2007-215
NH	Public Service Company of New Hampshire	2010-2015	Power distribution (generation regulated separately)	Stairstep: Rate increases allowed to account for distribution capital additions in 2010-2013	DE 09-035
NH	Unitil Energy Systems	2011-2016	Power distribution	Stairstep: Rate increases allowed to account for distribution capital additions in 2011-2013	DE 10-055
OH	AEP-OH	2012-2015	Power distribution	Rate Freeze supplemented by capex and other cost trackers	Case No. 11-346-EL-SSO, August 8, 2012
OH	First Energy Ohio	2011-2014, later extended to 2016	Power distribution	Rate Freeze with capex and other cost trackers	Case Nos. 11-388-EL-SSO, 12-1230-EL-SSO
VA	Virginia Electric Power	2010-2013	Bundled power service	Rate Freeze with capex and other cost trackers	Case No. PUE-2009-00019
VT	Green Mountain Power	2010-2013	Electric	Revenue cap index	Docket No. 7585
VT	Central Vermont Public Service	2011-2013	Electric	Revenue cap index	Docket No. 7627
VT	Vermont Gas Systems	2012-2015	Gas	Revenue cap hybrid	Docket No. 7803
Alberta	Enmax	2007-2013	Power distribution	Price Cap Index: Input Price Index -1.2%	Decision 2009-035
Alberta	Altagas Utilities	2013-2017	Gas	Revenue Per Customer Indexing: Input Price Index - 1.16%, separate capex trackers	Decision 2012-237
Alberta	ATCO Gas	2013-2017	Gas	Revenue Per Customer Indexing: Input Price Index - 1.16%, separate capex trackers	Decision 2012-237
Alberta	EPCOR, Fortis Alberta	2013-2017	Power distribution	Price Cap Index: Input Price Index - 1.16%, separate capex trackers	Decision 2012-237
Northwest Territories	Northland Utilities	2011-2013	Bundled power service	Stairstep	Decision 17-2011
Northwest Territories	Northland Utilities (Yellowknife)	2011-2013	Bundled power service	Stairstep	Decision 13-2011

Table 8 (continued)
Multiyear Price Cap Precedents[1,2]

Current

Jurisdiction	Company Name	Plan Term	Services Covered	Rate Escalation Provisions	Case Reference
Ontario	All Ontario distributors	2010-2013	Power distribution	Price Cap Index: GDP IPI for Final Domestic Demand - (0.92% to 1.32% depending on company's annual performance in benchmarking studies)	EB-2007-0673 (July 14, 2008, September 17, 2008, and January 28, 2009)
Prince Edward Island	Maritime Electric	2013-2016	Bundled power service	Stairstep: Bill defines rates for each year.	Bill 26 (2012) Electric Power (Energy Accord Continuation) Amendment Act

Historic

Jurisdiction	Company Name	Plan Term	Services Covered	Attrition Relief Mechanisms	Case Reference
CA	Sierra Pacific Power	2009-2011, extended to 2012	Bundled power service	Price Cap Index	Decision 09-10-041
CA	PacifiCorp	1994-1996, extended to 1999	Bundled power service	Price Cap Index	Decision 93-12-106; December 3, 1993
CA	PacifiCorp	2007-2009, extended to 2010	Bundled power service	Price Cap Index	Decisions 06-12-011 and 09-04-017
CA	San Diego Gas and Electric	1999-2002	Electric & Gas	Price Cap Index	Decision 99-05-030; May 13, 1999
CA	Southern California Edison	1997-2001	Electric	Price Cap Index	Decision 96-09-092; September 6, 1996
CT	United Illuminating	2006-2008	Power Distribution	Stairstep	Docket 05-06-04
FL	Florida Power & Light	2006-2009	Bundled power service	Rate Freeze with exception for new generating facilities after they are in service and multiple capex and other cost trackers	Docket 050045-EI
FL	Progress Energy Florida	2006-2009	Bundled power service	Rate freeze with 1 step to reflect generation brought in-service and multiple capex and other cost trackers	Docket No. 050078-EI
GA	Atlanta Gas Light	2005-2010	Gas distribution	Base rate freeze featuring a broad-based capex tracker	Docket No. 18638-U
MA	Bay State Gas	2006-2009	Gas distribution	Price Cap Index	Docket DTE 05-27
MA	Berkshire Gas	2002-2012	Gas distribution	No adjustment until September 2004, then Price Cap Index	Docket D.T.E. 01-56
MA	Boston Gas (I)	1997-2001	Gas distribution	Price Cap Index	Docket D.P.U. 96-50-C (Phase I) May 16, 1997
MA	Boston Gas (II)	2004-2010	Gas distribution	Price Cap Index	Docket DTE 03-40
MA	Blackstone Gas	November 1, 2004 - October 31, 2009	Gas distribution	Price Cap Index	Docket D.T.E. 04-79
MA	National Grid	2000-2010	Power distribution	Rate Freeze between 2000 and 2005, Price Cap Index: 2006-2010, inflation adjustment made based on index of regional power distribution charges.	Docket DTE 99-47 (November 29, 1999)
MA	Nstar	2006-2012	Power distribution	Price Cap Index	Docket D.T.E. 05-85
ME	Bangor Gas	2000-2009, extended to 2012	Gas Distribution	Price Cap Index	Docket 970795 (June 26, 1998)
ME	Bangor Hydro Electric (I)	1998-2000	Power distribution	Price Cap Index	Docket 97-116 (March 24, 1998)
ME	Bangor Hydro Electric (II)	2002-2007	Power Distribution	Stairstep	Docket No. 2001-410
ME	Central Maine Power (I)	1995-1999	Bundled power service	Price Cap Index	Docket 92-345 Phase II (January 10, 1995)
ME	Central Maine Power (II)	2001-2007	Power distribution	Price Cap Index	Docket 99-666 (November 16, 2000)

Table 8 (continued)
Multiyear Price Cap Precedents[1,2]

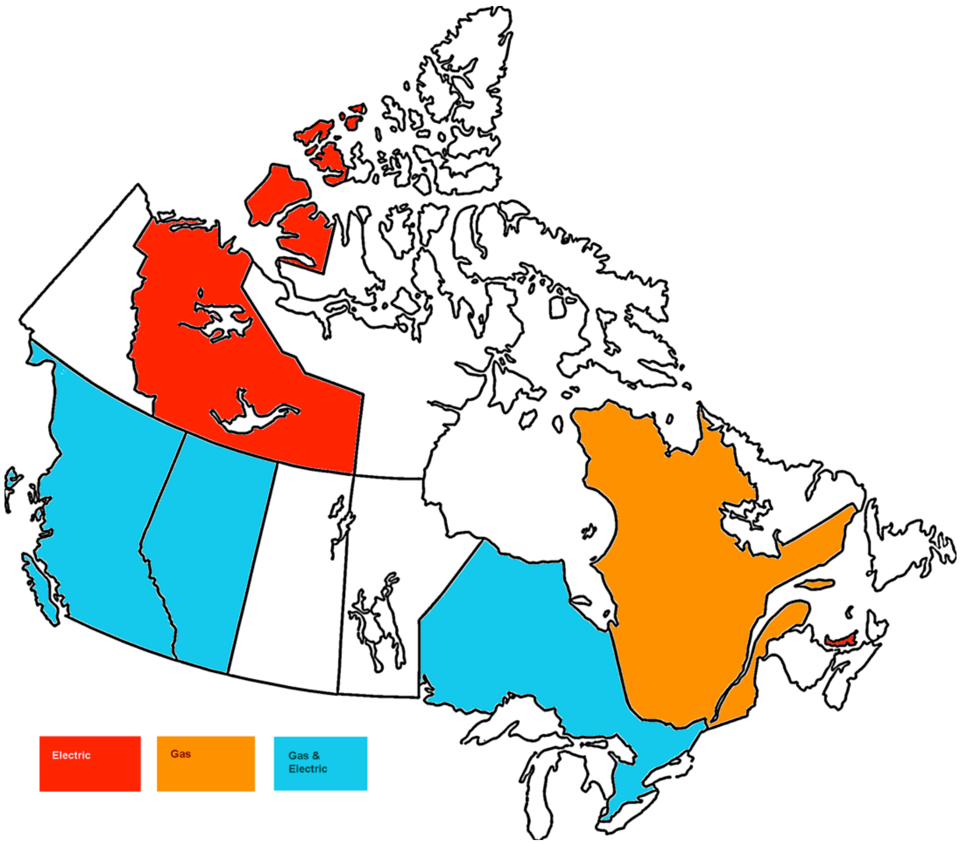
Historic

Jurisdiction	Company Name	Plan Term	Services Covered	Rate Escalation Provisions	Case Reference
NY	Brooklyn Union Gas	October 1, 1991 - September 30, 1994	Gas distribution	Stairstep	Case 90-G-0981, Opinion 91-21, October 9, 1991
NY	Brooklyn Union Gas	October 1, 1994 - September 30, 1997	Gas distribution	Stairstep	Case 93-G-0941, Opinion 94-22, October 18, 1994
NY	Central Hudson Gas & Electric	July 1, 2006 - June 30, 2009	Electric & Gas	Stairstep	Case 05-E-0934 & Case 05-G-0935; July 24, 2006
NY	Consolidated Edison	October 1, 1994 - September 30, 1997	Gas Distribution	Stairstep	Case 93-G-0996, Opinion 94-21, October 12, 1994
NY	Consolidated Edison	April 1, 2005 - March 31, 2008	Power distribution	Stairstep	Case 04-E-0572, March 24, 2005
NY	Long Island Lighting Company	December 1, 1993- November 30, 1996	Gas distribution	Stairstep	Case 93-G-0002, Opinion 93-23, December 23, 1993
NY	New York State Electric & Gas	December 1, 1993 - August 31, 1995	Gas	Stairstep	Case 92-G-1086, Opinion 93-22, November 9, 1993
NY	New York State Electric & Gas	August 1, 1995 - July 31, 1998, Years 2 and 3 not implemented due to restructuring	Electric	Stairstep	Case 94-M-0349, Opinion 95-27, September 27, 1995
NY	Niagara Mohawk	July 1, 1990 - December 31, 1992	Gas	Stairstep	Case 29327, Opinion 89-37, June 28, 1991
NY	Orange & Rockland Utilities	November 1, 2003- October 31, 2006	Gas	Stairstep	Case 02-G-1553, October 23, 2003
NY	Orange & Rockland Utilities	November 1, 2006 - October 31, 2009	Gas	Stairstep	Case 05-G-1494, October 20, 2006
NY	Rochester Gas & Electric	July 1, 1993 - June 30, 1996	Gas	Stairstep	Case 92-G-0741, Opinion No. 93-19; August 24, 1993
OH	Cincinnati Gas & Electric	2009-2011	Power generation	Stairstep	Case 08-920-EL-SSO
OH	Dayton Power & Light	2009-2012	Power Distribution	Rate freeze supplemented by capex and other cost trackers	Case No. 08-1094-EL-SSO (June 2009)
VT	Green Mountain Power	2007-2010	Electric	Stairstep	Docket No. 7176
VT	Vermont Gas Systems	2007-2012	Gas	Hybrid	Docket No. 7109
Alberta	Northwestern Utilities	1999-2002	Bundled power service	Stairstep	Decision U98060 (March 31, 1998)
Alberta	EPCOR	2002-2005, Terminated 12/31/2003	Power distribution	Price Cap Index	City of Edmonton Distribution Tariff Bylaw 12367 (August 18, 2000)
BC	Fortis BC	2006-2009, extended to 2011	Bundled power service	Revenue Cap Hybrid	Order G-58-06
Ontario	All Ontario distributors	2000-2003	Power distribution	Price Cap Index	RP-1999-0034
Ontario	All Ontario Distributors	2006-2009	Power Distribution	Price Cap Index	EB-2006-0089 (December 20, 2006)
Ontario	Union Gas	2001-2003	Gas distribution	Price Cap Index	RP-1999-0017 (July 21, 2001)

[1] Rate freezes without extensive supplemental funding from capex trackers are excluded from this table.

[2] MRPs with revenue decoupling and broad-based revenue cap escalators are detailed in Table 4.

Figure 9b: Recent Canadian Multiyear Rate Cap Precedents by Province



VI. Formula Rates

A cost of service formula rate plan ("FRP") is essentially a wide-scope cost tracker designed to help a utility's revenue track its pro forma cost of service. When revenue and cost are not balanced a utility's realized ROE deviates from the target set by regulators, and earnings surpluses or deficits occur. FRPs have earnings true up mechanisms that adjust rates so that earnings variances are substantially reduced or eliminated. Regulatory cost is reduced by limiting review of costs and revenues.

The earnings true up mechanism in an FRP calculates the revenue adjustment necessary to reduce or eliminate earnings variances. Some compare the earned ROE to the target (a/k/a benchmark) ROE and then calculate the rate adjustment needed to reduce the ROE variance. Another approach is to adjust rates for the difference between revenue and a pro forma cost of service that is calculated using a rate of return target. Both approaches often add interest on the variance to the revenue adjustment.

Earnings true up mechanisms in FRPs commonly move the ROE all, or almost all, of the way to its regulated target without sharing earnings variances. This is an important distinction between an FRP earnings true up mechanism and the earnings *sharing* mechanisms found in some multiyear rate plans. ESMs also frequently have sizable deadbands.

Expedited review of operating prudence does not always extend to major investment programs. In state-regulated FRPs for retail services, for instance, major investment programs are generally approved separately through such means as hearings on certificates of public convenience and necessity. The resultant cost is sometimes recovered through a separate tracker. Mechanisms are sometimes added to an FRP to encourage better operating performance in targeted areas. An example is a limit on the escalation of O&M expenses using an indexing formula.

Formula rates have been used at the FERC and its predecessor agency to regulate interstate services of gas and electric utilities since at least 1950. Use of FRPs was encouraged in the 1970s and early 1980s by rapid price inflation. Despite slower inflation in recent years, the FERC has made extensive use of formula rates for power transmission in an effort to simplify its daunting regulatory task and facilitate urgently needed investments.

Precedents for retail formula rates, which recover costs of generation and/or distribution, are listed in Table 9 and Figure 10[7]. It can be seen that FRPs for retail utility services are operative today in several Southeast and South Central states. Alabama was an early innovator, approving "Rate Stabilization and Equalization" plans for Alabama Power and Alabama Gas in the early 1980s.[8] Formula rates are, additionally, now used to regulate electric utilities in Mississippi, some gas and electric utilities in Louisiana, and some gas utilities in Oklahoma, Texas, and South Carolina. Utilities in other states have cost trackers that act like formula rates to recover their transmission costs from retail customers Most of the recent approvals of formula rates have been for gas distribution, as this is one means of avoiding the frequent rate cases that declining average use can trigger. However, formula rates were recently authorized for electric utilities in Illinois and two are now operating under FRPs there.

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[7] Some plans labeled as formula rates do not qualify for inclusion in this table and figure based on our definition.

[8] For further discussion of the Alabama FRP experience see Edison Electric Institute, *Case Study of Alabama Rate Stabilization and Equalization Mechanism*, June 2011.

Table 9
Retail Formula Rate Plan Precedents[1]

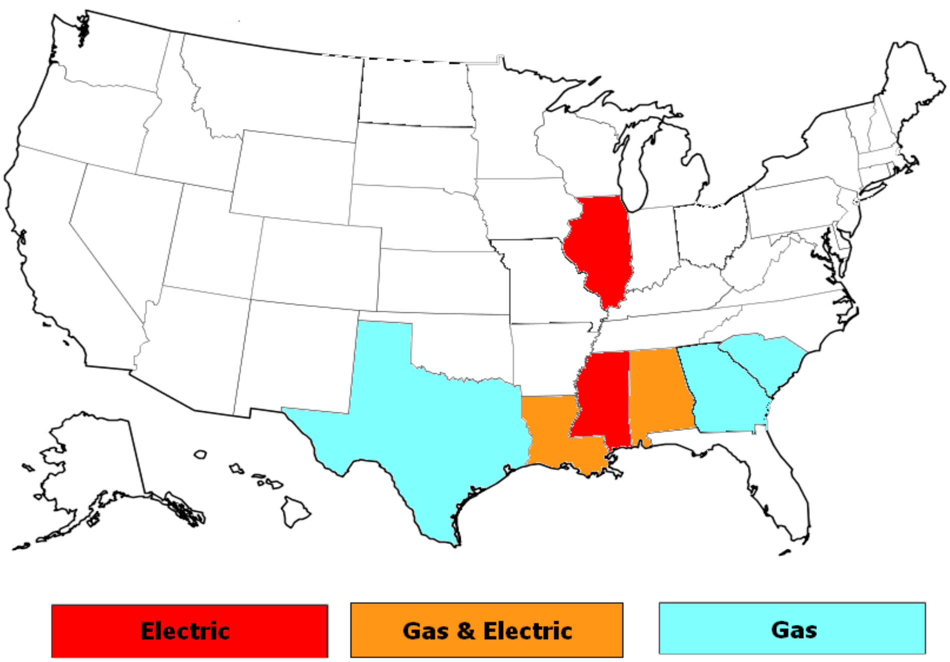
Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
Current					
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2006-open	Dockets No. 18117 and 18416 (October 2005)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2008-2014	Dockets No. 18406 and 18328 (December 2007)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2009-2013	Docket 28101 (December 2009)
GA	Atmos Energy	Gas	Georgia Rate Adjustment Mechanism (GRAM)	2012-open	Docket 34764 (December 2011)
IL	Ameren Illinois	Power Distribution	Rate Modernization Action Plan - Pricing (Rate MAP-P)	2011-2017	Case 12-0001 (September 2012)
IL	Commonwealth Edison	Power Distribution	Rate Delivery Service Pricing and Performance (Rate DSPP)	2011-2017	Case 11-0721 (May 2012)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2006-open	Docket No. U-21484 (May 2006)
LA	Atmos Energy - Trans Louisiana Gas	Gas	Rate Stabilization Plan	2006-open	Docket No. U-28814 and U-28588 and U-28587(May 2006)
LA	Entergy New Orleans	Electric and Gas	Formula Rate Plan	2010-2012	Docket No. UD-08-03 (April 2009)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2009-present	Docket No. 05-UN-0503 (December 2009)
MS	Centerpoint Energy Entex	Gas	Rate Regulation Adjustment Rider	2008-open	Docket No. 07-UN-548 (December 2007)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 5 (FRP 5)	2010-open	Docket No. 2009-UN-388 (March 2010)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 5 (PEP-5)	2010-open	Docket No. 2003-UN-0898 (November 2009)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2010-open	Docket No. 201000030 (July 2010)
OK	Oklahoma Natural Gas	Gas	Performance Based Rate of Change Plan	2010-2013	Docket No. 200800348 (April 2009)
SC	Piedmont Gas	Gas	NA	2005-present	Docket No. 2005-125-G (September 2005)
SC	South Carolina Electric and Gas	Gas	NA	2005-present	Docket No. 2005-113-G (October 2005)
TX	Centerpoint Energy-Texas Coast Division	Gas	Cost of Service Adjustment Clause	2008-open	Gas Utility Docket 9791 (October 2008)
TX	Atmos Energy-Mid Texas Division	Gas	Rate Review Mechanism	2008 - conclusion of rate case to be filed on or before June 1, 2013	Various Resolutions/Ordinances across cities in service territory, including City of Fort Worth Ordinance 17989-02-2008
TX	Atmos Energy West Texas Division	Gas	Rate Review Mechanism	2009 - conclusion of rate case to be filed on or before June 1, 2013	Various Resolutions/Ordinances across cities in service territory
TX	Texas Gas Service - North Service Area	Gas	Cost of Service Adjustment Tariff	2009-open	Various Resolutions/Ordinances in service territory and Gas Utility Docket 9839 (April 2009)
Historic					
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2006	Dockets No. 18117 and 18416 (March 2002)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1998-2002	Dockets No. 18117 and 18416 (March 1998)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1990-1998	Dockets No. 18117 and 18416 (March 1990)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1990	Dockets No. 18117 and 18416 (June 1985)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1982-1985	Dockets No. 18117 and 18416 (November 1982)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2007	Dockets No. 18046 and 18328 (June 2002)

Table 9 (continued)
Retail Formula Rate Plan Precedents[1]

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1996-2001	Dockets No. 18046 and 18328 (October 1996)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1991-1995	Dockets No. 18046 and 18328 (December 1990)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1987-1990	Dockets No. 18046 and 18328 (September 1987)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1987	Dockets No. 18046 and 18328 (May 1985)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1983-1985	Dockets No. 18046 and 18328 (January 1983)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2005-2009	Docket 28101 (June 2005)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2001-2005	Docket 28101 (June 2002)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2001-2003	Docket No. U-21484 (January 2001)
LA	Entergy New Orleans	Electric only	Formula Rate Plan	2004-2006	Docket No. UD-01-04 (May 2003)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2006-2009	Docket No. 05-UN-0503 (October 2005)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	1992-2006	Docket 92-UA-0230 (September 1992)
MS	Centerpoint Energy Entex	Gas	Rate Regulation Adjustment Rider	1996-2007	Docket No. 96-UN-0202 (September 1996)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 1 (FRP 1)	1995	Docket No. 93-UA-0301 (March 1994)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 4A (PEP- 4A)	2009	Docket No. 06-UN-0511 (January 2009)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 4 (PEP-4)	2004-2009	Docket No. 03-UN-0898 (May 2004)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 3 (PEP-3)	2002-2004	Docket No. 01-UN-0826 (October 2002)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 2A (PEP-2A)	2001-2002	Docket No. 01-UN-0548 (December 2001)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 1A (PEP-1A)	1992-1993	Docket 92-UN-0059 (July 1992)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 1 (PEP-1)	1991-1992	Docket No. 90-UN-0287 (December 1990)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan	1986-1990	Docket No. U-4761 (August 1986)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2008-2010	Docket No. 200800062 (July 2008)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2004-2008	Docket No. 200400187 (November 2004)

[1] Table excludes some mechanisms that do not conform to our FRP definition. Some of these are called formula rate plans.

Figure 10: Current Retail Formula Rate Precedents by State



VII. Conclusions

Regulation of North American energy utilities is evolving to remedy the chronic underearning and frequent rate cases that traditional regulation tends to produce under modern operating conditions. Innovations continue, while some older forms of Altreg are again finding favor. This brief survey has not considered all noteworthy approaches to Altreg. Here are some of the other approaches that merit recognition:

- Regulatory assets can provide delayed compensation with interest for the annual cost of newly used and useful plant that doesn't automatically produce revenue.
- Attrition adjustments to rates can provide some compensation for an ongoing tendency of cost growth to exceed billing determinant growth. See, for example, a recent decision of the Washington Utilities and Transportation Commission in a rate case for Avista[9].
- Utilities can be permitted to file rate cases on a limited set of issues, such as additions to generation plant, that are salient causes of potential attrition.

The variety of Altreg approaches that have been established reflects the varied circumstances of individual utilities. Some are vertically integrated, while others are more specialized wire companies. Investment needs and trends in average use vary greatly. No single Altreg approach is right for every situation. The availability of multiple remedies for the underlying problems increases the chance that an approach has already been tried that fits the regulatory inclinations of a particular jurisdiction. Numerous precedents for an approach should raise confidence that it makes good sense under fairly common circumstances.

Taken together, the many innovations described in this survey can encourage utilities to make smart investments, reduce long run costs, and improve service quality without rate shock or unnecessarily frequent rate cases. Utilities can be encouraged to promote energy efficiency and peak load management aggressively. Regulators and stakeholders to regulation across the US should give priority attention to these options and consider which Altreg combinations work best in their situation.

[9] Washington Utilities and Transportation Commission, Dockets UE-120436/UG-120437, Order 09, December 26, 2012.

SEC INTERROGATORY #22

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p. 34] Please describe what analysis Concentric did, if any, to determine which of the peers selected were under IRM regimes in which years, and to normalize the benchmarking to reflect the influence of IRM. Please confirm that the term "During IR" in Figure 14 refers only to Enbridge, and that the comparator companies were not necessarily in IR at that time, but may have been in the period marked Pre-IR.

RESPONSE

As discussed on pages 21 and 22, Concentric's selection criteria were based on the similarity of operations, similarity of weather conditions, and similarity of size to EGD, as well as data availability. A number of U.S. and Canadian utilities have operated under various types of incentive rate mechanisms at different times and for varying periods of time; however, Concentric did not use incentive rate plans as a selection criterion, did not conduct research to identify which utilities are under incentive regulation plans and the plan term, and did not adjust the benchmarking results to reflect the presence of an incentive rate mechanism. Concentric did not find it necessary to make such adjustments. All regulation contains incentives. We therefore did not find it appropriate or practical to measure the degree to which each utility operated under a specific set of incentives.

It is confirmed that "During IR" in Figure 14 refers to the period of Enbridge's last incentive rate mechanism and does not imply anything about the use of incentive rate mechanisms by the industry study group companies or the seven company sub-group companies. The purpose of this analysis was to compare EGD's productivity performance over time and to the industry study group and the seven company sub-group for the whole study period, as well as the period before EGD's last IR and during EGD's last IR.

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #23

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p. 35] Please describe what analysis Concentric did, if any, to normalize the benchmarking to reflect the influence of differing U.S. and Canadian economic factors on Enbridge and its peer groups.

RESPONSE

It is not clear, based on the question and page reference, what "benchmarking" the question refers to. Page 35 of Concentric's report summarizes the TFP results, and introduces the PFP results. We will therefore answer the question for both primary analyses: productivity (TFP and PFP), and the benchmarking, as reported in Appendix A, pages 76 to 94.

The productivity analyses (TFP and PFP) both relied on a combination of U.S. study groups in comparison to EGD. The indexes (input and output) computed for each was based on the costs and revenues for each company in the analysis. The resulting indexes are expressed in percent growth terms, weighted for each company in the group. The relationships between inputs and outputs (TFP and PFP indexes) were not specifically adjusted for any differences in economic factors, other than the screens for weather, size and customer growth that made the proxy companies appropriate for comparison to Enbridge. Country specific input price indices (e.g., GDPIPI-FDD, bond yields, ROE, etc.) were used where appropriate, as described in Appendix B, pages 100 to 107.

In the benchmarking analysis reported in Appendix A, Concentric directly compared costs between companies (in contrast to the indices developed in the TFP and PFP analyses). We therefore expressed all current year comparisons (the 2011 bar charts) in Canadian dollars, and the trend charts were expressed in own-country dollars (U.S. or Canadian) to avoid issues associated with year-to-year fluctuations in currency exchange rates. This is explained in Footnote 81 on page 82 of Concentric's report.

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #24

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/p/1, p. 35] Please confirm Concentric's conclusion that gas and electric distribution TFP over the period 2000 to 2011 was similar.

RESPONSE

Concentric did not conclude that gas and electric distribution TFP over the period 2000 to 2011 was similar. Concentric's study included only gas distributors, representing a more appropriate industry study group for EGDI. Concentric noted that PEG's proxy group was different, but observed that PEG's TFP results for Ontario electric distributors (in a range from -.05% to 0.1%, excluding Toronto Hydro and Hydro One) were very similar to those measured by Concentric for the seven company gas distributor proxy group (-.01%).

Witnesses: M. Bartos - Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #25

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p. 40] Please compare the X factor proposed by Concentric, 0%, with the agreed X factor for Union Gas, for the same period, of 60% of inflation, and explain why the Enbridge X factor should be so much lower.

RESPONSE

As explained in Concentric's report (Exhibit A2, pages 1 to 3), Concentric measured the productivity of Enbridge and the industry over the 2000 to 2011 period, and utilized the resulting "X-Factors" to evaluate the ability of an I-X framework to accommodate the Company's cost profile over the 2014 to 2016 period. Concentric concluded that the measured industry X-Factor for the seven company group, 0%, would not be sufficient to recover EGD's total O&M and capital costs over the 2014 to 2016 period.

In comparison to the Union agreement with a price cap index ("PCI") where PCI growth is driven by an inflation factor ("GDPIPI FDD"), less a productivity factor of 60% of GDP IPP FDD (2013-07-31, EB-2013-0202, Exhibit A), several factors must be considered:

- Union's Settlement Agreement was the result of a "comprehensive Settlement Agreement between stakeholders and Union" (July 31, 2013 accompanying letter to the Board requesting approval of the settlement)
- Union's originally proposed X-Factor was 0%
- The Settlement Agreement contains numerous features that presumably represented trade-offs in positions between the parties to the agreement
- Union and EGD had different productivity measures in their prior plans
- Union and EGD are subject to different company specific cost factors (e.g., capital expansion plans) and customer growth
- Concentric was not a party to the settlement discussions, and is unaware that Union's productivity factor was supported by an industry or company-specific TFP analysis.

Witnesses: M. Bartos - Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #26

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, fn.63] Please provide the basis for Concentric's conclusion that Ontario is a jurisdiction in which "leak-prone assets are a significant portion of total distribution assets and services".

RESPONSE

Concentric makes no such conclusion that Ontario is a jurisdiction in which "leak-prone assets are a significant portion of total distribution assets and services".

To clarify, Concentric prepared Figure 29: Capital Tracker Approaches to summarize the three most common non-traditional ratemaking approaches that have been applied recently in Canada and the U.S. to allow for timely recovery of the costs of capital spending between rate cases. Thus, neither Figure 29 nor the explanation for Figure 29 that is provided in Exhibit A2, Tab 9, Schedule 1, pages 56 to 58, including Footnote 63, was intended to refer specifically to Ontario gas distribution companies.

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #27

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p. 60] Please provide a calculation or estimate of the tax effect on depreciation on Concentric's revenue and revenue requirement calculations.

RESPONSE

The requested calculations are provided in the table on the following page.

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

Revenues Based on I-X Rate Adjustments, Tax Shield Included

		2014	2015	2016
	Revenue Requirement			
1	Average of Monthly Avgs Plant	$6,977,000,000	$7,441,000,000	$8,321,900,000
2	Depreciation Rate	3.58%	3.55%	3.50%
3	Depreciation Expense	$(250,100,000)	$(263,900,000)	$(291,200,000)
4	Tax Shield			
4a	CCA	$231,400,000	$279,500,000	$310,100,000
4b	Tax Rate	26.50%	26.50%	26.50%
4c	Total	$61,321,000	$74,067,500	$82,176,500
4d	Dep Exp net of Tax Shield	$(188,779,000)	$(189,832,500)	$(209,023,500)
5	Average of Monthly Avgs Rate Base	$4,081,300,000	$4,440,400,000	$5,203,200,000
6	ROR^{Pretax}	7.98%	8.19%	8.36%
7	Return: ROR^{Pretax} x RB	$325,500,000	$363,600,000	$435,200,000
8	Revenue Requirement: Return + DeprExp (Incld Tax Shield)	$514,279,000	$553,432,500	$644,223,500
9	Revenues			
10	Rebasing Return	$311,300,000	$311,300,000	$311,300,000
11	Rebasing Depreciation Expense	$237,300,000	$237,300,000	$237,300,000
11a	Tax Shield	$(61,400,000)	$(61,400,000)	$(61,400,000)
11b	Rebasing Depreciation Expense net of tax Shield	$175,900,000	$175,900,000	$175,900,000
12	P (Percent increase in Rates)	2.45%	2.45%	2.45%
13	G (Percent increase in Customers)	1.69%	1.73%	1.75%
14	(1 + P) x (1 + G)	1.04173	1.08571	1.13171
15				
16	$Revenues_{Plant\text{-}related}$ = [Rebasing Return + Depreciation] x (1+P) x (1+G)	$507,500,000	$529,000,000	$551,400,000
17				
18	Deficiency (Surplus) in Revenues	$6,779,000	$24,432,500	$92,823,500

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #28

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p/ 61] Please show where, in the calculations in Figure 30, the reductions in O&M associated with capital spending are captured.

RESPONSE

Figure 30 provides calculations of the projected Capital-related revenue deficiencies that Enbridge would experience in 2014 to 2016 under an I-X escalation formula. Concerning the projected capital spending that is reflected in Figure 30, this table does not include either (a) estimated increases in O&M for such incremental costs as (i) leak survey activity and maintenance activity for new services and mains extensions and (ii) meter reading, billing and customer service activities for new customer installations; or (b) estimated reductions in O&M for such savings as reduced maintenance activity for existing mains that would be replaced.

Enbridge and Concentric determined that including estimates of O&M increases and decreases associated with Enbridge's projected 2014 to 2016 plant in Figure 30 would not be appropriate or necessary because these estimated increases and decreases in plant-related O&M would not have any meaningful impact on the estimated total $141.5 million revenue deficiency for the 2014 to 2016 period.

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #29

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p. 67] Please confirm Concentric's opinion that any I-X IRM model will be contrary to the Fair Return Standard if the utility's forecast capital spending exceeds depreciation over the IRM period.

RESPONSE

No, it is not Concentric's opinion that any I-X model will necessarily be contrary to the Fair Return Standard if the utility's forecast capital spending exceeds depreciation over the IRM period. For example, if, during the IRM period, the cost of capital is declining, or if O&M expenses decrease, these reductions in costs may be sufficient to offset the impact of capital spending exceeding depreciation.

To determine if an I-X IRM model would be contrary to the Fair Return Standard, Concentric measured EGDI's overall revenue requirements against the I-X rate path; Concentric's assessment is summarized in Exhibit A2, Tab 9, Schedule 1, pages 73 to 74. We concluded in this case that an I-X rate path would not be sufficient and the gap between revenues and revenue requirements would be significant, and therefore would not allow EGDI a reasonable opportunity to earn a fair return during the IRM period.

Witnesses: M. Bartos - Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #30

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p. 73] *"EGD's projected O&M cost per customer is higher than recent history, but not by a significant amount."* Please provide details of the past O&M cost per customer data used to reach this conclusion. Please provide actual and forecast O&M cost per customer for the period 2000 through 2018.

RESPONSE

The historical and forecasted O&M cost per customer data used to reach this conclusion are presented in Figure 25, Page 51 of Concentric's report (Exhibit A2, Tab 9, Schedule 1) and are reproduced in the table below. Please note, by recent history, the reference is to 2012 to 2013.

EGD O&M Costs/Customer ($/customer)

2000	159
2001	167
2002	157
2003	174
2004	177
2005	171
2006	175
2007	176
2008	173
2009	178
2010	180
2011	184
2012	197
2013 (approved)	205
2014 (Forecast)	207
2015 (Forecast)	205
2016 (Forecast)	206
2017 (Forecast)	208
2018 (Forecast)	209

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #31

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p. 95] Please explain why EGD data was not taken from annual reports, to be consistent with the data from the peer group.

RESPONSE

Data for the peer group was collected from Local Distribution Company ("LDC") annual reports filed with their state regulatory commissions. These LDC annual reports contain standardized information at the gas distribution utility level, similar to the FERC Form 2, including cost information provided by FERC account, customer counts, and volumes. To our knowledge, EGD does not file a standardized report with its regulator similar to the FERC Form 2 that has a similar level of detail, therefore the necessary EGD data was collected directly from EGD.

Witnesses: M. Bartos – Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #32

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/9/1, p. 109] Please explain why Concentric has not concluded that the high annual increases in the Labour Quantity Index of EGD is evidence of inefficient management of labour resources. Please provide Concentric's explanation as to why Enbridge's Labour Quantity Growth Rate in the IR period was so much lower than in the pre-IR period.

RESPONSE

The measurement of labor quantity must be viewed in the context of output as well. As noted on pages 121 to122 of Concentric's report, "EGD's output quantities grew at a faster rate over this period than all except two companies in the industry study group, and faster than all except one company in the seven company sub-group". One would therefore expect that input quantities for all inputs, including labor, to grow at a faster rate to accommodate greater output. Productivity is measured as the differential between output and input for this reason. This being said, Enbridge's labor growth still exceeded output growth over the pre-IR period, but this trend reversed over the 2007 to 2011 IR period. Concentric has not specifically studied the causes for the change, but we presume that one factor was the IR plan in effect over this period.

Concentric notes that EGD's materials growth was significantly lower than both the industry and seven company groups over all periods and EGD's customer growth was greater than the industry and seven company groups over all periods. The net result is that EGD's PFP is better than both groups over the whole period and over the 2007 to 2011 IR Period. Labor should therefore not be viewed in isolation.

Witnesses: M. Bartos - Concentric
J. Coyne – Concentric
J. Simpson – Concentric

SEC INTERROGATORY #33

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/10/1, p. 3] Please provide the Applicant's study of "jurisdictions which apply building blocks".

RESPONSE

As stated on page 10 of our report, LEI examined the regulatory decisions from Australia and the UK to demonstrate the outcomes of building blocks approach. The building blocks approach in Australia and the UK is discussed throughout the report, such as in Sections 2.3 and 3 (pages 10 to13). No other studies were completed by LEI for the purposes of this assignment.

Witness: J. Frayer - London Economics International LLC

SEC INTERROGATORY #34

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/10/1, p. 4] Please advise whether LEI's "professional opinion" is limited to the Customized IR methodology, or whether it includes an opinion that the results of that methodology means that the Enbridge "ratepayers are well served". If it includes the latter, please provide details of any analysis LEI has done on the revenue requirements and rate levels proposed for Enbridge ratepayers over the 2014-2018 period, and in particular whether those rate levels are justified by the benefits the ratepayers are expected to enjoy as a result.

RESPONSE

As stated on page 4 of our report, London Economics International LLC ("LEI") evaluated Enbridge's proposed Customized IR plan in the context of LEI's experiences with building blocks regimes and familiarity with the Board's objectives and Board's recent guidance on the Custom IR Plan for electricity distributors. LEI were not asked to review the specific quantitative details of the Enbridge Customized IR Plan. However, LEI did review the conceptual framework that serves as the foundation for the proposed Customized IR Plan. At the conceptual level, we believe that Enbridge and its ratepayers are well served with the Customized IR Plan. Specifically, on page 4 of our report, we listed our key findings on the issue of customer protections and efficiency goals:

- With **strong built-in productivity measures** directed by Enbridge's Executive Management Team, **customers will not be exposed to any higher rates** than dictated by the allowed revenue amounts and on-going historical approach to adjusting revenue for changes in volumes;

- Earnings sharing mechanism ("ESM") will **provide additional protections for customers** to ensure that Enbridge is delivering on the efficient capital spending included in the forecast fixed revenue amounts; and

- Embedded productivity measures will **provide strong incentives for Enbridge to manage total costs of operation**.

Witness: J. Frayer - London Economics International LLC

SEC INTERROGATORY #35

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/10/, p. 5] Please confirm LEI's opinion that any I-X IRM model will be contrary to the Fair Return Standard if the utility's forecast capital spending exceeds depreciation over the IRM period.

RESPONSE

LEI understands that the Fair Return Standard ("FRS")[1] is the overarching legal principle that applies to Canadian utility regulation governing the recovery of costs, including the return on capital.[2] The Court Decision in a key Supreme Court of Canada case on this issue is a useful summary of the concept: "By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise."[3]

LEI believes that any findings or conclusions regarding the consistency of a proposed IR plan with the FRS need to be developed on the combined basis of three elements: the conceptual framework, the specific parameters that have been proposed/selected to be used in the IR plan, and consideration of the expected operating constraints of the business being regulated. Therefore, the hypothetical suggested in the question, of forecast capital spending exceeding depreciation, is not sufficiently complete to address the question of whether the FRS objective could or could not be met in principle.

[1] LEI notes that the Board has discussed specifically the issue of FRS and what it means: [FRS] is an opportunity cost of capital concept which is prospective rather than retrospective; [FRS standard] does not imply that investor and consumer interests are balanced; [applying the FRS standard] requires all three standards (comparable investment, financial integrity and capital attraction) must be met and are of equal ranking; [FRS should] not result in economic rent; and the capital attraction standard [under FRS] should be sufficient to attract capital over a long term time horizon. (*See* Board (2009) EB-2009-0084 *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* pp.19-20)

[2] The Board recognizes it as such in relation to the setting of the cost of capital (see p.15 EB-2009-0084 *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*).

[3] *Northwestern Utilities Ltd v. Edmonton* [1929] S.C.R. 186

Any conclusion of whether the FRS objective is met under an an I-X IRM model, or for that matter, another form of IRM, depends on other factors in addition to capital expenditure and depreciation expense, such as that reasonableness of the productivity targets, the utility's projected customer growth, in combination with the operating environment of the utility and its other costs of operation, as all these elements influence the expected return to the utility.

SEC INTERROGATORY #36

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/10/1, p. 6] Please explain how the "building blocks" approach LEI describes differs from multi-year forward cost of service forecasts.

RESPONSE

LEI is not familiar with the specific definition that SEC may have in mind when referring to "multi-year forward cost of service." However, given the use of the terminology "cost of service," that implies that a utility will have an opportunity to recover in rates the actual costs of service. In this regard, a cost-of-service regulatory regime has weak motivations for a utility to pursue productivity gains as revenues collected from customers will be set on the basis of costs. In contrast, a building blocks approach is a recognized form of incentive ratemaking where actual costs and revenues are intentionally and explicitly decoupled. Under a building blocks approach, annual revenue amounts are presented for each year of the term of the regulatory period, reflecting expected operating costs net of estimated productivity goals. Once the IR plan has been approved, these annual revenue amounts set the rates that will be recovered from customers. The regulated utility takes on the risk of the capital expenditure and operating costs exceeding the annual revenue amounts over the term of the IR plan. This same risk serves to motivate the utility – if it can achieve incremental efficiency gains and lower its actual total costs of operation, it will see its returns increase. Therefore, under the building blocks approach, the revenues are decoupled from actual operating costs.

See also Exhibit I.A1.EGDI.SEC.4 where Enbridge has responded to a similar question.

Witness: J. Frayer – London Economics International LLC

SEC INTERROGATORY #37

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/10/1, p. 15] Please provide details of all independent analysis carried out by LEI to confirm that the Applicant's forecasts for O&M and capital spending include productivity built into the forecasts.

RESPONSE

LEI did not do any analysis to confirm EGD's forecasts for O&M and capital spending; such analysis was not part of LEI's scope of work.

Witnesses: J. Frayer - London Economics International LLC

SEC INTERROGATORY #38

INTERROGATORY

Issue A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

[A2/10/1, p. 16] *"…longer periods between resets potentially increase the risk of rate shock because of the increased likelihood of discrepancies between actual and forecast expenditure increases…"* Please confirm that those longer periods can also provide increased runway for utilities to invest in productivity and drive down costs, so that on rebasing rates will go down.

RESPONSE

LEI does not disagree with SEC when it notes that "longer periods can also provide increased runway for utilities to invest in productivity and drive down costs, so that on rebasing, rates will go down." LEI believes that the selection of the term needs to balance competing pressures. A longer period can increase the motivation for the utility to make cost reductions as it will be able to retain increased profits over the term (barring an ESM). On the other hand, longer periods between resets potentially increase the risk for customers and utilities, due to an inability to act on changing circumstances in a timely fashion. However, frequent resets may negatively affect utilities' investment planning. The relative preference for term may also be affected on whether the utility is embarking on an extensive capital program: a utility may prefer a shorter term in order to have an opportunity to re-set rates such that any capital expenditures made can be directly reflected in the revenue requirement. A shorter period of time would also allow customers to enjoy more quickly benefits in the form of lower rates from achieved productivity gains.

VECC INTERROGATORY #1

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: A2/T3/S1pages 12-16, Rate Adjustment Process 2014-2018

a) Can EGO confirm that, operationally with respect to annually setting rates for 2014-2018, its IR proposal is the most complex rates application EGO has ever filed? If not, please provide a counter-example.

RESPONSE

EGD has updated its proposed Customized IR plan and Rate Adjustment Process within Exhibit A2, Tab1, Schedule 1 and Exhibit A2, Tab 3, Schedule 1. The update to the plan removes the previously intended capital refresh for 2017 and 2018 capital spend and instead requests to set Allowed Revenue amounts for 2014 to 2018 within this 2014 rate proceeding process.

As a result, the items required to be updated on an annual basis within each of the remaining 2015 to 2018 fiscal years are essentially identical to the items which were required and approved to be updated annually within EGD's 1st Generation IR model.

EGD does not view its first generation IR model as having been significantly complex and does not view the proposed Customized IR plan to be materially different in terms of complexity.

Witnesses: K. Culbert
R. Fischer
A. Kacicnik
M. Lister

BOARD STAFF INTERROGATORY #19

INTERROGATORY

ISSUE A2: Does Enbridge's Customized IR plan include appropriate incentives for sustainable efficiency improvements?

Evidence Ref: A2/T1/S2/P 6 of 15

Enbridge says that "the Company has implicitly recognized productivity into its forecast of O&M budgets for 2014 to 2016 by not accounting for known or highly probable cost increases over the forecast horizons, and by holding several costs flat, which in reality will not be flat, and by expecting the organization to deliver more output for the same inputs."

a) Please document and quantify all the "known or highly probable cost increases over the forecast horizons" which Enbridge did not include in its projected OM&A budgets over the 2014-2016 period.

b) Please document and quantify all the costs which Enbridge is holding flat, "which in reality will not be flat," in its projected OM&A budgets over the 2014-2016 period.

RESPONSE

a) Please see the following table for the quantification of all the known or highly probable cost increases not included within O&M budgets over the forecast horizons. Explanation of the items that are quantified below is set out within the D1 series of Exhibits.

Line No.	Particulars ($ millions)	2014	2015	2016
1).	Merit increase	$1.2	$2.0	$2.5
2).	Employee benefits	2.1	2.2	2.3
3).	Incremental cost to service new customers	1.5	1.6	1.7
4).	Incremental safety and integrity work	8.9	9.1	9.3
5).	External contractor rate increases	0.3	1.4	1.7
6).	Increased volume of locates - compliance with Bill 8	2.6	3.2	3.8
	Highly probable cost increases	$16.5	$19.4	$21.3

Witnesses: R. Fischer
S. Kancharla
M. Lister

1) Merit increase assumed 2.2% in the O&M budget but in reality the merit increase is expected to be around 3.0%.

2) Employee benefits costs are expected to increase 6.1% annually in 2014 and onwards as opposed to 2.2% assumed in the budget.

3) The service work associated with adding new customers is not embedded in the O&M budget. By excluding the incremental costs relating to customer care outsourcing charges which is covered under the CC/CIS service charges, the net impact is $1.5 to $1.7 million each year.

4) The Company has experienced significant requirements for safety and integrity work which has caused the cost to increase more than the inflation rate. The Company has made tremendous efforts to prioritize activities to alleviate the cost pressures.

5) External contractors for Operations are expected to increase their rates between 3% and 6% during the IR term. As a result, the cost increase is more than the inflation rate

6) The Company has experienced a substantial increase for locates requests since the new legislation Bill 8 took effect. Therefore the volume of locates are anticipated to go up at a rate of 6% per annum.

b) Please refer to the following table for the quantification of all the costs which Enbridge is holding flat, "which in reality will not be flat".

Line No.	Particulars ($ millions)	2014	2015	2016
1).	FTE's	$2.8	$5.7	$8.7
2).	Bad debt expenses	4.7	5.0	5.6
	Total	$7.5	$10.7	$14.3

1) The budget assumes that the Company keeps FTEs flat in the IR term. If FTEs increase 2% (or 47 FTEs) each year assuming 25% O&M and 75% capital, the salary, benefits and other labour related costs would go up significantly for both O&M and capital. The table above indicates the dollar impact for the O&M only.

Witnesses: R. Fischer
S. Kancharla
M. Lister

2) Bad debt expense is forecast to stay flat, but in reality bad debt expense would be expected to increase significantly based on external factors such as gas prices, weather, and economy.

Witnesses: R. Fischer
S. Kancharla
M. Lister

BOARD STAFF INTERROGATORY #20

INTERROGATORY

ISSUE A2: Does Enbridge's Customized IR plan include appropriate incentives for sustainable efficiency improvements?

Evidence Ref: A2/T1/S2/P 6 of 15

Enbridge says that "the Company has resolved to maintain its overall FTE level flat through the 2014 to 2016 period. To the extent that additional FTEs are needed to accomplish work, Enbridge will accommodate these costs within other parts of the 2014 to 2016 Capital Budget."

a) Please provide references in economic literature, incentive regulation literature and/or jurisdictional precedent where holding FTEs flat is viewed as a "sustainable efficiency gain".

b) Enbridge says that if additional FTEs are needed, the Company will accommodate these costs in other parts of its capital budget. Does Enbridge plan (or expect) to substitute capital for labor during the term of its Customized IR plan? Please explain why or why not.

RESPONSE

a) Enbridge is not aware of specific literature which speaks to holding FTEs flat for a period of time to be a "sustainable efficiency gain." The Company recognizes that holding FTEs flat may not be sustainable beyond the end of the IR term, however, it views the 5 year term of the Customized IR plan to be a sufficiently long enough period to require the implementation of significant efficiency measures to achieve what it views to be an extremely challenging target.

Enbridge also believes that maintaining tight limits on FTEs for a 5 year period will inherently create a "productivity culture" that will endure beyond that period. Holding FTEs constant will enhance productivity performance over the IR term.

During the IR term, EGD may need to find other areas to contribute to the productivity embedded in the forecast by assuming flat FTEs over the IR term, if

Witnesses: R. Fischer
S. Kancharla
M. Lister
J. Sanders

increased FTE resources are in fact required to ensure the safe and reliable operation of the distribution system.

b) EGD has no plans to substitute capital for labour during the term of its Customized IR plan. The statement referenced in the pre amble of the question reflects EGD's commitment to manage its costs in line with the projections through the term of the plan. It is a significant risk for the Company to assume the challenge of completing more work with the same labour resources. In the event that the Company cannot physically manage the work required without an increase to FTEs, then the Company is at risk given that the Allowed Revenue amounts are a revenue cap, and no incremental revenue will be afforded. It will be up to the Company to manage its costs, including the costs of increased number of FTEs, if required. Just as in any IR construct, if the costs cannot be contained in one area of the business, then they will need to be made up for elsewhere for which the Company will be challenged to accomplish. This reality reflects the fundamental nature of the proposed Customized IR plan which clearly distinguishes it from a forward test year cost of service application.

Witnesses: R. Fischer
S. Kancharla
M. Lister
J. Sanders

BOARD STAFF INTERROGATORY #21

INTERROGATORY

ISSUE A2: Does Enbridge's Customized IR plan include appropriate incentives for sustainable efficiency improvements?

Evidence Ref: Exhibit A2, Tab 11, Schedule 2, Page 4 of 13

Enbridge states that in determining the productivity and efficiency initiatives that it will pursue over the incentive regulation term, Management has established guiding principles.

a) Please explain whether initiatives that have been mandated by, for example, Measurement Canada, the Gov't of Ontario and /or the OEB, will meet Enbridge's guiding principles.

b) If so, please explain why these initiatives should be considered a "productivity and/or efficiency initiative".

c) Does Enbridge support the following definition for a sustainable productivity/efficiency gain: 1) it is an opportunity that results in net cost savings and/or incremental revenue generation in excess of the costs incurred to implement the opportunity; and 2) it is an opportunity that provides net cost savings or net revenue generation that is sustainable over multiple years and is not a one-time exercise (or gain)?

d) If not, please provide an alternate definition of sustainable productivity/efficiency gains

RESPONSE

a) As each initiative that is mandated by Measurement Canada, the Government of Ontario and/or the Board has a different purpose, original initiator, and targeted outcomes, each has to be comprehensively reviewed and examined on a case by case basis to determine if the initiative meets the Company's guiding principles as set out in Exhibit A2, Tab 11, Schedule 2, page 4, paragraph 11, and reproduced below:

Witnesses: I. Chan
S. Kancharla
I. MacPherson

i. Efficient and effective use of resources;
ii. Doing things right (efficient) and doing the right things (effective);
iii. Sustainable savings over multiple periods; and
iv. Optimal balance between effort and outcomes that are valued by stakeholders, e.g. safe and reliable energy supply at a reasonable cost.

b) Enbridge believes that any activities that enhance productivity of efficiency should be tracked and reported.

At times, mandated initiatives were also actively pursued and initiated by the Company. For instance, as mentioned in Exhibit D1, Tab 17, Schedule 1, page 2, the Company's Integrity group has been heavily involved with the development of regulations for Bill 8, the Ontario Underground Infrastructure Notification System Act, which was passed into law in 2012.

The purpose of this passage of the law is to reduce strikes and damage to underground infrastructure by establishing a single organization to route all underground utility locate requests in Ontario. Correspondingly, damage accidents and injuries will also be reduced which will improve public and worker safety, reduce unplanned service interruptions to customers (i.e. reliable energy supply), and increase efficiency in construction and planning. A single phone number for Ontario will also deliver increased economies of scale that will lead to a lower cost service for a "One Call" system over the medium term.

Consequently, this initiative will help increase the integrity of the Company's pipeline by extending the longevity of infrastructure and generate sustainable actual and avoided savings over multiple periods. As this mandated initiative meets the Company's guiding principles as mentioned above, it should be considered a productivity initiative to be tracked and reported. This is consistent with one of the objectives of the proposed Productivity Initiatives Report as stated in Exhibit A2, Tab 11, Schedule 2, page 3, paragraph 9, which is to provide transparency between initiatives and outcomes that are valued by customers and stakeholders.

c) Enbridge generally accepts the proposed definition, however, the Company believes that sustainable productivity/efficiency gains could also include activities which lead to current and/or future avoided costs. By their nature, avoided costs can be difficult to precisely quantify.

d) Please refer to the response to c) above.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

CCC INTERROGATORY #6

INTERROGATORY

Issue A2 - Does Enbridge's Customized IR plan include appropriate incentive for sustainable efficiency improvements?

(Ex. A2/T1/S1/p.12) The evidence states that one of the objectives of the plan is to improve productivity in all of the Company's operations. Please provide copies of all correspondence sent to employees regarding productivity initiatives and directions to meet EGD's productivity objectives during the plan. How does EGD expect to achieve productivity in "all of the Company's operations"? How does EGD plan to incent its employees to achieve efficiency gains through the term of the plan?

RESPONSE

Attached please find the most recent correspondence sent to employees regarding productivity initiatives and directions to meet the Company's productivity objectives during the IR term. These attachments include information provided to all employees, objective expectations and budget directions to all people leaders.

The Company is in the process of identifying productivity opportunities from individual departments and developing companywide productivity initiatives. Aggregating all of these productivity opportunities, as well as challenges, from individual departments, the Company is expects to achieve overall Company-wide productivity.

The Company is evaluating its total compensation program to incent all employees to achieve, or even exceed, the Company's strategic objectives including productivity. Detailed explanation of the Company's compensation program is set out at Exhibit D1, Tab 3, Schedule 1.

In order to promote and provide visibility into the Company's efforts in implementing sustainable Productivity initiatives over the IR term, a Performance Measurement Framework has been proposed within the IR application, as described in Exhibit A2, Tab 11, Schedule 2. In addition, the Company has proposed a modified Sustainable Efficiency Incentive Mechanism ("SEIM"). Details on the SEIM can be found at Exhibit A2, Tab 11, Schedule 3.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

CME INTERROGATORY #6

INTERROGATORY

Issue: A2

Reference: Exhibit A2, Tab 1, Schedule 1, page 25, para.75
Exhibit A2, Tab 1, Schedule 2, page 1

The evidence indicates that budgets were modified to ensure that forecasts did not exceed specified inflation targets. In connection with this evidence, please provide the following:

(a) A comprehensive list of each of the inflation targets which were used for the various line items in each of the OM&A expense budgets for 2014 to 2018 inclusive.

RESPONSE

The inflation targets were applied to all departments in anticipation that costs can be managed within an envelope amount at the O&M departmental levels. Please see the following for the inflation targets each year:

2014	2015	2016	2017*	2018*
2.22%	2.23%	2.26%	2.24%	2.24%

*2017 and 2018 is the three-year average of 2014 through 2016

Witnesses: S. Kancharla
R. Lei

VECC INTERROGATORY #2

INTERROGATORY

ISSUE A2: Does Enbridge's Customized IR plan include appropriate incentives for sustainable efficiency improvements?

Evidence Ref: A2/T11/S3 pages 3-6, SEIM proposal

a) The proposal by EGD for an SEIM appears similar to a "glide path" or an "efficiency carryover mechanism" proposal with the following difference: in the case of the SEIM, once EGD has forecasted that a project "qualifies," EGD will take for itself 20% of the project's NPV "off the top", regardless of whether or not the forecasted savings materialize and regardless as to whether or not the forecasted savings persist beyond the IR term. Please comment.

RESPONSE

Enbridge has responded to various criticisms of the Sustainable Efficiency Incentive Mechanism ("SEIM") as it was originally filed and as result has updated its proposal for the SEIM to operate in a similar manner as the Efficiency Carryover Mechanism approved by the Alberta Utilities Commission in 2012. Please see the updated evidence filed at Exhibit A2, Tab 11, Schedule 3, for further details.

Witnesses: R. Fischer
S. Kancharla
M. Lister
I. MacPherson

VECC INTERROGATORY #3

INTERROGATORY

ISSUE A2: Does Enbridge's Customized IR plan include appropriate incentives for sustainable efficiency improvements?

Evidence Ref: A2/T1/S1page 13, paragraph 30

Preamble: The referenced paragraph states:

> *30. The result is that the Company is "at risk" for costs over the projected Allowed Revenue amounts and is incented to manage costs within that level, as there is no sharing for cost overruns. Unlike an annual Cost of Service ("COS") approach, this will create fixed Allow Revenue amounts that are decoupled from actual costs over theIR plan term. The Company will not have recourse to request rate relief over the plan term absent a 300 basis point shortfall against allowed ROE which is unfound in COSregulation.*

a) Does EGD agree that under its proposal, the vast majority of its costs will be adjusted/revised/trued up during the IR term?

RESPONSE

Enbridge does not agree with this proposition. Enbridge has provided an update of its evidence at Exhibits A2, Tab 1, Schedule 1 and Exhibit A2, Tab 3, Schedule 1, outlining proposed changes to the Customized IR plan to provide for Allowed Revenues to be set for 2014 to 2018 in this proceeding.

Under the updated Customized IR plan, the vast majority of Enbridge's Allowed Revenue will be set now, at the outset of the IR term. Some items will be updated each year in Rate Adjustment proceedings. The number of such items is similar to Enbridge's 1st Generation IR plan.

Witnesses: K. Culbert
R. Fischer
M. Lister

VECC INTERROGATORY #4

INTERROGATORY

ISSUE A2: Does Enbridge's Customized IR plan include appropriate incentives for sustainable efficiency improvements?

Evidence Ref: A2/T1/S2 page 6, paragraph 21

Preamble: The referenced paragraph states:

> *21. As described, the Company has resolved to maintain its overall FTE level flat through the 2014 to 2016 period. To the extent that additional FTEs are needed to accomplish work, Enbridge will accommodate these costs within other parts of the 2014 to 2016 Capital Budget.*

a) Please explain how the costs of additional FTEs will be accommodated "within other parts of the 2014 to 2016 Capital Budget For example, will the capital budget merely be increased to cover an increase in costs that would otherwise not be capitalized?

b) How will EGD deal with this challenge in 2017 and 2018?

RESPONSE

a) Please refer to the response to question b) of Board Staff Interrogatory #20, found at Exhibit I.A2.EGDI.STAFF.20.

b) Within Enbridge’s updated Customized IR Plan there will be no reforecasting of capital budgets for 2017 and 2018, as Allowed Revenues for those years are being set in this case. As within any IR plan, EGD will manage its costs within the Allowed Revenue amount. In the event that the actual costs experienced are over and above the allowed envelope amount, EGD will work to find efficiencies to accommodate the additional costs.

Witnesses: R. Fischer
S. Kancharla
M. Lister

CCC INTERROGATORY #7

INTERROGATORY

Issue A3 - Does Enbridge's Customized IR plan ensure appropriate quality of service for customers?

Please explain if EGD intends to deal with the quality of service to its customers within the context of this Custom Framework in any way that differs from the last IRM period. Does EGD expect quality of service to be enhanced or maintained, at current levels, during this 5-year period?

RESPONSE

As outlined in Exhibit A2, Tab 11, Schedule 2, page 12 in the chart titled Appendix 3, Benchmarking Report – Performance Metrics, Enbridge will strive to be recognized through the IR term as the best provider of utility services in North America.

The Company proposes to maintain the existing SQR's and targets, with the exception of Time to Reschedule Missed Appointments ("TRMA"), where the Company recommends the TRMA target be reviewed and set to a more appropriate target of 90% to 95%. In any event, the Company will continue to place priority on this standard, striving to reach the current target of 100% (see Exhibit A2, Tab 11, Schedule 1).

In addition, the Company proposes to track as a performance metric, overall Customer Satisfaction. In 2012, the overall Customer Satisfaction level was 68%, whereas the target for 2013 is 71%. The aspirational target for Customer Satisfaction through the IR period is in the mid 70's.

Witnesses: R. Fischer
K. Lakatos-Hayward
M. Lister

SEC INTERROGATORY #39

INTERROGATORY

Issue A4: Does Enbridge's IR plan create an environment that is conducive to investment, to the benefit of customers and shareholders?

Please provide a table for the years 2000 through 2018, showing the total depreciation expense in each year, the total capital expenditures in each year, and the total capital expenditures in each year excluding GTA Reinforcement and Ottawa Reinforcement, in each case using actuals for 2000 through 2012, forecast (e.g. 9+3) actuals for 2013, and forecast (from the Application) for 2014 through 2018.

RESPONSE

Please see the table on the following page.

Witness: L. Au

Total Depreciation Expense and Capital Expenditures - Excluding GTA and Ottawa Reinforcement Projects

2000-2012 Actual and 2013 -2018 Forecast

($millions)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19
	2000 Actual	2001 Actual	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 9+3 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Total Depreciation	169.7	156.4	161.8	170.0	178.4	244.6	210.3	226.1	237.1	251.3	267.0	276.9	292.9	279.1	262.3	273.7	289.1	298.5	307.2
Total Capital Expenditures	215.2	249.8	252.9	224.8	278.4	315.5	364.5	354.9	366.0	349.1	337.6	339.2	437.9	439.3	480.1	472.3	450.0	442.2	442.2

CCC INTERROGATORY #8

INTERROGATORY

Issue A5 – Is the methodology within Enbridge's Customized IR plan for determining annual Allowed Revenue amounts appropriate?

(Ex. A2/T1/S1, pp. 4-5) Please explain the difference between setting an "Allowed Revenue" and a traditional cost of service "Revenue Requirement". What is the purpose of setting "Preliminary Rates" for 2015-2018 if they are subject to update and approval in the annual rate proceedings?

RESPONSE

Allowed Revenue is the same terminology used in Australia in the building block approach. In the Company's view it also reflects that the Customized IR plan is a revenue cap as it is based upon a pre-set level of revenues. Given that the Allowed Revenues span a 5-year period, whereas the traditional cost of service "Revenue Requirement" looks out one-year ahead, it can be seen that there will be much more risk associated with setting Allowed Revenue. A further difference is seen in the fact that Enbridge's Allowed Revenues contain multiple years and increasing levels of embedded productivity which is not traditionally included in cost of service revenue requirements.

As indicated at Exhibit A2, Tab 1, Schedule 1, the "Preliminary Rates" for 2015-2018 are intended to show the estimated impacts of the Company's Customized IR plan, based on the Allowed Revenues to be approved in this proceeding. The future adjustments relate only to volume adjustments, and for adjustments that are the subject of separate agreements. Just as with the 1st Generation IR plan, Enbridge does not believe it is appropriate for either ratepayers or shareholders to carry the risk that volumetric forecasts materially change over time. Separate agreements exist for the treatment of Pension costs, DSM costs are Customer Care/CIS costs, and it would be inappropriate for this IR plan to circumvent those agreements / treatments.

Witnesses: R. Fischer
M. Lister

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

Ref: Exhibit A1, Tab 2, Schedule 1, page 2

Please explain why Allowed Revenues need to be adjusted in 2017 and 2018 based on updated forecasts of capital spending, cost of capital, taxes and depreciation, while these items are not among the adjustments proposed for 2015 and 2016.

RESPONSE

The Company has updated its proposal to remove the originally proposed 'capital refresh'. As a result all of the elements of the Allowed Revenue will be determined in this case for each of 2014 through 2018. The proposal does include some annual rate adjustment items to account for other items or agreements made independently of the IR plan (for example, with respect to Customer Care/CIS and DSM) and pension costs. The proposal to make annual adjustments for gas supply costs and volumetric updates remains.

Please see the updated Overview evidence filed at Exhibit A2, Tab 1, Schedule 1 and the updated Rate Adjustments evidence filed at Exhibit A2, Tab 3, Schedule 1.

Witness: M. Lister

ENERGY PROBE INTERROGATORY #3

INTERROGATORY

Ref: Exhibit A2, Tab 1, Schedule 1, page 6

EGD states that *"The operating costs, municipal taxes and other revenues components of the 2017 and 2018 Allowed Revenue amounts will be set in the 2014 proceeding, based upon an adjustment of the forecast 2016 operation costs."*

a) What does EGD mean by "based upon an adjustment of the forecast 2016 operation costs"?

b) How would 2016 operation costs be adjusted to determine other revenues in 2017 or 2018?

RESPONSE

a) Enbridge will determine O&M Costs and Municipal and Property Taxes for 2017 and 2018 by calculating the average rate of change in these costs from 2013 to 2016, and applying that rate of change to the 2016 value, and then to the resulting 2017 value. Other Operating Revenue for 2017 and 2018 will be held flat at the 2016 level. The statement "based upon an adjustment of the forecast 2016 operation costs" means that 2017 and 2018 costs are based on 2016 costs with the adjustments as previously described.

b) Please see the response to a).

Witnesses: K. Culbert
R. Fischer
M. Lister

SEC INTERROGATORY #40

INTERROGATORY

Issue A6: Is the methodology within Enbridge's Customized IR plan for updating the 2017 and 2018 Annual Revenue amounts within the 2016 Rate Adjustment proceeding appropriate?

[A2/3/1, p. 7] Please confirm that the Applicant is proposing to increase the combination of Other O&M and RCAM by 3.3% for each of 2017 and 2018.

RESPONSE

The growth rate for the combination of Other O&M and RCAM is 3.12% for each of 2017 and 2018.

Witnesses: K. Culbert
R. Fischer
M. Lister

BOARD STAFF INTERROGATORY #22

INTERROGATORY

ISSUE A7: Is the methodology within Enbridge's Customized IR plan for determining final rates for 2014 appropriate?

Evidence Ref: A2/T3/S2/ Attachment B

Please provide a table in a similar format to Attachment B showing the adjustments to the 2013 Board-approved Revenue Requirement to arrive at the proposed 2014 Revenue Requirement.

RESPONSE

The following table provides the requested information.

Witness: K. Culbert

2014 FISCAL YEAR VERSUS 2013 BOARD APPROVED
ALLOWED REVENUE

Line No.		Col. 1 2013 Board Approved (Incl. CIS/CC)	Col. 2 Adjustments	Col. 3 2014 Fiscal Year
		($Millions)	($Millions)	($Millions)
	Cost of Capital			
1.	Rate base	4,162.0	269.6	4,431.6
2.	Required rate of return	6.80%	-0.06%	6.74%
3.		283.2	15.7	298.9
	Cost of Service			
4.	Gas costs	1,342.8	113.1	1,455.9
5.	Operation and maintenance	414.9	10.4	425.3
6.	Depreciation and amortization	279.3	(16.5)	262.8
7.	Fixed financing costs	2.3	(0.4)	1.9
8.	Municipal and other taxes	39.3	1.9	41.2
9.		2,078.6	108.5	2,187.1
	Miscellaneous operating and non operating revenue			
10.	Other operating revenue	(44.3)	3.8	(40.5)
11.	Other income	(0.7)	0.6	(0.1)
12.		(45.0)	4.4	(40.6)
	Income taxes on earnings			
13.	Excluding tax shield	90.9	(17.9)	73.0
14.	Tax shield provided by interest expense	(39.0)	(0.5)	(39.5)
15.		51.9	(18.4)	33.5
	Taxes on sufficiency			
16.	Gross sufficiency	-	35.1	35.1
17.	Net sufficiency	-	25.8	25.8
18.		-	(9.3)	(9.3)
19.	Sub-total Allowed Revenue	2,368.7	100.9	2,469.6
20.	Customer Care Rate Smoothing Var. Adj.	(4.6)	1.7	(2.9)
21.	**Allowed Revenue**	2,364.1	102.6	2,466.7
	Revenue at existing Rates			
22.	Gas sales	2,043.8	209.70	2,253.5
23.	Transportation service	318.6	(75.8)	242.8
24.	Transmission, compression and storage	1.7	0.1	1.8
25.	Rounding adjustment	-	(0.2)	(0.2)
26.	Total	2,364.1	133.8	2,497.9
27.	**Gross revenue sufficiency**	-	31.2	31.2

Witness: K. Culbert

BOARD STAFF INTERROGATORY #23

INTERROGATORY

ISSUE A7: Is the methodology within Enbridge's Customized IR plan for determining final rates for 2014 appropriate?

Evidence Ref: A2/T3/S2/ Attachment B

Please provide the most recent 2013 utility revenue forecast with a comparison to the 2013 Board-approved Revenue Requirement.

RESPONSE

The Company submits that a comparison of 2013 Actual (or forecast) Utility revenue is only properly comparable to a like 2013 Actual (or forecast) Revenue Requirement and is not to the 2013 Board Approved Revenue Requirement and as such has not provided the requested comparison.

Witness: K. Culbert

CCC INTERROGATORY #9

INTERROGATORY

Issue A8 – Is the methodology within Enbridge's Customized IR plan for setting final rates for 2015 through 2018 through annual rate adjustment proceedings, including cost allocation and rate design appropriate?

(Ex. A2/T3/S1/p. 2) The evidence indicates that EGD is not seeking approval of rates for 2015-2018 at this time. Please explain, in detail, what approvals are being sought in this proceeding specific to each year 2015, 2016, 2017 and 2018. To what extent will the rate order in this proceeding apply to the years 2015-2018? Please explain.

RESPONSE

As indicated in the Updated Exhibit A2, Tab 3, Schedule 1 evidence, under EGD's Customized IR plan, the base Allowed Revenue amounts for each of 2015 through 2018 will be set within the 2014 proceeding process. As with the 1st Generation IR plan, the only adjustments to the Allowed Revenues will be for discrete pass through items, mainly related to separate agreements (i.e. Customer Care/CIS and DSM). The gas supply plan will also be updated annually for gas costs and dealt with through the QRAM process. The volume updates will not impact Allowed Revenues, but will ensure that the Allowed Revenues are spread over the most up to date volumetric forecast available at the time.

Witnesses: K. Culbert
R. Fischer
A. Kacicnik
M. Lister

OAPPA INTERROGATORY #1

INTERROGATORY

Issue 8 – Is the methodology within Enbridge's Customized IR plan for setting final rates for 2015 through 2018 through annual Rate Adjustment proceedings, including cost allocation and rate design, appropriate?

Please describe how Enbridge proposes to address cost allocation in the annual Rate Adjustment proceedings for the years in the IR term beyond 2014, and explain how this proposed approach compares to the way cost allocation was handled during the 2008-2012 IR term.

RESPONSE

The key difference between the two IR terms is in the determination of revenue requirement. In the 2008 to 2012 IR term, revenue requirement was determined using the IR formula, while in the 2014 to 2018 IR term, forecasts of costs are used to determine the Allowed Revenue for each year of the proposed IR term.

While using an IR formula to determine revenue requirement for the 2008 to 2012 IR term, the Company updated forecasts and allocators used to assign revenue requirement to the customer classes for each test year. By updating forecasts and allocators annually, the assignment of revenue requirement by rate class – and, consequently, rate impacts – remained responsive to factors such as customer growth, volume gain or loss, and customer migration between various rates and service offerings. Given that the year-over-year change in revenue requirement was determined by an IR formula (rather than a forecast of costs), a summary version of cost allocation exhibits was filed with each rate case during the 2008 to 2012 IR term. For example, please see EB-2011-0277, Exhibit B, Tab 3, Schedule 10, pages 1 to 9.

For the 2014 to 2018 IR term, the Company proposes to file a full complement of the FACS exhibits (as prepared for the 2014 filing) in each test year. For 2014 Cost Allocation Evidence and Exhibits, please see Exhibits G1 and G2.

Witnesses: A. Kacicnik
M. Kirk

SEC INTERROGATORY #41

INTERROGATORY

Issue A9: Are the cost of capital parameters for 2014 to 2018 (ROE, debt rates) within Enbridge's Customized IR plan appropriate?

[A2/5/1, p. 2] Please explain why the Applicant is planning to reduce its reliance on lower cost short-term debt, and increase its reliance on higher cost long term debt, in the years 2015 and 2016.

RESPONSE

Enbridge's use of short term debt during the IR term is in line with historic levels (2004 to 2012 average = 4.1% of Rate Base, range 0.2% to 11.5% of Rate Base). Enbridge's use of short term debt as well as long term debt and preferred shares during the IR term have been developed according to the pace of required capital spending and the timing for cash flow needs, while maintaining prudent financing flexibility.

Witness: P. Bhatia

SEC INTERROGATORY #42

INTERROGATORY

Issue A9: Are the cost of capital parameters for 2014 to 2018 (ROE, debt rates) within Enbridge's Customized IR plan appropriate?

[A2/5/1. P. 2] Please expand the table at the top of the page to include 2007 to 2012 actuals, and 2013 forecast (9+3 or 10+2) and Board-approved.

RESPONSE

The information is provided in the table below. EGD is not in a position to provide a 2013 9+3 forecast.

Capital Structure Component	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Board Approved
Equity	36%	36%	36%	36%	36%	36%	36%
Long term debt	60.34%	61.17%	57.46%	57.08%	58.36%	58.67%	60.17%
Short term debt	0.91%	0.18%	3.90%	4.31%	3.12%	2.84%	1.39%
Preferred shares	2.75%	2.65%	2.64%	2.61%	2.52%	2.49%	2.44%

Capital Structure Component	2014 Weight	2015 Weight	2016 Weight	2017 Weight	2018 Weight
Equity	36%	36%	36%	36%	36%
Long term debt	59.23%	61.41%	61.31%	61.49%	61.28%
Short term debt	2.49%	0.49%	0.87%	0.76%	1.02%
Preferred shares	2.28%	2.10%	1.82%	1.75%	1.70%

Witness: K. Culbert

SEC INTERROGATORY #43

INTERROGATORY

Issue A9: Are the cost of capital parameters for 2014 to 2018 (ROE, debt rates) within Enbridge's Customized IR plan appropriate?

[A2/5/1, p. 3] Please provide a calculation showing the Allowed Revenue for each of 2014, 2015 and 2016 on the assumption that the cost of capital and ratios of capital components are identical to those approved by the Board in EB-2011-0354. Please provide the calculation of the cost of capital for each of 2014 through 2016 using that basis.

RESPONSE

The following table calculates 2014 to 2018 Allowed Revenues, in a format comparable to those shown in Exhibits F3, F4, F5, F6, & F7, Tab 1, Schedule 1, page 2, Column 4, assuming that in each year the cost of capital cost rates and component ratios are equivalent to amounts approved for 2013 in EB-2011-0354. The result of maintaining fixed cost rates and component ratios is a fixed overall required rate of return % equivalent to 2013.

While the Company is able to perform these scenarios for interrogatory response purposes, it would not be able to actually maintain a fixed overall required rate of return for 2014 to 2018. As the Company's financing requirements grow, it would not be practical to assume it would able to issue debt or preferred shares at fixed rates, or in increments which would be required to maintain a constant overall required rate of return.

Witness: K. Culbert

2014 - 2018 ALLOWED REVENUE AMOUNTS

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	4,431.6	4,797.6	5,524.4	5,736.6	5,906.1
2.	Required rate of return	6.81%	6.81%	6.81%	6.81%	6.81%
3.		301.6	326.5	376.1	390.6	402.2
	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 rev. & income					
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	73.0	56.3	52.9	58.8	67.9
14.	Tax shield provided by interest expense	(41.5)	(44.9)	(51.6)	(53.5)	(55.1)
15.		31.5	11.4	1.3	5.3	12.8
	Taxes on sufficiency / (deficiency)					
16.	Gross sufficiency / (deficiency) - with CIS/CC	34.4	(11.7)	(86.5)	(125.4)	(164.5)
17.	Net sufficiency / (deficiency) - with CIS/CC	25.3	(8.6)	(63.5)	(92.2)	(120.9)
18.		(9.1)	3.1	22.9	33.2	43.6
19.	Sub-total Allowed Revenue	2,470.5	2,656.9	2,782.3	2,834.0	2,886.0
20.	Customer Care Rate Smoothing Var. Adj.	(2.9)	(1.1)	0.8	2.9	5.0
21.	**Allowed Revenue**	2,467.6	2,655.8	2,783.1	2,836.9	2,891.0
	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	-	(0.1)	(0.1)	(0.1)	(0.1)
26.	Total	2,498.1	2,635.6	2,683.3	2,693.1	2,702.9
27.	**Gross revenue sufficiency / (deficiency)**	30.5	(20.2)	(99.8)	(143.8)	(188.1)

Witness: K. Culbert

BOARD STAFF INTERROGATORY #24

INTERROGATORY

ISSUE A10a: Are the following components within Enbridge's Customized IR plan appropriate?

a. Z Factor mechanism

Evidence Ref: Exh A2/Tab 4/ Sch 1/P 7 of 9

Enbridge states that the Company would "need only show that a 'significant portion' of the cost increase or decrease claimed is linked to the unexpected non-routine cause..." Please explain how:

a) Enbridge defines what portion of a cost increase or decrease is 'significant.'

b) Enbridge will demonstrate that only a 'significant portion' of a cost increase or decrease has been linked to an unexpected, non-routine cause.

RESPONSE

a) The Company expects that it will be the Board which will determine what constitutes a 'significant portion' of the total cost. The term 'significant portion' is included in the criteria to cover circumstances where the cost increase or decrease may not be entirely linked to the unexpected cause

b) Enbridge will file evidence that supports any application for a Z-factor, in which it will identify the unexpected non-routine cause and its associated cost impact. It is expected that the Company's evidence would provide sufficient detail to clearly define the link between the cause and the associated cost.

Witnesses: R. Fischer
M. Lister

BOARD STAFF INTERROGATORY #25

INTERROGATORY

ISSUE A10a: Are the following components within Enbridge's Customized IR plan appropriate?

a. Z Factor mechanism

Evidence Ref: Exh A2/Tab 4/ Sch 1/P 7 of 9

Enbridge states that "unexpected, non-routine cause" is a more appropriate requirement, as compared to linking the costs to a particular "event", because the term "cause" will take away focus on a discrete item or circumstance and allow for cases where there may be a collection of related "events" that are the "unexpected, non-routine cause" of a cost increase or decrease.

a) Please provide specific examples of an "unexpected, non-routine cause". Please compare these examples of "unexpected, non-routine cause" with examples of an unexpected or unforeseen event (such as an ice storm, etc.) and explain the difference.

b) Please provide references in economic literature, incentive regulation literature and precedent where the criteria for requesting cost recovery through the Z-factor is based on an "unexpected, non-routine cause".

RESPONSE

a) Please see response to SEC Interrogatory #45, found at Exhibit I.A10.EGDI.SEC.45.

b) No review of economic or regulatory literature was carried out. The difference in language between the terms "event" and "cause" was considered to be a wording, or clarity issue. The Company believes that the language enhancement will make the identification and evaluation of potential Z-Factors requests more clear and consistent.

Witnesses: R. Fischer
M. Lister

BOARD STAFF INTERROGATORY #26

INTERROGATORY

ISSUE A10a: Are the following components within Enbridge's Customized IR plan appropriate?

a. Z Factor mechanism

Evidence Ref: Exh A2/Tab 4/ Sch 1/P 4, 5 of 9

Enbridge states that in its experience, the interpretation of the Board's Z-factor criteria over the five years of the Company's 1st Generation IR term has led to confusion and uncertainty around what costs would qualify for Z-factor treatment. In particular,

- The reference to a discrete "event" leads to a requirement to pinpoint a single development or occurrence which has caused increased or decreased costs. In Enbridge's view, there may be more than one item or event that leads to changes in costs from what was known and included within Allowed Revenue amounts set at the start of an IR term.
- The requirement that the "cost" associated with the Z-factor request be beyond the control of the Company's management. In Enbridge's view, this makes it unreasonably difficult to qualify for Z-factor recovery.
- The requirement that the cost not be "a risk in respect of which a prudent utility would take risk mitigation steps" is difficult to understand and interpret.

a) Please identify and summarize the actual difficulties that Enbridge has experienced in relation to the interpretation of the Z-factor criteria over the five years of Enbridge's most recent IR plan. In Enbridge's summary of its actual difficulties, please refer to the three concerns that Enbridge has identified above.

b) Please provide references in economic literature, incentive regulation literature and/or jurisdictional precedent for this change in the criteria for the "Z factor".

RESPONSE

a) As indicated to the response filed at Exhibit I.A10.EGDI.CCC.10, the Company filed applications for Z-Factor relief related to Pension Costs and the Cross-Bore (Sewer Lateral) program. An application for each of these was first made for the 2010 rate

Witnesses: R. Fischer
M. Lister

year (EB-2009-0172), but ultimately withdrawn without prejudice. Another application for Z-Factor treatment of the same issues was brought before the Board for the 2012 rate year (EB-2011-0277). Both of these issues went to Hearing for the Board's adjudication.

The specific difficulties that Enbridge experienced with respect to these issues and in relation to the interpretation of the Z-Factor criteria proposed in this application follows.

<u>Pension Funding:</u>
From the Board's EB-2011-0277 Decision issued on May 10, 2012:

> It is the Board's view that the Applicant's request fails on two of the five criteria established for qualification as Z factor. It fails on the first criterion which is the cause of the event and it fails on the second criterion which relates to the cost being beyond the control of management. There is no serious question in this case as to whether the costs meet the materiality threshold, which for Enbridge is $1.5 million.

In describing how the Company failed to meet the criterion related to the cause of the event the Board said:

> The event which was causally related to the nominal shortfall in the pension plan is the relatively poor performance of the financial markets, and is perhaps most particularly, the fall in interest rates which have characterized financial markets for the last several years. This underperformance has reduced the returns the Company was relying upon to maintain the buoyancy of its pension fund. We use the word nominal to describe the shortfall because there is no actual funding crisis associated with the underperformance of the plan. The Company is an ongoing operation with very significant assets, revenues and opportunities and there is no evidence of any actual difficulty in meeting the obligations the Company assumed when it created the plan. The provincial regulator in making the changes that it did in 2009 imposed the reporting and contribution requirement to avoid such a crisis in the future.

The Company's difficulty with this application of the first Z-Factor criterion is that there was no condition within the Z-Factor criteria that the 'event' had to occur only where there was 'any actual difficulty in meeting the obligations'. There was an event (a change in legislation) which was not known before the IR plan was struck, which had cost consequences and should therefore have met the criterion, in the Company's opinion. The Company believes the phraseology proposed for Z-Factor criteria on page 1 of Exhibit A2, Tab 4, Schedule 1 would be more clear on this point:

(i) Causation: The cost increase or decrease, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine cause.

With respect to the issue of management control, the Board said:

> The Board finds that the cost of this Z factor is within the control of management and represents a risk in respect of which a prudent utility would take risk mitigation steps. The Board's analysis of this question begins with the assumption of those obligations by the Company at the time that the plan was created. There is no obligation under the law to offer employees noncontributory pension benefits…. But when it adopted the noncontributory pension plan, it accepted the responsibility to maintain funding for it.

If this is how the existing Z-Factor criterion is to be interpreted, then in the Company's opinion there is no condition in which a cost would not be considered within the control of the Company's management. The implication is that any cost associated with any activity chosen by the Company is within its control. If there is no condition by which a Z-Factor could be applied, then there is effectively no Z-Factor. This comment specifically relates to the second bullet listed in the preamble to this interrogatory, namely, that in Enbridge's view, the existing management control criterion makes it unreasonably difficult to quality for Z-Factor recovery.

The Board's comments within the pension Z-Factor decision about "risk" further underscores the difficulties with the previous Z-Factor wording:

> In addition, the risk of underperformance is a risk that the Company ought to have anticipated and taken steps to address. If one thing is predictable about financial markets it is that there is an element of volatility to them, and that markets can materially underperform according to projection. In the Board's view this is a risk for which the utility ought to have made provision. It is a risk that a prudent utility should take steps to mitigate.

As explained within Exhibit A2, Tab 4, Schedule 1, Enbridge does not believe that it is appropriate or necessary to include the phrase "risk in respect of which a prudent utility would take risk mitigation steps" within any updated Z-Factor wording.

Cross Bores:
From the Board's EB-2011-0177 Decision issued on May 10, 2012:

> The Board finds that the request for Z factor treatment of the cross bores fails with respect to two of the tests associated with the Z factor definition in the Settlement Agreement. These two tests are those that relate to management's control of the costs and the triggering event that gave rise to the Z factor claim.

Regarding the issue of management control, the Board said:

> First, the Board does not consider the management and control of issues related to cross bores to be matters that are in any meaningful sense beyond the control of management. The provision of gas to its customers in a safe and reliable manner is the fundamental undertaking of the utility. There are many challenges associated with accomplishing that goal, and at its core the utility is organized, staffed and financed in order to be able to meet that standard…. The fact that a previously unidentified risk has now been identified does not take the responsibility to identify this type of risk out of the realm of the basic undertaking of the utility.

The difficulty the Company has with the application of Z-Factors in this way is that it pre-supposes that there is nothing about the gas distribution business that is not within the Company's control. In the Company's opinion, this is too broad, and undermines the very purpose of the Z-Factor. Enbridge's new proposed Z-Factor wording addresses this issue by indicating that the cause of the cost increase or decrease must not be reasonably within the control of the utility.

The Board went on in its Decision to say the following:

> The TSSA regulatory innovation in this case, which the Company describes as the triggering event, is nothing more than a codification of what a prudent utility would have, should have, and has been doing as its awareness of the cross bore evolved over the last number of years. It is telling, and comforting, that the utility has been directly involved with the regulator, in this case the TSSA, to develop the action plan requirement that gives rise to this claim. However, the TSSA codification of the response to cross bores is not the causal event underlying the Z factor claim.

EGD's difficulty with this application of the Z-Factor criterion is that the Board saw in this case that a change in legislation was not a causal event. As described in the first bullet in the preamble to this interrogatory, there may be more than one item or event that leads to changes in costs from what was known and included within Allowed Revenue amounts set at the start of an IR term. With the new phraseology for Z-Factors as submitted by the Company in this application, it is the Company's intention to remove the linkage to an 'event' and instead rest the criterion around the 'causation' of a cost.

b) No review of economic or regulatory literature was carried out. The Company believes that these enhancements will make the identification and evaluation of potential Z-Factor requests more clear and consistent.

Witnesses: R. Fischer
M. Lister

BOARD STAFF INTERROGATORY #27

INTERROGATORY

ISSUE A10f: Are the following components within Enbridge's Customized IR plan appropriate?

f. Sustainable Efficiency Incentive Mechanism

Evidence Ref: A2/T11/S3/P 3 of 6

When calculating SEIM payment, how will "benefits" be computed? Please indicate if the benefit calculation will include:

- Cost reductions
- The quantified value of improved safety
- The quantified value of improved product quality
- The quantified value of improved customer service
- Other factors

RESPONSE

Enbridge has responded to various criticisms of the Sustainable Efficiency Incentive Mechanism ("SEIM") as it was originally filed and as result has updated its proposal for the SEIM to operate in a similar manner as the Efficiency Carryover Mechanism approved by the Alberta Utilities Commission in 2012. Please see the updated evidence filed at Exhibit A2, Tab 11, Schedule 3 for further details.

Witnesses: R. Fischer
S. Kancharla
M. Lister
I. MacPherson

BOARD STAFF INTERROGATORY #28

INTERROGATORY

ISSUE A10f: Are the following components within Enbridge's Customized IR plan appropriate?

f. Sustainable Efficiency Incentive Mechanism

Evidence Ref: A2/T11/S3/P6 of 6

a) How does the Company proposed to collect the SEIM payment from customers?

b) Would Enbridge's proposed method of collecting SEIM payments differ if Enbridge did not have to distribute a share of its earnings to customers under the Company's proposed ESM? Please explain.

RESPONSE

a) and b) Enbridge has responded to various criticisms of the Sustainable Efficiency Incentive Mechanism ("SEIM") as it was originally proposed in the prefiled evidence, and as result has updated its proposal to operate in a similar manner as the Efficiency Carryover Mechanism approved by the Alberta Utilities Commission in 2012.

If incentive payments are earned, collection will now occur after the end of the Customized IR term as an adjustment to revenue requirement or Allowed Revenue in those years.

Enbridge believes the Earnings Sharing Mechanism and SEIM are distinct incentive mechanisms that stand on their own, but are complementary in the sense that they together provide strong incentives for the Company to find sustainable efficiencies during the IR term.

Please see the updated evidence filed at Exhibit A2, Tab 11, Schedule 3 for further details.

Witnesses: R. Fischer
S. Kancharla
M. Lister
I. MacPherson

BOARD STAFF INTERROGATORY #29

INTERROGATORY

ISSUE A10 f: Are the following components within Enbridge's Customized IR plan appropriate?

f. Sustainable Efficiency Incentive Mechanism

Evidence Ref: A2/T10/S1/The Building Blocks Approach (LEI)/P 19 of 24

LEI states that the Alberta Utilities Commission ("AUC") has approved an efficiency carry-over mechanism ("ECM") for ATCO Gas, ATCO Electricity and EPCOR which provides for an upper limit on the earnings that can be carried over between regulatory periods of 0.5% of ROE to apply for two years after the end of the previous IR plan.

a) Please provide a complete list of all the ECMs proposed by gas or electricity distributors in Alberta
b) Please provide a complete list of all the ECMs approved for gas or electricity distributors in Alberta
c) Please compare in detail the differences between the ECMs proposed by Alberta utilities and those approved by the AUC
d) Please compare in detail the ECMs approved by AUC and Enbridge's SEIM.
e) Please compare in detail Australia's EBSS and Enbridge's SEIM.
f) Please compare in detail the efficiency carryover mechanisms approved in the UK and Enbridge's SEIM.

RESPONSE

a) See response provided on the following page:

Company	Proposed ECM schemes
ATCO Gas	ATCO Gas proposed an ROE ECM: "The ROE ECM would award ATCO Gas a post PBR add-on to the approved ROE equal to one half of the difference between the simple average ROE achieved over the term of the Plan and the simple average approved ROE over the term of the Plan (providing the difference is positive), multiplied by 50%, to a maximum of 0.5%. The ROE bonus would apply for 2 years after the end of the PBR Plan."[1] ATCO Gas originally proposed a K factor ECM as well, but withdrew it later in updated filing.[2]
ATCO Electric	ATCO Electric proposed an ROE ECM: "The ROE ECM would award ATCO Electric a post PBR add-on to the approved ROE equal to one half of the difference between the simple average ROE achieved over the term of the Plan and the simple average approved ROE over the term of the Plan (providing the difference is positive), multiplied by 50%, to a maximum of 0.5%. The ROE bonus would apply for 2 years after the end of the PBR Plan." [3] ATCO Electric also proposed a K factor ECM: "The K Factor Efficiency Incentive ("KFEI") amount will be calculated as the difference between the K Factor used to determine ATCO Electric revenues and the revenue requirement of the actual amount invested in the K Factor programs over the PBR term, providing that amount is positive. The KFEI amount that ATCO Electric will be allowed to retain after the PBR Plan ends will be equal to one half of the revenue requirement difference in the first year post PBR and one third of the revenue requirement difference in the second year post PBR."[4]

[1] ATCO Gas (2011) *ATCO Gas Performance Based Rate Application* (Rate Regulation Initiative Proceeding ID. 566), July 22, 2011, p. 44.
[2] ATCO Gas and ATCO Electric (2012) *ATCO Gas and ATCO Electric Performance Based Regulation Application - PBR Plan Finalization* (Rate Regulation Initiative, Proceeding ID. 566), February 22, 2012, p. 10.
[3] ATCO Electric (2011) *ATCO Electric Performance Based Rate Application* (Rate Regulation Initiative Proceeding ID. 566), July 22, 2011, pp. 11-1 – 11-2.
[4] Ibid.

EPCOR Distribution & Transmission Inc. ("EPCOR" or "EDTI")	EPCOR proposed an ROE ECM in "the form of a partial true-up of rates to a target rate of return at the end of the five-year PBR term."[5,6] In addition to promoting dynamic efficiency, EPCOR's proposed ECM mechanism also attempts to encourage compliance with service quality benchmarks: "In the case of the EDTI PBR plan, the ECM is directly linked to EDTI's provision of service quality over the course of the PBR regime. The provision of target level service quality results in EDTI being able, on a prospective basis, to (i) retain a share of any excess returns for a period of two years following the end of the PBR regime; or (ii) fully true-up rates to a target rate-of-return should there be deficient returns at the end of the PBR regime. Conversely, the provision of "inferior quality" results in EDTI (i) being forced to disgorge excess returns at the end of the PBR regime; or (ii) not being able to fully true-up rates to a target rate-of-return in the event of deficient returns at the end of the PBR regime."[7] "To summarize, the ECM is expressed formally by $\text{T-ROR}_{t+1} = \text{T-ROR}_t + (1 - \alpha) \times [\text{A-ROR}_t - \text{T-ROR}_t]$, where T-ROR is the target rate of return and A-ROR is the average rate of return as measured over the course of the PBR regime. The subscript "t" refers to the current PBR period, the subscript "t+1" refers to the subsequent PBR period and $0 \leq \alpha \leq 1$ is the rate-of-return adjustment parameter. "The ECM is designed to reward EDTI for, at a minimum, achieving target levels of service quality performance. EDTI proposes default values of $\alpha = ½$ when $\text{A-ROR}_t > \text{T-ROR}_t$ and $\alpha = 1$ when $\text{A-ROR}_t < \text{T-ROR}_t$. As such, when EDTI meets each of its four service quality benchmarks for each year of the PBR term, it is allowed to prospectively retain 50% of its excess returns (or be made whole should there be deficient returns) at the end of the PBR regime. "To provide strong incentives to comply with EDTI's service quality targets, α is adjusted by an increment of 0.025 for each service quality target that is not satisfied in any given PBR year. The adjustment in α is upward in the case of excess returns (i.e., the firm retains a smaller share of its excess returns) and downward in the case of deficient returns (i.e., the firm retains α larger share of its deficient returns). Given that there are four service quality measures and the term of the PBR plan is 5 years, there are a total of 20 annual service quality targets and the maximum adjustment in the value of $\alpha = 20 \times 0.025 = ½$."[8]

[5] EPCOR (2011) *EPCOR Distribution & Transmission Inc. 2013 – 2017 Performance Based Regulation Submission* (Rate Regulation Initiative Proceeding ID. 566), July 22, 2011, p. 3.
[6] "EPCOR, ATCO Gas and ATCO Electric proposed ECMs based on ROE as part of their PBR plans." Source: AUC Decision 2012-237 (September 12, 2012), p. 166.
[7] EPCOR (2012) *Final Argument of EPCOR Distribution & Transmission Inc.* (Rate Regulation Initiative Proceeding ID. 566, Exhibit 630.02), June 13, 2012, p. 100, paragraph 264.
[8] EPCOR (2012) *Final Argument of EPCOR Distribution & Transmission Inc.* (Rate Regulation Initiative Proceeding ID. 566, Exhibit 630.02), June 13, 2012, p. 102, paragraphs 272-274.

b) See response provided below.

Company	AUC-approved ECM schemes
ATCO Gas and ATCO Electric	AUC approved ATCO Gas's and ATCO Electric's proposed ROE ECM. In its Decision, the Commissions stated that "[it] agrees that ECMs are an innovative mechanism that will allow for a strengthening of incentives in the later years of the PBR term and may discourage gaming regarding the timing of capital projects. The Commission finds that the incentive properties of an ECM encourage companies to continue to make cost saving investments near the end of the PBR term. The Commission agrees with ATCO's proposal for an upper limit for earnings that can be carried over and finds the limit of 0.5 per cent to be reasonable. Accordingly, the Commission approves the ATCO companies' ROE ECM for inclusion in the ATCO companies' PBR plans. If any of the other companies wish to submit the same ECM in their PBR plans, they may do so in their compliance filings."[9]
EPCOR	AUC also approved EPCOR's proposed ECM but with adjustments: "EPCOR's proposed ECM includes adjustments for both over- and under-earnings in the two years following the end of the PBR term. The UCA (Utilities Consumer Advocate) did not support EPCOR's ECM because it compensates for under-earning which would dampen incentives and shield the utility from the full impact of its decisions. The Commission agreed. As discussed above, the Commission also supported a 0.5 per cent limit to the amount of earnings which may be carried over. Accordingly, the Commission found that EPCOR's ECM should not include an adjustment for under-earning and should limit the amount of earnings which can be carried over to a maximum of 0.5 per cent.[10] The Commission also rejected, EPCOR's proposed service quality adjustments to its ECM formula.[11]

[9] AUC Decision 2012-237 (September 12, 2012), p. 169.
[10] AUC Decision 2012-237 (September 12, 2012), p. 169.
[11] Ibid.

c) See response provided below:

Company	Proposed ECM schemes
ATCO Gas	As is detailed in LEI's responses to I.A10.EGDI.STAFF.29 (a) and (b), AUC approved ATCO Gas's ROE ECM in the form as it was proposed.
ATCO Electric	As is detailed in LEI's responses to I.A10.EGDI.STAFF.29 (a) and (b), AUC approved ATCO Electric's ROE ECM in the form as it was proposed, while the proposed K factor ECM was denied.
EPCOR	As is detailed in LEI's responses to I.A10.EGDI.STAFF.29 (a) and (b), AUC denied in part EPCOR's proposed ECM, and instead approved the ECM scheme that was similar to that approved for ATCO Gas and ATCO Electric.

d) Enbridge's newly revised SEIM is similar in some respects to the ECM that was approved by AUC for ATCO Electric, ATCO Gas and EPCOR, namely in the estimate of the award amount and its basis related to actual ROE. However, LEI believes that the revised SEIM has better incentive properties for long term sustainable productivity growth, as it requires that EGD document and show that it has indeed brought about initiatives that would improve productivity over the long run. Please refer to EGDI's updated SEIM filed at Exhibit A2, Tab 11, Schedule 3.

e) Australia's efficiency benefit sharing scheme ("EBSS") has been in place for distribution network service providers ("NSP") since June 2008 and for transmitters since September 2007.[12] Australia's EBSS applies only to opex,[13] and not to capex.[14] EBSS rewards outperformance in opex savings and penalizes overspends in opex (as measured by the difference between forecast opex in the building blocks stage with actual opex). The EBSS is measured on a five-year rolling basis, and employs a real discount rate of 6%. Under the EBSS, NSPs can retain approximately 30% of the opex underspend, while the remaining 70% return to ratepayers through lower rates in the next regulatory term; and, symmetrically, NSPs bear approximately 30%

[12] AER (June 2008) *Electricity distribution network service providers - Efficiency benefit sharing scheme*, Final Decision, June 2008; AER (September 2007) *Electricity transmission network service providers efficiency benefit sharing scheme*, Final Decision, September 2007.
[13] AER (June 2008) *Electricity distribution network service providers - Efficiency benefit sharing scheme*, Final Decision, June 2008, p. 11.
[14] Currently, Australian NSPs use a capital expenditure sharing scheme ("CESS"): "For capex, the sharing of underspends/overspends currently occurs by updating the regulatory asset base (RAB) for actual capex at the end of each regulatory control period. If a NSP has underspent, it will benefit during the regulatory control period. Consumers will benefit at the end of the period when the RAB is rolled forward at a lower level than if the full amount of the capex allowance had been spent." Source: AER (March 2013) *Better Regulation, Expenditure incentives guidelines for electricity network service providers*, Issues Paper, March 2013, p. v.

of the opex overspend, and the remaining are passed through to ratepayers in the form of higher rates in the next regulatory period.[15] EBSS does not apply to uncontrollable opex, as well as operating costs related to non-network alternatives, pass-through events, and changes in capitalisation policy impacting forecast opex.[16]

In 2012, Australian Energy Regulator ("AER") initiated Better Regulation consultation to "set out our [AER's] approach to regulation under the new rules. They will cover how we [AER] assess expenditure proposals, calculate the allowed return on assets, allocate costs, engage with consumers, and more."[17] Better Regulation Final Guidelines have been published on November 29, 2013. AER has outlined new forecasting methodology for opex, and therefore the new adjusted opex EBSS because "EBSS is intrinsically linked to the forecasting approach for opex."[18] The new opex EBSS will operate as follows:

- "The regulatory regime provides for ex ante opex forecasts. The NSP keeps the benefit (or incurs the cost) of delivering actual opex lower (higher) than forecast opex in each year of a regulatory control period.

- The EBSS carries forward a NSP's incremental efficiency gains for the length of the carryover period. This carryover period length will typically be five years for a five year regulatory control period.

- The carryover amounts accrued in year i of period n + 1 will be the summation of the incremental efficiency gains in period n that are carried forward into year i.

- We [AER] add the carryover amounts as an additional 'building block' when setting the NSP's regulated revenue for the period n + 1.

[15] AER (March 2013) *Better Regulation, Expenditure incentives guidelines for electricity network service providers*, Issues Paper, March 2013, pp. vi – vii and 24-25.
[16] AER (June 2008) *Electricity distribution network service providers - Efficiency benefit sharing scheme*, Final Decision, June 2008, p. 45.
[17] See http://www.aer.gov.au/Better-regulation-reform-program for more information
[18] The new opex forecasting method is called "revealed cost base-step-trend" forecasting approach: "When forecasting opex we [AER] typically use one year of actual opex to forecast future opex (typically the penultimate year of the current regulatory control period). We [AER] then make changes for factors such as output growth, real price changes, productivity growth and any other efficient cost changes." Source: AER (November 2013) *Better Regulation: Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November 2013, p. 6. For more information on Better Regulation's new expenditure forecasting and incentive guidelines, see http://www.aer.gov.au/Better-regulation-reform-program.

- The actual opex incurred in the base year is used as the starting point for forecasting opex for period n + 1.

- Under this approach, the benefits of any increase or decrease in opex is shared approximately 30:70 between NSPs and consumers."[19]

According to the November 2013 "Better Regulation: Explanatory Statement – Efficiency Benefit Sharing Scheme for Electricity Network Service Providers," the EBSS has stayed largely the same, with the following changes:

1) AER has merged EBSS for DNSPs and TNSPs into a single EBSS, which will have no impact on operation of the EBSS;[20]

2) AER has clarified how carryover period will be determined, which will also not affect operation of EBSS;[21] and

3) The only changes to the operation of the opex EBSS are changes "to the allowed adjustments and exclusions, and accounting for adjustments for one-off factors in the base year when forecasting opex."[22] AER determined that there will be no longer exclusions of 'uncontrollable' opex costs,[23] that exclusions of opex from EBSS ex post will now be "limited to those categories of opex not forecast using a single year revealed cost approach in the following period,"[24] and AER has "amended the EBSS to account for any adjustments made to base opex to remove the impacts of one-off factors."[25]

EGD has revised its proposed SEIM. Please refer to the updated Exhibit A2, Tab 11, Schedule 3.

f) In the UK, Ofgem "undertake[s] an ex post review of GDNs [gas distribution networks] **output performance** in relation to asset health/risk, asset load/capacity utilisation secondary deliverables, as well as safety risk primary output at the end of RIIO-GD1" and uses a carry-over mechanism that is set out to "carry-over any

[19] AER (November 2013) *Better Regulation: Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November 2013, pp. 6-7.
[20] AER (November 2013) *Better Regulation: Explanatory Statement - Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November 2013, p. 8.
[21] Ibid.
[22] Ibid, pp. 7-8.
[23] Ibid, pp. 16-17.
[24] Ibid, p. 25.
[25] Ibid, p. 20.

under- or over-delivery of outputs at the next review, with the GDN incurring the cost (or benefit) of the under (over) delivery."[26]

Ofgem elaborated: "As with the other ex post reviews of outputs, our review of GDNs' performance in relation to NOMs [network output measures] will not consider GDNs' cost efficiency; our assessment will focus only on output performance. In general, we propose to take the NOMs secondary deliverable target for the end of RIIO-GD1 as the opening position in determining funding levels to meet RIIO-GD2 NOMs target. Any under-delivery or over-delivery against the NOMs target during RIIO-GD1 would either require catch-up or be carried forward in order to meet its RIIO-GD2 NOMs target. In relation to the reward, we have decided to apply a reward of 2.5 per cent of additional costs associated with a material over-delivery if the GDNs are able to robustly justify that the over-delivery is in the consumer interest. Similarly, we will apply a penalty of 2.5 per cent of the avoided costs associated with a material under-delivery if the GDN is unable to robustly justify that the under-delivery is in the consumer interest. Where there is substantial unjustified under-delivery we may consider whether it is appropriate also to use our powers relating to enforcement of licence conditions."[27]

In addition, Ofgem uses a rolling incentive mechanism to enhance incentives for achieving reduction targets of gas shrinkage (i.e., gas lost during transportation) "to ensure that companies retain the benefits of outperformance (or costs of underperformance) for eight years irrespective of when in the price control period the outperformance or underperformance is realized,"[28] and "a true-up in RIIO-GD2 [the next regulatory period] then adjusts these revenues to take account of any performance which proved not to be enduring."[29] Ofgem explained that "the proposed rolling incentive mechanism will enhance GDNs' prospective rewards and penalties for their performance in minimising shrinkage volumes without exposing them to increased commodity price risk (which they recover through allowed revenues). Companies will receive a forecast allowance for shrinkage based on allowed shrinkage volumes … and a forecast gas price. These forecast costs will then be adjusted to take account of actual gas costs."[30]

EGD has revised its proposed SEIM. Please refer to the updated evidence at Exhibit A2, Tab 3, Schedule 11.

[26] Ofgem (2012) *RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation*, p.67.
[27] Ofgem (2012) *RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation*, pp. 68-69.
[28] Ofgem (2012) *RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation*, p. 15.
[29] Ofgem (2012) *RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation*, p. 16.
[30] Ofgem (2012) *RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation*, p. 17.

BOARD STAFF INTERROGATORY #30

INTERROGATORY

ISSUE A10f: Are the following components within Enbridge's Customized IR plan appropriate?

f. Sustainable Efficiency Incentive Mechanism

Evidence Ref: A2/T10/S1/The Building Blocks Approach (LEI)/P 19 of 24

LEI writes that "regulators are increasingly recognizing the limitations imposed by allowing a utility to benefit from efficiencies achieved only during the term of the IR plan. While mechanisms vary in the detail, they all have a number of common features – a fixed term, limits on the amount a utility can retain, ex post awarding of the benefits and a review or application mechanism to demonstrate that savings have occurred. They all also recognize that unlike rate periods that are finite, utility operations operate over longer and more dynamic timeframes."

a) Please explain how the SEIM overcomes "the limitations imposed by allowing a utility to benefit from efficiencies achieved only during the term of the IR plan."

b) Please provide a numerical example which shows how the SEIM encourages Enbridge to retain the benefits of an initiative designed to improve its efficiency that it would otherwise not pursue because the Company would only be allowed to retain the benefits of those efficiency gains within the term of its IR plan.

c) LEI says that one of the common features of the mechanisms it references is "ex post awarding of the benefits;" would the SEIM reward Enbridge ex post (i.e. after the initiatives have been implemented) or ex ante (before the initiatives have been implemented)? Please explain.

d) LEI says that one of the common features of the mechanisms it references that "they all recognize that unlike rate periods which are finite, utility operations operate over longer and more dynamic timeframes." Please explain how the SEIM satisfies this criterion.

Witness: J. Frayer - London Economics International LLC

RESPONSE

a) It is recognized that incentives to reduce costs differ over the duration of the regulatory period. Generally, utilities achieve cost savings or reduce costs during the first few years of the regulatory period because that would yield a greater return than cost reductions achieved during the last year of the regulatory period that may be kept for only one year. An Efficiency carryover mechanism ("ECM") can be adopted to address this concern. With ECM, later-year efficiency gains could be preserved in the subsequent regulatory period. EGDI's updated SEIM is similar to an ECM in that it creates incentives in such a way that they relate directly to long-term, sustainable efficiencies or benefits. Please refer to Exhibit A2, Tab 11, Schedule 3 for information on the updated SEIM.

b) EGD has revised its proposed SEIM, please refer to Exhibit A2, Tab 11, Schedule 3.

c) EGD has revised its proposed SEIM, please refer to Exhibit A2, Tab 11, Schedule 3.

d) EGD has revised its proposed SEIM, please refer to Exhibit A2, Tab 11, Schedule 3.

Witness: J. Frayer - London Economics International LLC

BOARD STAFF INTERROGATORY #31

INTERROGATORY

ISSUE: A10f: Are the following components within Enbridge's Customized IR plan appropriate?

f. Sustainable Efficiency Incentive Mechanism

Evidence Ref: A2/T10/S1/The Building Blocks Approach (LEI)/P 20 of 24

"LEI finds that Enbridge's proposed (SEIM) mechanism is consistent with the overarching principles applied in other jurisdictions for allowing 'roll over' mechanisms for efficiency savings.'

a) Please describe the "overarching principles" in the jurisdictions referenced by LEI.

b) Please explain whether any of the mechanisms in these jurisdictions award a utility upfront because of efficiency gains it has forecast?

c) Please explain whether awarding a utility based on forecast efficiency savings is consistent with a "roll over" of efficiency savings into the term of a subsequent incentive regulation plan?

RESPONSE

a) The "overarching principles" of an efficiency carryover mechanism conceptually and generically is to address the incentive issue of companies implementing less cost savings in later years of an IR term because the expected returns will be too short-lived given the term of the IR. In other words, an ECM would overcome the motivation to hold off making efficiency improvements until after rates are re-set and that will mean overall more efficiency endeavors on a more constant basis, regardless of when the IR term expires. This then provides benefits to consumers in the long run.

   However, in the specific jurisdictions of Australia and UK, the conceptual principles have been verbalized and clarified and we excerpt some of the specific regulations below as further reference for the Board.

Witness: J. Frayer - London Economics

In Australia, "Clauses 6.5.8 and 6A.6.5 of the NER [National Energy Rules] outline the requirements for an EBSS. In developing and implementing any EBSS the AER must have regard to:

1) the need to provide NSPs with a continuous incentive to reduce opex

2) the desirability of both rewarding NSPs for efficiency gains and penalising NSPs for efficiency losses

3) any incentives that NSPs may have to capitalise expenditure; and

4) the possible effects of the scheme on incentives for the implementation of non-network alternatives.

In addition, for DNSPs [distribution network service providers], the AER must ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs.[1]

AER employs EBSS to address the following incentive issues:

1. A NSP has an incentive to increase opex in the expected 'base year' to increase its forecast opex allowance for the following regulatory control period.

2. A NSP's incentive to make sustainable change to its practices, and reduce its recurrent opex, declines as the regulatory control period progresses. It then increases again after the base year used to forecast opex for the following regulatory control period. By deferring these ongoing efficiency gains until after the base year the NSP can retain the benefits of doing so for longer because they won't be reflected in the opex forecasts for the following period.[2]

The Australian EBSS (both used by NSPs currently and per new November 2013 Better Regulation Final Guidelines) "aims to provide a continuous incentive for NSPs to pursue efficiency improvements in opex,"[3] and ensures "a fair sharing between NSPs and network users of efficiency gains and losses made during a regulatory control period"[4] via a symmetric scheme on gains and losses that provides "the same

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[1] AER (November 2013) *Better Regulation: Explanatory Statement - Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November 2013, p. 15.
[2] AER (November 2013) *Better Regulation: Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November 2013, p. 6.
[3] AER (November 2013) *Better Regulation: Explanatory Statement - Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November 2013, p. 6.
[4] AER (November 2013) *Better Regulation: Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November 2013, p. 5.

reward for an underspend and the same penalty for an overspend in each year of the regulatory control period."[5]

The UK carry-over mechanism enhances current RIIO incentives by incentivizing "the delivery of outputs by means of an ex-post review of outputs with carry forward or catch-up of the incremental output over-delivery or shortfall in the next period."[6]

In addition, the rolling incentive mechanism for shrinkage and leakage ensures that "companies retain the benefits of outperformance (or costs of underperformance) for eight years irrespective of when in the price control period the outperformance or underperformance is realized."[7]

b) Please see the response to Board Staff Interrogatory #33(a) found at Exhibit I.A10.EGDI.STAFF.33.

c) There are similarities with regards to awarding a utility based on forecast efficiency savings and a "roll over" of efficiency savings into the term of a subsequent incentive regulation plan. Under a roll over efficiency mechanism, any efficiency gains are retained by the utility for a set period of time before being allocated to consumers. This allocation can be a one-off price reduction or phased in over time. Similarly, when awarding a utility based on forecast efficiency savings, the utility retains the efficiency gains for a set period of time (or during the regulatory period), and only after the requisite timeframe runs out will these efficiency gains be allocated to consumers.

   EGD has updated its SEIM plan where it has committed to request an ECM award (SEIM award) only if EGD is successful at demonstrating to the Board that the forecast efficiency savings are sufficiently greater than the award payout. It should also be noted that OEB will still have to review EGD's efficiency gains or savings before allowing EGD's award under SEIM.

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[5] AER (November 2013) *Better Regulation: Explanatory Statement - Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November 2013, p. 10.
[6] Ofgem (2012) *RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation*, p.72.
[7] Ofgem (2012) *RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation*, p.15.

BOARD STAFF INTERROGATORY #32

INTERROGATORY

ISSUE: A10f: Are the following components within Enbridge's Customized IR plan appropriate?

f. Sustainable Efficiency Incentive Mechanism

Evidence Ref: A2/T10/S1/The Building Blocks Approach (LEI)/P 21 of 24

"In summary, the proposed SEIM arrangement provides a positive incentive for Enbridge to implement efficiency measures towards the end of a regulatory period or over longer timeframes, where they might otherwise be discouraged from doing so as the timeframes may be too short for them to recover their costs."

a) Please explain in detail how the SEIM would encourage "Enbridge to implement efficiency measures towards the end of a regulatory period or over longer timeframes, where they might otherwise be discouraged from doing so."

b) Please provide a numerical example which demonstrates how an incentive payment in year 1 of Enbridge's proposed Customized IR plan would encourage Enbridge to undertake an initiative in year 4 of that plan that it would not have undertaken in the absence of the incentive payment in year 1.

c) In the example provided in part b), please explain whether the incentive payment provided in advance in year 1 would reduce Enbridge's incentive to follow through in year 4 on the efficiency-improving initiative in question.

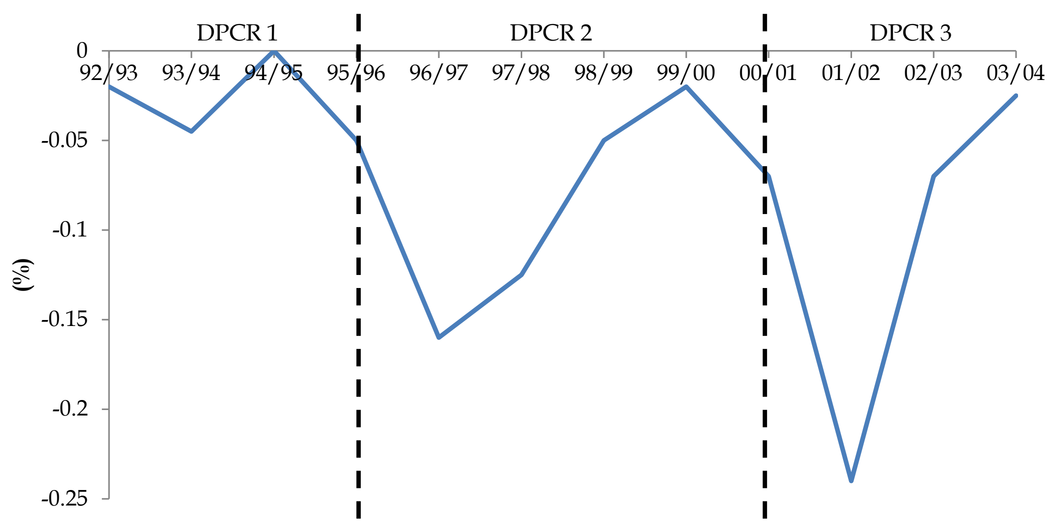
RESPONSE

a) Generally, utilities act differently when the strength of regulatory incentives changes within and between regulatory periods. For instance, in the UK before the 5th Distribution Price Control Review ("DPCR5"), the level of cost reductions achieved in the year following the price review was significantly higher than other years, and costs reductions gradually trail off until the next price review (see Figure 1 below). This can be explained by the declining reward for efficiency over the regulatory period under the IRM framework used in the UK, and specifically because the later years would be referred to and used as the base year to reset prices for the next regulatory period. For DPCR5, the UK regulator (Ofgem) strengthened the IRM with the rolling mechanism incentive to ensure stable incentives for efficiency throughout the regulatory period.

Similarly, incorporating EGDI's proposed SEIM in the IRM plan would provide for time-consistent incentive to EGDI. By maintaining consistent incentives throughout the regulatory period, EGDI's investment decisions are not distorted. The absence of SEIM will skew cost reduction initiatives to the early years of the price control and results in declining of cost reduction incentives at the end of the price control period.

EGDI revised its proposed SEIM. Please refer to Exhibit A2, Tab 11, Schedule 3.

Figure 1. Growth in Real Unit Operating Expenditure (UK Electric Distribution)



Source: Crew, Michael and Parker, David. International Handbook on Economic Regulation (Figure 8.3)

b) EGD has revised its proposed SEIM, please refer to Exhibit A2, Tab 11, Schedule 3.

c) EGD has revised its proposed SEIM, please refer to Exhibit A2, Tab 11, Schedule 3.

BOARD STAFF INTERROGATORY #33

INTERROGATORY

ISSUE A10f.: Are the following components within Enbridge's Customized IR plan appropriate?

f. Sustainable Efficiency Incentive Mechanism

Exhibit: I.A10f.EGDI.Staff.33

Evidence Ref: Exhibit A2, Tab 10, Schedule 1, Page 21 of 24

LEI states that the key difference in Enbridge's proposal from the schemes outlined by LEI [Alberta, UK and Australia] is that Enbridge's SEIM is based on estimated rather than actual benefits.

a) Please provide references in jurisdictional precedent where the utility's financial gains under an efficiency carryover mechanism are based on estimated benefits rather than achieved / actual benefits.

b) In the examples mentioned in part a) where efficiency carryovers are based on estimated benefits, is there a true-up mechanism when the actual benefits become known (i.e., is there is a true-up in the utility's financial gain when actual /achieved benefits are less than estimated benefits)? If so, please explain these true-up mechanisms in detail.

RESPONSE

a) We are not aware of any jurisdictional precedent where the utility's financial gains under an ECM are based on estimated benefits rather than actual benefits, but that does not preclude the fact that there are other examples where financial remuneration in regulatory—proved utility programs are based on forecasted benefits and forecasted measures of impact – such as energy efficiency programs.

b) See answer on (a) above.

BOARD STAFF INTERROGATORY #34

INTERROGATORY

ISSUE A10f: Are the following components within Enbridge's Customized IR plan appropriate?

f. Sustainable Efficiency Incentive Mechanism

Evidence Ref: Exhibit A2, Tab 11, Schedule 3, Page 2 of 6

Enbridge states that the Productivity Initiatives Report will provide details about any such projects that meet certain criteria. One of the criteria is that the project(s) have been implemented.

a) Please define what is meant by "implemented". For example, does this mean that the project is fully completed and functional?

b) Please confirm whether Enbridge would implement an "implemented project" if it did not have the SEIM? Alternatively, would Enbridge implement an "implemented project" only because of the SEIM? Please explain in detail.

RESPONSE

a) and b) Enbridge has responded to various criticisms of the Sustainable Efficiency Carryover Mechanism ("SEIM") as it was originally proposed in the pre-filed evidence, and as result has updated its proposal to operate in a similar manner as the Efficiency Carryover Mechanism approved by the Alberta Utilities Commission in 2012.

Please see the updated evidence filed at Exhibit A2, Tab 11, Schedule 3, for further details.

Witnesses: R. Fischer
S. Kancharla
M. Lister
I. MacPherson

BOARD STAFF INTERROGATORY #35

INTERROGATORY

ISSUE A10g: Are the following components within Enbridge's Customized IR plan appropriate?

g. Annual reporting requirements

Evidence Ref: Exh A2, Tab 11, Sch 2, Page 1 of 13

Enbridge states that this framework is comprised of two reporting mechanisms: (1) Productivity Initiatives Report, and (2) Performance Metrics Benchmarking Report.

In Enbridge's Settlement Agreements (EB-2007-0615 / 0606), Enbridge's annual requirements (2008-2012) were state as the following:

1. Calculation of revenue deficiency/sufficiency
2. Statement of utility income
3. Statement of earnings before interest and taxes
4. Summary of cost of capital
5. Total weather normalized throughput volume by service type and class
6. Total actual (non-weatherized) throughput volumes by service type and rate class
7. Total weather normalized gas sales revenue by service type and rate class
8. Total actual (non-weather normalized) gas sales revenue by service type and rate class
9. T-service revenue by service type and rate class
10. Total customers by service type and rate class
11. Other revenue
12. Operating and maintenance expenses by department
13. Calculation of utility income taxes
14. Calculation of capital cost allowance
15. Provision of depreciation, amortization and depletion
16. Capital budget analysis by function
17. Statements of utility rate base

a) Please confirm whether Enbridge would agree to file the above information on annual basis with the Board during its proposed Customized IR plan.

Witnesses: S. Kancharla
I. MacPherson

b) In Exhibit L, Tab 1, Page 139 of 160, an additional reporting requirement was identified regarding Enbridge filing information on its gas delivery revenues by rate class and service type. Please confirm whether Enbridge would agree to file on annual basis its delivery revenue by service type and rate class with the Board during its proposed Customized IR plan.

RESPONSE

a) Confirmed.

b) Confirmed.

Witnesses: S. Kancharla
I. MacPherson

BOARD STAFF INTERROGATORY #36

INTERROGATORY

ISSUE A10: Are the following components within Enbridge's Customized IR plan appropriate?

h. Rebasing proposal

Evidence Ref: A2/T8/S1/

For rebasing filing requirements, could the Company please comment on the usefulness of providing 5 years of historical actual data, including the 2017 historical year in its Cost of Service rebasing filing. Would the Company commit to a fixed filing date for the rebasing and a set of filing requirements to be developed with stakeholders?

RESPONSE

The provision of five years of historical data in a cost of service rebasing filing may or may not be useful depending on a variety of circumstances. For example, if the revenue and cost information and related data for historical years are used to create or develop trends or conclusions about likely future revenue or costs, without consideration of the many other factors which could influence, future revenues and costs, then five years of historical data may not be useful, or may need to be supplemented by other data or information.

There are potentially many influences that could affect the Company's rebasing application and as a result it is unable to commit to a fixed filing date.

Witnesses: R. Fischer
M. Lister

BOARD STAFF INTERROGATORY #37

INTERROGATORY

ISSUE 10: Are the following components within Enbridge's Customized IR plan appropriate?

i. Treatment of pension expense and employee future benefits costs

Evidence Ref: EB-2013-0046 Exh D/Tab 1/Sch 1/Page 31, EGD December 31, 2012 Audited Financial Statements

At EB-2013-0046, Exhibit D/Tab1/Sch1/Page31, Note 18 to EGD's December 31, 2012 audited financial statements states the following:

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

a) Please provide the rationale as to why EGD maintains a pension plan (defined benefit and defined contribution) and two supplemental non-contributory defined benefit pension plans that are non-contributory by EGD's employees, as opposed to plans to which employees make contributions.

b) Please provide the rationale as to why the Board should approve rate recovery of EGD's requested 2014, 2015, and 2016 pension amounts in view of the fact that employees contribute 0% of these costs to the plans. Please state why the Board should approve EGD's non-contributory pension amounts considering the percentage that employees of most utilities regulated by the Board (e.g. utilities in OMERS plan) contribute 50%.

c) Please provide an estimate of EGD's 2014, 2015 and 2016 pension costs if a 50% contribution rate percentage by employees was instituted instead of these plans being non-contributory.

Witnesses: K. Culbert
S. Trozzi

RESPONSE

a) EGD provides non-contributory pension plans as a component of the employees' total compensation package. Enbridge's compensation philosophy is to position itself at the 50th percentile of the market in which it competes for talent. An employee contributory plan would result in the Company allocating equivalent funds elsewhere within the Total Compensation Package in order to maintain its competitive position in the market and therefore it would be cost neutral. Additionally, a change such as this would need to be negotiated through collective bargaining with the unionized workforce.

b) A request has been made to the Board to approve EGD's total employee compensation costs. The Company's non-contributory pension amounts are only one component of the employees' total compensation package as stated above. If EGD moved to a contributory plan, it would need to adjust other components in order for the total compensation to remain the same.

c) The provision of an estimate of EGD's 2014, 2015 and 2016 pension costs using a 50% contribution rate percentage by employees would be a complex, costly and time consuming exercise. Based on the explanation provided in a) and b). The Company does not believe that this is not a valuable exercise.

Witnesses: K. Culbert
S. Trozzi

BOARD STAFF INTERROGATORY #38

INTERROGATORY

ISSUE 10: Are the following components within Enbridge's Customized IR plan appropriate?

i. Treatment of pension expense and employee future benefits costs

Evidence Ref: EB-2011-0354 ExA2/Tab3/Sch2/Appendix A filed June 8, 2012
EB-2011-0354 ExA2/Tab3/Sch1/Appendix 5 filed January 31, 2012,
ExD1/Tab16/Sch1/App1/page 20, ExD1/Tab16/Sch1/App2/page 15.

www.bankofcanada.ca Selected Monthly Canada Bond Yields – see Table 1\ below

Table 1 - Selected Monthly Canada Bond Yields as at November 11, 2013
www.bankofcanada.ca
Monthly series: 2012-03-01 - 2013-10-01
V122543 = Government of Canada benchmark bond yields - 10 year
V122544 = Government of Canada benchmark bond yields - long-term

Date	V122543	V122544
2013-10	2.42	3.01
2013-09	2.57	3.09
2013-08	2.63	3.09
2013-07	2.45	2.97
2013-06	2.50	2.96
2013-05	2.07	2.65
2013-04	1.72	2.38
2013-03	1.76	2.49
2013-02	1.86	2.53
2013-01	1.99	2.57
2012-12	1.82	2.37

Witnesses: K. Culbert
B. Yuzwa
Mercer

As per EB-2011-0354 ExA2/Tab3/Sch2/Appendix A page 17 filed June 8, 2012 and prepared by Mercer on June 1, 2012, the discount rate used in the actuarial valuation for pension costs on an accrual basis was 4.33% as at December 31, 2011.

As per EB-2011-0354 ExA2/Tab3/Sch1/Appendix 5 page 14 filed January 31, 2012 and prepared by Mercer January 19, 2012, the discount rate used in the actuarial valuation for OPEB costs on an accrual basis was 4.80% as at December 31, 2010.

As per ExD1/Tab16/Sch1/App1/page 20 and ExD1/Tab16/Sch1/App2/page 15 filed June 28, 2013 and prepared by Mercer March 28, 2013, the discount rate used in the actuarial valuation for pension & OPEB costs on an accrual basis was 4.30% as at December 31, 2012.

EGD explains that the requested 2014, 2015, and 2016 pension & OPEB costs in this proceeding have decreased from the forecasts for 2014, 2015, and 2016 approved by the Board in EB-2011-0354 due to "higher expected returns on pension plan asset balances." However, EGD has included an immaterial decrease in the discount rate in the actuarial valuations prepared on March 28, 2013 and filed in this proceeding (4.30% for pension & OPEB), compared to the valuations filed in EB-2011-0354 (4.33% for pension and 4.80% for OPEB).

a) Please confirm that higher bond yields and discount rates would decrease forecasted pension and OPEB expenses for 2014 through 2018 rates. If EGD disagrees, please explain why.

b) As per Table 1 above, both the Canada 10 year and long term benchmark bond yields have increased by approximately 60 basis points from December 31, 2012 to October 31, 2013. Please provide what the updated EGD discount rate would be as at October 31, 2013, considering this increase in benchmark bond yields. Please explain how the discount rate was selected in line with these Canada bond yields.

c) Has EGD prepared an updated actuarial valuation or accounting update to reflect this increase in bond yields and discount rate for pension and OPEB? If so, please file this valuation or accounting update. If not, please explain why an updated valuation or accounting update was not prepared for both pension and OPEB if EGD agrees that an increase in bond yields would decrease forecasted pension & OPEB expenses for 2014 through 2018 rates.

Witnesses: K. Culbert
B. Yuzwa
Mercer

d) Please explain why the Board should approve pension & OPEB costs for 2014, 2015, 2016, 2017, and 2018 based on actuarial valuations that have been prepared with outdated discount rates – market discount rates have increased since the valuations were prepared on March 28, 2013, as indicated in Table 1 above.

e) What would the cost be to EGD to obtain an updated actuarial valuation for each of pension and OPEB costs as at October 31, 2013.

f) What would the cost be to EGD to obtain an actuarial valuation accounting update for each of pension and OPEB costs as at October 31, 2013.

RESPONSE

a) We confirm that higher bond yields and discount rates would decrease the forecasted pension and OPEB expenses for 2014 through 2018.

b) The updated EGD discount rate would be 4.80% at October 31, 2013. The discount rate was selected based on Canadian high-quality corporate bonds. Under the Mercer Model, short term yields to maturity are derived by fitting a curve through actual AA rated corporate bond yield data. Because of the limited number of AA rated corporate bonds in the Canadian market, especially at longer maturities, for longer terms a curve is fitted through extrapolated data created by adding a spread (the “Mercer Spread”) to long AA provincial bond yields. The Mercer Spreads are derived by determining the average observed AA corporate to provincial spread and average corresponding maturity for three different maturity bands (6 to 10 years, 11 to 20 years, and 21 to 30 years). Once the Mercer Spreads are established, AA rated corporate bond yields are extrapolated by adding the Mercer Spreads to the AA rated provincial bond data for all maturities greater than the average maturity in the 6 to 10 maturity range.

As described above, the discount rate for accrual cost purposes is an accounting discount rate based on high-quality corporate bond yields.

c) We have not prepared an updated actuarial valuation or accounting update to reflect the increase in bond yields and discount rates. Instead of continually updating actuarial valuations to reflect changing discount rates, we have proposed a pension true-up variance account to capture any differences between the estimated and actual pension and OPEB expenses for 2014 to 2018.

Witnesses: K. Culbert
B. Yuzwa
Mercer

d) Please see response to c) above.

e) An updated actuarial funding valuation to determine cash contributions for 2014 to 2018 would involve extrapolating the most recent actuarial funding valuation to the next actuarial funding valuation date at December 31, 2013 using the most recent economic data. The cost to obtain an updated actuarial funding valuation for each of pension and OPEB costs as at October 31, 2013 would be $12,000–$17,000 for the pension funding valuation and $4,000 to $5,000 for the OPEB valuation. Note that for question f) below, there are efficiencies in updating both the actuarial funding valuation for cash contribution projections and the accounting valuation for pension costs projections. The combined cost to provide both would be $25,000–$30,000 for the pension valuations and $12,000 to $17,000 for the OPEB valuations.

f) An updated actuarial accounting valuation to determine projected pension costs for 2014 to 2018 would involve extrapolating the most recent actuarial valuation to the next accounting year year-end date at December 31, 2013 using the most recent economic data. The cost to obtain an updated actuarial accounting valuation for each of pension and OPEB costs as at October 31, 2013 would be $20,000 to $25,000 for pension and $10,000 to $15,000 for OPEB. Note that for question e) above, there are efficiencies in updating both the actuarial funding valuation for cash contribution projections and the accounting valuation for pension costs projections. The combined cost to provide both would be $25,000 to $30,000 for the pension valuations and $12,000 to $17,000 for the OPEB valuations.

Witnesses: K. Culbert
B. Yuzwa
Mercer

BOARD STAFF INTERROGATORY #39

INTERROGATORY

ISSUE A10: Are the following components within Enbridge's Customized IR plan appropriate?

h. Rebasing proposal

Evidence Ref: A2/T8/S1/

No question / exhibit not used.

RESPONSE

No response required.

CCC INTERROGATORY #10

INTERROGATORY

Issue A10 – Are the following components within Enbridge's Customized IR plan appropriate?

Z-Factor

(Ex. A2/T1/S1) EGD is proposing a threshold of $1.5 million for Z-factor treatment. The Council is interested in assessing the appropriateness of level of the threshold. With respect to the first IRM plan please indicate, for each year each instance where the threshold was reached, the nature of the expense and associated costs, whether recovery was sought, and any relief approved by the Board. Please include instances when EGD applied for z-factor relief, but the request was withdrawn as a result of the settlement negotiations.

RESPONSE

It is unclear to Enbridge what information this information request is seeking. For example, if the question is intended for Enbridge to review all of its historical costs over the 1st Generation IR term to assess whether certain programs might have met or surpassed the $1.5 million revenue requirement threshold, Enbridge is unable to provide a response. The Company did not track costs on a revenue requirement basis and could not construct the data required to do this now.

Below EGD provides a summary of each Z-factor request that was made during the course of the 1st Generation IR term, by year.

2010 (EB-2009-0172)

Request # 1– The Company sought recovery of incremental operating costs due to pension funding shortfalls.

Threshold – The estimated annual operating cost to fund the pension was $17.1 million plus an annual Pension Benefits Guarantee Fund ("PBGF") premium of $1.8 million in 2010, for a total of $18.9 million.

Result – For the purposes of settling the issues in the proceeding, Enbridge agreed to withdraw its request for the relief sought. All parties agreed that this withdrawal was without prejudice to Enbridge's right to request the same or similar relief in respect of pension costs for 2011 or subsequent years.

Request # 2– The Company sought a Z-Factor to allow for the recovery of costs related to the Sewer Lateral Initiative, and a variance account to record the differences between the costs incurred and the amount forecast in the Z-Factor

Threshold – The estimated Revenue Requirement impact for 2010 was approximately $3.6 million.

Result – For the purposes of settling the issues in the proceeding, Enbridge agreed to withdraw its request for the relief sought. All parties agreed (with the exception of APPrO, who took no position) that this withdrawal was without prejudice to Enbridge's right to request the same or similar relief in respect of crossbores/sewer lateral costs for 2011 or subsequent years.

<u>2012 (EB-2011-0277)</u>

Request # 1– EGD applied for Z-Factor treatment to fund a deficit in its pension plan.

Threshold – The estimated shortfall was $16.6 million.

Result – The Board denied the Company's request for Z-Factor treatment for the pension funding requirement.

Request # 2– EGD requested recovery of the revenue requirement associated with its Cross Bore Action Plan be included in the revenue requirement as a Z-Factor in its application, along with a Variance Account to record any variances from expected costs.

Threshold – The forecast impact on the 2012 revenue requirement associated with implementing the cross bore Action Plan was $3.8 million.

Result – The Board denied the Company's request for Z-Factor treatment related to cross bore management.

Witnesses: R. Fischer
M. Lister

CCC INTERROGATORY #11

INTERROGATORY

Issue A10 – Are the following components within Enbridge's Customized IR plan appropriate?

Z-Factor

(Ex. A2/T4/S1)
Please indicate if the wording regarding Z-factors agreed to by Union Gas Limited and accepted by the Board in Union's recent IRM negotiations would be acceptable to EGD (EB-2013-0202). If not, please explain why the wording would not be acceptable to EGD.

RESPONSE

The Union Gas Limited Z-factors wording is not acceptable to Enbridge. The wording agreed to by Union Gas in EB-2013-0202 is essentially the wording of the 1st Generation IR plan, which Enbridge proposes to modify for the reasons discussed at Exhibit A2, Tab 4, Schedule 1.

Witnesses: R. Fischer
M. Lister

CCC INTERROGATORY #12

INTERROGATORY

Issue A10 – Are the following components within Enbridge's Customized IR plan appropriate?

Earnings Sharing Mechanism

For each year in the last IRM period please provide a schedule setting out the allowed ROE, the actual ROE achieved (actual and weather normalized), total earnings, and the amounts shared between shareholders and ratepayers.

RESPONSE

The 2008 to 2012 IRM period information as presented within annual Earnings Sharing Mechanism proceedings is provided in Table 1 on the following page.

EGD's September 30, 2013 Financial Statements and Management Discussion and Analysis identify the correction of an error, which occurred in Enbridge's recording of costs in 2010 to 2012 and in prior months within 2013. As a result of this error, EGD's Utility Income and ROE results for 2010 to 2012 were overstated. This means that the amount of earnings shared with ratepayers was overstated. Please note, though, that EGD is not seeking an adjustment to the previously Board approved and reported ratepayer earning sharing amounts for 2010 to 2012.

Witness: K. Culbert

TABLE -1

Line No		2008 Historical	2009 Historical	2010 Historical	2011 Historical	2012 Historical
1.	Allowed ROE (without 100bp ESM allowance)	8.66%	8.31%	8.37%	7.94%	7.52%
2.	Actual ROE Before Earnings Sharing	11.87%	12.36%	10.25% (2)	10.43% (2)	7.62% (2)
3.	Actual Normalized ROE Before Earnings Sharing	10.21%	11.20%	11.10% (2)	10.38% (2)	9.28% (2)
4.	Gross Overearnings ($millions) (Note 1)	31.7	59.0	54.7	48.4	34.4
5.	Shareholders' Share of Gross Overearnings ($millions) (Note 1)	26.1	39.7	37.4	34.1	27.0
6.	Ratepayers' Share of Gross Overearnings ($millions)	5.6	19.3	17.4	14.3	7.4
7.	Actual Normalized ROE /After Earnings Sharing	9.94%	10.26%	10.24% (2)	9.66% (2)	8.90% (2)

Note 1: Amounts include impact of 100bp allowed for earnings sharing purposes during the 2008-2012 incentive term, additionally, these are not true resulting net earnings amounts as they include tax amounts payable.

Note 2: These are the previously reported actual and normalized ROE%'s which have not taken into account the impact of the accounting error identified within EGDI's September 30, 2013 Financial Results.

Witness: K. Culbert

CCC INTERROGATORY #13

INTERROGATORY

Issue A10 – Are the following components within Enbridge's Customized IR plan appropriate?

Earnings Sharing Mechanism

(Ex. A2/T1/S1/p. 36) EGD is proposing an ESM that has 100% of earnings flowing to the shareholder from 0-100 basis points above the allowed return, and earnings 100 basis points above the allowed ROE shared on a 50:50 basis. What other ESM mechanisms did EGD consider? If other models were considered why were they rejected?

RESPONSE

Enbridge considered the possibility of different dead bands or sharing percentages from the ESM in the 1st Generation IR. In the end it was determined that the ESM design that was accepted for the 1st Generation IR plan which resulted in the Ratepayers' share of gross overearnings from 2008 to 2012 being approximately $64 million would once again be appropriate for the proposed plan.

It was determined that some amount of dead band was required in order to preserve strong incentives. Similarly, for the sharing split, it was determined that tilting the balance one way or the other would result in either weaker incentives or would be seen as not fair to the ratepayer.

As LEI comments in their report at Exhibit A2, Tab 10, Schedule 1, page 18.

It should be noted that there is some opposition to ESMs as a basic construct, because it complicates administration of a IR system; and in theory, it weakens the productivity incentives created by moving to IR. Some critics have even argued that ESM is not technically essential for successful IR implementation. However, by allowing customers to share in benefits which arguably would not have occurred in absence of incentives, the overall political acceptability of an IR plan is increased with an ESM. Furthermore, Enbridge is proposing a one-sided or asymmetric ESM, which is a significant advantage to consumers.

Witnesses: R. Fischer
M. Lister

Enbridge's proposal to continue its conservative, customer-favoring ESM is consistent with all the principles discussed above and will provide a strong incentive to implement efficiency measures, as Enbridge will receive the initial benefits, while customers will also share in the gains above the threshold.

Enbridge believes that the ESM design proposed, which was also used for the 1st Generation IR plan, creates the right equilibrium for both the utility and ratepayers.

Witnesses: R. Fischer
M. Lister

CCC INTERROGATORY #14

INTERROGATORY

Issue A10 – Are the following components within Enbridge's Customized IR plan appropriate?

Treatment of Cost of Capital

(Ex. A2/T5/S1/p. 1) EGD proposes that the capital structure ratios will be fixed for the term of the plan. What happens if the Board undertakes a review of cost of capital and capital structure during the plan? Is it EGD's position that despite a review, capital structure changes will only be made upon rebasing (if at all)?

RESPONSE

Yes. See Exhibit A2, Tab 5, Schedule 1, paragraphs 7 and 16. The Company's position is that the equity ratio will remain fixed for the duration of the Customized IR plan term and if there is a change such as the result from a Board review of cost of capital and capital structure, it will be applied upon rebasing. The long-term debt, short-term debt, and preferred share ratios will be pre-set at the forecast weights that can be found at Exhibit A2, Tab 5, Schedule 1, page 2, and EGD proposes no changes to those weights for ratemaking purposes during the 2014 to 2018 term.

Witnesses: K. Culbert
R. Fischer
M. Lister

CCC INTERROGATORY #15

INTERROGATORY

Issue A10 – Are the following components within Enbridge's Customized IR plan appropriate?

Sustainable Efficiency Incentive Mechanism

(Ex. A2/T11/S3/p. 1) Does EGD have examples of mechanisms similar to the SEIM that have been employed in other jurisdictions? If so, please describe how those mechanisms have worked to incent sustainable productivity gains.

RESPONSE

EGD does not have examples of mechanisms similar to the originally proposed SEIM that have employed in other jurisdictions.

EGD is proposing to revise the SEIM as contemplated and adopt an approach similar to an Efficiency Carryover Mechanism ("ECM"). Please see the updated evidence filed at Exhibit A2, Tab 11, Schedule 3 for an explanation of the rationale for the change and description of the updated SEIM. As explained within that updated evidence, the form of SEIM now being proposed is substantially similar to the ECM which has been approved in Alberta. The updated evidence explains how this type of mechanism works to incent sustainable productivity gains.

Witnesses: R. Fischer
S. Kancharla
M. Lister
I. MacPherson

CCC INTERROGATORY #16

INTERROGATORY

Issue A10 – Are the following components within Enbridge's Customized IR plan appropriate?

Sustainable Efficiency Incentive Mechanism

(Ex. A2/T1/S3) Please describe the types of projects that EGD envisions for the SEIM. Does EGD currently have certain projects in mind? If so, please describe those projects. What would be the size of these projects in terms of overall cost? How did EGD arrive at a 20% incentive amount?

RESPONSE

EGD is revising its proposal for the SEIM, and is instead adopting an approach similar to an Efficiency Carryover Mechanism ("ECM"). This updated approach to SEIM will be based on measuring and rewarding the Company's overall annual savings, and will not involve any project-specific examinations or derminations.

Please see the updated evidence filed at Exhibit A2, Tab 11, Schedule 3.

Witnesses: K. Culbert
R. Fischer
A. Kacicnik
M. Lister

CME INTERROGATORY #4

INTERROGATORY

Issue: A10f

Reference: Exhibit A2, Tab 1, Schedule 1, page 14
Exhibit A2, Tab 1, Schedule 3

EGDI's proposal SEIM is criticized by PEG in Exhibit L, Tab 1, Schedule 2 at page 23. In connection with these criticisms, please provide the following:

(a) EGDI's comments and responses to these criticisms.

RESPONSE

EGD has responded to criticisms of the proposed Sustainable Efficiency Incentive Mechanism ("SEIM") by reconstituting the mechanism to operate in a similar manner to the Efficiency Carryover Mechanism approved by the Alberta Utilities Commission in 2012. Please see the updated evidence for Exhibit A2, Tab 11, Schedule 3 for discussion on this proposed change.

Witnesses: R. Fischer
S. Kancharla
M. Lister
I. MacPherson

CME INTERROGATORY #5

INTERROGATORY

Issue: A10f

Reference: Exhibit A2, Tab 1, Schedule 1, page 14
Exhibit A2, Tab 1, Schedule 3

At Exhibit A2, Tab 11, Schedule 3, page 6, an illustration is provided of a SEIM calculation which identifies three (3) hypothetical projects costing $1M, $5M and $500,000 respectively. In connection with this evidence, please provide the following information:

(a) What initiatives has EGDI identified that would qualify for this proposed incentive treatment in 2014?

(b) If EGDI's SEIM proposal is approved, then what is the possible Net Present Value ("NPV") potential for such projects in each of the years 2014 to 2018 inclusive?

(c) On what basis did EGDI derive the proposed 20% incentive factor?

RESPONSE

(a) Enbridge has reconsidered its proposed Sustainable Efficiency Incentive Mechanism ("SEIM") and updated its evidence to reconstitute the SEIM to operate in a similar manner to the Efficiency Carryover Mechanism approved by the Alberta Utilities Commission in 2012. Please see Exhibit A2, Tab 11, Schedule 3, for a discussion on the proposed changes to the SEIM.

(b) See answer to (a).

(c) See answer to (a).

Witnesses: R. Fischer
S. Kancharla
M. Lister
I. MacPherson

CME INTERROGATORY #8

INTERROGATORY

Issue: A10c

Reference: Exhibit A2, Tab 1, Schedule 1, page 35
Exhibit A2, Tab 7, Schedule 1

EGDI is proposing an asymmetric ESM with a 100 bp deadband and 50/50 sharing thereafter. Assume that the risk of excessive forecasts under the auspices of EGDI's proposal is high and that, to protect ratepayers, the ESM allocates 90% of the first 100 bp of earnings over the allowed Return on Equity ("ROE") to ratepayers with 50/50 sharing to prevail for over-earnings in excess of 100 bp of ROE over the Board allowed return.

(a) Will EGDI operate under the auspices of its proposal in this scenario or will it revert to an annual cost of service filing?

RESPONSE

EGD expects to operate under the parameters of the Customized IR Plan as approved by the Board in this proceeding.

With respect to the ESM design posed in this interrogatory, Enbridge believes that a strong incentive is a motivator to encourage efficiencies where both ratepayer and shareholder can benefit. The shift of the first 90% of the first 100 bp of earnings to the ratepayer does not provide that strong incentive to operate efficiently. As described in CCC Interrogatory #13, found at Exhibit I.A10.EGDI.CCC.13, the Company does not ascribe to an assumption that there is a risk of excessive forecasted costs. With the likelihood that Enbridge will have to spend more capital than requested to maintain a safe and reliable distribution system, an ESM design that has the first 100 bp of earnings provisioned for the shareholder will provide a strong incentive for the utility to find efficiencies in other areas of operations.

Witnesses: R. Fischer
M. Lister

CME INTERROGATORY #9

INTERROGATORY

Issue: A10d

Reference: Exhibit A2, Tab 5, Schedule 1
Exhibit E2, Tab 1, Schedules 1 and 2

Please list and provide copies of the sources of information which the Enbridge Inc. Treasury Dept. used to estimate the short-term debt, long Canada bond yields and utility bond and 30 year Government of Canada spreads which EGDI has used to derive the forecast ROEs for the years 2014 to 2018 inclusive under the auspices of the Board's formula.

RESPONSE

Please refer to the response to Energy Probe Interrogatory #20, found at Exhibit I.B17.EGDI.EP.20.

Witnesses: P. Bhatia
M. Suarez

ENERGY PROBE INTERROGATORY #4

INTERROGATORY

Ref: Exhibit A2, Tab 1, Schedule 1, page 6

a) With respect to the Z factor mechanism, please provide possible examples of unexpected cost decreases that would qualify for this reduction.

b) Does the Z factor mechanism apply to unexpected revenue increases or decreases that are outside of management control, such as the loss or gain of a major customer?

c) How will the difference in the ROE used in setting rates in any of 2014 through 2018 and the corresponding figure for the year in question that is calculated using the Board's most up-to-date formula be accounted for in the off-ramp provision? For example, if the ROE used in setting 2016 rates is 10% and the Board's most-up-to-date formulate has an ROE of 12%, would the off-ramp provision be triggered if EGD's normalized ROE for 2016 was less than 9%?

RESPONSE

a) Specific examples of items that might be applicable, resulting in reduced costs, could include changes in legislation or regulations resulting in favorable revenue requirement impact and which meet the proposed criteria for Z-factor treatment.

b) No. The Z-factor mechanism only applies to revenue requirement impacts due to unexpected cost increase or decreases that are outside of management control.

c) There was an error in the originally pre-filed evidence which indicated that the ROE to be used for purposes of ESM and the ROE to be used for the Off-Ramp provision were to be different. Specifically, the ROE to be used for ESM was the EB-2009-0084 formula (“the 2009 formula”) and the ROE to be used for the Off-Ramp was the “then current ROE formula”. This should have read that both the ROE for ESM and for the Off-Ramp would be based off the EB-2009-0084 formula. This has been corrected in the updated evidence at Exhibit A2, Tab 1, Schedule 1.

Witnesses: R. Fischer
M. Lister

ENERGY PROBE INTERROGATORY #5

INTERROGATORY

Ref: Exhibit A2, Tab 1, Schedule 1, pages 36-37

On page 36, paragraph 117 indicates that the ROE formula from the Board's EB-2009-0084 Cost of Capital Report would be used for earnings sharing calculations, while on page 37 at paragraph 119, EGD indicates that the off-ramp would be triggered if the weather normalized utility earnings are more than 300 basis points above or below the amount calculated annually by the application of the Board's then-current ROE formula.

Given that the Board may review the cost of capital and the formula in the 2014 to 2018 period, does this mean that there could be two different ROE formulae used - one for earnings sharing, and one for off ramps?

RESPONSE

No. In calculating the Formula ROE for earnings sharing calculations the ROE Formula for off-ramps, Enbridge will use the Board's ROE formula from the EB-2009-0084 Cost of Capital report. Evidence filed at Exhibit A2, Tab 1, Schedule 1, paragraph 120 has been corrected to reflect the same.

Witnesses: R. Fischer
M. Lister

ENERGY PROBE INTERROGATORY #6

INTERROGATORY

Ref: Exhibit A2, Tab 1, Schedule 1, page 37 & Exhibit F1, Tab 1, Schedule 2

EGD is proposing a threshold for the Z-factor of $1.5 million.

a) What is $1.5 million as a percentage of the fiscal 2014 allowed revenue, excluding gas costs?

b) Please explain why EGD believes $1.5 million is a material amount.

c) Please confirm that the allowed revenue for fiscal 2014, excluding gas costs is $1,011.7 million based on the figures shown in Exhibit F1, Tab 1, Schedule 2. If this is not confirmed, please show the calculation of the allowed revenue excluding gas costs for 2014.

RESPONSE

a) $1.5 million is 0.15% of the $1,011.7 million allowed revenue, excluding gas costs.

b) The $1.5 million threshold was agreed to as material for the 1st Generation IR plan. As Enbridge understands it, the materiality threshold for large electricity distributors was determined in the 3GIRM as $1 million and this was re-affirmed by the Board as part of the Renewed Regulatory Framework for Electricity Distributors for 4GIRM. The Company continues to believe that $1.5 million represents a material amount, particularly where this revenue shortfall could repeat for each year of the IR term, if there was no Z-Factor protection. A $1.5 million revenue threshold effectively translates to a capital expenditure approximating $15 million.

c) Confirmed.

Witnesses: K. Culbert
R. Fischer
M. Lister

ENERGY PROBE INTERROGATORY #7

INTERROGATORY

Ref: Exhibit A2, Tab 4, Schedule 1

a) Please comment on the applicability to EGD of the agreed upon Z-factor criteria in the Union Gas EB-2013-0202 evidence (Section 4.8). Please explain fully if EGD does not believe it could accept the same Z-factor agreement as did Union Gas.

b) Does EGD plan to continue to share any tax changes on a 50:50 basis as it did under the previous IRM plan and has been approved for Union Gas (see Section 4.9 in the EB-2013-0202 evidence)? If not, why not?

c) Does a loss of revenue due to the loss of a large customer qualify as cost increase? Does the gain of a large customer qualify as a cost decrease?

RESPONSE

a) Please refer to the response to CCC Interrogatory #11, found at Exhibit I.A10.EGDI.CCC.11.

b) No. There is no tax rate sharing mechanism in the Customized IR plan. Favourable tax changes, all else being equal, would be shared with ratepayers through the Earnings Sharing Mechanism proposal in years where EGD's earnings exceeded the relevant threshold. These examples would not qualify as cost increases or decreases for Z-Factor purposes.

Witnesses: K. Culbert
R. Fischer
M. Lister

ENERGY PROBE INTERROGATORY #8

INTERROGATORY

Ref: Exhibit A2, Tab 5, Schedule 1

a) Please add a column to the table on page 2 that shows the Board approved capital structure for 2013 from EB-2011-0354.

b) Has EGD filed the update for 2017 and 2018 noted in paragraph 6?

RESPONSE

a) Please see table below:

Capital Structure Component	2013 Board Approved	2014 Weight	2015 Weight	2016 Weight
Equity	36%	36%	36%	36%
Long term debt	60.17%	59.37%	61.41%	61.31%
Short term debt	1.39%	2.34%	0.49%	0.87%
Preferred shares	2.44%	2.29%	2.10%	1.82%

b) Yes EGD filed the update as noted. Please refer to the updated evidence filed in Exhibit A2, Tab 5, Schedule 1, which includes a breakdown of EGD's capital structure by component for 2017 and 2018.

Witnesses: K. Culbert
R. Fischer
M. Lister
M. Suarez

ENERGY PROBE INTERROGATORY #9

INTERROGATORY

Ref: Exhibit A2, Tab 11, Schedule 1

Please add the data for 2010 to Table 1.

RESPONSE

Please see the following table:

Table 1: SQR Targets vs. Actuals

Service Quality Requirement	Target	2010	2011	2012
Appointments Met Within the Designated Time Period	85.00%	94.70%	95.30%	93.30%
Emergency Calls Responded within One Hour	90.00%	94.20%	95.20%	96.90%
Time to Reschedule Missed Appointments	100.00%	95.20%	92.80%	93.80%
Number of Days to Reconnect a Customer	85.00%	93.90%	93.80%	94.10%
Call Answering Service Level	75.00%	65.30%	75.20%	78.40%
Number of Calls Abandon Rate	10.00%	11.60%	4.10%	2.40%
Meter Reading Performance	0.50%	0.66%	0.70%	0.46%
Number of Days to provide a Written Response	80.00%	N/A	N/A	83.14%

Witnesses: L. Cowie
T. Ferguson
K. Lakatos-Hayward
M. Torriano

ENERGY PROBE INTERROGATORY #10

INTERROGATORY

Ref: Exhibit D1, Tab 3, Schedule 1

If the bad debt expense, which is forecast at $9.5 million in each of 2014 through 2016 were to increase to $11.5 million in one of those years, would that increase of $2.0 million qualify as a Z-factor? Please explain.

RESPONSE

The hypothetical question cannot be acutely answered without understanding the nature of the hypothetical increase in costs. To the extent that the cost increase did or did not meet the cost causation, materiality, management control, and prudence tests that would qualify it for a Z-Factor, the increase in bad debt cost may or may not qualify as a Z-Factor.

Witnesses: R. Fischer
S. Kancharla
R. Lei
M. Lister
M. Torriano

SEC INTERROGATORY #44

INTERROGATORY

Issue A10: Are the following components within Enbridge's Customized IR plan appropriate?

a. Z Factor mechanism
b. Off-ramp condition
c. Earnings Sharing Mechanism
d. Treatment of Cost of Capital
e. Performance Measurement mechanisms, including Service Quality Requirements (SQRs)
f. Sustainable Efficiency Incentive Mechanism
g. Annual reporting requirements
h. Rebasing proposal
i. Treatment of pension expense and employee future benefits costs
j. Treatment of DSM costs
k. Treatment of Customer Care and CIS costs

[A2/1/2, p. 13] *"If the utility cannot find projects that generate sustainable efficiencies then ratepayers will be assured that the costs at rebasing represent the most efficient costs in providing safe, reliable distribution."* Please explain how the Applicant's failure to find incremental productivity during IRM is proof that there was no productivity to be found.

RESPONSE

Enbridge indicates in its Application that it will be challenged to meet the budget cost estimates. The Company has embedded productivity, such as operating at cost levels that assume no change to FTEs and managing future capital costs that do not include "variable" capital. Further, the Company believes it is already an efficient operator and that there are diminishing opportunities to find incremental productivity. To the extent Enbridge is unable to find additional efficiencies, even though it is clearly incented to do so, then that should provide some assurance to ratepayers that opportunities for incremental productivity have been exhausted. As Concentric points out at page 3 of their report (Exhibit A2, Tab 9, Schedule 1):

> Concentric's benchmarking analysis demonstrated that EGD is currently an efficient utility and that EGD has continued to improve its performance relative to its industry peers, especially related to O&M costs. Furthermore, Concentric's productivity analysis

Witnesses: R. Fischer
S. Kancharla
M. Lister

> demonstrated that EGD improved its productivity as measured by both TFP and PFP during the 1st Generation IR plan (2007 to 2011) compared to the pre-IR plan period (2000 to 2007) relative to performance of both the 25 company industry study group and the seven company sub-group during those same periods, which indicates that EGD made productivity improvements during the 1st Generation IR plan. This also suggests that the relatively "easy" productivity improvements that are often available at the onset of IR may not be as available to EGD in the 2nd Generation IR. While it is important that EGD continue to look for additional efficiency and productivity improvement opportunities, they may be more difficult for EGD to find.

The Company is incented through the Earnings Sharing Mechanism and revised Sustainable Efficiency Incentive Mechanism to find further efficiencies beyond the budget cost estimates which already include embedded productivity.

Witnesses: R. Fischer
S. Kancharla
M. Lister

SEC INTERROGATORY #45

INTERROGATORY

Issue A10: Are the following components within Enbridge's Customized IR plan appropriate?

a. Z Factor mechanism
b. Off-ramp condition
c. Earnings Sharing Mechanism
d. Treatment of Cost of Capital
e. Performance Measurement mechanisms, including Service Quality Requirements (SQRs)
f. Sustainable Efficiency Incentive Mechanism
g. Annual reporting requirements
h. Rebasing proposal
i. Treatment of pension expense and employee future benefits costs
j. Treatment of DSM costs
k. Treatment of Customer Care and CIS costs

[A2/4/1] Please provide examples of circumstances in which the change from "unexpected events" to "unexpected costs" would result in a change from non-recovery to recovery from ratepayers.

RESPONSE

The Company is not proposing a change from "unexpected events" to "unexpected costs".

It is proposing that one of the Z-Factor criteria be "The cost increase or decrease, or significant portion of it, must be demonstrably linked to an unexpected, non-routine cause." This is in contrast to the current criteria which, as described in Exhibit A2, Tab 4, Schedule 1, page 4, require the identification of a discrete event.

Since Z-Factors are used for unexpected events, it is challenging to envision the unexpected, however, the following illustrates the difference between an "event" and "cause" could be perceived.

Consider the unexpected catastrophic failure of a component of the distribution system. Assume there had been no previous suspicions or cause for concern regarding this component, however, as a result of the failure and an imminent risk to public safety the

Witnesses: R. Fischer
M. Lister

Company deemed it prudent to begin a replacement program for 15,000 units across the system. It cost $10,000 to replace each component.

In this case the “event” could be considered the single component failure, which would have failed the threshold test of $1.5 million impact on revenue requirement and consequently would not qualify as a Z-Factor. Alternatively though, the component failure could be seen as the “cause” of a $150 million cost, which would qualify as long as it was found to be prudently incurred.

Witnesses: R. Fischer
M. Lister

SEC INTERROGATORY #46

INTERROGATORY

Issue A10: Are the following components within Enbridge's Customized IR plan appropriate?

a. Z Factor mechanism
b. Off-ramp condition
c. Earnings Sharing Mechanism
d. Treatment of Cost of Capital
e. Performance Measurement mechanisms, including Service Quality Requirements (SQRs)
f. Sustainable Efficiency Incentive Mechanism
g. Annual reporting requirements
h. Rebasing proposal
i. Treatment of pension expense and employee future benefits costs
j. Treatment of DSM costs
k. Treatment of Customer Care and CIS costs

[A2/4/1, p. 5] Please confirm that the Applicant is proposing to narrow the "outside of management's control" criterion so that it only applies when "management could have entirely prevented the costs".

RESPONSE

The intention of modifying wording relating to management control was to make the wording more clear. As explained at paragraph 20 of Exhibit A2, Tab 4, Schedule 1, page 5 the management control criterion should focus on the cause of the costs not on whether an aspect of the costs could be controlled by management. Pacific Economics Group Research, LLC ("PEG"), at Exhibit L, Tab 1, Schedule 2, page 24, agreed with the Company that there was some merit to the Company's position.

Witnesses: R. Fischer
M. Lister

SEC INTERROGATORY #47

INTERROGATORY

Issue A10: Are the following components within Enbridge's Customized IR plan appropriate?

a. Z Factor mechanism
b. Off-ramp condition
c. Earnings Sharing Mechanism
d. Treatment of Cost of Capital
e. Performance Measurement mechanisms, including Service Quality Requirements (SQRs)
f. Sustainable Efficiency Incentive Mechanism
g. Annual reporting requirements
h. Rebasing proposal
i. Treatment of pension expense and employee future benefits costs
j. Treatment of DSM costs
k. Treatment of Customer Care and CIS costs

[A2/4/1, p. 8] Please confirm that, under the Applicant's Z-factor proposal, only costs that had already been incurred at the time of the application would be eligible, and that the test of prudence proposed by the Applicant would require a presumption of prudence by the Board, and the prohibition against the use of hindsight in determining prudence.

RESPONSE

The Company does not agree that the Z-factor proposal only applies to costs that have already been incurred at the time of the application. However, for costs which have been incurred, the Company agrees that there is a presumption of prudence and the Board must consider the circumstances at the time of the cost incurrence.

Witnesses: R. Fischer
M. Lister

SEC INTERROGATORY #48

INTERROGATORY

Issue A10: Are the following components within Enbridge's Customized IR plan appropriate?

a. Z Factor mechanism
b. Off-ramp condition
c. Earnings Sharing Mechanism
d. Treatment of Cost of Capital
e. Performance Measurement mechanisms, including Service Quality Requirements (SQRs)
f. Sustainable Efficiency Incentive Mechanism
g. Annual reporting requirements
h. Rebasing proposal
i. Treatment of pension expense and employee future benefits costs
j. Treatment of DSM costs
k. Treatment of Customer Care and CIS costs

[A2/4/1, p. 8/9] Please confirm that, under the Applicant's Z-factor proposal, the Applicant can apply for Z-factor treatment notwithstanding that it spent less than its Allowed Revenue for the year, and notwithstanding that it earned an amount in excess of its allowed ROE in that year.

RESPONSE

Confirmed.

Witnesses: R. Fischer
M. Lister

SEC INTERROGATORY #49

INTERROGATORY

Issue A10: Are the following components within Enbridge's Customized IR plan appropriate?

a. Z Factor mechanism
b. Off-ramp condition
c. Earnings Sharing Mechanism
d. Treatment of Cost of Capital
e. Performance Measurement mechanisms, including Service Quality Requirements (SQRs)
f. Sustainable Efficiency Incentive Mechanism
g. Annual reporting requirements
h. Rebasing proposal
i. Treatment of pension expense and employee future benefits costs
j. Treatment of DSM costs
k. Treatment of Customer Care and CIS costs

[A2/7/1, p. 1] Please confirm that, under the Applicant's ESM proposal, the ROE used would be different from the ROE built into rates, i.e. the ESM would be based on the ROE calculated each year using the Board's formula, but the ROE in rates would be based on the Applicant's ROE forecasts in the Application.

RESPONSE

Confirmed.

Witnesses: R. Fischer
M. Lister

SEC INTERROGATORY #50

INTERROGATORY

Issue A10: Are the following components within Enbridge's Customized IR plan appropriate?

a. Z Factor mechanism
b. Off-ramp condition
c. Earnings Sharing Mechanism
d. Treatment of Cost of Capital
e. Performance Measurement mechanisms, including Service Quality Requirements (SQRs)
f. Sustainable Efficiency Incentive Mechanism
g. Annual reporting requirements
h. Rebasing proposal
i. Treatment of pension expense and employee future benefits costs
j. Treatment of DSM costs
k. Treatment of Customer Care and CIS costs

[A2/11/2, p. 1] *"Over the past decade the Company has benchmarked its performance with peer utilities across various aspects of the business."* Please provide those benchmarking studies or reports. If the content in response to this interrogatory is greater than 100 pages, please provide a list with sufficient description of each to allow parties to understand which such studies or reports are likely to be relevant and material in the context of this Application.

RESPONSE

Table 1 on the following pages provides a listing of benchmarking studies or reports that the Company participated in over the past decade. The content in response to this interrogatory would be significantly more than 100 pages.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

Table 1
Description of the Benchmarking Studies or Reports that the Company has participated over the Past Decade

Metrics	Description of Benchmarking Studies or Reports
Customer Satisfaction Index	1. 2004 Corporate Reputation and Image Study. The Company conducted a survey by comparing the Company's reputation and image with Natural Gas Resellers/Brokers, Electricity, Cable TV and Local Telephone companies. 2. 2005 Corporate Reputation and Image Study. Please refer to #1 above for the description. 3. 2004-2007 Customer Satisfaction Research. The purpose of the study is to monitor customers' impressions, expectations, perceptions and performance assessments of their experience with the Company based on various interaction points. The Company's results are then compared with Electricity, Cable/Satellite and Local Telephone companies. 4. 2007 Corporate Reputation Customer Research. The Company conducted a survey by comparing the Company with Natural Gas Resellers/Brokers, Electricity, Cable/Satellite TV and Local Telephone companies. 5. 2008-2011 Customer Satisfaction Research. Please refer to #3 above for the description. 6. 2009-2011 Corporate Reputation Customer Research. Please refer to #4 above for the description. 7. 2006-2008. Canadian Electricity and Gas Distributors Benchmarking Study conducted by Ipsos Reid. The purpose of the study was to compare the Company's residential energy customer satisfaction and reputation perception among Canadian electric and natural gas distributors. 8. 2012-2013 Gas Utility Residential Customer Satisfaction Study and Gas Utility Business Customer Satisfaction Study. J.D. Power and Associates conducted the satisfaction study by ranking the Company against 75 natural gas utilities. Research is conducted online over 4 quarterly fielding periods for complete annual and seasonal perspectives. 9. 2013 Utility Website Evaluation Study. J.D. Power and Associates conducted the study by evaluating the Company's website with large US natural gas and electric utilities.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

Metrics	Description of Benchmarking Studies or Reports
	10. 2013 Esource Web and Interactive Voice Response ("IVR", or Automated Telephone System) Study. Esource conducted this study by evaluating the Company's website and IVR performance against American and Canadian electric and natural gas utilities. 11. 2012 Customer Satisfaction Research and Corporate Reputation Customer Research. The Company conducted a survey by comparing the Company's customer satisfaction and reputation performances with Natural Gas Resellers/Brokers, Electricity, Landline or Home Phone, Cell Phone, Cable/Satellite TV and Bank/Financial institutions. 12. 2013 Corporate Reputation Customer Research. The Company is currently conducting a survey by comparing the Company's reputation with Natural Gas Resellers/Brokers, Electricity, Landline or Home Phone, Cell or Smart Phone, Cable/Satellite TV and Bank/Financial institutions.
Employees Health and Safety	1. The Company has participated in the American Gas Association ("AGA") annual Safety and Occupational Health summary since the organization's inception in 1993. This summary covers both worker and vehicle safety data such as number of injury and vehicle accidents. The report provides comparative statistics of all participating AGA companies, grouped by company size in addition to detailed injury and accident analysis. The output of this annual report determines the AGA Safety Award recipients. 2. The Company has participated in the Canadian Gas Association ("CGA") Quarterly Health and Safety Statistic Report Form submission since 1996 by providing worker and vehicle safety data such as number of injury and vehicle accidents. The report provides comparative statistics of all participating CGA companies. The output of this annual report determines the CGA Safety Award recipients.
Damage Prevention, Leak Management, Outages	1. 2007-2012 Annual Damage Information Reporting Tool ("DIRT") Reports. The DIRT Report provides a data comparison between Ontario utilities and other American utilities and root cause analysis of damages, number of damages, and ratio of damages per 1,000 locate requests. Reports are available to the public from the Ontario Regional Common Ground Alliance ("ORCGA") web site.[1] Since 2007, the Company has participated along with other members (which include gas, electric and municipal utilities) in submitting data to ORCGA for the creation

[1] http://www.orcga.com/StaticTeaserTemplate.asp?itemCode=PUBLICATIONS-AND-RESOURCES&CssPath=css/TeaserTemplateSample/PublicationsResources.css&CssDivID=PublicationsResources&TeaserLength=100&Path=/StaticTemplate.asp&title=Publications

Witnesses: I. Chan
S. Kancharla
I. MacPherson

Metrics	Description of Benchmarking Studies or Reports
	of the annual DIRT report. The Company was a founding member of the ORCGA back in 2003. ORCGA is a nonprofit organization dedicated to shared responsibility in damage prevention and in the promotion of damage prevention Best Practices. In 2013, the Company was presented with an award for 10 years of support as a Gold Level sponsor. In June 2012, the Ontario Legislature passed Bill 8, the Ontario Underground Infrastructure Notification System Act, a new law to establish a mandatory "Call Before You Dig" regime in Ontario. ORCGA and the Company were active in support of the legislation's passage. Figure 1 of Exhibit D1, Tab 17, Schedule 1, Page 8, illustrates that the Company has been successful in reducing total number of damages. There has been a 47% reduction in number of damages between 2003 and 2012. 2. The Company has participated in the AGA Gas Utility Operations Best Practices Program since the organization's inception in 1993. Examples of this program are Damage Prevention, Leak Management, Employee Safety, etc. This program provides a forum for the identification of procedures and practices that can improve the reliability, safety and cost-efficiency of a company's operations. Program participants have the opportunity to learn of practices effectively implemented, and new innovative practices that are being utilized, by industry leaders in different aspects of natural gas operations. The AGA Operations Best Practices Program is intended to highlight how particular companies may address a specific operational issue and may not include all of the data related to a highlighted practice. The need to implement and the timing of any implementation of highlighted practices will vary with each utility operator. Each utility operator serves a unique and defined geographic area and their system infrastructures vary widely based on a multitude of factors, including, condition, engineering practices and materials. Each utility operator needs to evaluate highlighted practices in light of their system variables. Not all highlighted practices will be applicable to all utility operators due to the unique set of circumstances that are attendant to their specific systems. Companies are not ranked through this program and no one practice is identified as the best for a particular topic. 3. The Company has participated in the Gas & Electric Utility Peer Panel program since 2007. It is an independent program, fully operated and funded by Public Service Electric and Gas Company ("PSE&G"). This program includes the same topics annually, and produces report, Gas Delivery, Benchmarking Study, that enable the participants to trend their results against both the participants and themselves year over year.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

Metrics	Description of Benchmarking Studies or Reports
Operating and Maintenance Cost ("O&M")per Customer	1. Cost Per Customer. RP-2002-0133, Exhibit A6, Tab 1, Schedule 2. The Company provided a comparison of the Company's O&M cost per customer with a benchmark (average) of gas and gas/electric utilities in the United States for fiscal year ended September 30 over the 1992 to 2000 time period. 2. Benchmarking Study. EB-2011-0354, Exhibit A2, Tab 1, Schedule 2. Concentric benchmarked the Company's O&M per customer against the U.S. and Canadian peer group in 2009 and 2010 and the U.S. peer group over the 2000 to 2010 time period. 3. Incentive Ratemaking Report. Exhibit A2, Tab 9. Schedule 1. Concentric benchmarked the Company's O&M cost per customer in the industry study group for 2011 and against the industry study group average over the 2000 to 2011 time period.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

SEC INTERROGATORY #51

INTERROGATORY

Issue A10: Are the following components within Enbridge's Customized IR plan appropriate?

a. Z Factor mechanism
b. Off-ramp condition
c. Earnings Sharing Mechanism
d. Treatment of Cost of Capital
e. Performance Measurement mechanisms, including Service Quality Requirements (SQRs)
f. Sustainable Efficiency Incentive Mechanism
g. Annual reporting requirements
h. Rebasing proposal
i. Treatment of pension expense and employee future benefits costs
j. Treatment of DSM costs
k. Treatment of Customer Care and CIS costs

[A2/11/2, p. 2] Please explain why the Applicant proposes to file performance benchmarking data only at the end of the IR term, rather than annually.

RESPONSE

As stated at Exhibit A2, Tab 11, Schedule 2, page 5, paragraph 14, the purpose of benchmarking is to compare the metrics relative to comparable peer companies in terms of direction and trending. Results from the benchmarking comparison may be used as inputs to further inform improvements or adopt specific best practices from gas utilities that have similar operations to the Company's, as appropriate.

Given that the availability of benchmarking data may be made available with a one-year lag and/or at an unspecified date, filing the performance benchmarking data annually as part of the annual Earnings Sharing Mechanism application will not be feasible. Moreover, as the purpose of the benchmarking is to assess the direction and trending of metrics, it will require at least three years of actual benchmarking results in order to enable the Company to conduct meaningful year over year analytics in the direction and trending of the relevant metrics.

In view of these practical considerations, the most useful benchmarking comparisons will be available at the end of the IR term.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

SEC INTERROGATORY #52

INTERROGATORY

Issue A10: Are the following components within Enbridge's Customized IR plan appropriate?

a. Z Factor mechanism
b. Off-ramp condition
c. Earnings Sharing Mechanism
d. Treatment of Cost of Capital
e. Performance Measurement mechanisms, including Service Quality Requirements (SQRs)
f. Sustainable Efficiency Incentive Mechanism
g. Annual reporting requirements
h. Rebasing proposal
i. Treatment of pension expense and employee future benefits costs
j. Treatment of DSM costs
k. Treatment of Customer Care and CIS costs

[A2/11/2, p. 9] Please explain why Operating and Maintenance Cost per Customer is to be reported and benchmarked, but there is no equivalent reporting or benchmarking of capital expenditures.

RESPONSE

The reasons for reporting the Operating and Maintenance Cost ("O&M") per Customer metric and not the Capital Expenditures ("CAPEX") per Customer measure is because O&M per Customer is a reasonable and generally accepted basis to compare performance among different utilities, subject to recognition of factors that account for explainable differences in O&M cost per customer.

It is more challenging to benchmark capital expenditures than O&M as capital expense benchmarking cannot meaningfully account for difference in capital plans between utilities related to system expansion, system reinforcement, and system replacement. Also, this utility specific information on capital expenditures is usually not easily or readily available from public documents. Conversely, utility O&M expenses are typically readily available, comprised of elements such as employee (e.g., salaries, benefits, pension, etc.) and customer care related expenses for which the underlying measurement definition is relatively standard and largely consistent across utilities.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

As stated in Exhibit A2, Tab 11, Schedule 2, page 6, the corresponding implementation costs[1] would not outweigh the value for the metrics to be reported and benchmarked.

[1] Examples of the implementation costs are hiring additional employees, developing new systems or applications, efforts and expenses in collecting and compiling data, membership or subscriptions fees, etc.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

SEC INTERROGATORY #53

INTERROGATORY

Issue A10: Are the following components within Enbridge's Customized IR plan appropriate?

a. Z Factor mechanism
b. Off-ramp condition
c. Earnings Sharing Mechanism
d. Treatment of Cost of Capital
e. Performance Measurement mechanisms, including Service Quality Requirements (SQRs)
f. Sustainable Efficiency Incentive Mechanism
g. Annual reporting requirements
h. Rebasing proposal
i. Treatment of pension expense and employee future benefits costs
j. Treatment of DSM costs
k. Treatment of Customer Care and CIS costs

[A2/11/2, App. 3] Please provide a comparison of the proposed benchmarking metrics with the Applicant's corporate scorecards for senior executives. Please provide a rationale for any material differences between the two.

RESPONSE

The proposed Benchmarking Report as stated at Exhibit A2, Tab 2, Schedule 11, and the Corporate Scorecard for all employees as described in the Employee Expenses and Workforce Demographics evidence at Exhibit D1, Tab 3, Schedule 2, have different purpose, focus, and usage. Therefore, it is important to understand the differences from a conceptual framework perspective first. These conceptual differences are summarized in Table 1 on the next page.

In sum, the purpose of the Benchmarking report is to compare the benchmarking metrics proposed in Exhibit A2, Tab 2, Schedule 11, Appendix 3, against comparable peer regulated utilities in terms of direction and trending. It is an ongoing activity and it is not a one year or annual event. Results from the benchmarking comparison may be used as inputs to further inform improvements or adopt specific best practices from gas utilities that have similar operations to EGD's, as appropriate. The metrics reported here are outcome based metrics or lagging performance indicators to reflect the utility outcomes of the Company's strategic objectives. The metrics also have to be currently supported or published by reputable external benchmarking publications.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

The Company's Corporate Scorecard is used as a measurement of organizational performance including utility and non-utility operations for the year. The purpose of the scorecard is to align business and employee objectives. It is a conceptual framework for translating an organization's objectives into a set of leading and lagging performance indicators.

Table 1
Summary of the Conceptual Framework differences between the Benchmarking Report and the Corporate Scorecard

	Benchmarking Report	Corporate Scorecard
Purpose or Goal	▪ Best practices benchmarking ▪ Trend and direction comparison	▪ Performance measurement and management
Focus	▪ EGD regulated operations only ▪ Exclude Non-Utility and Subsidiaries	▪ Enbridge East operation ▪ Include Non-Utility and Subsidiaries: New Brunswick, St. Lawrence and Gazifere.
Rationale of the Metrics	▪ Common or standard metrics that are published by external benchmarking publications ▪ Reflect the outcomes of the strategic objectives, i.e. lagging performance indicators.	▪ Reflect the progress towards to achieving the strategic objectives, i.e. leading performance indicators ▪ Reflect the outcomes of the strategic objectives, i.e. lagging performance indicators
Evaluation Timeframe	▪ Minimum 3+ years horizon ▪ Continuous trend and direction monitoring	▪ Annual horizon

Tables 2 to 4 provide a comparison with explanation of the proposed benchmarking metrics with the Company's Corporate Scorecard metrics among three categories: customer relationship, operational performance and financial performance. As can be seen, there are substantial similarities between the Benchmarking Metrics and the Corporate Scorecard.

Table 2 on the following page presents the customer relationship category comparison. The Service Quality Requirements ("SQR") metrics are not reported on the Corporate Scorecard as these metrics have been established by the Board to track the gas utility's service quality performance and are therefore already embedded into the mandatory

Witnesses: I. Chan
S. Kancharla
I. MacPherson

performance objectives. It is beneficial for the Company to benchmark these SQR metrics against the other Ontario gas utilities from a trend or direction comparison perspective understanding each utility operator serves a unique geographic area, unique customer mix, and unique operational circumstances.

Table 2
Customer Relationship Category

Benchmarking Metrics	Corporate Scorecard Metrics
• Customer Experience: Customer Satisfaction Index	• Customer Experience: Customer Satisfaction Index
• Call Answering Service Level (SQR)	
• Percentage of Emergency Calls Responded to within One Hour (SQR)	
• Meter Reading Performance Measurement (SQR)	
• Appointments Met within the Designated Time Period (SQR)	
• Time to Reschedule a Missed Appointments (SQR)	
• Number of Days to Reconnect a Customer (SQR)	
• Number of Days to provide a Written Response (SQR)	
• Number of Calls Abandon Rate (SQR)	

Table 3 on the next page illustrates the operational performance category comparison. As detailed in the Pipeline Integrity and Engineering evidence at Exhibit D1, Tab 17, Schedule 1, Page 1, recent industry events or regulatory expectations, such as the natural gas explosion in San Bruno, California (2010), and the Technical Standards and Safety Authority Code Adoption Document FS-196-12, which came into effect November 2012, have caused the Company to reexamine and enhance its work practices to further prevent incidents, and improve environmental, worker and public safety. This has led to the Company's increasing focus to further reduce operational risks, with a goal of further reducing incidents and injuries. Therefore, the metrics reported on the Corporate Scorecard are mainly leading performance indicators. They are used to measure the organization's progress towards achieving the Pipeline Integrity and Engineering business objectives stated in the evidence.

Table 4 on the next page presents the financial performance category. As the Company's Corporate Scorecard is used as a measurement of organizational performance including utility and non-utility operations for the year, net earnings is the usual metric for measuring financial performance. Operating and maintenance ("O&M")

Witnesses: I. Chan
S. Kancharla
I. MacPherson

cost per customer, return on equity and interest coverage ratios are included in the proposed Benchmarking Reporting in order to provide a balanced view of the Company's financial performance when benchmarking its performance against other utilities'.

Table 3
Operational Performance Category

Benchmarking Metrics	Corporate Scorecard Metrics
• Damage Prevention: Number of Excavation Damages per 1,000 Locates	• Damage Prevention: Number of Excavation Damages per 1,000 Locates
• Leak Management: Service Leaks Repaired per Mile of Service	• % of Leaks found through Leak Survey
• Leak Management: Total Number of Grade 1 (A) leaks eliminated or repaired during the year	• Leak year-end average exit rate (days)
• Employees Health and Safety: Total Reportable Injury Frequency Rate	• Employees Health and Safety: Total Reportable Injury Frequency Rate
• Operational Effectiveness: All outages per 1,000 Customers	• Motor Vehicle Incident Frequency Rate
	• Safety Observations
	• Environment, Health and Safety Required Courses Training Attendance
	• Verify Maximum Allowable Operating Pressure on Targeted Lines – Delivery to Plan
	• % of High Stress and Targeted Pipelines Inspections Completed
	• Significant Incident / Asset Rupture

Table 4
Financial Performance Category

Benchmarking Metrics	Corporate Scorecard Metrics
• Financial Efficiency: Operating and maintenance cost per customer	• Net Earnings - Utility and Non-Utility
• Return on Equity	
• Financial Obligations Met: Interest Coverage Ratios (Legal Entity)	

Witnesses: I. Chan
S. Kancharla
I. MacPherson

SEC INTERROGATORY #54

INTERROGATORY

Issue A10: Are the following components within Enbridge's Customized IR plan appropriate?

a. Z Factor mechanism
b. Off-ramp condition
c. Earnings Sharing Mechanism
d. Treatment of Cost of Capital
e. Performance Measurement mechanisms, including Service Quality Requirements (SQRs)
f. Sustainable Efficiency Incentive Mechanism
g. Annual reporting requirements
h. Rebasing proposal
i. Treatment of pension expense and employee future benefits costs
j. Treatment of DSM costs
k. Treatment of Customer Care and CIS costs

[A2/11/3] Please confirm that the Applicant's proposed SEIM would give the Applicant incentives based on forecast efficiency improvements in future years, and the Applicant would keep the incentives regardless of whether the efficiency improvements actually materialized. Please confirm that the future efficiency improvements used in the calculation would include those during the IRM term, or any future IRM term, in which the benefits would be enjoyed by the shareholder rather than the ratepayer.

RESPONSE

As a result of various criticisms of the proposed Sustainable Efficiency Incentive Mechanism ("SEIM") received since the filing of the Application, Enbridge is proposing to reconstitute the SEIM to operate in a similar manner as the Efficiency Carryover Mechanism approved by the Alberta Utilities Commission in 2012. Please see the updated evidence filed at Exhibit A2, Tab 11, Schedule 3 for more details on the Company's proposal to restructure the SEIM.

Witnesses: R. Fischer
S. Kancharla
M. Lister
I. MacPherson

BOARD STAFF INTERROGATORY #40

INTERROGATORY

ISSUE A11: Is the proposal to continue Enbridge's current deferral and variance accounts through the IR term appropriate?

Evidence Ref:
• D1/T8/S1/page 22 and 23
• EB-2011-0354 Exhibit N1/ Tab 1 Schedule 1 Pages 19 and 20

As per Exhibit D1/Tab 8/Sch1/page 22 and 23, EGD is requesting continuance of the 2013 Post-Retirement True-Up Variance Account from 2014 to 2018 ("2014-2018 PTUVA").

As per the 2013 EGD cost of service proceeding settlement agreement, ExhN1/Tab1/Sch1/page 19 & 20, states:

> " …All parties agree to the creation of a Post-Retirement True-Up Variance Account (PTUVA) which will record any differences between the Company's forecast pension and OPEBs expense and the actual pension and OPEBs expense (both determined on an accrual basis). In future years, and in the absence of any new Board decision or policy on the Pensions Issue that is made to apply to Enbridge during the term of its upcoming IR plan, the PTUVA will include any uncleared balances from previous years, as well as the difference between the amount otherwise included in that year's rates, and actual pension and OPEBs expenses for that year (again, on an accrual basis)….
>
> …There is no agreement as to the clearance methodology that will be applied to the PTUVA in future years beyond 2013. No party will raise any procedural objection if Enbridge or any other party seeks approval of a different clearance methodology for the PTUVA as part of Enbridge's 2014 rates proceeding (which is anticipated to be an application for approval of an IR methodology, which is not the type of case where such issues would ordinarily be raised). All parties are free to take whatever positions they determine with respect to the PTUVA clearance methodology at that time.

Witness: K. Culbert

The parties agree that this approach will continue until the earlier of a) a decision by the Board to implement a policy respecting the Pensions Issue that is applicable to Enbridge during the term of its upcoming IR plan, and b) the next rebasing application for Enbridge."

a) Please confirm that EGD is proposing the PTUVA as the methodology for 2014 through 2018 rates.

b) Please explain why EGD is not requesting the PTUVA on an annual basis, rather it is requesting the PTUVA for the next 5 years – 2014 through 2018. In other words, why is EGD not requesting the PTUVA solely for 2014 rates?

RESPONSE

a) Confirmed.

b) EGD believes it is important and only fair to stakeholders and the Board that the Company indicate up front in this 2014 process which deferral and variance accounts have either been previously approved by the Board for the IR term or that EGD believes are appropriate and required for part of or the duration of the IR term.

Witness: K. Culbert

CCC INTERROGATORY #17

INTERROGATORY

Issue A11 – Is the proposal to continue Enbridge's current deferral and variance accounts through the IR term appropriate?

(Ex. A2/T1/s1/p. 6) EGD's proposal is to maintain all existing deferral and variance accounts. Did EGD consider eliminating some of those accounts? If not, why not? If so, what accounts did EGD consider eliminating and on what basis was elimination rejected?

RESPONSE

Enbridge reviewed the rationale and appropriateness of each deferral and variance account included within the development of its proposed Customized IR plan. It was determined that all of the deferral accounts in existence within the 2013 approved list of accounts are appropriately continued within the IR term. For any account where a re-scoping is proposed or which is newly proposed, it was determined that it is fair and appropriate to propose such accounts within the first year, 2014, of the IR term regardless of the potential expected timing of the requirement of the account.

Witnesses: R. Fischer
M. Lister

SEC INTERROGATORY #55

INTERROGATORY

Issue A11: Is the proposal to continue Enbridge's current deferral and variance accounts through the IR term appropriate?

[D1/8/1, p. 12] Please advise whether the Applicant intends to dispose of the CCSPDA in 2017, or in an unspecified "future rate hearing".

RESPONSE

As indicated in the response to SEC Interrogatory #62, found at Exhibit I.A12.EGDI.SEC.62, it is the Company's proposal that appropriate costs will be recorded in the account over the course of the services procurement process and be brought forward for clearance after the implementation of the post 2017 customer care service arrangements.

Witness: K. Culbert

SEC INTERROGATORY #56

INTERROGATORY

Issue A11: Is the proposal to continue Enbridge's current deferral and variance accounts through the IR term appropriate?

[D1/8/1, p. 17] Please describe the types of "revenue changes" that the Applicant is now proposing to include in the GDARIDA, and any restrictions on that category. What rules or guidance is the Applicant proposing to determine if a revenue change is the result of GDAR?

RESPONSE

The proposed revenue changes to be included within the GDARIDA would include any impacts to the manner in which late payment penalty revenue was allowed to be recovered within the base year, 2013, which was subsequently changed within 2014 to 2018 as a result of any further amendments to GDAR. EGD would bring forward an analysis outlining the impacts to late payment penalty revenue of any such further amendments.

Witness: K. Culbert

SEC INTERROGATORY #57

INTERROGATORY

Issue A11: Is the proposal to continue Enbridge's current deferral and variance accounts through the IR term appropriate?

[D1/8/1, p. 18] Please provide a detailed justification for the protection given to the Applicant in the OHCVA.

RESPONSE

The rationale for the existence of the Ontario Hearing Cost Variance Account ("OHCVA") is unchanged from the rationale for its existence since its acceptance by EGD and its stakeholders, and approval by the Board, for approximately the past 15 to 20 rate proceedings. The different types and level of costs incurred by the Company within its directly related regulatory proceedings and various potential Board initiated generic or policy related proceedings are not completely within its control. Each of the stakeholders and the Board, and the variety of views and requests of these parties, has an impact on the level of regulatory proceeding related costs which are incurred each year within EGD. As such, it is impossible for EGD to be able to forecast annual regulatory proceeding related costs with any significant degree of accuracy. Therefore, the Company does not believe that the ratepayers or the Company should benefit at the expense of the other as a result of circumstances which cause the incurrence of these costs at a level which is higher or lower than the amount embedded in Allowed Revenue.

Therefore, Enbridge views the protection provided by the OHCVA as applying equally to ratepayers and the Company. During the 1st Generation IR term, the OHCVA provided a credit to ratepayers in some years, and a credit to Enbridge in other years.

Witness: K. Culbert

BOARD STAFF INTERROGATORY #41

INTERROGATORY

ISSUE A12a: Is the proposal for the creation of the following new deferral and variance accounts appropriate?

a. Greater Toronto Area Project Variance Account ("GTAPVA")

Evidence Ref: D1/T8/S2/ para 4 / GTA Variance Account

Please discuss why the account is needed now given that the true-up of actual project costs to rate base is scheduled to occur in 2016.

RESPONSE

Please see EGD's updated Customized IR plan and Rate Adjustment Process evidence at Exhibit A2, Tab1, Schedule 1 and A2, Tab 3, Schedule 1 indicating the Company is no longer proposing a capital forecast refresh for 2017 and 2018 and true up of GTA project costs to occur in 2016.

EGD also updated its GTAPVA evidence at Exhibit D1, Tab 8, Schedule 2 to take account of the proposed change to the Customized IR plan. This means that the GTAPVA is now being requested for the years 2015 to 2018. The account is proposed for the purposes of recording the revenue requirement difference between GTA forecast costs included within each year's Allowed Revenue and the eventual actual GTA costs incurred in order to ensure the actual costs of the project are what are recovered from ratepayers.

Witness: K. Culbert

BOARD STAFF INTERROGATORY #42

INTERROGATORY

ISSUE A12c: Is the proposal for the creation of the following new deferral and variance accounts appropriate?

c. Customer Care Services Procurement Deferral Account ("CCSPDA")

Evidence Ref: D1/T8/S4/ para 3 /

Enbridge is requesting a new CCSPDA. Would tendering costs be typically considered a normal part of doing business and recovered under O&M expenses? Does Enbridge tender on a regular basis for any aspects of its business without deferral account treatment?

RESPONSE

As indicated in the response to SEC Interrogatory #62, found at Exhibit I.A12.EGDI.SEC.62, EGD's outsourced service arrangements for its customer care business function have been considered and approved by the Board within each of the EB-2006-0034 and EB-2011-0226 past EGD Customer Care/Customer Information System proceedings. Board-approved settlements in each of these proceedings recognized that it is reasonable for EGD to recover its costs related to the procurement of outsourced customer care services. EGD's customer care costs have been treated as a separate pass-through item, outside of the "Other O&M" envelope, since 2008.

Witness: K. Culbert

BOARD STAFF INTERROGATORY #43

INTERROGATORY

ISSUE A12a: Is the proposal for the creation of the following new deferral and variance accounts appropriate?

a. Greater Toronto Area Project Variance Account ("GTAPVA")

Evidence Ref: C1/T5/S1/

Please indicate if a comprehensive evidence update will be filed concerning the impact of GTA Project on the customized IR plan.

RESPONSE

The Company proposes to update its evidence concerning the GTA project once the Board has issued a Decision in the EB-2012-0451 Leave-to-Construct proceeding. EGD anticipates a Board Decision in EB-2012-0451 by the end of 2013.

Witnesses: K. Culbert
C. Fernandes
A. Kacicnik

BOARD STAFF INTERROGATORY #44

INTERROGATORY

ISSUE A12: Is the proposal for the creation of the following new deferral and variance accounts appropriate?

b. Constant Dollar Net Salvage Adjustment Deferral Account (“CDNSADA”)

Evidence Ref: D1/T8/S3/Pages1-2

Does Enbridge propose recording costs that are not its actual costs in its general ledger for its corporate general purpose financial statements?

RESPONSE

The Company does not understand the question on its own nor within the context of the evidence quoted.

The amount that is being proposed to be treated within the CDNSADA, is the result of findings within the Gannett Fleming Net Salvage Study which recommended a change to the Constant Dollar Method and a re-estimated required future removal costs reserve.

All of the costs considered within the use of the Constant Dollar Method and treatment of the CDNSADA are either former estimates of current and future costs or updated estimates of current and future costs.

Witnesses: K. Culbert
S. Kancharla
B. Yuzwa

BOARD STAFF INTERROGATORY #45

INTERROGATORY

ISSUE: A12: Is the proposal for the creation of the following new deferral and variance accounts appropriate?

b. Constant Dollar Net Salvage Adjustment Deferral Account (“CDNSADA”)

Evidence Ref: D1/T8/S3/Pages1-2

What economic and physical factors caused the depreciation rates calculated by Gannett Fleming to over-recover depreciation from customers since 2001 up to 2010 and beyond?

RESPONSE

As indicated in Schedules 2A through 2E of the Gannett Fleming Net Salvage Study filed as Exhibit D2, Tab 1, Schedule 1 of this proceeding, the total accumulated depreciation variance (difference between a calculated theoretical accumulated depreciation balance and the actual accumulated depreciation balance) caused by conversion to the CDNS method was $292.8 million, as of December 31, 2010 (Column 5). It is further noted in these same schedules that the total accumulated depreciation variance as of December 31, 2010 was $261.6 million (Column 4). As such, prior to the use of the CDNS method, the accumulated depreciation variance as of December 31, 2010 was a small accumulated depreciation deficiency of approximately $31 million (or 1.34% of the theoretical amount). Generally, accumulated depreciation variances of less than +/- 5% are considered immaterial. Given the immaterial nature of the accumulated depreciation variance (after consideration of the CDNS impact) Gannett Fleming did not attempt to precisely identify the remaining variance. However, Gannett Fleming does note that it would have accumulated over the period since 2001 due to retirement of assets occurring earlier than anticipated in the average service life estimate and costs of retirement being higher than anticipated in the net salvage percentage.

Witnesses: B. Yuzwa
L. Kennedy - Gannett Fleming

BOARD STAFF INTERROGATORY #46

INTERROGATORY

ISSUE: A12: Is the proposal for the creation of the following new deferral and variance accounts appropriate?

b. Constant Dollar Net Salvage Adjustment Deferral Account ("CDNSADA")

Evidence Ref: D1/T8/S3/Pages1-2

If Enbridge's proposal to increase rate base by refunding to ratepayers excess accumulated depreciation already recovered from ratepayers is denied, will Enbridge still require the CDNSADA?

RESPONSE

The required increase to rate base only occurs as a result of the proposed use of the Constant Dollar Net Salvage Method approach as recommended within the Gannett Fleming Net Salvage Study filed at Exhibit D2, Tab 1, Schedule 1.

If the Board does not approve the use of the use of Constant Dollar method then it would not be approving of the approach which would credit ratepayers the $259.8 million through the proposed CDNSADA so the deferral account would not be required.

Witnesses: K. Culbert
S. Kancharla
B. Yuzwa

BOMA INTERROGATORY #4

INTERROGATORY

Ref: Proposed GTAPVA Variance Account

a) Is Enbridge seeking a guaranteed recovery of GTA costs in rates through such an account? Please explain fully.

b) Can Enbridge provide a ten year cash flow forecast:

   a. for the IRM period which would illustrate, assuming that the GTA project is approved in its entirety, and is built within five percent of its updated budget (over or under) (see updated evidence in EB-2012-0451);

   b. the degree to which the project is financially viable for Enbridge (i.e. does not result in the breach of any existing financial covenants), which assures the following conditions hold:

      - the company currently approved debt to equity ratio, at current interest rates, remain in effect for the next twelve to twenty-four months;

      - that revenue/prices are escalated at the five year rate, agreed to by Union in EB-2012-0451;

      - that revenues are escalated each year for five years, according to EGD IRM proposal in the case;

      - dividends to Enbridge Inc. remain at 2013 levels and preferred share dividends remain at 2013 levels;

      - if any covenants are breached, please explain which ones, and by how much.

   c. provide the same analysis, assuming the OEB were to approve the distribution portion of the GTA, but not the transmission portion;

   d. on the assumption that the OEB would approve only the North-South part of Segment B of the GTA;

   e. on the assumption that the OEB approves no part of the GTA project.

Witnesses: K. Culbert
C. Fernandes
S. Murray

Please provide the analysis in readable, tabular form.

RESPONSE

a) The Company updated its GTAPVA evidence at Exhibit D1, Tab 8, Schedule 2 to take account of the proposed change to the Customized IR plan, under which Allowed Revenue will be set for five years. This means that the GTAPVA is now being requested for the years 2015 to 2018. The account is proposed for the purposes of recording the revenue requirement difference between GTA forecast costs included within each year's Allowed Revenue and the eventual actual GTA costs incurred in order to ensure the actual costs of the project are what are effectively recovered from ratepayers. Subject to appropriate prudence reviews, EGDI expects to recover the costs of the GTA project in rates over time.

b) through e):
Please refer to the response to Board Staff Interrogatory #43 found at Exhibit I.A12.EGDI.STAFF.43. The Company proposes to update its evidence concerning the final approved budgeted amounts for the GTA project once the Board has issued a Decision within the EB-2012-0451 Leave-to-Construct proceeding. EGDI anticipates a Board Decision within Fiscal 2013.

The Company does not wish to speculate on different scenarios or outcomes given that the LTC decision is pending, and the requests involve a substantial effort.

Witnesses: K. Culbert
C. Fernandes
S. Murray

SEC INTERROGATORY #58

INTERROGATORY

Issue A12: Is the proposal for the creation of the following new deferral and variance accounts appropriate?
a. Greater Toronto Area Project Variance Account ("GTAPVA")
b. Constant Dollar Net Salvage Adjustment Deferral Account ("CDNSADA")
c. Customer Care Services Procurement Deferral Account ("CCSPDA")
d. Greenhouse Gas Emission Impact Deferral account ("GGEIDA")

[D1/8/1, p. 25] Please confirm that, currently, the excess amount of depreciation that has been claimed for salvage, $292.8 million, reduces the Applicant's cost of capital each year by an amount equal to $292.8 million times the weighted average cost of capital. Please confirm that, when the amount of $259.8 million is moved to the CDNSADA, the Applicant's cost of capital each year will increase by that amount. Please confirm that $259.8 million is only part of the over-collection amount, and that the full total is $292.8 million, of which $33 million is proposed to be refunded to ratepayers through the new depreciation rates.

RESPONSE

As explained in evidence at Exhibit D1, Tab 5, Schedule 1 and Exhibit D2, Tab 1, Schedule 1, the study performed by Gannett Fleming estimates that if the Constant Dollar Net Salvage method had been in use by EGD rather than the more traditional method for calculating net salvage percentages currently included within EGD's depreciation rates, then the accumulated depreciation related to net salvage would have been $292.8 million less than the current amount. EGD's rate base includes the $292.8 million amount, proposed to be treated within the CDNSADA, as a credit or reduction to rate base and therefore we confirm that EGD's cost of capital is reduced by an amount equal to $292.8 million times the weighted average cost of capital.

As was attempted to be indicated in the CDNSADA evidence at Exhibit D1, Tab 8, Schedule 3, in 2014 to 2018 EGD will transfer amounts as shown on page 1 of that exhibit, to the CDNSADA on a monthly basis which will result in the fiscal year end rate base values increasing by $68.1 million in 2014, $63.1 million in 2015, 58.1 million in 2016, $53.1 million in 2017, and 17.4 million in 2018. The increased year end rate base values are the result of the $259.8 million amount currently crediting rate base, being drawn down or reduced by equal monthly amounts transferred to the deferral account. As a result it is not the case and Enbridge does not confirm that the cost of capital will increase each year by an amount equal to $259.8 million times the weighted average cost of capital.

As indicated in the above referenced evidence, Enbridge confirms that $33 million of the total proposed $292.8 million adjustment is to be refunded through an element of new depreciation rates.

SEC INTERROGATORY #59

INTERROGATORY

Issue A12: Is the proposal for the creation of the following new deferral and variance accounts appropriate?
a. Greater Toronto Area Project Variance Account (“GTAPVA”)
b. Constant Dollar Net Salvage Adjustment Deferral Account (“CDNSADA”)
c. Customer Care Services Procurement Deferral Account (“CCSPDA”)
d. Greenhouse Gas Emission Impact Deferral account (“GGEIDA”)

[D1/8/1, p. 25] Please explain why the CDNSADA should not operate in a manner similar to the PP&E Deferral Account for electricity distributors, which deals with over collection of depreciation and the mechanism for refunding it to ratepayers.

RESPONSE

EGD has reviewed the letter from the Ontario Energy Board to Licensed Electricity Distributors (“LED’s”) and all Other Interest Parties, dated July 17, 2012, concerning regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013.

EGD interprets the letter and resulting accounting policy direction as requiring LED’s to use a new variance account, number 1576, in relation to regulatory accounting changes required as a result International Financial Reporting Standards coming into effect and required to be followed by many regulated LED’s. EGD is not fully cognizant of all of the details of the filing and regulatory accounting requirements or rationale of the Boards policy direction to the LED’s.

Regardless of EGD’s understanding of such policy direction, the Board approved the use of USGAAP by EGD for regulatory accounting purposes beginning in Fiscal 2012. The Company’s proposed use of the Constant Dollar Method for Net Salvage purposes within depreciation rates is not the result of any required change within the accounting standards pertinent to EGD.

The evidence filed at Exhibit D1, Tab 8, Schedule 3 and Exhibit D2, Tab 1, Schedule 1 explains and support EGD’s treatment and operation of the proposed CDNSADA.

Witness: K. Culbert

SEC INTERROGATORY #60

INTERROGATORY

Issue A12: Is the proposal for the creation of the following new deferral and variance accounts appropriate?

a. Greater Toronto Area Project Variance Account (“GTAPVA”)
b. Constant Dollar Net Salvage Adjustment Deferral Account (“CDNSADA”)
c. Customer Care Services Procurement Deferral Account (“CCSPDA”)
d. Greenhouse Gas Emission Impact Deferral account (“GGEIDA”)

[D1/8/3, p. 1] Please provide all documents, including without limitation communications to or from Gannett Fleming, dealing with

a. the pattern of clearance of this account, or
b. the desire, if any, on the part of Enbridge to increase the amount they would be able to refund to ratepayers in 2014 through 2018.

RESPONSE

Part A:

Enbridge’s interaction with Gannett Fleming on the pattern of clearance of the CDNSADA was through several phone conference calls in the spring of 2013. Given the complexity of the approach Enbridge recommended as the pattern of clearance, this method of communication was deemed the most appropriate form of communications to ensure alignment.

Enbridge commenced internal discussions regarding the pattern of clearance of this account upon receipt and acceptance of the recommendation from Gannett Fleming that the Constant Dollar method was the preferred Net Salvage method to manage Site Restoration Costs. Enbridge expected that stakeholders would push for a pattern of clearance that would return the greatest amounts in the fastest timeframe and that the Board would want to have the pattern of clearance in a manner that would reduce the bill shock to Ratepayers. Enbridge decided that the most prudent and reasonable manner for the pattern of clearance of this account would be one which aligned with the IR term and had recoveries weighted towards the early years.

Part B:

There was no desire or communications with Gannett Fleming on the part of Enbridge to increase the amount Enbridge would be able to refund to ratepayers through the

Witnesses: K. Culbert
S. Kancharla
B. Yuzwa

CDNSADA. The amounts Gannett Fleming calculated as total reduction to the SRC accumulated depreciation account was their own independent calculation and based on their recommendation to move to the Constant Dollar method.

Witnesses: K. Culbert
S. Kancharla
B. Yuzwa

SEC INTERROGATORY #61

INTERROGATORY

Issue A12: Is the proposal for the creation of the following new deferral and variance accounts appropriate?

a. Greater Toronto Area Project Variance Account ("GTAPVA")
b. Constant Dollar Net Salvage Adjustment Deferral Account ("CDNSADA")
c. Customer Care Services Procurement Deferral Account ("CCSPDA")
d. Greenhouse Gas Emission Impact Deferral account ("GGEIDA")

[D1/8/2, p. 1] Please confirm that the GTAPVA is intended to include protection for the Applicant for recovery of cost overruns, subject to a prudence review. Please confirm that, in any such review, it is the Applicant's view that the presumption of prudence and prohibition against using hindsight would apply.

RESPONSE

As indicated in the updated GTAPVA evidence found at Exhibit D1, Tab 8, Schedule 2, the principle rationale of the proposed account is that given the scale of the GTA project, even a modest variance in actual costs versus projected costs included within Allowed Revenue could result in a significant over or under payment or recovery for ratepayers and the Company.

EGD confirms that any material amount recorded in the account would be subject to a prudence review. Such a review would be made in light of the circumstances at the time expenditures were made, and the prohibition against hindsight would apply.

Witness: K. Culbert

SEC INTERROGATORY #62

INTERROGATORY

Issue A12: Is the proposal for the creation of the following new deferral and variance accounts appropriate?

a. Greater Toronto Area Project Variance Account (“GTAPVA”)
b. Constant Dollar Net Salvage Adjustment Deferral Account (“CDNSADA”)
c. Customer Care Services Procurement Deferral Account (“CCSPDA”)
d. Greenhouse Gas Emission Impact Deferral account (“GGEIDA”)

[D1/8/4, p. 2] Please provide a budget for the $4-5 million estimated cost to be included in this account.

RESPONSE

Customer Care Services Procurement Deferral Account (“CCSPDA”)

The Company’s current outsourced service arrangements that support the customer care business function date back to April 2007 and are supported by the EB-2006-0034 Settlement Proposal For Customer Care and Customer Information System (“CIS”) Issues (the “Settlement”) which was approved by the Board in its EB-2006-0034 Interim Rate Order dated March 26, 2007. These arrangements and the underlying service agreements with Accenture Business Services for Utilities Inc. (“ABSU”) and MET Utilities Management Ltd. (“MET”) were extended in 2011 and now are both set to expire on December 31, 2017. The extension of these arrangements was the subject of the EB-2011-0226 proceeding accepted by the Board in September 2011. The original arrangements dating back to 2007 were the product of a rigorous competitive tendering process which took place in 2006 and 2007. It is the Company’s position that the Company’s customer care outsourcing strategy should be reviewed and a further tendering process should be completed before customer care service arrangements extending beyond 2017 are entered into.

This position is consistent with the one taken by the Company leading up to the implementation of its current customer care outsourcing arrangement and supported by intervenors in the Settlement. The Settlement recognized that it is reasonable that the Company be able to recover costs related to the procurement of the outsourced customer care services and specifically provided for the Company’s recovery of $4.9 million of such costs from ratepayers over the 2008 through 2012 period.

Witnesses: K. Culbert
K. Lakatos-Hayward
S. McGill

Given the lead times required to undertake a tendering process appropriate to the scope and value of Enbridge's customer care outsourcing arrangements and potentially transition to new service providers it is anticipated that this process will commence late in 2014. This process will include the following steps:

- The development of a customer care repatriation financial model to assess the costs and benefits of strategic sourcing for all or part of Enbridge's customer care business functions.
- Benchmarking, to assess the competitiveness of the Company's current arrangements in terms of cost, service levels and contractual terms and conditions.
- Determination of the customer care business process outsourcing requirements, including but not limited to the scope of service, statement(s) of work, service levels and acceptable contract terms and conditions.
- Request for proposals including requests for information to qualify potential vendors.
- New customer care business model implementation / transition.

These activities will be performed by Enbridge personnel supported by outside consultants and legal resources. Although the Company has not prepared a detailed budget for this work at time it is anticipated that the costs incurred will be on the same order of magnitude as those experienced in 2006 and 2007. It is the Company's proposal that the costs associated with these activities be recorded in the requested Customer Care Services Procurement Deferral Account over the course of this activity and be brought forward for recovery in rates after the implementation of the Company's post 2017 customer care service arrangements. The use of a deferral account will allow for the prudence of these expenditures to be determined by the Board, and will ensure that Enbridge does not over-or under-recover its costs.

Witnesses: K. Culbert
K. Lakatos-Hayward
S. McGill

SEC INTERROGATORY #63

INTERROGATORY

Issue A12: Is the proposal for the creation of the following new deferral and variance accounts appropriate?

a. Greater Toronto Area Project Variance Account (“GTAPVA”)
b. Constant Dollar Net Salvage Adjustment Deferral Account (“CDNSADA”)
c. Customer Care Services Procurement Deferral Account (“CCSPDA”)
d. Greenhouse Gas Emission Impact Deferral account (“GGEIDA”)

[D1/8/5, p. 1] Please explain why this account is appropriate now, rather than if and when government announcements are made or programs are implemented.

RESPONSE

EGDI submits that it is appropriate to consider the GGEIDA now because EGDI is proposing to discontinue a previous Board Approved deferral account, CDOCDA. Going forward, items previously within the CDOCDA are proposed to be dealt with in 2014 and beyond within the GGEIDA as is explained within the GGEIDA evidence, filed at Exhibit D1, Tab 8, Schedule 5.

Witnesses: T. Adamson
K. Culbert

CCC INTERROGATORY #18

INTERROGATORY

Issue A13 – Is the proposal to permit Enbridge to apply for changes in rate design and new energy and non-energy services during the IR term appropriate?

(Ex. A2/T3/S1/p. 16) EGD is seeking approval in the context of this plan for rate design flexibility “to respond to changing marketplace needs”. This would include developing rates, and service or changes to existing rates. Please explain the types of new rates and services EGD is contemplating. Does EGD anticipate changing the approved cost allocation if new rates are applied for and approved?

RESPONSE

Please see responses to OAPPA Interrogatory #2, found at Exhibit I.A1.EGDI.OAPPA.2; and OAPPA Interrogatory #3, found at Exhibit I.A1.EGDI.OAPPA.3 for the illustrative examples of the type of changes in rate design and new energy and non-energy services that could be proposed during the term of the IR plan.

If a proposal to make changes to rate design and/or services would also require changes to the approved cost allocation methodology, the Company’s evidence would include supporting evidence for changes to cost allocation as well. As outlined in the evidence at Exhibit A2, Tab 3, Schedule 1, page 16, if the proposed changes are significant and warrant a longer review period, the Company will file a separate application on a sufficiently timely basis.

Witnesses: K. Culbert
R. Fischer
A. Kacicnik
M. Lister

OAPPA INTERROGATORY #2

INTERROGATORY

Issue 13 - Is the proposal to permit Enbridge to apply for changes in rate design and new energy and non-energy services during the IR term appropriate?

(Reference: Exhibit A2, Tab 3, Schedule 1, p. 16, para. 29) - Please provide examples of the types of rate-related changes for energy services that Enbridge would consider: (a) minor in nature and with customer impacts that are minimal and (b) significant in nature and requiring a longer review period.

RESPONSE

Please see below for examples of minor and significant changes to rate design or services:

(a) an example of a minor change would be if the Company needed to make a change in the reference source (i.e., Gas Daily) it uses to derive unauthorized overrun gas rate.

Another example of a change that is minor in nature with minimal customer impacts is the proposal within this proceeding to introduce an additional provision within Part III: Terms and Conditions Applicable to All Services of the Company's Rate Handbook. The proposed provision obligates the Company and large customers to meet once annually to review customers' expected consumption and to confirm that emergency contact information that the Company has on file is current.

The text of the proposed provision is provided below.

SECTION P – OBLIGATION FOR LARGE CUSTOMERS TO PROVIDE CONSUMPTION AND EMERGENCY CONTACT INFORMATION

> All customers whose annual consumption exceeds 1,000,000 m^3 are obligated to provide their expected annual consumption, peak demand, and emergency contact information to the Company annually.

Witnesses: K. Culbert
R. Fischer
A. Kacicnik
M. Lister

(b) the unbundled rates and services that the Company developed as part of the EB-2005-0551 Natural Gas Electricity Interface Review (NGEIR) are an example of introduction of new rates and services that would require a longer review period.

Similarly, the change in the clearance methodology for the Purchased Gas Variance Account ("PGVA") to a 12-month rolling clearance methodology that the Company developed as part of EB-2008-0106 (QRAM Generic Proceeding) and the EB-2011-0242 Renewable Natural Gas proposal is a further example that would require a longer review period.

Witnesses: K. Culbert
R. Fischer
A. Kacicnik
M. Lister

OAPPA INTERROGATORY #3

INTERROGATORY

Issue 13 - Is the proposal to permit Enbridge to apply for changes in rate design and new energy and non-energy services during the IR term appropriate?

(Reference: Exhibit A2, Tab 3, Schedule 1, p.16, para. 30) - Enbridge indicates that should it need to change or introduce new miscellaneous or non-energy services during the IR term, it will seek approval for the changes and provide supporting evidence. Please indicate if any such filing would be part of the annual Rate Adjustment proceeding or a separate application.

RESPONSE

The evidence supporting a change to or an introduction of new miscellaneous or non-energy services during the IR plan period would be part of the annual Rate Adjustment proceeding.

An example of such a change would be a proposal to change the level of the charge for one or more Rider G: Service Charges within the Company's Rate Handbook.

Witnesses: K. Culbert
R. Fischer
A. Kacicnik
M. Lister

CCC INTERROGATORY #19

INTERROGATORY

Issue A15 – Is Enbridge's proposal to continue the current methodologies to cost and price other service charges and late payment penalties appropriate?

(Ex. A1/T5/S2/p.1) The evidence states that EGD has undertaken a review of its Schedule of Service Charges, as shown at Rider G of the Rate Handbook. The Company has concluded that its current rates for these services are comparable with those of other Ontario service delivery organizations and utilities, and in most cases are lower. EGD has concluded that it will not change its fees throughout the 2014-2016 period. To what extent did EGD assess whether the fees were over or under-recovering the costs of providing the services? Please provide evidence to demonstrate that each of the fees is cost-based. What is the expected net revenue from each service expected in 2013? What is the expected revenue for each year 2014-2018? To what extent does EGD intend to look at improving the efficiency of providing those services over the next 5 years?

RESPONSE

This interrogatory poses five questions concerning the Company's proposed service fees for "Other Services" in this application:

1) To what extent did EGD assess whether the fees were over or under-recovering the costs of providing the services?
2) Please provide evidence to demonstrate that each of the fees is cost-based.
3) What is the expected net revenue from each service expected in 2013?
4) What is the expected revenue for each year 2014 to 2018?
5) To what extent does EGD intend to look at improving the efficiency of providing those services over the next 5 years?

Answers:

1) To what extent did EGD assess whether the fees were over or under-recovering the costs of providing the services? The Company does not account for Rider G services in such a way that would allow for the determination of each service's margin. The Company's rate setting process provides for forecast other service revenue to be credited against Enbridge's annual revenue requirement serving to reduce gas distribution rates. To the extent that actual other service revenue

Witnesses: S. McGill
M. Torriano

varies from budget such variance will either contribute to, or serve to reduce overall earnings in that year.

2) Please provide evidence to demonstrate that each of the fees is cost-based. In determining the fees set-out in Rider G, the Company gives consideration to costs that can be attributed to each respective service. However, the fees applicable to each of these services are not solely cost based. Late in 2011 Enbridge undertook to review its Rider G fees in anticipation of the Company's 2013 rate application. This review indicated that Enbridge's then current fees in respect of the services listed in Rider G were recovering the costs allocated to each of the respective Rider G services and were comparable to fees charged by other Ontario utilities for similar services. As such, the Company did not propose to revise these fees in 2013 and is not requesting any change in these fees in this application.

3) What is the expected net revenue from each service expected in 2013? The Company does not account for Rider G services in such a way that would allow for the determination of each service's net revenue. Other service revenues are expected to recover the costs associated with providing the underlying services and on a forecast basis are included as part of the Company's overall revenue requirement.

4) What is the expected revenue for each year 2014 to 2018? Please see the Company's response to VECC Interrogatory #15 found at Exhibit I.B17.EGDI.VECC.15.

5) To what extent does EGD intend to look at improving the efficiency of providing those services over the next 5 years? The provision of the services identified in Rider G is fully integrated in Enbridge's business processes. To the extent that the Company can introduce efficiencies that impact upon the delivery of Ridge G services any economic benefit resulting from such efficiencies will flow to reported earnings over the term of the upcoming IR period.

Witnesses: S. McGill
M. Torriano

ENERGY PROBE INTERROGATORY #11

INTERROGATORY

Ref: Exhibit A1, Tab 2, Schedule 1

Please provide a revised paragraph 6 that shows the impacts of the proposed application, excluding the impact of the proposed treatment of site restoration costs, including the five-year rate rider proposed by EGD.

RESPONSE

The rate impacts in the revised paragraph 6 below were determined using the forecast allowed revenues and resultant deficiency amounts shown in the table below. The table illustrates the allowed revenues and deficiencies if the status quo were maintained and the Company's proposed changes for site restoration costs were removed.

The proposed site restoration cost changes include the implementation of new depreciation rates, and the return of site restoration cost amounts via a five year rate rider, as detailed in Exhibits D1, Tab 5, Schedule 1 and Exhibit D2, Tab 1, Schedule 1.

Witnesses: K. Culbert
A. Kacicnik
S. Kancharla

ALLOWED REVENUE AND DEFICIENCIES (INCL. CIS/CC)
ASSUMING PROPOSED SITE RESTORATION COST CHANGES ARE REMOVED
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	4,377.0	4,647.2	5,280.1	5,400.4	5,499.5
2.	Required rate of return	6.77%	6.94%	7.08%	7.08%	7.15%
3.		296.5	322.7	373.6	382.3	393.2
	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	292.6	308.3	339.6	350.9	361.2
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.		2,216.9	2,388.6	2,459.0	2,483.7	2,507.8
	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	91.0	73.0	68.2	72.8	72.5
14.	Tax shield provided by interest expense	(39.4)	(41.8)	(47.0)	(47.7)	(49.2)
15.		51.6	31.2	21.2	25.1	23.3
	Taxes on deficiency					
16.	Gross deficiency - with CIS/CC	(26.7)	(76.8)	(158.5)	(191.8)	(219.8)
17.	Net deficiency - with CIS/CC	(19.7)	(56.4)	(116.5)	(141.0)	(161.5)
18.		7.1	20.3	42.0	50.8	58.2
19.	Sub-total Allowed Revenue	2,531.5	2,721.8	2,854.5	2,900.6	2,941.2
20.	Customer Care Rate Smoothing Var. Adj.	(2.9)	(1.1)	0.8	2.9	5.0
21.	**Allowed Revenue**	2,528.6	2,720.7	2,855.3	2,903.5	2,946.2
	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	(0.1)	(0.3)	0.1	0.1	(0.2)
26.	Total	2,498.0	2,635.4	2,683.5	2,693.3	2,702.8
27.	**Gross revenue deficiency**	(30.6)	(85.3)	(171.8)	(210.2)	(243.4)

Witnesses: K. Culbert
A. Kacicnik
S. Kancharla

Based on the above scenario, the revised paragraph 6 from Exhibit A1, Tab 2, Schedule 1, Page 4 would read:

> In the event that Enbridge's application is approved by the Board, the average rate increase for residential customers for 2014 will be approximately 2.4%, or about $14, on a T-Service basis (that is, excluding Gas Supply Charges). The estimated average rate increase for residential customers for 2015 will be approximately 3.4%, or about $20, on a T-Service basis, and the average rate increase to residential customers for 2016 will be approximately 5.2%, or about $31, on the same basis.

Please also note that if the Company were not proposing the Site Restoration Cost refund then paragraph 7 from Exhibit A1, Tab 2, Schedule 1, page 4 would be eliminated.

Witnesses: K. Culbert
A. Kacicnik
S. Kancharla

ENERGY PROBE INTERROGATORY #12

INTERROGATORY

Ref: Exhibit A2, Tab 1, Schedule 1, page 8

a) Does the customer bill include the commodity cost of gas? If yes, please provide the table showing distribution only average bill increases over the 2014 to 2016 period.

b) Please split the total bill for an average residential customer increase over 2014 to 2016 into the reduction due to the treatment of the site restoration costs, distribution costs, gas costs and anything else at both a dollar level and percentage level.

RESPONSE

a) The table on page 8 reflects the total bill, including the commodity cost of gas, for the average residential customer.

For T-service bill increases (excluding commodity), please refer to "Sample Typical Customer T-service Bill Impacts from 2013 to 2018" on page 1 of EB-2012-0459, Exhibit H3, Tab 1, Schedule 2, Appendix C, Column 2, Line 1.0 (Rate 1: Annual Consumption of 2,480 m3).

b) Please refer to "Sample Typical Customer total Bill Impacts from 2013 to 2018" on page 1 of EB-2012-0459, Exhibit H3, Tab 1, Schedule 2, Appendix B (Rate 1: Annual Consumption of 2,480 m^3).

Witnesses: R. Fischer
M. Lister

OAPPA INTERROGATORY #4

INTERROGATORY

Issue 16 – Are the overall levels of allowed revenue, rates and bill impacts for each of the years of the IR plan reasonable given the impact on consumers?

(Reference: Exhibit H3, Tab1, Schedule 1, Appendix C and Exhibit H3, Tab 1, Schedule 2, Appendix C) - With respect to the two schedules indicated in the reference, please provide estimates of the T-service bill impacts for typical customers in the Rate 115, Rate 145 and Rate 170 rate classes.

RESPONSE

This table on the following page now includes the estimated T-service bill impacts for typical customers in the Rate 115, Rate 145 and Rate 170 rate classes.

Witnesses: J. Collier
A. Kacicnik

Sample Typical Customer Estimated T-Service Bill Impacts from 2013 to 2018

	Col.1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7	Col.8	Col.9	Col.10	Col.11	Col.12	Col.13
Item No.	Rate class	Annual Consumption m^3	**2013 April QRAM Annual T-Service Bill $**	Change from 2013 April Q2 to 2014	**2014 Estimated Annual T-Service Bill $**	Change from 2014 to 2015	**2015 Estimated Annual T-Service Bill $**	Change from 2015 to 2016	**2016 Estimated Annual T-Service Bill $**	Change from 2016 to 2017	**2017 Estimated Annual T-Service Bill $**	Change from 2017 to 2018	**2018 Estimated Annual T-Service Bill $**
			EB-2013-0045		EB-2012-0459								
1.0	Rate 1	1,955	497	(3)	494	9	503	21	524	11	535	13	548
2.0	SRC Credits		-		(21)		(19)		(18)		(16)		(5)
3.0	Rate 1 with SRC		497	(24)	472	11	483	23	506	13	519	23	542
1.0	Rate 1	2,480	566	(4)	562	12	574	27	601	15	615	16	631
2.0	SRC Credits		-		(27)		(25)		(23)		(21)		(7)
3.0	Rate 1 with SRC		566	(31)	535	14	549	29	578	17	595	30	625
1.0	Rate 1	3,064	641	(5)	636	14	651	33	684	18	701	20	721
2.0	SRC Credits		-		(33)		(30)		(28)		(25)		(8)
3.0	Rate 1 with SRC		641	(38)	603	17	620	35	656	20	676	37	713
1.0	Rate 6	22,606	3,528	(20)	3,508	54	3,562	160	3,722	99	3,821	105	3,926
2.0	SRC Credits		-		(79)		(73)		(66)		(60)		(20)
3.0	Rate 6 with SRC		3,528	(100)	3,429	60	3,489	167	3,656	104	3,760	146	3,906
1.0	Rate 6	29,278	4,307	(26)	4,281	69	4,351	205	4,556	126	4,682	135	4,817
2.0	SRC Credits		-		(103)		(94)		(86)		(78)		(26)
3.0	Rate 6 with SRC		4,307	(129)	4,178	78	4,256	214	4,470	134	4,604	187	4,791
1.0	Rate 6	43,285	5,815	(37)	5,778	98	5,876	283	6,159	175	6,334	187	6,521
2.0	SRC Credits		-		(152)		(139)		(127)		(116)		(38)
3.0	Rate 6 with SRC		5,815	(188)	5,627	110	5,737	296	6,033	186	6,219	264	6,483
1.0	Rate 110	598,568	54,207	(724)	53,482	588	54,071	1,027	55,098	496	55,594	500	56,094
2.0	SRC Credits		-		(622)		(572)		(520)		(475)		(156)
3.0	Rate 110 with SRC		54,207	(1,346)	52,860	638	53,499	1,079	54,578	541	55,119	820	55,939
1.0	Rate 110	9,976,121	789,242	(12,070)	777,172	8,549	785,721	14,929	800,650	7,206	807,856	7,271	815,127
2.0	SRC Credits		-		(10,368)		(9,528)		(8,672)		(7,921)		(2,594)
3.0	Rate 110 with SRC		789,242	(22,438)	766,804	9,389	776,193	15,784	791,978	7,957	799,935	12,598	812,533
1.0	Rate 115	69,832,850	4,755,935	(36,180)	4,719,755	56,637	4,776,392	90,751	4,867,143	43,804	4,910,948	44,199	4,955,146
2.0	SRC Credits		-		(41,308)		(37,989)		(38,199)		(34,916)		(11,453)
3.0	Rate 115 with SRC		4,755,935	(77,487)	4,678,447	59,956	4,738,403	90,542	4,828,945	47,086	4,876,031	67,662	4,943,694
1.0	Rate 145	339,188	29,320	(278)	29,042	319	29,361	617	29,978	270	30,247	272	30,520
2.0	SRC Credits		-		(267)		(246)		(223)		(204)		(67)
3.0	Rate 145 with SRC		29,320	(546)	28,774	341	29,116	639	29,754	289	30,044	409	30,453
1.0	Rate 145	598,567	47,308	(491)	46,817	515	47,332	994	48,326	435	48,761	439	49,200
2.0	SRC Credits		-		(472)		(433)		(394)		(360)		(118)
3.0	Rate 145 with SRC		47,308	(963)	46,346	553	46,899	1,033	47,933	469	48,402	681	49,082
1.0	Rate 170	9,976,120	519,899	(6,403)	513,496	4,621	518,118	8,808	526,926	3,688	530,614	3,714	534,328
2.0	SRC Credits		-		(2,416)		(2,245)		(2,035)		(1,856)		(609)
3.0	Rate 170 with SRC		519,899	(8,819)	511,080	4,793	515,873	9,017	524,891	3,868	528,759	4,961	533,720
1.0	Rate 170	69,832,850	3,503,614	(44,819)	3,458,795	31,129	3,489,925	59,329	3,549,253	24,845	3,574,098	25,019	3,599,117
2.0	SRC Credits		-		(16,912)		(15,712)		(14,246)		(12,989)		(4,260)
3.0	Rate 170 with SRC		3,503,614	(61,731)	3,441,883	32,329	3,474,212	60,795	3,535,007	26,102	3,561,109	33,748	3,594,857

Witnesses: J. Collier
A. Kacicnik

SEC INTERROGATORY #64

INTERROGATORY

Issue A16: Are the overall levels of allowed revenue, rates and bill impacts for each of the years of the IR plan reasonable given the impact on consumers?

Please provide a table showing the proposed revenue requirements for each of 2014 through 2018 on the assumption that

a. Pension costs would remain at 2014 levels;
b. Depreciation rates would remain at 2013 rates;
c. Depreciation of net salvage would continue the current methodology; and
d. The amount of $292.8 excess net salvage is not refunded to ratepayers.

RESPONSE

The following table illustrates the forecast allowed revenues and deficiencies that would result assuming: pension and other post-employment benefit costs are maintained at the 2013 approved level of $42.8M, and all impacts from the proposed site restoration cost changes are removed (i.e., 2013 depreciation rates are maintained, existing net salvage methodology is maintained, and $292.8M in site restoration cost reserve amounts are not returned to ratepayers).

ALLOWED REVENUE AND DEFICIENCIES (INCL. CIS/CC) ASSUMING PENSION AND OPEB COSTS ARE FIXED AT 2013 AMOUNTS AND PROPOSED SITE RESTORATION COST CHANGES ARE REMOVED
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	4,377.0	4,647.0	5,280.0	5,400.3	5,499.3
2.	Required rate of return	6.77%	6.94%	7.08%	7.08%	7.15%
3.		296.5	322.7	373.6	382.2	393.2
	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	430.9	437.5	451.4	464.8	478.4
6.	Depreciation and amortization	292.6	308.3	339.6	350.9	361.2
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.		2,222.5	2,397.6	2,470.9	2,498.0	2,524.4
	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	89.5	70.6	65.1	69.1	68.1
14.	Tax shield provided by interest expense	(39.4)	(41.7)	(47.0)	(47.7)	(49.2)
15.		50.1	28.9	18.1	21.4	18.9
	Taxes on deficiency					
16.	Gross deficiency - with CIS/CC	(32.3)	(85.8)	(170.4)	(206.2)	(236.4)
17.	Net deficiency - with CIS/CC	(23.8)	(63.1)	(125.3)	(151.6)	(173.7)
18.		8.6	22.7	45.2	54.6	62.6
19.	Sub-total Allowed Revenue	2,537.1	2,730.9	2,866.5	2,914.9	2,957.8
20.	Customer Care Rate Smoothing Var. Adj.	(2.9)	(1.1)	0.8	2.9	5.0
21.	**Allowed Revenue**	2,534.2	2,729.8	2,867.3	2,917.8	2,962.8
	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	(0.1)	(0.2)	0.2	-	(0.2)
26.	Total	2,498.0	2,635.5	2,683.6	2,693.2	2,702.8
27.	**Gross revenue deficiency**	(36.2)	(94.3)	(183.7)	(224.6)	(260.0)

Witness: K. Culbert

VECC INTERROGATORY #5

INTERROGATORY

ISSUE A16: Are the overall levels of allowed revenue, rates and bill impacts for each of the years of the IR plan reasonable given the impact on consumers?

Evidence Ref: A1/T2/S1/pages 4-5

a) The proposal forecasts that distribution rates for residential consumers will decrease slightly in 2014, only to increase by a greater in the following two years. Did EGD consider smoothing the delivery bill impacts by not providing a decrease (or a smaller increase) in 2014 in order to moderate later year increases?

RESPONSE

a) Enbridge did not consider an approach that would smooth distribution rates over the 2014 to 2018 term. The Company did, however, consider and propose a smoothing approach for the SRC Rate Rider as set out at Exhibit D1, Tab 5, Schedule 1, in order to mitigate bill impacts over the IR term.

Witnesses: R. Fischer
M. Lister