500 Consumers Road
North York, Ontario M2J 1P8
PO Box 650
Scarborough ON M1K 5E3

Lorraine Chiasson
Regulatory Coordinator
Regulatory Affairs
phone: (416) 495-5499
fax: (416) 495-6072
Email: egdregulatoryproceedings@enbridge.com

December 18, 2013

VIA RESS, EMAIL and COURIER

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

Re: EB-2012-0459 - Enbridge Gas Distribution Inc. ("Enbridge")
2014 – 2018 Rate Application
Updated Evidence and Interrogatory Response

Enclosed please find the final interrogatory response (Exhibit I.A1EGDI.CME.1).

The response to CCC Interrogatory #6 has been updated and the omitted attachment has also been included (Exhibit I.A2.EGDI.CCC.6 and Attachment 1).

In addition, updates are attached regarding the Unaccounted For ("UAF") Gas evidence, which were mistakenly omitted from the evidence update of December 11, 2013. This includes the following exhibits:

Exhibit D3, Tab 4, Schedule 1
Exhibit D4, Tab 4, Schedule 1
Exhibit D5, Tab 4, Schedule 1
Exhibit D6, Tab 4, Schedule 1
Exhibit D7, Tab 4, Schedule 1

Please contact the undersigned if you have any questions.

Yours truly,

(original signed)

Lorraine Chiasson
Regulatory Coordinator

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

CME INTERROGATORY #1

INTERROGATORY

Issue: A1

Reference: Exhibit A2, Tab 1, Schedule 1
Exhibit L, Tab 1, Schedule 2

Attachment 1 to these Interrogatories consists of pages 1 to 8 of the Report prepared by Pacific Economics Group Research, LLC ("PEG") entitled *"Enbridge Gas Distribution's Customized Incentive Regulation Proposal: Assessment and Recommendations, October 23, 2013".* This Report was distributed by Ontario Energy Board ("OEB") staff on October 23, 2013. The paragraphs in the Executive Summary of this Report have been numbered from 1 to 19 inclusive.

(a) Please provide the responses and comments of EGDI, Concentric Energy Advisors Inc. ("CEA"), and London Economics International LLC ("LEI") to the comments and criticisms of EGDI's Customized IR proposal contained in each and every numbered paragraph.

RESPONSE

The response below presents EGD's reply to the Executive Summary of the PEG Report, on a paragraph by paragraph basis.

Before responding to the specific paragraphs from the Executive Summary of the PEG Report, there are two items that EGD would like to highlight.

First, EGD notes that an underlying premise of the PEG Report is an apparent assumption that the Company's cost projections are inflated. PEG then uses this assumption to seek to invalidate the Customized IR model. EGD does not believe that PEG's characterization of EGD's cost projections is fair. Extensive evidence has been prepared to explain how the cost forecasts were developed, and why the requested budgets are reasonable. EGD has presented evidence and answered interrogatories explaining how productivity challenges are already embedded within the cost forecasts. EGD has further explained how it has accepted the risk of more than $100 million of "variable" capital costs which may arise during the IR term. In EGD's view, if PEG were to take the starting point that the cost forecasts set out in EGD's Application are reasonable, then PEG may well have reached a different overall conclusion about the

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Customized IR plan. Indeed, PEG appears to concede this point, when it states (at page 3), that "[t]he reasonableness of EGD's Custom[ized] IR application depends on the reasonableness of its cost projections."

Second, EGD has now filed updated evidence describing why and how it has updated the Customized IR plan to allow for Allowed Revenue amounts to be set for all five years of the IR term within this proceeding. As explained in the updated Customized IR Plan Overview Evidence at Exhibit A2, Tab 1, Schedule 1, Paragraphs 7 and 8:

> This Application is Enbridge's proposal for a 2nd Generation Incentive Regulation ("IR") or Customized IR plan for five years from 2014 to 2018, to address and accommodate the challenges described above and throughout the evidence. In its original filing, the Company proposed a Customized IR plan with a five year term, including an update of capital spending requirements for 2017 and 2018 to address the difficulty in forecasting such costs at this time. Now, having considered concerns raised about the plan to revisit costs midway through the IR term, Enbridge has updated its Customized IR Plan to allow for all aspects of 2014 to 2018 Allowed Revenue to be set in this proceeding.
>
> Enbridge's proposed updated Customized IR plan fixes the Company's allowed distribution revenue amounts ("Allowed Revenue") for 2014 to 2018 based upon the Company's forecast costs, inclusive of productivity savings, for each of those years. This Updated Customized IR plan, which no longer requires that Enbridge's 2017 and 2018 Capital Budgets be determined midway through the IR term is made possible by using the 2016 Capital Budget (except for the removal of $8.1 million in costs related to WAMS which will not be included for 2017 and 2018) as a reasonable forecast of the Company's 2017 and 2018 capital spending requirements. As this was the same approach used in the original filing to set "Preliminary" Allowed Revenue amounts for 2017 and 2018, there is no effect on the numerical evidence and forecasts of 2017 and 2018 Allowed Revenue that results from the updated Customized IR plan. Under this approach, Enbridge is at risk (except within two specified areas of spending described below) for any additional capital spending requirements in 2017 and 2018 other than those identified within the 2016 Capital Budget.

Thus, under the updated Customized IR plan, there is no longer any requirement for a 2017/2018 "capital refresh" within the 2017 Rate Adjustment process. Instead, Allowed Revenues are to be set for each year from 2014 to 2018 within this proceeding.

EGD has also updated the Sustainable Efficiency Incentive Mechanism ("SEIM"), in response to questions and concerns raised by stakeholders and PEG. As explained at Exhibit A2, Tab 11, Schedule 3, Paragraph 2,

> [T]he updated SEIM that the Company is proposing balances the goal of incenting the utility to find and take advantage of sustainable efficiency initiatives with measures to protect customers by ensuring that Enbridge only receives a reward where its performance merits a reward. The SEIM reward will only be available where EGD can demonstrate that the value of the efficiency initiatives undertaken exceed the amount of

> the reward, and where EGD can demonstrate that it has maintained strong service and operations through the IR term. Additionally, the SEIM reward will not apply until after rebasing, and there will be a cap on the amount of the SEIM reward that is available.

What follows are EGD's responses to each of the paragraphs within the Executive Summary of the PEG Report (with cross-references to the paragraph numbers used by CME). The Company's responses to PEG's Executive Summary are made based upon the updated proposed Customized IR plan, inclusive of the changes described above.

Also attached are two documents containing the responses of Concentric and LEI to the Executive Summary of the PEG Report (Attachment 1 & 2, respectively). In many cases, as noted within EGD's response below, PEG's comments are directed at Concentric and LEI. In those cases, the main response to PEG can be found in the attachments from Concentric and LEI.

<u>CME numbered paragraph 1 – Overview</u>

EGD disputes that its Customized IR proposal is "flawed". The major criticism identified by PEG within this opening paragraph does not apply to the updated Customized IR plan. The updated Customized IR plan treats Capital and Operating and Maintenance (O&M) spending in the same manner. It is not analogous to the TPBR model that applied to EGD in in the 2000 to 2002 period. As described above, EGD is now asking the Board to set Allowed Revenue amounts for each of the five years of the IR term.

The Customized IR plan is not a "targeted" IR plan as asserted by PEG, but rather a comprehensive model that addresses both O&M and Capital costs. EGD's proposed plan is a multi-year revenue cap, with built-in productivity. The Allowed Revenue amounts are built up from customized cost components and forecasts. The total costs are customized in that various costs are forecast to grow at various rates and/or for known future activities. With the revenue cap in place (having been set in this proceeding), future revenues are decoupled from future costs. The resulting incentives to find and achieve productivity savings are the same as within EGD's 1st Generation IR plan.

In addition, the Customized IR plan also contains other features that preserve or enhance incentives while affording ratepayer benefits.

The Earnings Sharing Mechanism ("ESM") ensures that if actual revenues exceed actual costs by more than 100 basis points in ROE (including where actual costs are below forecast), then ratepayers will share in the benefit. Further, if EGD's actual costs are higher than expected (or actual revenues lower), then EGD will have to fully absorb the financial consequences because the ESM is asymmetrical.

The updated SEIM incents the utility to look for and implement activities that directly result in long term sustainable efficiencies, where the benefit for ratepayers exceeds that for the shareholder. EGD will only be eligible for a SEIM reward where it can identify concrete efficiency-enhancing projects leading to measureable benefits for customers, and where its overall results exceed the Board-Allowed ROE (which signifies that EGD has found a way to be efficient during the IR term).

Annual reporting and a rebasing application ensure that all stakeholders are kept abreast of actual activity at the utility, including information relating to actual costs and revenues, annual performance, customer satisfaction, service quality standards, and productivity initiatives.

Concentric's response to this paragraph is found at Attachment 1 and LEI's response is found at Attachment 2.

CME numbered paragraphs 2 & 3 – Length of the Plan Term

EGD has updated its proposed Customized IR plan such that Allowed Revenues will be set within this proceeding for each of the five years over the 2014 to 2018 period. With this update, EGD will no longer re-visit its capital spending requirements for 2017 and 2018 mid-way through the IR plan. EGD believes that this change addresses the concerns raised by PEG within the above-noted paragraph.

CME numbered paragraph 4 – Building Blocks

The response from LEI addresses PEG's assertion that EGD's Customized IR application is somehow at odds with current forms of Building Blocks regulation. The LEI response is found as Attachment 2.

EGD maintains that the Customized IR plan appropriately draws upon regulatory models that use the Building Blocks approach. Insights have also been drawn from the Board's "Custom IR" model for electricity distributors.

The Company disputes the assertion that the Customized IR model incents EGD to inflate its cost forecasts. As explained by EGD in its prefiled evidence, the cost forecasts are reasonable and tailored to EGD's particular circumstances. Moreover, EGD agrees with LEI's assessment that the ongoing nature of utility regulation in Ontario works against EGD submitting inflated forecasts. The Company will annually report on its actual spending (in the form seen within the B series of exhibits in EGD's 1st Generation IR term ESM applications such as EB-2013-0046), and will be subject to annual ESM reviews. Then, at rebasing, the Company will be required to justify its capital spending (on a prudence basis) and establish a proper new spending level. The risk of adverse consequences in later proceedings resulting from a determination that EGD inflated cost estimates in this proceeding is a real risk to EGD.

As a final matter, EGD disputes the suggestion that the Customized IR plan shifts risks from the Company to ratepayers. In EGD's opinion, the establishment of five years of Allowed Revenues in this 2014 proceeding creates risks for both the ratepayer and the shareholder because cost forecasts set today may differ from actual cost requirements, either on the high or the low side. Similarly, revenues may not occur as forecast (although the Company is proposing annual establishment of volume forecasts). The Company's proposed one-sided ESM, which is the same as that used in the 1st generation plan, provides an effective shield for ratepayers against these risks. If EGD's approved Allowed Revenue is understated, then EGD's shareholder will have to absorb the entire shortfall. If the Allowed Revenue is overstated, then EGD will share earnings with ratepayers. In this way, the asymmetrical ESM clearly allocates the risk of the cost forecasts which build to the Allowed Revenue amounts onto EGD.

Concentric's response to items contained within the above-noted paragraph is found at Attachment 1.

<u>CME numbered paragraph 5 – ESM and Reasonableness of Forecasts</u>

EGD believes that the proposed ESM does provide comfort that the Company's cost forecasts are reasonable. First, EGD is at risk for under-performance, because the ESM is asymmetrical. Second, EGD is not completely insulated if its costs come in lower than forecast (and revenues stay on track), because then there will be over-earnings which EGD will share with ratepayers. If overearnings exceed 300 basis points, then the off-ramp provisions apply (meaning that EGD must file an application with the Board to determine whether, and on what basis, the IR plan should continue). Finally, the existence of the ESM process ensures that EGD will be required to report about its expenditures each year, so that differences between forecast and actuals can be observed.

PEG's comments about EGD's ESM are also addressed in LEI's response, found as Attachment 2.

EGD also disputes PEG's broader criticism about the reasonableness of the Company's cost forecasts. EGD has produced detailed accounts describing how cost forecasts were created. EGD has produced detailed accounts for how productivity has been embedded within the cost forecasts. EGD has committed to providing annual information regarding actual spending and revenues, performance, Service Quality Requirements, and Productivity. Concentric has provided benchmarking and TFP analysis to demonstrate that EGD's operations in recent years compare favourably (from a costs and productivity perspective) with its peers. All these items combine to support the reasonableness of EGD's forecast costs.

Concentric's response to items contained within the above-noted paragraph is found at Attachment 1.

CME numbered paragraph 6 – Z-Factors

EGD has answered numerous other interrogatories explaining the rationale and impact of the proposed Z-factor changes. Please see, for example, the response filed at Exhibit I.A10.EGDI.STAFF.26 for a detailed response regarding the challenges and issues associated with the Z-Factor criteria as they existed in the 1st Generation IR plan. See also Exhibit I.A10.EGDI.STAFF.24 and 25.

EGD does not expect or anticipate that the amended Z-factor language will result in more frequent and contentious Z-factor proceedings. The "unexpected cause" language properly captures the goal of a Z-factor, which is to provide protection against extraordinary changes in costs that were not expected at the time when rates were set. Looking at the "causes" of such extraordinary changes, and asking whether such causes were expected, is more appropriate than isolating the review to a particular event and asking whether that singular item led to the unexpected costs.

More broadly, as stated in the pre-filed evidence, (Exhibit A2, Tab 4, Schedule 1, paragraph 2), the Company believes that the proposed amendments to the Z-factor language will make the identification and evaluation of potential Z-factor requests more clear and consistent.

CME numbered paragraph 7 – Deferral & Variance Accounts

EGD notes that PEG does not object to the continuation of existing deferral and variance accounts, or to the addition of appropriate new accounts.

EGD does disagree, though, with PEG's contention that such deferral and variance accounts shift the risk-reward balance in favour of the utility. In EGD's view, Incentive Regulation creates a very large risk reduction for ratepayers at the expense of the shareholder. That is, by pre-determining the future course of rates, ratepayers face far less risk of variability in rates. The Company, on the other hand, assumes the risk that it can effectively manage the business, with many unknown factors and variables at play, over a five year period within the confines of the pre-set revenues. This holds true whether the IR model is based on a Building Blocks or I-X paradigm.

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In EGD's opinion, the variance accounts that it has proposed operate to mitigate risk to the joint benefit of ratepayers and the Company.

For example, the Average Use Factor account balances the risk of changes in consumption patterns for the mutual benefit of both ratepayers and EGD's shareholder. The Company has documented on numerous occasions the decline in average use over a long period of time. This variance account ensures that one party does not gain at the expense of the other for factors that neither can predict with certainty. In the absence of the variance account, if average uses decline more than expected, then ratepayers would benefit at the utility's expense, and if average uses decline less than expected, then the utility would benefit at the ratepayers' expense.

As a further example, the GTA project variance account will protect all parties from actual costs and project timing that are different from what has been forecast. Given the very large amounts to be spent on the GTA project, variances in spending or in timing could have material consequences if the variance account was not in place.

Finally, the two new variance accounts proposed by EGD in its updated evidence appropriately balance the risk of a five year IR plan. These accounts, which relate to 2017 and 2018 capital costs around relocations and mains replacements identified through pipeline inspections, provide an appropriate level of protection to EGD from discrete activities that cannot be forecast, and that are to large extent beyond management control. As explained within Exhibit B2, Tab 1, Schedule 1, the inclusion of these new variance accounts for the final two years of the IR term allows EGD to assume all other risks associated with extending the 2016 Capital Budget (without inflation) for two more years.

<u>CME numbered paragraph 8 – SEIM</u>

The Company has modified its proposal for a Sustainable Efficiency Incentive Mechanism, which can be found at Exhibit A2, Tab 11, Schedule 3. The modified mechanism has closer links to the form of Efficiency Carryover Mechanism ("ECM") that has been approved by the Alberta Utilities Commission. EGD believes, however, that the modified SEIM goes beyond and improves upon the Alberta model by stipulating that no SEIM reward is available unless EGD can demonstrate that the net present value of the productivity benefits exceeds any potential reward to the utility. In addition, EGD's proposal contains other features that only allow the SEIM reward if current performance and service quality are maintained.

In EGD's opinion, the modified SEIM appropriately enhances performance incentives, and creates no new risk for ratepayers. In fact, EGD sees that the mechanism creates only upside for ratepayers – that is, a reward is only applicable if the benefits to ratepayers exceed the reward amount.

Comments from LEI about the updated SEIM can be found within Attachment 2, and also within LEI's report at Exhibit A2, Tab 11, Schedule 3, Attachment.

<u>CME numbered paragraph 9 – Term Length</u>

Please see the response to CME numbered paragraphs 2 and 3, above.

In response to the last sentence in the above-noted paragraph, EGD believes that the five year term of the Customized IR plan, along with the incentives provided by the SEIM, succeed in encouraging EGD to find and implement sustainable productivity initiatives.

<u>CME numbered paragraphs 10 to 16 – Concentric's Empirical Research and Other Work</u>

Each of the above-noted paragraphs within the PEG report appears to relate directly to the work and associated report prepared by Concentric. These items are addressed in Concentric's response, found as Attachment 1 to this response.

<u>CME numbered paragraph 17 – Cost Forecasts</u>

As explained above, in the preamble to this response and in response to CME numbered paragraphs 4 and 5, EGD has presented compelling evidence to support the forecast for both O&M and Capital expenditures.

Further, as discussed above, EGD disputes PEG's contention that the Customized IR model incents the Company to artificially inflate its proposed cost forecasts. To the contrary, the ongoing nature of the regulatory framework prompts EGD to present reasonable forecasts. This item is further dealt with in the LEI response, at Attachment 2.

<u>CME numbered paragraph 18 – Overall Assessment</u>

The Customized IR plan is appropriately tailored to EGD's circumstances, and meets the Board's objectives, as explained within Exhibit A2, Tab 1, Schedule 1. EGD believes that the Customized IR plan creates strong incentives and that the resulting prices are reasonable. As stated above, EGD believes that the plan's design squarely places the majority of risks with the utility, and several measures have been introduced to reduce ratepayer risk. Compelling evidence has been produced to support the forecast for both O&M and Capital expenditures. EGD is confident that the empirical analysis from Concentric and further expert evidence from LEI provide persuasive support for EGD's Customized IR proposal.

In Attachments 1 and 2, Concentric and LEI provide their perspectives in response to this item.

<u>CME numbered paragraph 19 – Overall Assessment</u>

The Company disputes that the IR plan suggested by PEG at the end of the Executive Summary is appropriate. To the contrary, such a plan will not allow EGD to earn a fair return over the coming years.

As explained throughout its prefiled evidence, particularly within the A2 series of exhibits, an IR plan of the same form as EGD's 1st Generation IR term will not accommodate the Company's forecast spending requirements over the next five years. The Company is facing large and uneven capital spending requirements. The Board identified within the Renewed Regulatory Framework for Electricity that this scenario may not be accommodated within an "I-X' type model. The Board identified that a different model is appropriate in such circumstances, stating that "The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels" (RRFE Report, at page 19).

In Attachments 1 and 2, Concentric and LEI provide their perspectives in response to this item.

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Concentric Energy Advisors, Inc.'s Response to Interrogatory CME-1

Interrogatory I.A1.EGDI.CME.1 requests the responses and comments of EGD and EGD's experts, Concentric Energy Advisors ("Concentric") and London Economics International LLC ("LEI") on the report "Enbridge Gas Distribution's Customized Incentive Regulation Proposal: Assessment and Recommendations, October 23, 2013," prepared by Pacific Economics Group Research, LLC ("PEG").

There are several issues raised by PEG in its report, but the two recurring themes are criticisms of the incentive properties of EGD's proposed IR plan and the empirical work supporting the plan. The following Attachment 1 contains Concentric's responses to the issues raised by PEG pertaining to Concentric's empirical analysis and related matters. These responses specifically address each of the relevant issues identified by the numbers assigned in I.A1.EGDI.CME.1 to paragraphs in the Executive Summary to the PEG report.

Concentric's responses demonstrate that PEG's criticisms are, in part, based on mischaracterizations of Concentric's analyses or reflect a misunderstanding of the relationship between the analysis and the proposed EGD plan, or a mischaracterization of the plan itself. We also illustrate that PEG's criticisms are in certain cases contrary to positions PEG has taken before other regulators, and in other respects reflect legitimate differences in approach to a complex topic – the measurement of utility efficiency and productivity.

It is Concentric's view that the benchmarking and productivity analyses we have conducted provide a clear picture of EGD's relative efficiency and a solid foundation for evaluating the Company's proposed plan. These analyses have assisted the Company in formulating its proposal. The data sources, assumptions, and methodologies are all presented for scrutiny, and are designed to assist the Board and stakeholders with evaluating the reasonableness of the Company's proposal.

Paragraphs 1 and 18

Paragraph 1: *Our analysis can be briefly summarized. Regarding the regulatory design issues, PEG's review leads us to conclude that the Company's IR proposal is flawed. EGD's Customized IR plan has some similarities to the Company's first generation, "targeted" IR plan which the Board found in the Natural Gas Forum ("NGF") Report did not work effectively. EGD's IR proposal exacerbates the disparate treatment of capital and operation, maintenance and administrative ("OM&A") costs and thereby tends to create unbalanced incentives similar to those identified by the Board in the NGF.*

Paragraph 18: *Overall, PEG finds that EGD's Customized IR proposal raises serious concerns. The proposed plan has poor incentive properties that may generate unreasonable prices and shift risks to customers. The empirical analysis presented in support of the proposed plan is also not compelling and does not allay PEG's fundamental concerns with the Customized IR proposal.*

Response:

The Company's current proposal is comprehensive and includes both O&M and capital costs, which is in contrast to EGD's first, targeted IR plan which covered OM&A only. As opposed to "exacerbate[ing] the disparate treatment of capital and OM&A costs," EGD's proposed plan explicitly incorporates specific forecasts for each of the major costs and recognizes that capital cost drivers can be unique from OM&A cost drivers. The need for separate treatment of OM&A and capital is not unique to EGD. In fact, in sharp contrast to PEG's criticism that EGD's IR proposal exacerbates the disparate treatment of capital and operation, maintenance and administrative ("OM&A") costs, PEG supported separate treatment of O&M and capital in a 2013 Central Maine Power ("CMP") filing concerning a proposal for a hybrid incentive rate plan:

> …most MRPs [multi-year rate plans] in the English-speaking world are based on alternative approaches to ARM design that provide more flexibility with respect to capital expenditure ("capex") funding. These include "stairstep" trajectories based on cost forecasts and "hybrid" ARMs which involve a mix of cost forecasting and index research. The hybrid approach to ARM design that is popular in North America uses indexes to address O&M expenses and stairsteps to address capital cost… The

> stairsteps are usually based on cost forecasts. The stairstep approach can therefore accommodate a wide variety of capital spending plans.[1]

In addition, EGD's Customized IR proposal is consistent with the Board's explicit adoption of a custom IR plan option for electric utilities, who like EGD are facing large multi-year capital spending plans. The Board has stated that "the Custom Incentive Rate-setting ("Custom IR") method may be appropriate for distributors with significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures," and that the associated "rates are set based on a five year forecast of a distributor's revenue requirement and sales volumes."[2]

Finally, Concentric's empirical analysis supporting EGD's proposed Customized IR plan is robust, objective and transparent. Responses regarding specific criticisms of the empirical evidence in support of EGD's proposed Customized IR plan are provided in the remainder of this response.

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1 Pacific Economics Group Research, LLC, "Central Maine Power Company Request for New Alternative Rate Plan ("ARP 2014"): Productivity Offset Factor," Testimony of Mark N. Lowry, May 1, 2013, pages 3 and 7.

2 Ontario Energy Board, "Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach," October 18, 2012, pages 14 and 18.

Paragraph 4

> ***Paragraph 4:*** *EGD says its Customized IR proposal is an example of "building block" regulation, but it is a version of building blocks that the UK energy regulator abandoned nearly a decade ago because of its poor incentive properties. The EGD's Customized IR proposal creates the same perverse ex ante incentives to inflate capital cost projections as the early UK building block plans. Because the Company's capital expenditure forecasts are not supported by independent and external benchmarking evidence, the inherent incentive to inflate these forecasts under the Customized IR proposal can generate unreasonably high prices and shift risks to customers*

Response:

LEI is providing perspective on the use of building blocks in the UK in Attachment 2 to this response; in addition, Concentric is providing the following general comments on the building block approach.

First, the Company's capital cost projections, which are provided with supporting detail in the 542 pages of Exhibit B2, are subject to both regulatory and stakeholder review during the course of this proceeding. Additional regulatory review of the Company's Ottawa and GTA reinforcement projects has occurred in EGD's Leave to Construct applications (EB-2012-0099 and EB-2012-0451).

In addition, PEG's criticism of EGD's building block approach is inconsistent with PEG's recommendations on behalf of CMP in its Request for New Alternative Rate Plan ("ARP 2014"). Specifically, PEG recommended that CMP's ARP 2014 should include

> "… an alternative approach to [attrition relief mechanisms] ("ARMs") design. The proposed "hybrid" approach is well established and uses index research only to provide compensation for its operation and maintenance ("O&M") expenses. Compensation for capital cost would have a stairstep trajectory. Lowry, page 1)
>
> …
>
> As for stairstep treatment of capital costs in hybrid revenue caps, these typically are based on cost forecasts. This approach therefore accommodates diverse capital cost trajectories. (Lowry, Page 8)
>
> …

> When a utility expects an unusual capital cost trajectory it can be argued then that a hybrid ARM combines the best of both worlds, using indexing where it works best and stairsteps where they work best. (Lowry, Page 8)[3]

[3] Pacific Economics Group Research, LLC, "Central Maine Power Company Request for New Alternative Rate Plan ("ARP 2014"): Productivity Offset Factor," Testimony of Mark N. Lowry, May 1, 2013.

Paragraphs 5 and 17

Paragraph 5: *EGD claims its proposed ESM provides assurance to the Board that its cost forecasts are reasonable, but PEG disagrees. The ESM does not provide any independent verification that the ex ante cost forecasts reflected in rates are reasonable. The Customized IR can also create incentives for EGD to act inefficiently in order to avoid triggering the off-ramp and a review of the Company's cost projections*

Paragraph 17: *EGD also discusses the process used to develop its forecasts for OM&A and capital expenditures. While the Company's testimony on these issues is interesting, it ultimately provides no assurance that the cost projections embedded in the Customized IR proposal are efficient. If the capital cost forecasts submitted at the outset of the budget process are inflated, the capital cost projections at the end of the process can also be inflated. Given the Company's incentives to err on the "high" side when forecasting capital expenditures for a Customized IR plan, PEG believes EGD must provide compelling evidence to the Board that both its initial and final capital cost projections are efficient and will generate reasonable prices. PEG does not believe EGD's application contains such evidence.*

Response:

Concentric has demonstrated that EGD's forecasted O&M costs are reasonable based on a comparison to benchmark utilities and in relation to productivity from the seven company subgroup (Exhibit A2, Tab 9, Schedule 1, Pages 51 – 53). In addition, the efficiency and cost effectiveness of EGD's capital forecast is demonstrated in detail throughout the 542 pages of Exhibit B2 of EGD's evidence in this proceeding. The efficiency of a gas distribution company's capital spending plans cannot be reliably evaluated by benchmarking, indexing or trend analyses, because a gas distribution company's capital spending is impacted by circumstances that are unique to that distribution company at a specific point in time. As explained throughout Exhibit B, EGD's capital spending plans are strongly affected by unique and unprecedented circumstances related to safety and reliability requirements that must be addressed in the upcoming five years. Also, the reasonableness of the company's capital cost projections is subject to both regulatory and stakeholder review during the course of this proceeding;

additional review of the Company's Ottawa and GTA reinforcement projects has occurred in EGD's Leave to Construct applications (EB-2012-0099 and EB-2012-0451).

Lastly, PEG states that it does not oppose EGD's proposed use of variance accounts, including EGD's proposed new variance for the GTA reinforcement project ("GTAPVA"), which will true-up EGD's actual GTA project costs with actual revenues collected. (Exhibit L Tab 1 Schedule 2 Page 5) Thus, the GTAPVA will ensure that EGD has no incentive to err on the "high" side when forecasting capital expenditures for the GTA reinforcement project, which is a significant portion of the Company's projected capital spending.

Paragraphs 10 & 11

Paragraph 10: *The empirical research presented in support of the proposed plan is primarily used to evaluate whether conventional IR rate adjustment formulas would recover EGD's projected costs. Whenever CEA finds revenues under a potential rate adjustment formula are below EGD's costs, it concludes that the rate adjustment formula is inappropriate, not the cost levels reflected in the Customized IR proposal. CEA is therefore using the Company's cost proposals to "benchmark" the reasonableness of IR rate adjustment formulas, not the other way around.*

Paragraph 11: *CEA's research does not support the efficiency of EGD's projected costs or the reasonableness of the Customized IR proposal itself. CEA takes the reasonableness of EGD's cost forecasts as given and simply evaluates whether alternate rate adjustment formulas calibrated with its research would allow EGD to recover these projected costs. CEA has not developed any independent evidence that can be used to confirm, reject or otherwise test the reasonableness of EGD's forecast costs over the term of its Customized IR proposal. The reasonableness of EGD's Custom IR application depends on the reasonableness of its cost projections. Since CEA's empirical analysis provides no evidence on the latter issue, it does not affirm the reasonableness of EGD's Customized IR proposal.*

Response:

Concentric has demonstrated that EGD's forecasted O&M is efficient; EGD's forecast 2014 – 2016 O&M per customer is lower than the industry average for 2011 (Exhibit A2, Tab 9, Schedule 1, Page 51), and the cumulative 2014 to 2016 productivity savings based on a comparison of EGD's O&M forecast relative to I-X O&M growth is approximately $12 million (Tab 9, Schedule 1, Page 52). These analyses demonstrate the efficiencies that are reflected in EGD's O&M forecast.

Assuming that PEG's criticism is directed at Concentric's assessment of EGD's proposed capital recovery approach, PEG's criticism is misplaced and misleading. Concentric's capital spending analysis is not represented or intended to be a test or measure of the efficiency of EGD's capital plans. Rather, Concentric's analysis was specifically designed to test whether an I-X plan, by itself or in combination with one of three approaches to recover capital costs, would allow the Company a reasonable opportunity to recover its costs and thereby meet the Fair Return Standard. (Exhibit A2, Tab 9, Schedule 1, Pages 58 - 68). The Board is guided by fundamental regulatory principles that any ratemaking solution must satisfy:

> As a regulator, the OEB balances the interests of consumers and utilities.
>
> Consumers are well served if both the pricing and the standard of service being provided are fair and reasonable. In this regard, the OEB's mandate includes setting distribution and transmission rates that are "just and reasonable" and establishing standards and conditions of service for utilities to follow in their operations.
>
> 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. [4]

EGD has provided substantial evidence in the 542 pages of Exhibit B2, Tabs 1 – 10 concerning the efficiencies and considerations of cost effectiveness that that are reflected in the Capital Budget. The Company's capital spending plans are subject to scrutiny in this hearing, and in the leave to construct process. To meet the balance of interests described above, the Company must also "have a reasonable opportunity to recoup costs and earn a fair return". Concentric's empirical analysis focused on measuring whether or not an I-X rate trajectory would satisfy that standard. Based on this analysis of capital combined with O&M, we concluded that an I-X with industry parameters would not satisfy the Fair Return Standard. Moreover, the Board has stated that "Meeting the [Fair Return] standard is not optional; it is a legal requirement."[5] Therefore, it a requirement that EGD's Custom IR plan, or any other rate plan, provide EGD with a reasonable opportunity to recover its prudently incurred costs, and to earn a fair return on invested capital.

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4 Ontario Energy Board, Energy Sector Regulation – A Brief Overview/Balancing Consumer and Utility Interests, http://www.ontarioenergyboard.ca/OEB/Industry/About+the+OEB/What+We+Do

5 Ontario Energy Board, "Report of the Board on the Cost of Capital for Ontario's Regulated Utilities," EB-2009-0084, December 11, 2009, page 18.

Paragraph 12

Paragraph 12: *Although CEA has not benchmarked EGD's cost projections, it has benchmarked the Company's historical costs, but no conclusions can be drawn about EGD's cost efficiency from this analysis. CEA's benchmarking methodology provides no persuasive evidence on EGD's cost efficiency for four main reasons. First, CEA relies entirely on a peer group benchmarking approach, which is almost never sufficient to yield robust inferences on utility efficiency. Second, CEA provides no justification for the similar-weather criterion it uses to select its peer group. This criterion tilts the peer group towards a high-cost set of US "rust belt" distributors struggling with slow customer growth and aged delivery systems constructed with materials prone to gas leaks. Third, CEA's benchmarking methodology does not control for differences in scale economies among the distributors that are selected for its peer group; all else equal, this will tend to improve benchmarking assessments for larger distributors in the group, like EGD. Fourth, CEA does not attempt to undertake comprehensive cost comparisons even though such comparisons are feasible given its methodology. The partial OM&A cost comparisons that CEA relies on provide an incomplete and potentially misleading measure of relative cost efficiencies.*

Response:

Concentric's analysis provides meaningful and valid information about EGD's cost efficiency vis a vis the performance of comparable industry peers. Concentric's response to each of PEG's four specific criticisms is provided below:

First, Concentric does not rely entirely on peer group benchmarking to assess EGD's cost efficiency as PEG suggests. Concentric uses both peer group benchmarking and productivity analysis in evaluating EGD's relative cost efficiency, as explained in section IV of Concentric's report "Evaluation of EGD's Productivity". The results of Concentric's benchmarking and productivity analyses, which compare EGD's performance against the industry study group and the seven company sub-group, are contained on pages 25-38 of Concentric's report. In addition, the Board's critiques of peer group benchmarking as presented in PEG's report on page 37 are specifically related to using benchmarking to assign all benchmarked companies to groupings ("cohorts") for the purposes of assigning stretch factors. Concentric is not proposing to use peer group benchmarking to assign all benchmarked companies to cohorts for the purposes of assigning stretch factors, therefore the Board's critiques about using benchmarking to assign all benchmarked companies to cohorts for the purposes of assigning stretch factors is irrelevant.

Second, as described in detail in the response to I.A1.EGDI.STAFF.12, Concentric designed the similar weather criterion to identify U.S. distribution companies that have construction and operating conditions that are similar to those experienced by EGD and that would affect plant and O&M costs. For example, "per unit" costs of construction and maintenance are higher for cold weather gas distribution utilities, which (1) are restricted to performing non-emergency mains and services construction during only non-winter months; (2) face challenges locating and repairing leaks in the winter through frozen ground; (3) experience "frost heave", which can cause leaks in the distribution system; and (4) are affected by winter storms, which results in increased travel time and overtime costs for meter reading, service calls, emergency response, and other related activities.

In addition, gas companies must design and manage their distribution systems to provide reliable, uninterrupted service on a specifically defined extremely cold "design day," which is much higher for a cold weather gas utility than for a warm weather gas utility of the same size. Thus, the distribution system of a cold weather gas utility 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 weather and warm weather gas distribution companies are well understood in the industry, i.e., construction and operating conditions experienced by cold and warm weather gas distribution companies are fundamentally different, and thus the costs associated with those construction and operating conditions are also fundamentally different, therefore the similar weather criterion is critical to developing a peer group of companies that are similar to EGD.

Third, Concentric's methodology explicitly accounts for scale economies by including the size criterion in developing the industry study group. Concentric excluded all U.S. gas utilities that have fewer than 500,000 customers in a single state. Furthermore, Concentric further narrowed its study group to focus on a seven company subgroup that represents the largest and fastest growing companies. These largest companies have at least 850,000 customers, which again, explicitly recognizes economies of scale.

Fourth, Concentric presented and discussed full benchmarking results for capital costs, as shown in Exhibit A2, Tab 9, Schedule 1, Figures 8, 10, A-8, A-9, A-10, A-11. In fact, Concentric presented the exact same figures for the capital results as it presented for the OM&A cost results. In addition, Concentric provides comprehensive cost comparisons through its TFP analysis. This analysis includes both O&M and capital inputs, and Concentric determined that EGD's productivity was better than both the industry and seven company subgroup over the 2007-2011 period. To claim that Concentric relied only on OM&A benchmarking results is misleading.

Paragraphs 13 and 14

Paragraph 13: *CEA has also undertaken a productivity study for EGD and a group of US utilities. This study yields markedly lower estimates of total factor productivity ("TFP") growth for the Company and the industry than credible estimates of these TFP trends that have been presented elsewhere. A likely explanation (at least in part) for CEA's anomalous results is that its sample is tilted towards slow-growth rust belt utilities. Economic and output growth for these gas distributors will be below the industry norm. All else equal, slower output growth will be reflected in slower TFP growth.*

Paragraph 14: *A TFP study like CEA's that arbitrarily rules out half of the US gas distribution industry cannot yield a credible estimate of the industry's TFP trend. Such a trend is also not relevant for EGD, since the Company continues to experience rapid customer and output growth. PEG is likely to have further comments on CEA's TFP results after we have had an opportunity to review CEA's work in detail.*

Response:

First, PEG's claim that Concentric's TFP "study yields markedly lower estimates…than credible estimates…that have been presented elsewhere" is false. Concentric's TFP results are not "markedly lower" than other recent TFP results. PEG's own recent work for the Ontario RRFE would presumably be considered "credible". In that case, PEG's presented TFP results for Ontario electric distributors of -0.05% and 0.1% using indexing methods[6] which is not "markedly" different from Concentric's TFP results of -0.01% for the seven company sub-group. When PEG's TFP results for Ontario electric distributors were expanded to include Toronto Hydro and Hydro One, PEG's TFP results of -1.24% and -1.10% are lower than Concentric's TFP results of -0.32% for the industry study group, and -0.28% for EGD. The Brattle Group (based on the work of NERA) presented TFP results ranging from -0.28% to -1.09% for ATCO Gas,[7] which also is not "markedly" different from Concentric's TFP results. The Brattle Group further adjusts its TFP results by subtracting 1.31% to 1.73% to account for the difference in Canadian and US

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[6] Pacific Economics Group Research, LLC, "Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board," May 3, 2013, subsequently revised on May 31, 2013.

[7] The Brattle Group, "Written Evidence of Paul R. Carpenter for ATCO Gas and ATCO Electric," AUC ID 566 RRI, July 22, 2011, page 30.

productivity, yielding an X factor estimate ranging from -1.59% to -2.82%, which is lower than Concentric's results. In addition, Christensen Associates Energy Consulting (also based on the work of NERA) presented TFP results of -1.4% for Alta Gas,[8] which is lower than Concentric's TFP results. Therefore, there is no evidence to suggest that Concentric's results are "markedly lower" than other recent TFP studies.

PEG's critique that Concentric relies on a sample "that arbitrarily rules out half of the US gas distribution industry" and "is tilted towards slow-growth rust belt utilities" is without merit. As described in Concentric's report, the criteria that Concentric used to screen distribution companies for the industry study group is not "arbitrary." Companies were excluded from the study group if they did not meet the similarity of operations, weather, or size to EGD criteria, or if the necessary data was not available. The criteria were carefully developed to identify companies that are similar to EGD, while allowing for a sufficient number of companies in the study group to ensure the analysis would be robust and provide an appropriate perspective for industry comparisons. As described in our response to Paragraph 12 above, there are fundamental differences between cold-weather and warm-weather construction and operating conditions for gas distribution companies that translate into fundamental differences in costs. Therefore the weather criterion is critical to developing a peer group of companies that are similar to EGD. In addition, it is commonly accepted that there are economies of scale associated with operating a large utility, therefore Concentric developed a similar size criterion based on customer counts to ensure the study group companies are similar to EGD. Finally, from a practical perspective, companies for which the necessary data is not available cannot be included in the analysis. Therefore, there is specific reasoning behind each company that was excluded from Concentric's analysis and no company was excluded arbitrarily.

Regarding PEG's assertion that Concentric's study group is flawed because (a) slow-growth utilities were over-sampled, (b) economic and output growth for these gas distributors will be below the industry norm, and (c) all else equal, slower output growth will be reflected in slower TFP growth, Concentric does agree with PEG that slower output growth will result in slower TFP growth, *all else being equal*. However, more correctly stated, all else equal, slower output growth will be reflected in slower input

[8] Christensen Associates Energy Consulting, LLC, "Review & Evaluation of AUI Incentive Regulation Plan", AUC ID 566 RRI, July 22, 2011, page 12.

growth; whether TFP growth increases, decreases or remains constant depends on the relative changes in input and output growth. In fact, the study group company that has the highest TFP result (National Fuel NY) is one of three companies in Concentric's study group that has negative customer growth. Therefore, slower growth companies should not necessarily have lower TFP growth and the inclusion of such companies should not necessarily skew the TFP results.

Further, the seven company subgroup was specifically screened for the fastest growing and largest utilities. While the TFP results for the seven company sub-group were higher than for the larger industry study group, EGD outperformed the seven company sub-group during the 2007-2011 time period.

In addition, there is significant overlap between PEG's and Concentric's study groups, and only a small amount of the differences are related to Concentric's weather criterion. PEG relied upon 34 gas distribution companies in its analysis presented in Alberta, which we presume did not "arbitrarily rule[s] out half of the US gas distribution industry." As shown in the following table, more than half (i.e., eighteen) of PEG's companies are included in Concentric's industry group, thirteen of PEG's companies were too small to be included, and only three would have been excluded by Concentric due to weather, so any claims that Concentric's weather criterion "tilted" the results are false.

PEG's Sampled Gas Distributors for Productivity Research in Alberta[9] Relative to Concentric's Screening Criteria

PEG's Sampled Gas Distributors that are Included in Concentric's Industry Study Group	PEG's Sampled Gas Distributors that are Small Utilities and thus Excluded from Concentric's Industry Study Group	PEG's Sampled Gas Distributors that are Warm Weather Utilities and thus Excluded from Concentric's Industry Study Group
Baltimore Gas & Electric	Alabama Gas	Pacific Gas and Electric
Boston Gas	Cascade Natural Gas	San Diego Gas & Electric
Brooklyn Union Gas	Central Hudson Gas & Light	Southern California Gas
Consolidated Edison of NY	Connecticut Natural Gas	
Consumers Energy	Louisville Gas and Electric	
East Ohio Gas	Madison Gas and Electric	
Niagara Mohawk Power	New Jersey Natural Gas	
North Shore Gas	NSTAR Gas	
Northern Illinois Gas	PECO Energy	
Northwest Natural Gas	Peoples Natural Gas	
Orange and Rockland Utilities	Public Service of North Carolina	
Peoples Gas Light and Coke	Southern Connecticut Gas	
Public Service Electric and Gas	Wisconsin Power and Light	
Puget Sound Energy		
Questar Gas		
Rochester Gas and Electric		
Washington Gas Light		
Wisconsin Gas		

[9] Pacific Economic Group Research LLC, "PBR Plans for Alberta Energy Distributors," AUC ID 566 RRI, December 17, 2011, Table 1.

Paragraph 15

Paragraph 15: *CEA also excludes a stretch factor from the empirical analyses it uses to evaluate alternate rate adjustment mechanisms. PEG believes this conclusion is unwarranted for four reasons: 1) there is no persuasive evidence that EGD is actually an efficient cost performer; 2) the Board has rejected the view that stretch factors are appropriate only for distributors under a "first generation" IR plan in its findings for both 3rd Generation IR and 4th Generation IR for electricity distributors; 3) the Board cannot be assured that EGD's proposed ESM will either protect customers or allow them to share in EGD efficiency gains under the Company's proposed Custom IR plan; and 4) CEA's TFP evidence is inconsistent with credible TFP evidence that has been presented elsewhere.*

Response:

Concentric continues to believe that a stretch factor of zero is warranted in this case. First, Concentric has presented plenty of persuasive evidence that EGD is an efficient cost performer. As discussed in Concentric's response to Paragraph 12 above, and in section IV of Concentric's report, "Evaluation of EGD's Productivity," Concentric's benchmarking, TFP, and PFP analyses demonstrate that: (a) EGD is currently an efficient utility, (b) EGD has continued to improve its performance relative to its industry peers, and (c) EGD improved its productivity during the 1st generation IR plan (2007-2011) compared to the pre-IR Plan period (2000-2007) relative to its industry peers.

Furthermore, as cited by Concentric, PEG (and now the Board) found that a stretch factor of zero was appropriate for the most efficient electric distributors in its current proceeding regarding incentive rate-setting for Ontario's electric distributors. It its draft report, the Board stated that "The Board has determined that the appropriate stretch factor values range from 0.0% to 0.6%. The Board is setting the lower-bound stretch factor value to zero to strengthen the efficiency incentives in the rate-adjustment mechanism and in doing so reward the top performers."[10]

[10] Ontario Energy Board, "Draft Report of the Board on Empirical Research to Support Incentive Rate-setting for Ontario's Electricity Distributors," EB-2010-0379, September 6, 2013, page 28.

The Board has repeatedly re-iterated that "[stretch factors] are somewhat analogous to earnings sharing mechanisms."[11] As explained on pages 67-69 of Concentric's report, EGD's earning sharing mechanism allows for 50/50 sharing of earnings surpluses with customers, beyond a 100 basis point deadband. EGD's proposed ESM plan is consistent with the company's prior IR plan, is more advantageous to customers compared to ESMs that are symmetrical and have larger deadbands, and explicitly provides for sharing further productivity gains with customers.

Lastly, as discussed in detail in Concentric's response to Paragraphs 13 and 14 above, Concentric's TFP analysis is credible. Concentric's TFP results are consistent with, and sometimes higher than recent TFP results presented in Ontario and Alberta.

[11] Ontario Energy Board, "Draft Report of the Board on Empirical Research to Support Incentive Rate-setting for Ontario's Electricity Distributors," EB-2010-0379, September 6, 2013, page 26.

Paragraph 16

***Paragraph 16:** The industry-specific inflation factor used in CEA's empirical research is unacceptable (as currently designed) because it excludes the rate of return on a utility's capital stock, as well as depreciation of that capital stock. These are large components of capital input prices, and any input price inflation measure that excludes them is not a credible measure of input prices for the gas distribution industry. The Board should reject CEA's proposed inflation factor.*

Response:

Concentric's empirical research explicitly addresses both the rate of return and depreciation on the utility capital stock in its capital input price. As stated on page 107 of Concentric's report, "The price of capital is based on the cost of capital, depreciation, and capital gains." This page goes on to explain "The summation of the cost of capital and depreciation applied to the applicable annual construction cost, and reductions for applicable capital gains determine the capital price for each year." These calculations have been provided in the *Capital Service Price Index* tab, in response to I.A1.EGD.Staff.1. The capital price, based on these calculations for both the peer groups and EGD, were used in the determination of the historical TFP results.

If PEG's critique is directed at the forward looking inflation factor, as described on pages 40-41 of Concentric's report, there are several practical problems associated with capturing utility specific capital cost components in a forward index. I factors adopted in I-X plans invariably reflect a simplification of actual utility cost drivers. One could certainly not argue that GDP IPI used in prior electric and gas plans in Ontario and elsewhere explicitly recognized utility capital costs. As explained in Concentric's report:

> Concentric considered the benefits of the continued use of the existing GDP-IPI-FDD inflator versus a composite factor to evaluate the Allowed Revenue amounts included in EGD's Customized IR plan. In doing so, Concentric researched a broad array of potential indices and examined their sources, components and availability. Based on the availability of price indexes that more specifically reflect labour and capital costs, and the historical evidence that illustrates the potential for these cost indices to diverge from the general rate of inflation, we believe it is appropriate to utilize those more specific indices to reflect price changes in those specific

> inputs. In addition, the implicit adjustments to the X Factor that are necessary to account for the differences in productivity and input prices embedded in the generic macroeconomic index require additional data, can be imprecise, and the appropriate methodology can be controversial. Concentric therefore believes it is preferable to use a composite I Factor that explicitly tracks changes in input prices and eliminates the need for X Factor adjustments. On balance, we recommend a composite I Factor comprised of a weighted average of the following indices: (1) Ontario Average Hourly Wages (all employees) for labour-related prices, (2) Canada GDP-IPI-FDD for materials prices, and (3) Canada implicit price index for net gas distribution plant for capital prices as shown in the following graph. [footnotes omitted].

Importantly, Concentric's composite I Factor index <u>includes</u> an implicit price index for net gas distribution plant, which is substantial improvement over a simple GDP IPI index with no explicit recognition of utility capital costs other than that captured in this very broad index.

Paragraph 19

Paragraph 19: *PEG notes that our analysis of the Company's previous IR plan indicated that it generated benefits for both shareholders and customers and was consistent with the Board's criteria for effective regulation. We believe that an IR plan for the 2014-18 period that is calibrated using objective measures of industry TFP growth, appropriate benchmarking studies, and well-designed benefit sharing provisions will also be effective. This plan can also contain Y factors that recover the costs of large capital projects. PEG believes the input price and TFP research for US gas distributors that was presented in Alberta can be used to assess the appropriateness of the elements of an IR plan for EGD.*

Response:

Concentric is assuming that the referenced "input price and TFP research for US gas distributors that was presented in Alberta" is PEG's evidence on behalf of the Consumer Coalition of Alberta filed in December 2011, cited on page 43, footnote 43 of PEG's report in the current case. If so, Concentric cannot evaluate the merits of PEG's statement without examining the supporting analysis behind the PEG's input price and TFP research for US gas distributors that was presented in Alberta.

Notwithstanding the above, the Alberta Utilities Commission criticized PEG's work that was presented in Alberta on behalf of the Consumers' Coalition of Alberta ("CCA"). In its decision, the Alberta Utilities Commission stated:[12]

> 174. With respect to the customized index for labour, capital and materials proposed by the CCA [PEG], the Commission notes that a similar index was proposed by the UCA in the ENMAX FBR proceeding, as outlined in Decision 2009-035. In that decision, it was noted that this type of I factor was more data intensive and more complex than the Commission considered desirable for the purposes of a PBR plan. Indeed, in this proceeding, the CCA [PEG] pointed out that the selection of an inflation measure for a PBR plan is difficult because greater accuracy comes at the cost of greater complexity. ATCO Gas pointed out that the CCA's [PEG's] index needed a 15 page spreadsheet with a number of significant, complex

12 The Alberta Utilities Commission, "Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation," Application No. 1606029, Proceeding ID No. 566, September 12, 2012.

calculations. During the hearing, Dr. Lowry [of PEG] concurred that the calculation of the proposed customized index would likely require a Ph.D.'s expertise. As such, the Commission considers that the customized index proposed by the CCA [PEG] suffers from the same data intensity and complexity drawbacks as did the UCA's proposal for ENMAX. [citations omitted][13]

412. In the Commission's view, NERA's study was more objective and transparent compared to PEG's analysis. First, as the Commission observed in Section 6.3.2 above, the choice of a sample period in PEG's study was primarily based on Dr. Lowry's personal judgment, not on objective criteria. Moreover, as set out in Section 6.3.4, PEG's lack of transparency in data processing did not allow either the other parties nor the independent consultant NERA, to fully test and verify its TFP recommendation. As such, while the Commission recognizes the value of a separate productivity study focusing on gas distributors, the drawbacks of PEG's TFP research do not allow the Commission to rely on it.

13 Concentric notes that the Alberta Utilities Commission's concerns with the complexity of the PEG proposed I factor related to the complexity of the calculations (i.e. the "15 page spreadsheet with a number of significant, complex calculations") rather than with the merits of a three factor index versus a two factor index. Concentric further notes that the I Factor used in our analysis explicitly addresses labour, capital and materials growth, but does not require the complex calculations implicit in the approach proposed by PEG in Alberta.

LEI's Response to CME-1 Interrogatory

Prepared for Enbridge Gas Distribution ("Enbridge" or "EGD") by London Economics International LLC ("LEI")

December 18, 2013

Below is LEI's response to Interrogatory ("IR") CME-1 from Canadian Manufacturers & Exporters ("CME") regarding Enbridge's 2014-2018 rates application EB-2012-0459 (June 28, 2013). CME-1 IR was filed as I.A1.EGDI.CME.1 on November 13, 2013. CME-1 IR asked LEI to comment on the Executive Summary in the Pacific Economics Group ("PEG") Assessment report (filed as Exhibit L-1-2 on October 23, 2013). EGD's proposed Customized IR plan has strong incentive properties because it uses building blocks approach to calculate allowed revenue amounts, embedding productivity in total cost projections, in compliment with various incentive mechanisms, such as the earnings sharing mechanism ("ESM") and the sustainable efficiency incentive mechanism ("SEIM"). The building blocks approach used in the proposed Customized IR plan has been used in the UK and Australia for more than a decade, and continues to be used in those jurisdictions. Furthermore, PEG's considerations of the incentive properties of the Customized IR plan are flawed as they are based on incomplete assessment of how future interactions with the regulator impact near term actions of the regulated firm.

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London Economics International LLC
717 Atlantic Ave, Suite 1A
Boston, MA 02111
www.londoneconomics.com

contact:
Julia Frayer/Cherrylin Trinidad
617-933-7221
julia@londoneconomics.com

1 Executive Summary

London Economics International LLC ("LEI") prepared a report, *Building Blocks Approach to Incentive Regulation*, which was filed with the Ontario Energy Board ("OEB" or the "Board") as Exhibit A2-10-1 on June 28, 2013, with Enbridge's 2014-2018 rate application EB-2012-0459. LEI's report described the use of the building blocks approach in the UK and Australia and compared it to EGD's Customized IR Plan. On October 23, 2013, Pacific Energy Group ("PEG") issued its own report, *Enbridge Gas Distribution's Customized Incentive Regulation Proposal Assessment and Recommendations* ("PEG Assessment Report"), which encompassed a review of LEI's work.

This memo is in response to Canadian Manufacturers & Exporters' ("CME") interrogatory ("IR") CME-1 which asked LEI to comment on the Executive Summary in the PEG Assessment Report.

LEI has organized PEG's comments and critiques into two areas as it relates to the LEI Report:

- ***PEG's assertion that EGD's plan has weak incentive properties is incorrect***: [1]

    a. the analogy of EGD's proposed Customized IR plan with EGD's targeted performance-based regulation ("TPBR") is inappropriate;[2]

    b. the assertion that the proposed Customized IR plan will let EGD to game on an *ex post* basis is unfounded;[3]

    c. the Customized IR plan does not treat capital and O&M separately. Therefore, PEG's belief that the Customized IR plan provides weak incentives due to this separation is not valid;[4]

    d. PEG is mistaken in claiming the that Earnings Sharing Mechanism ("ESM") is not an effective feature of EGD's proposed Customized IR plan;[5] and

    e. PEG's assertion that EGD's proposed Sustainable Efficiency Incentive Mechanism ("SEIM") is incompatible with the Board's objectives for incentive regulation is also incorrect.[6]

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[1] CME. Interrogatories of CME to EGD (filed as "1.AI.EGDI.CME.1" on November 13, 2013), p. 9, paragraph 18 of the Executive Summary of the PEG Assessment and Recommendation Report [PEG. *Enbridge Gas Distribution's Customized Incentive Regulation Proposal Assessment and Recommendations*. (OEB EB-2012-0459, Exhibit L-1-2, October 23, 2013), p. 5.]

[2] CME. Interrogatories of CME to EGD, p. 9, paragraph 1.

[3] CME. Interrogatories of CME to EGD, p. 10, paragraph 4.

[4] CME. Interrogatories of CME to EGD, p. 9, paragraph 1.

[5] CME. Interrogatories of CME to EGD, p. 10, paragraph 5.

- ***PEG's contention that experience of building blocks in the UK and Australia does not support EGD's Customized IR plan is mis-placed***:[7]

    a. specifically, PEG's claim that LEI's description of the UK experience is "the version of building blocks that Ofgem abandoned nearly a decade ago" is untrue;[8] and

    b. PEG dismissed, without specifying reasons, the Australian experience. The Australian experience is both relevant to and supportive of the Customized IR Plan proposed by EGD.

In our review of the arguments put forth by PEG in its Assessment Report and further examination of the facts and details of EGD's proposed Customized IR plan, we conclude that PEG is not correct in its assertion about the weak properties of EGD's Customized IR Plan. The analogy to TPBR is inappropriate and misses the crux of EGD's Customized IR Plan. Furthermore, the presumption of gaming due to differences in motivations for the company *ex post* (after the rates and IR plan are approved by the Ontario Energy Board ("OEB")) are too simplistic and overlook a key element of the regulatory compact in Ontario: the regulated utility must repeatedly and effectively forever disclose its accounts to the regulator, and that creates significant deterrence to any gaming activities alleged by PEG.

In addition, PEG is mistaken in its interpretation of the proposed ESM – the ESM will *reinforce* efficiency goals and also will *safeguard* consumers.[9] As an example of these two beneficial dynamics, ESM serves as a safeguard to consumers specifically if there is actual under-spending of capital investment as compared to forecast amounts during the term of this IR plan. Therefore, the presence of ESM is a stimulus to EGD for achieving the capital productivity embedded in the forecast revenue requirements. Of course, the ESM does not itself validate the forecast amounts that form the basis of the revenue requirement projections in EGD's Customized IR Plan, but that is not the purpose of an ESM.

The SEIM, as revised,[10] is also a driver of productivity. It has been designed to specifically engage management in undertaking efficiency incentives that will provide benefits longer than the currently proposed 5-year term; therefore, it is similar to efficiency carryover mechanisms used in other jurisdictions. We believe that it is in fact better than efficiency carryover mechanisms used in some jurisdictions because it balances the need to demonstrate productivity gains (before receiving the reward) with the need for simple, tractable calculations of the reward itself.

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[6] CME. Interrogatories of CME to EGD, p. 11, paragraph 8.

[7] CME. Interrogatories of CME to EGD, p. 10, paragraph 4.

[8] CME. Interrogatories of CME to EGD, p. 10, paragraph 4.

[9] PEG Assessment Report, p. 19.

[10] Please refer to Exhibit A2-11-3.

Furthermore, PEG is wrong in its representation about the case studies presented by LEI for building blocks. Building blocks are still a widely used regulatory form of incentive regulation mechanism ("IRM"). Building blocks are the basic foundation to UK's current RIIO framework,[11] and have been successfully deployed – in fact, in much the same manner as proposed in EGD's Customized IR plan – in Australia for over a decade. PEG concedes, in its Assessment Report, that some of the elements of the RIIO framework are not transferrable to Ontario, such as the Information Quality Incentive ("IQI").[12] We noted as well in our Report that the IQI would not be simple to implement or efficient use of regulatory effort given the few regulated gas utilities in Ontario. In addition, given the experience in Australia, and furthermore, the deterrence of the repeated interactions between the regulated utility and the regulator, we believe an incentive scheme like the IQI is not necessary for Enbridge's Customized IR plan to be successful at motivating efficiencies and creating benefits for customers.

2 Overview of CME-1 IR

CME submitted interrogatory CME-1 asking EGD and its consultants to comment on the Executive Summary in the PEG Assessment Report. In the IR, CME asked:

> "Attachment 1 to these Interrogatories consists of pages 1 to 8 of the Report prepared by Pacific Economics Group Research, LLC ("PEG") entitled *"Enbridge Gas Distribution's Customized Incentive Regulation Proposal: Assessment and Recommendations, October 23, 2013"*. This Report was distributed by Ontario Energy Board ("OEB") staff on October 23, 2013. The paragraphs in the Executive Summary of this Report have been numbered from 1 to 19 inclusive.
>
> (a) Please provide the responses and comments of EGDI, Concentric Energy Advisors Inc. ("CEA"), and London Economics International LLC ("LEI") to the comments and criticisms of EGDI's Customized IR proposal contained in each and every numbered paragraph."[13]

The next sections will provide LEI's responses to CME's IR - 1.

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[11] RIIO is an acronym that stands for "Revenue=Incentives+Innovation+Outputs."

[12] PEG Assessment Report, p. 56.

[13] CME. Interrogatories of CME to EGD, p. 2.

3 EGD's Customized IR plan has strong incentive properties

LEI does not agree with PEG's claim that EGD's Customized IR plan provides poor incentives that lead to higher prices and shift risks to customers.[14] PEG's analogy of the Customized IR plan to TPBR, which was EGD's first transitional IR plan from more than 10 years ago, is not accurate, nor is there a factual or theoretical basis for PEG's discussion of EGD's potential gaming on an *ex post* basis. EGD's proposed Customized IR plan has strong incentive properties because it encompasses multiple features that motivate EGD to achieve productivity gains over the term of the IR plan and into the future.

3.1 EGD's proposed customized IR plan is not the same as the first targeted PBR plan

PEG claims that the perceived failure of TPBR was linked to the fact that capital costs were based on cost of service ("COS") regulation.[15] PEG claims that EGD's Customized IR plan is also similar to the TPBR.[16] However, this is inconsistent with the Customized IR plan that Enbridge has proposed.

Under TPBR, capital costs remained under COS regulation,[17] while under EGD's proposed Customized IR plan, the capital costs will not be re-set every year according to a COS application. Instead, according to the proposed Customized IR plan, which uses the building blocks approach, EGD will estimate capital spending which will then be used to set allowed revenue amounts under the IR plan.[18] Therefore, under EGD's Customized IR plan, if capital needs exceed the allowed revenue amounts anytime during the term, EGD will not be able to return to the Board for additional rate increases to fund such investment.[19] EGD has to wait until rebasing in 2019, and only if the Board approves the re-set of rates, to recover any total costs that exceeded its forecast revenue requirement.[20, 21]

In addition, the Customized IR plan is different from TPBR as it has embedded productivity in both Operating and Maintenance ("O&M") and capital costs.[22] Furthermore, with EGD's updated Customized IR Plan, there will be no refresh or update of the allowed revenue

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[14] PEG Assessment Report, p. 5.

[15] PEG Assessment Report, pp. 4 and 11-12.

[16] Ibid.

[17] Also noted by PEG in its Assessment Report, p. 11.

[18] EGD revised evidence (December 11, 2012) EB-2012-0459, Exhibit A2-1-1, pp. 4-5.

[19] EGD revised evidence (December 11, 2012) EB-2012-0459, Exhibit A2-1-1, p. 14.

[20] Ibid.

[21] Unless the incremental revenue requirement meets the Z factor threshold and eligibility requirements.

[22] EGD revised evidence (December 11, 2012) EB-2012-0459, Exhibit A2-1-1, p. 4.

amounts set in this proceeding for 2017 and 2018, so unlike the TPBR which was implemented over three years (2000-2002), the Customized IR plan will now encompass a 5-year term (2014-2018).[23]

3.2 Building block approach to OM&A and capital provides robust incentives for productivity improvement

PEG states on page 1 of its report that "EGD's IR proposal exacerbates the disparate treatment of capital and operation, maintenance and administrative ("OM&A") costs and thereby tends to create unbalanced incentives."[24] In particular, PEG contends that EGD's Customized IR plan will put more weight on cost-based regulation of capital costs than on OM&A expenditures and that this creates relatively weaker incentives to control capital costs.[25] This is not true because EGD's IR Customized plan is a total cost plan, rather than an OM&A only plan. EGD is using the building blocks approach where capital and OM&A costs are both included in the derivation of the allowed revenue amounts. And once the Customized IR plan is approved, EGD will be incented to manage both capital and O&M costs in their entirety.

3.3 There is little incentive for EGD to game and inflate its forecast capex because of repeated interactions with the Board and its stakeholders

PEG claims that the forecast capex approach that Enbridge is using in the Customized IR plan creates the wrong incentives because of the potential for gaming by the regulated company. Specifically, PEG contends that Enbridge will over-forecast future capex on an *ex ante* basis and then under-spend on an *ex post* basis.[26]

PEG's theoretical model of *ex ante* versus *ex post* behavior of the regulated utility is incomplete, as it fails to recognize that EGD's interactions with regulators and consumers are repeated. PEG also failed to realize that EGD will be under repeated scrutiny of the Board and stakeholders, within the term of the IR cycle (because of annual reporting obligations) and also at re-setting once it updates the capex forecast after the regulatory period and requests a new IR plan. Therefore, there will be real consequences to EGD if it attempted to game the regulatory system, as suggested by PEG.[27]

By its nature, a building blocks approach requires that a capital cost forecast be included in the derivation of the revenue requirement. We acknowledge that EGD developed the capital investment forecast. However, the company's evidence provided in Exhibit B is validation of

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[23] EGD revised evidence (December 11, 2012) EB-2012-0459, Exhibit A2-1-1, p. 2.

[24] PEG Assessment Report, p. 1.

[25] PEG Assessment Report, p. 16.

[26] PEG Assessment Report, p. 2.

[27] The deterrence is multi-dimensional and could include the risk of disallowance, potential rate impacts, and, theoretically, even sanctions for intentional misconduct.

the reasonableness of the forecast, and stakeholders are welcome to further examine the reasonableness of the forecast.

3.3.1 Interactions between EGD and the Board are repeated and long term

PEG's description of the *ex ante* and *ex post* behavior falls into a discipline of economics known as game theory. Repeated "principal-agent" interactions (such as between EGD and the Board) have been studied extensively in this field of economics. However, PEG appears to be describing an intertemporal "game" but only within a single IR term. This is not a reasonable description of the interaction between EGD and the Board and other stakeholders. Game theory states that the motivations of the regulated utility in a repeated game are different from those in a 'single shot' game. PEG's consideration of the incentives created by the *ex ante* approval of the revenue requirement and *ex post* actions of the utility are therefore incomplete.

First, it should be stated that there is no factual basis for PEG's claim of gaming. In addition, the theoretical basis does not exist. Had PEG applied the theoretical concepts of game theory properly in elaborating its model of *ex ante* to *ex post* incentives, PEG would have recognized that there is a high likelihood that the alleged gaming would be discovered and that then real "punishments" would be applied in the next round of regulatory review – especially given the annual reporting requirements and the extensive review of the Board and stakeholders.

Under the repeated game environment, the players take into consideration the impact of their current actions on the future actions of other players. Therefore, "credible threats or promises about future behavior can influence current behavior."[28] In a repeated interaction, the players take into consideration the likelihood of detection and punishment, and therefore adjust their current behavior to the best course of action. Dr. Sergui Hart, an economist renowned for his experience with game theory, noted that "the threat of punishment ensures that each player fulfills his part of the plan… since any deviation by a player will make the punishments against him go into effect."[29]

Furthermore, game theory also suggests that repeated interactions, of the kind we see between the Board and regulated entities, can induce and sustain cooperative behavior. In late 1950s, Dr. Robert Aumann was the first to provide an extensive analysis of indefinitely repeated games, and demonstrated how repeated interaction yields cooperative outcomes.[30] In his work, Dr. Aumann showed that cooperation will lead to an equilibrium outcome – in other words, a sustainable working relationship between the players (in this instance, that would be EGD, the Board, and stakeholders). The motivation for cooperation is that players can now threaten to punish any deviation from cooperative play today by refusing to cooperate in the future,

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[28] Gibbons, Robert. *A Primer in Game Theory*. Prentice Hall.1992. p. 86.

[29] Hart, Sergui. "Robert Aumann's Game and Economic Theory." *Journal of Economics* (2006):185-211.

[30] Dr. Robert Aumann won the Nobel Prize in Economic Sciences in 2005 for his work on game theory. His 1959 paper on repeated games "Acceptable Points in General Cooperative *n*-Person Games" is available online at <http://www.ma.huji.ac.il/raumann/pdf/Acceptable%20Points%20in%20General.pdf>.

because the "short-term gain from defection today is more than outweighed by the reduction in future cooperation."[31]

The key consideration regarding the likelihood of such an equilibrium in a repeated game concept is whether the risk of discovery and threat of punishment are sufficient in the context of inflated capital expenditure budgets. The information regarding forecast capital expenditures is now part of the EGD application, and EGD will be making annual filings to demonstrate its progress within the term. Under the ESM, EDG will also be obligated to document is annual earnings and net asset base. Moreover, after the end of the IR term, the re-basing will require further documentation of then current costs of service, as well as historical trends in both operating expenses and capital spending. Furthermore, through the SEIM, EGD plans to request incentive rewards for achieving long term sustainable productivity initiatives, and therefore the details of its spending and performance will be thoroughly documented for presentation to the Board.

In contrast to PEG's assertions, theory and practical wisdom would suggest that EGD would be incentivized to provide an accurate forecast capex rather than risk the negative consequences of inflating capex for the sake of short-term gain and taking the risk of that being exposed in future regulatory reviews. Therefore, with the threat of "punishment" on the next IR term, it is unlikely that EGD would inflate their forecasts in the current application.

3.4 ESM reinforces efficiency goals and provides safeguard to consumers

PEG does not agree with EGD that ESM provides assurance to the Board that its cost forecasts are reasonable.[32] In addition, PEG states that it does not believe that ESM protects consumers.[33] In our opinion, neither of these assertions is correct. EGD's proposed ESM is both an implicit and an explicit safeguard to consumers. If the cost forecasts are not reasonable and EGD has over-inflated them, then EGD's actual ROE in future years will exceed the allowed ROE. In such a case, sharing of benefits may be triggered under the ESM and customers will get a share of the savings for any under-spending relative to the forecast in any given year. Given the ESM may be triggered if capital spending is lower than forecast, there is also implicit pressure on EGD, arising as a result of the existence of the ESM, to ensure that the forecasts it is providing are accurate. In addition, with regards to the reasonableness of EGD's cost forecasts, we believe that EGD will have little incentive to inflate its forecasts as discussed earlier in Section 3.3.

EGD's ESM provides safeguard to consumers should there be a wide divergence between revenues and costs. As mentioned in the EGD application filing,[34] the proposed ESM is

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[31] The Royal Swedish Academy of Sciences. *Robert Aumann's and Thomas Schelling's Contributions to Game Theory: Analyses of Conflict and Cooperation*. October 10, 2005. p. 14.

[32] PEG Assessment Report, p. 2.

[33] PEG Assessment Report, p. 19.

[34] EGD 2014-2018 rate application, Exhibit A2-1-2, pp. 13-14.

asymmetric where sharing only happens if EGD over-earns, which means that the risk of under-achieving on its productivity goals resides with EGD.

Moreover, EGD's proposed ESM is compatible with the Board's objectives as shown below:

- ***protecting consumers in respect of price and reliability –*** consumers are protected from the divergence between revenues and costs. They also benefit from getting a share on the improved performance;
- ***encouraging efficient utilities and quality of service –*** ESM encourages efficiency gains by allowing EGD to retain some return on equity ("ROE") gains; and
- ***industry financial viability –*** ESM helps avoid the possibility of unscheduled regulatory interventions, such as windfall profits, which distort patterns of investment and returns.

3.5 EGD's updated sustainable efficiency incentive mechanism ("SEIM") is compatible with incentive regulation

EGD has proposed a revised SEIM[35] that will achieve the common goals and objectives of an efficiency carryover mechanism. The basic objective of such mechanisms is to overcome a known incentive problem with a finite IR term. Under IRM, a utility benefits from efficiency gains during the term because the cost reductions flow through to earnings. However, at re-setting, those efficiency gains are captured for the benefit of customers. Therefore, if an efficiency initiative is identified late in the IR term, it may not be undertaken as it would not provide any meaningful returns to the company to cover the effort expended. With an efficiency carryover mechanism, the weakening of efficiency incentives later in the IR term can be reduced. By rewarding the utility for long run efficiency gains, which may create cost reductions and improvements in service beyond the term, utility management will be incented to seek out efficiency gains over the entire regulatory period and even for longer term.

EGD's updated SEIM is compatible with the Board's objectives as shown below:

- ***protecting consumers in respect of price and reliability*** – under EGD's revised proposal for SEIM, any award that EGD receives would be demonstrated to be smaller than the expected benefits to consumers. The expected benefits will include both achieved benefits, as the SEIM would be analyzed after the end of the term, and future expected benefits. The revised timing of the SEIM, effectively at the end of the IR term, will allow EGD to have data showing actual achievements, and more data for better forecasting of future benefits to customers;
- ***encouraging efficient utilities*** – the goal of the SEIM is to produce incentives for management to undertake long-term, sustainable efficiencies. Through the "carrot" of the potential "award," the SEIM will encourage management to pursue initiatives where

[35] EGD revised its proposed SEIM. Please refer to Exhibit A2-11-3.

benefits may accrue beyond the term of the IRM cycle, which would exclusively benefit customers;

- *quality of service* – EGD will only be rewarded on the condition that it has achieved its performance targets in terms of Service Quality Requirements ("SQR") and customer satisfaction; and

- *industry financial viability* – SEIM will not undermine the viability of the regulated firm. Carryover mechanisms in other jurisdictions sometimes involve penalties in addition to rewards. EGD is not proposing a penalty scheme because EGD is already taking the risks in its proposed asymmetric ESM, where sharing only occurs if EGD over-earns and not under-earns.

4 PEG's contention that experience of building blocks in the UK and Australia does not support EGD's Customized IR plan is mis-placed

PEG is incorrect to say that LEI's description of the UK experience is the "version of building blocks that Ofgem abandoned nearly a decade ago."[36] In fact, the UK's RIIO model still uses the basic building blocks approach to set the amount of base revenue for each year of the price control. The UK's RIIO model also has additional elements such as a more extensive use of objective goals ("Outputs") and an IQI to incentivize the utilities to provide more accurate cost forecasts.

Likewise, Australia has been using the building blocks approach for more than 10 years now, and its experience has been relatively successful. The building blocks approach of the UK and Australia is similar to the EGD's Customized IR Plan where EGD's allowed revenue amounts for 2014-2018 are determined by summing together the appropriate forecast levels of operating costs, depreciation costs, taxes and cost of capital.[37]

4.1 Building blocks approach is still the widely used regulatory form of IRM in UK

LEI was not mistaken in its description of the UK RIIO framework using building blocks approach. As with all regulation, RIIO has evolved the IRM formula from the first days of implementation of an RPI-X approach in the UK. However, the most basic approach has remained unchanged.

Despite having added more provisions of incentives to encourage cost efficiency and quality of service, Ofgem still continues to refer to the whole RIIO model as "a 'building block' approach,"[38] as demonstrated in Figure 12 of the RIIO Handbook. RIIO continues to require a

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[36] PEG Assessment Report, p. 9.

[37] EGD revised evidence (December 11, 2012) EB-2012-0459, Exhibit A2-1-1, pp. 4-5.

[38] "The price control will be set using a 'building block' approach, incorporating incentives to encourage network companies to deliver outputs and value for money over the long term." Source: Ofgem. *Handbook for Implementing the RIIO Model*. October 4, 2010. p. 29.

building blocks modeling approach to set the amount of base revenue for each year of the price control, consisting of:

- expected efficient expenditure;
- allowance for taxation;
- regulatory asset value ("RAV"), capitalization and depreciation; and
- Weighted Average Cost of Capital ("WACC").[39]

PEG also errs in characterizing RIIO as creating significantly different treatment of capex.[40] Indeed, there are no substantial changes with respect to how capex will be dealt with under the RIIO model and under the revised Customized IR proposed by EGD. For example, the regulatory asset value ("RAV") will still be used to value the network assets.[41] A percentage of the opex and capex will be added to the RAV, which will be determined during the price control review.[42] Nevertheless, under RIIO, some specific implementation details have changed. For example, the depreciation in the RIIO model will be based on the economic asset lives, as opposed to the fixed 20 years that had been used in prior price controls by Ofgem.[43] This modification under the RIIO model signifies a longer depreciation term which means less annual depreciation expense, assuming no other change to RAV. This is intended to strike a balance between costs faced by existing and future consumers.

4.2 Complexity and costs of IQI mechanism and its implementation means this may not be a cost beneficial proposition in Ontario

As PEG has raised the focus of the IQI in its description of the UK performance-based ratemaking regime, it is worthwhile to explore the dimensions of the IQI further.

First, it is important that PEG's description of the IQI is corrected. The IQI is <u>not</u> meant to "potentially reward utilities for keeping capital cost projections relatively low" as claimed by PEG in its Assessment.[44] More accurately, the aim of the IQI mechanism is to "encourage companies to submit more accurate expenditure forecasts to Ofgem."[45] We believe that the

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[39] Ofgem. *Handbook for Implementing the RIIO Model*. October 4, 2010. p. 29.

[40] PEG Assessment Report, p. 18.

[41] Ofgem. *Handbook for Implementing the RIIO Model*. October 4, 2010. p. 28.

[42] Ofgem. *Handbook for Implementing the RIIO Model*. October 4, 2010. p. 109.

[43] Ofgem. *RIIO – GD1: Final Proposals – Finance and Uncertainty Supporting Document*. December 17, 2012. p. 6.

[44] PEG Assessment Report, p. 18.

[45] Ofgem. *Handbook for Implementing the RIIO Model*. October 4, 2010. p. 66.

ESM, coupled with all the dimensions of the Customized IR plan such as the five year term and the SEIM, also reinforce this same objective.

Second, the IQI is only one component of the IRM and the presence of the IQI (or lack thereof) does not change the essential building blocks foundation. The IQI, in and of itself, has not been the sole source of improvement in incentive properties in UK's performance-based ratemaking regime. Notably, even Ofgem has indicated that the IQI may not be a permanent feature of its performance-based ratemaking regime in the future:

> "The use of the IQI will be subject to review in future price control periods. The incremental benefit of using the IQI depends on the contribution that the other tools in the assessment tool-kit can make. For instance, as companies become experienced in developing well-justified long-term business plans, and as we become experienced in assessing those plans, the incremental benefits of the IQI may reduce. At some point in the future, we may decide that the potential benefits of the IQI are not sufficient to justify the additional complexity and administrative burden that it brings."[46]

The IQI is also a complex mechanism[47] that requires considerable information and judgment to design. For example, in determining the level of the efficiency incentive rates in the IQI back in 2010, Ofgem noted the subjectivity required in formulating the IQI:

> "the incentive rate would vary across companies according to the IQI. We would decide the range of efficiency incentive rates for companies. There is no exact science to determining "optimal" rates, as evidenced by all regulators adopting similar approaches, and there are a number of issues to consider when determining the appropriate rates."[48]

Furthermore, implementation of the IQI mechanism is not simple. According to Ofgem, there were a number of concerns that the IQI itself could lead to unintended consequences, including by way of inappropriately representing management as risk neutral.[49]

In addition, given the significant amount of regulatory effort needed to design a similar scheme, this may not be a cost beneficial proposition in Ontario, especially for purposes of establishing

[46] Ofgem. *Handbook for Implementing the RIIO Model*. October 4, 2010. p. 66.

[47] UK stakeholders have commented on the complexity of the IQI. See Ofgem's *Regulating Energy Networks for the Future: RPI-X@20 Emerging Thinking – Simplicity of the Framework: Issues to Consider (Supporting Paper)*. January 20, 2010. p. 3.

[48] Ofgem. Regulating Energy Networks. July 26, 2010. p. 99.

[49] Ofgem. *Electricity Distribution Price Control Review Policy Paper – Supplementary Appendices*. December 5, 2008. p. 111.

an IR plan for one utility. As a result, LEI did not refer to the IQI mechanism in detail in its Report on the Customized IR plan for EGD. PEG acknowledges this same concern even in the context of the multi-utility electric distribution sector:

> "…developing and implementing such mechanisms is likely to be difficult and costly in Ontario, particularly since separate capex benchmarks would need to be developed for more than 80 distributors."[50]

4.3 Australia still employs the building blocks approach in its performance based ratemaking regime

In Australia, Victoria first adopted the building blocks approach to regulate electric distribution and transmission networks around 1994.[51] The building blocks approach to determination of price caps and revenue caps under performance-based ratemaking was then deployed in other utility sectors and by other state regulators. Since 2009, the Australian Energy Regulator ("AER") regulates the gas distribution networks.

According to *Natural Gas Rules*, Australia's gas distribution network providers use building blocks-based price setting, as Rule 76 states:

> "Total revenue is to be determined for each regulatory year of the access arrangement period using the building block approach in which the building blocks are:
>
> (a) a return on the projected capital base for the year (See Divisions 4 and 5); and
>
> (b) depreciation on the projected capital base for the year (See Division 6); and
>
> (c) the estimated cost of corporate income tax for the year (See Division 5A); and
>
> (d) increments or decrements for the year resulting from the operation of an incentive mechanism to encourage gains in efficiency (See Division 9); and
>
> (e) a forecast of operating expenditure for the year (See Division 7)."[52]

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[50] PEG Assessment Report, p. 56.

[51] Independent Pricing and Regulatory Tribunal ("IPART"). *Regulation of New South Wales Electricity Distribution Networks: Determination and Rules under the National Electricity Code.* December 1999. p. vii. <http://www.efa.com.au/Library/IPART1999PricingDet.pdf>

[52] Australia *Natural Gas Rules* Version 18 - Part 9: Price and Revenue Regulation. July 4, 2013. p. 54. <http://www.aemc.gov.au/gas/national-gas-rules/current-rules.html>

Accordingly, AER's latest *Access Arrangement Guideline* (March 2009) outline key features of the process, relevant criteria, and other information that gas service providers need to prepare their access arrangement proposals.[53] AER's *Access Arrangement Guideline* summarizes the importance of the building blocks as follows: "[t]he building block approach is used to identify the costs that comprise total revenue and that are expected to be incurred by an efficient service provider providing pipeline services. This revenue is used as the basis to calculate reference tariffs."[54]

The Australian regulatory regime was established on the experiences of the UK. Not surprisingly, similar to the UK, Australia uses the building blocks approach in much the same way as we described in Section 4.1 above.[55] More recently, other countries, such as Malaysia[56] and the Philippines,[57] have emulated Australia's building blocks approach. Notably however, Australia's building blocks approach does not employ an IQI mechanism.

4.4 Concluding remarks

As described in the previous sections, both the UK and Australia continue to use the concept of building blocks to set rates that motivate efficiency improvements among regulated utilities. EGD is proposing to use the basic building blocks approach to calculate its allowed revenue amounts for 2014-2018:

> "To be determined by summing together, for each year, the appropriate forecast level of operating costs, depreciation costs, taxes and cost of capital. These annual amounts are what Enbridge will be entitled to collect in rates each year."[58]

Given the experiences in both the UK and Australia with building blocks, and the specific considerations of IR mechanisms that would be workable in the context of the Board's regulation of EGD, we believe that the building blocks approach used in EGD's Customized IR plan is consistent with the Board's objectives and should produce strong incentives for Enbridge to seek out productivity gains.

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53 AER. *Access Arrangement Guideline*. March 2009. <http://www.aer.gov.au/node/12715>

54 Ibid. p. 54.

55 Australian Energy Market Commission. *Perspective on the Building Block Approach – Review into the use of Total Factor Productivity for the Determination of Prices and Revenues*. July 30, 2009. pp. 7-8.

56 For the largest electric distribution company in Malaysia - Tenaga Nasional Berhad.

57 For the nineteen privately owned distribution companies in the country.

58 EGD revised evidence (December 11, 2012) EB-2012-0459, Exhibit A2-1-1, pp. 4-5.

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. This attachment includes information provided to all employees, /u objective setting 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 that may be pursued during the IR term. It is expected that there will be communications to employees on /u this topic over the coming months. Aggregating all of these productivity opportunities, as well as challenges, from individual departments, the Company 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

Irene Chan

From: Employee News
Sent: Thursday, August 08, 2013 1:52 PM
To: Employee News
Subject: Update on Incentive Regulation Plan

Update on Incentive Regulation Plan

In late June, Enbridge Gas Distribution filed an application with the Ontario Energy Board to establish an Incentive Regulation (IR) plan. When approved, this plan will set the framework used to establish utility rates each year from 2014 through to the end of 2018.

The plan we've proposed is similar to Enbridge's last incentive regulation framework in that it incents us to find efficiencies in our operations and includes a mechanism that enables customers to benefit from those efficiencies by providing them with a share of utility earnings that exceed a predetermined level.

There are however some unique features to this application:

Capital
The plan includes the biggest capital expenditure in the company's history – from $304 million in 2011 to $832 million in 2015. In addition to the capital expenditures required for more traditional types of utility operations, three key initiatives are also included:

- The GTA project, which is critical to maintaining continued reliable service within Enbridge's main operating area, will also bring increased pipeline capacity to support customer growth in the Greater Toronto Area. It will also provide access to diversified sources of gas supply, which could result in lower commodity prices for those who choose Enbridge as their gas supplier.
- Increased capital spending and activities related to safety and reliability projects and programs.
- The Work and Asset Management System (WAMS) implementation, which will give us the tools to manage our field activities effectively.

Despite these significant investments, customers who buy their gas from Enbridge are projected to see their bill increase by only $12 from 2013 to 2016. That amounts to a 1.4 per cent total increase over three years – or less than half a per cent per year.

Rates for the last two years of the five-year IR term have not been finalized but are expected to stay within a similar impact range.

O&M

Spending increases for departmental Operations and Maintenance expenses will be set at approximately 2 per cent annually. This increase is less than in previous years and although it will be challenging, we believe it is achievable and in line with the needs of our customers.

The incentive regulation team and management worked diligently to ensure our IR plan included only the most essential expenditures to support the safe and reliable operation of the distribution system, with a strong focus on customer satisfaction and continued development of our employees.

Thank you to the many employees who worked long hours over several months to contribute to the development of our IR application. The impact of this application, which will touch all areas of the business for at least the next five years, is significant. The pride, dedication and sense of ownership that have been consistently demonstrated by team members have been truly inspiring – thank you!

We expect a decision from the Board in the first quarter of 2014 and will keep employees updated accordingly.

Norm Ryckman
Director, Regulatory

Ralph Fischer
Director, Regulatory Special Projects

UNBILLED AND UNACCOUNTED-FOR GAS VOLUMES

Producing the UUF Forecast – 2014 Test Year & 2015-2018 Forecasts

1. This evidence describes the forecast methodology and updates the forecast of Unbilled and Unaccounted-For Gas ("UUF") for the 2014 test year. Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") asks the Board to approve the 2014 UUF forecast of 78,284 10^3m^3 as part of the 2014 volumes budget, as well as the continued use of the Unaccounted-For Variance Account ("UAFVA"). Deferral account evidence can be found at Exhibit D1, Tab 8, Schedule 1.

2. Only the 2014 UUF is subject to approval in this proceeding as the Company intends to update 2015 to 2018 UUF in subsequent annual adjustments as detailed at Exhibit A2, Tab 1, Schedule 1. For the purpose of generating preliminary rate impacts for 2015 to 2018, UUF forecasts are provided for those years as outlined in paragraphs 6, 10 and 11 below. The 2016 forecast is used as a proxy basis for generating preliminary forecasts for 2017 and 2018.

3. The UUF forecast is produced using a two-step process involving the forecast of both Unaccounted-For Gas ("UAF") and unbilled volumes. For instance, the 2014 UUF forecast is equal to the 2014 UAF forecast plus the expected difference between the December 2014 and December 2013 unbilled volumes (i.e., change in unbilled volumes). Both the UAF and unbilled volumes forecasts are produced via a statistical model.

4. UAF data for years prior to 2005 have been transformed to calendar year format in order to produce a calendar year UAF forecast. For an explanation of the transformation of volumes from fiscal to calendar year format, please see EB-2006-0034, Exhibit C1, Tab 3, Schedule 1.

Unbilled Volumes

5. The Company uses a regression model to forecast the level of unbilled volumes. The model relies on the high degree of correlation between volumes and degree days.

6. As noted in paragraph 3, the UUF forecast necessitated year-end unbilled volumes forecasts for 2013 and 2014 to forecast 2014 UUF. For preliminary 2015 to 2018 forecasts, the level of unbilled volumes was held constant as underlying degree days are assumed constant over this period. As a result, the change in unbilled volumes or net impact of constant unbilled volumes is zero. It is the Company's intent to update its degree day and unbilled forecasts as part of the annual volumetric updates for 2015 to 2018.

Unaccounted For Gas Forecast (UAF)

7. The Company regularly tests a variety of forecasting models in order to ensure that the UAF forecasts are as accurate as possible. These models incorporate multiple explanatory variables to model the variability in UAF actuals. For a number of years now, the same regression model that features the number of unlocked customers (i.e., unlocks) as an independent variable has continued to show the highest degree of relative accuracy. The rationale for including unlocks as an explanatory variable is that the greater the size of the distribution system, the greater the level of UAF volume, holding other things constant. Thus the

expectation is that the coefficient on the unlock variable (i.e., β_1 in Figure 1) will be positive.

Figure 1
UAF forecasting model specification[1]

$$UAF_t = \beta_0 + \beta_1 * LOG(ULKS)_t + \beta_2 * DUM02_t + \beta_3 * DUMNEG_t + \varepsilon_t$$

8. The model also includes variables to account for a structural change in 2002, as well as a negative UAF value. Since the UAF values are generally lower after 2002 compared to before 2002, the expectation is that the coefficient on the corresponding variables will be negative. Further, the expectation is that the variable that accounts for the negative UAF value will have a negative coefficient. Including the variable to account for the negative values in 2004 ensures that the forecast is greater than zero. As the term ‘unaccounted-for’ suggests, it is expected that billed consumption will be less than sendout volumes and thus UAF volumes should be greater than zero.

9. The proposed model specification (model ‘A’) performs well relative to other models, as demonstrated in Table 1 provided below. It produces an in-sample forecast error of five percent and an out-of-sample forecast error of six percent in 2012, the last year of available actual data. Meanwhile, the other specifications yield larger errors. Figure 2 provided below gives the meaning of the independent variables in Table 1.

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[1] The UAF model is specified as a linear equation of the following form:

UAF =	-2820813	+ 2064798 * LOG(ULKS)	– 103600 * DUM02	– 59080 * DUMNEG
(t-stats in parentheses)	(-3.39)	(3.49)	(-4.36)	(-2.11)

$R^2 = 0.63$ F-statistic=10.24 Prob(F-statistic)=0.00

Witnesses: H. Sayyan
M. Suarez

Table 1
UAF model specification testing results (volumes in 10^3m^3)

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*
Model	**Dependent Variable**	**Independent Variable(s)**	**2012 In-Sample Forecast**	**Percent Error (Forecast - Actual)**	**2012 Out-of-Sample Forecast**	**Percent Error (Forecast - Actual)**
A	UAF	LOG(ULKS), DUM02, DUMNEG	70,891	-5.2%	70,237	-6.1%
B	UAF	LOG(ULKS), DUM02	67,431	-9.8%	66,231	-11.4%
C	UAF	LOG(VOLPERCUST), DUM02, DUMNEG	50,435	-32.5%	47,706	-36.2%
D	UAF	LOG(ULKS), DUM02, DUMNEG, UAF(-1)	70,356	-5.9%	69,542	-7.0%
E	UAF	LOG(TSVOL), DUM02, DUMNEG	46,322	-38.0%	42,762	-42.8%
F	UAF	DUM02, DUMNEG, AR(1), MA(1)	79,104	5.8%	86,738	16.0%
G	UAF	LOG(CAPEX), DUM02, DUMNEG, TREND	81,573	9.1%	83,911	12.2%

Figure 2
Mnemonics of variables used in testing

Col. 1	*Col. 2*
Mnemonic	**Definition**
ULKS	Unlocked customers/meters (unlocks)
DUM02	Dummy variable to account for 2002 structural break
DUMNEG	Dummy variable to account for negative UAF values
VOLPERCUST	Volume per general service customer
UAF(-1)	UAF lagged one year
TSVOL	T-Service volumes
CAPEX	Capital expenditures (customer-related system improvements and upgrades)
AR(N)	N-th order auto-regressive term
MA(N)	N-th order moving average term
TREND	Time (year)

10. The 2014 UAF forecast is produced by model 'A' using data until 2012, the last full year of available actuals. To derive estimates for 2015 and 2016, the 2014 UAF forecast is divided by the proposed 2014 throughput volumes (Exhibit D3, Tab 3, Schedule 1, page 2, Item 4) to obtain the ratio of UAF to throughput volume. The resulting 2014 UAF to throughput ratio is 0.69% (77.7/11,232.2 10^6m^3). This ratio is applied to 2015 and 2016 total throughput volumes (as shown at Exhibit D4, Tab 3, Schedule 2, and Exhibit D5, Tab 3, Schedule 2) to arrive at a preliminary UAF forecast for those respective years. UAF values are held constant at the 2016 level for 2017 and 2018 as throughput volumes are similarly consistent with

the 2016 projection. It is the Company's intent to update the 2015 UAF forecast as part of the 2015 annual volumetric update proposed in the Customized IR application using the most accurate model as assessed by the inclusion of actual data to 2013. Forecasts for 2016 to 2018 UAF will be updated in the same way in the following years.

11. The resulting UAF estimates for 2015 to 2018 are shown in Table 2. Although values in this corrected evidence reflect a slight change to the UAF to throughput ratio, the resulting volumetric impacts are immaterial and will not alter preliminary volumetric evidence already filed.

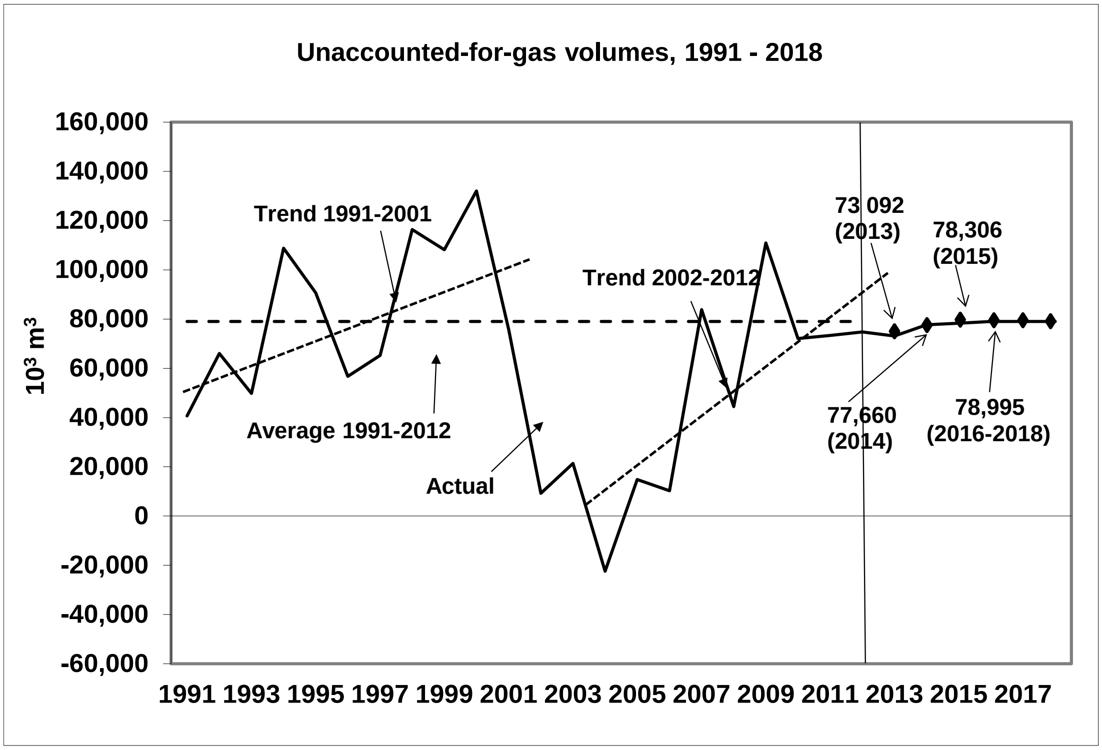
Table 2

2015 - 2018 UAF forecasts (volumes in 10^3m^3)

Col. 1	*Col. 2*	*Col. 3*	*Col. 4 = Col. 2 * Col. 3*
Calendar Year	**Throughput**	**2014 UAF to Throughput Ratio**	**UAF Forecast**
2015	11,325,686	0.69%	78,306
2016	11,425,260	0.69%	78,995
2017	11,425,260	0.69%	78,995
2018	11,425,260	0.69%	78,995

12. Figure 3 shows historical UAF data to 2012 along with the 2013 Board Approved, 2014 Test Year as well as 2015 to 2018 forecasts. The graph also shows the 1991 to 2001 trend, the 2002 to 2012 and the 1991 to 2012 average.

Witnesses: H. Sayyan
M. Suarez



***Forecast values are based on a regression model produced in February 2013**.

<u>Actual versus Board Approved– Last Five Years</u>

13. Table 3 below presents UAF actuals along with Board Approved values for the past five years.

Table 3
UAF Actuals vs Board Approved

Col. 1	*Col. 2*	*Col. 3*
Calendar Year	**Actual**	**Board Approved**
2008	44,424	39,444
2009	110,917	31,841
2010	72,104	37,795
2011	73,355	64,211
2012	74,762	68,925

Witnesses: H. Sayyan
M. Suarez

Calculation of 2014 UUF

14. The total UUF forecast is generated by adding the forecasted change in December 2014 versus December 2013 unbilled volumes to the 2014 UAF forecast. As such, the 2014 Test Year UUF forecast is as follows:

2014 UUF = (Forecast of UAF Gas) + (Change in Unbilled Gas)

= (Forecast of UAF Gas) + (Forecast of December 2014 Unbilled Gas - Forecast for December 2013 Unbilled Gas)

= 77 660 10^3m^3 + (704 606 10^3m^3 – 703 982 10^3m^3)

= 77 660 10^3m^3 + 624 10^3m^3

= 78 284 10^3m^3

Witnesses: H. Sayyan
M. Suarez

15. Table 4 below displays the historical UAF and unlock data used in the selected regression model to generate the forecast UAF for the 2014 test year.

Table 4
UAF Volumes and total unlocks, calendar 1991 to 2014
(volumes in 10^3m^3)

Col. 1 Calendar Year	*Col. 2* UAF Volumes	*Col. 3* Unlocks
1991	40,662	1,067,691
1992	66,028	1,104,224
1993	49,782	1,146,420
1994	108,765	1,188,226
1995	90,655	1,232,989
1996	56,739	1,274,338
1997	65,228	1,325,700
1998	116,376	1,376,564
1999	108,201	1,426,783
2000	132,021	1,479,413
2001	75,606	1,529,651
2002	9,284	1,580,819
2003	21,412	1,635,855
2004	-22,406	1,688,843
2005	14,815	1,735,906
2006	10,274	1,782,813
2007	83,823	1,824,789
2008	44,424	1,865,020
2009	110,917	1,887,605
2010	72,104	1,926,294
2011	73,355	1,960,378
2012	74,762	1,994,900
2013 Board Approved	73,092	2,026,392
2014 Test Year*	77,660	2,059,619

*Forecast values are based on a regression model produced in February 2013.

Witnesses: H. Sayyan
M. Suarez

Calculation of 2015 to 2018 UUF

16. The forecast of December unbilled volumes from 2015 to 2018 are held constant at December 2014 levels as described at paragraph 6. Consequently, there is no change in unbilled volumes for 2015 to 2018. The resulting UUF estimates for those years are hence equal to the UAF forecasts shown in Table 2 at page 5 of this exhibit.

2014 Test Year Forecast versus 2013 Board Approved

17. Table 5 compares 2014 Test Year Forecast and 2013 Board Approved UUF volumes. The 2013 Board Approved UUF is equal to the 2013 Board Approved UAF plus the change in forecast unbilled gas volumes between December 2013 and December 2012.

Table 5
2014 Test Year Forecast versus 2013 Board Approved (10^3 m^3)

Col. 1	*Col. 3*	*Col. 2*
	2014 Test Year	**2013 Board Approved**
Unaccounted-for volumes	77,660	73,092
Change in unbilled	624	1,088
Unbilled and unaccounted-for	78,284	74,180

Witnesses: H. Sayyan
M. Suarez

UNBILLED AND UNACCOUNTED-FOR GAS VOLUMES

2015 UUF Forecast for Preliminary Volumes

1. The 2015 UUF forecast is provided for the purpose of generating preliminary rate impacts for 2015. It is the Company's intent to update the 2015 UAF and Unbilled forecasts as part of the 2015 Rate Adjustment application using the most accurate models as assessed by the inclusion of actual data to 2013.

2. The 2015 UAF forecast draws from the results of the UAF methodology applied for the 2014 Test Year. The 2014 UAF forecast represents 0.69% of the total throughput for 2014. To generate preliminary 2015 UAF, 0.69% is applied to the estimated 2015 volumes. Please see Exhibit D3, Tab 4, Schedule 1 for full details on the methodology employed.

3. The 2015 change in unbilled volumes is assumed to be zero. Unbilled volumes are highly correlated with the level of degree days. As degree days are held constant at the 2014 level until each annual volumetric update for the years 2015 to 2018, there is no change in unbilled volumes. Please see Exhibit D3, Tab 4, Schedule 1 for more detail.

4. The 2015 Preliminary Forecast for UUF is calculated as follows:

2015 UUF = (Forecast UAF Gas) + (Change in Unbilled)
= (Forecast UAF Gas) + (Forecast unbilled volumes December 2015) – (Forecast unbilled volumes December 2014)
= 78 306 10^3m^3 + (704 606 10^3m^3 – 704 606 10^3m^3)
= 78 306 10^3m^3 + 0 10^3m^3
= 78 306 10^3m^3

Witnesses: H. Sayyan
M. Suarez

UNBILLED AND UNACCOUNTED-FOR GAS VOLUMES

2016 UUF Forecast for Preliminary Volumes

1. The 2016 UUF forecast is provided for the purpose of generating preliminary rate impacts for 2016. It is the Company's intent to update the 2016 UAF and Unbilled forecasts as part of the 2016 Rate Adjustment application using the most accurate models as assessed by the inclusion of actual data to 2014.

2. The 2016 UAF forecast draws from the results of the UAF methodology applied for the 2014 Test Year. The 2014 UAF forecast represents 0.69% of the total throughput for 2014. To generate preliminary 2016 UAF, 0.69% is applied to the estimated 2016 volumes. Please see Exhibit D3, Tab 4, Schedule 1 for full details on the methodology employed.

3. The 2016 change in unbilled volumes is assumed to be zero. Unbilled volumes are highly correlated with the level of degree days. As degree days are held constant at the 2014 level until each annual volumetric update for the years 2015 to 2018, there is no change in unbilled volumes. Please see Exhibit D3, Tab 4, Schedule 1 for more detail.

4. The 2016 Preliminary Forecast for UUF is calculated as follows:

2016 UUF = (Forecast UAF Gas) + (Change in Unbilled)
= (Forecast UAF Gas) + (Forecast unbilled volumes December 2016)
– (Forecast unbilled volumes December 2015)
= 78 995 10^3m^3 + (704 606 10^3m^3 – 704 606 10^3m^3)
= 78 995 10^3m^3 + 0 10^3m^3
= 78 995 10^3m^3

Witnesses: H. Sayyan
M. Suarez

TAB 3 – NOT USED

UNBILLED AND UNACCOUNTED-FOR GAS VOLUMES

2017 UUF Forecast for Preliminary Volumes

1. The 2017 UUF forecast is provided for the purpose of generating preliminary rate impacts for 2017. It is the Company's intent to update the 2017 UAF and Unbilled forecasts as part of the 2017 Rate Adjustment application using the most accurate models as assessed by the inclusion of actual data to 2015.

2. The 2017 UAF forecast draws from the results of the UAF methodology applied for the 2014 Test Year. The 2014 UAF forecast represents 0.69% of the total throughput for 2014. To generate preliminary 2017 UAF, 0.69% is applied to the estimated 2017 volumes. Please see Exhibit D3, Tab 4, Schedule 1 for full details on the methodology employed.

3. The 2017 change in unbilled volumes is assumed to be zero. Unbilled volumes are highly correlated with the level of degree days. As degree days are held constant at the 2014 level until each annual volumetric update for the years 2015 to 2018, there is no change in unbilled volumes. Please see Exhibit D3, Tab 4, Schedule 1 for more detail.

4. The 2017 Preliminary Forecast for UUF is calculated as follows:

2017 UUF = (Forecast UAF Gas) + (Change in Unbilled)
= (Forecast UAF Gas) + (Forecast unbilled volumes December 2017)
– (Forecast unbilled volumes December 2016)
= 78 995 10^3m^3 + (704 606 10^3m^3 – 704 606 10^3m^3)
= 78 995 10^3m^3 + 0 10^3m^3
= 78 995 10^3m^3

Witnesses: H. Sayyan
M. Suarez

TAB 3 – NOT USED

UNBILLED AND UNACCOUNTED-FOR GAS VOLUMES

2018 UUF Forecast for Preliminary Volumes

1. The 2018 UUF forecast is provided for the purpose of generating preliminary rate impacts for 2018. It is the Company's intent to update the 2018 UAF and Unbilled forecasts as part of the 2018 Rate Adjustment application using the most accurate models as assessed by the inclusion of actual data to 2016.

2. The 2018 UAF forecast draws from the results of the UAF methodology applied for the 2014 Test Year. The 2014 UAF forecast represents 0.69% of the total throughput for 2014. To generate preliminary 2018 UAF, 0.69% is applied to the estimated 2018 volumes. Please see Exhibit D3, Tab 4, Schedule 1 for full details on the methodology employed.

3. The 2018 change in unbilled volumes is assumed to be zero. Unbilled volumes are highly correlated with the level of degree days. As degree days are held constant at the 2014 level until each annual volumetric update for the years 2015 to 2018, there is no change in unbilled volumes. Please see Exhibit D3, Tab 4, Schedule 1 for more detail.

4. The 2018 Preliminary Forecast for UUF is calculated as follows:

2018 UUF = (Forecast UAF Gas) + (Change in Unbilled)
= (Forecast UAF Gas) + (Forecast unbilled volumes December 2018) – (Forecast unbilled volumes December 2017)
= 78 995 10^3m^3 + (704 606 10^3m^3 – 704 606 10^3m^3)
= 78 995 10^3m^3 + 0 10^3m^3
= 78 995 10^3m^3

Witnesses: H. Sayyan
M. Suarez