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By electronic filing

November 13, 2013

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

Dear Ms Walli,

Enbridge Gas Distribution Inc. ("EGD")
2014 to 2018 Rate Application
Board File No.: EB-2012-0459
Our File No.: 339583-000165

Please find attached the Interrogatories of Canadian Manufacturers & Exporters ("CME") for EGD in the above-noted proceeding.

Yours very truly,

Peter C.P. Thompson, Q.C.

PCT\slc
enclosure
c. Norm Ryckman (EGD)
Fred Cass (Aird & Berlis)
Intervenors EB-2012-0459
Paul Clipsham

OTT01: 6012083: v1

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

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an order or orders approving or fixing rates for the sale, distribution, transmission and storage of gas commencing January 1, 2014.

INTERROGATORIES OF CANADIAN MANUFACTURERS & EXPORTERS ("CME") TO ENBRIDGE GAS DISTRIBUTION INC. ("EGDI")

Appropriateness of Customized IR Plan

I.A1.EGDI.CME.1

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

1. 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.

I.A1.EGDI.CME.2

Reference: **Exhibit A1, Tab 2, Schedule 1**
Exhibit A2, Tab 1, Schedule 1, page 40, para.12

2. CME is interested in determining the proportion of the revenue requirement in each of the years 2014 to 2018 inclusive which will not be subject to adjustment in future years. The evidence indicates that revenue requirements in 2015, 2016, and 2018 will be adjusted for updated volumes and gas costs, and amounts related to pension, DSM and customer care costs. The same items will be the subject matter of adjustments in 2017 and in addition, the revenue requirements for 2017 and 2018 will be adjusted for updated forecasts of capital spending, cost of capital, taxes and depreciation. For example, the evidence at Exhibit A1, Tab 2, Schedule 1, page 22 in paragraph 63 indicates that the categories of OM&A expenses that will be subject to adjustment in future years ranges between 45% to 48% of total OM&A expenses in the years 2014 to 2016 inclusive. In addition to all of these adjustments, the company will benefit from the

protection provided by the 24 deferral accounts listed in Exhibit D1, Tab 8. In connection with this information, please provide the following:

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

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

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

Compatibility of Rate and Bill Impacts with I–X Calculations

I.A1.EGDI.CME.3

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

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

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

Sustainable Efficiency Incentive Mechanism ("SEIM")

I.A10f.EGDI.CME.4

Reference: Exhibit A2, Tab 1, Schedule 1, page 14
Exhibit A2, Tab 1, Schedule 3

4. EGDI's proposal SEIM is criticized by PEG in Exhibit L, Tab 1, Schedule 2 at page 23. In connection with these criticisms, please provide the following:

(a) EGDI's comments and responses to these criticisms.

5. At Exhibit A2, Tab 11, Schedule 3, page 6, an illustration is provided of a SEIM calculation which identifies three (3) hypothetical projects costing $1M, $5M and $500,000 respectively. In connection with this evidence, please provide the following information:

(a) What initiatives has EGDI identified that would qualify for this proposed incentive treatment in 2014?

(b) If EGDI's SEIM proposal is approved, then what is the possible Net Present Value ("NPV") potential for such projects in each of the years 2014 to 2018 inclusive?

(c) On what basis did EGDI derive the proposed 20% incentive factor?

Productivity Targets

I.A2.EGDI.CME.5

Reference: **Exhibit A2, Tab 1, Schedule 1, page 25, para.75**
Exhibit A2, Tab 1, Schedule 2, page 1

6. The evidence indicates that budgets were modified to ensure that forecasts did not exceed specified inflation targets. In connection with this evidence, please provide the following:

(a) A comprehensive list of each of the inflation targets which were used for the various line items in each of the OM&A expense budgets for 2014 to 2018 inclusive.

Regulatory Alternatives Considered

I.E35.EGDI.CME.6

Reference: **Exhibit A2, Tab 1, Schedule 1, page 25**
Exhibit A2, Tab 1, Schedule 3

7. Did EGDI and Union Gas Limited ("Union") have discussions pertaining to the nature of the IRM plans to be proposed for the period 2014 to 2018 inclusive before EGDI determined to proceed with its customized IRM Plan? If so, please provide the following:

(a) The details of these discussions and explain why EGDI determined that the approach Union has adopted and the Board has approved was not suitable for its circumstances.

(b) Provide copies of any calculations that EGDI did to apply Union's model to its circumstances for the years 2014 to 2018 inclusive.

Earnings Sharing Mechanism ("ESM")

I.A10c.EGDI.CME.7

Reference: **Exhibit A2, Tab 1, Schedule 1, page 35**
Exhibit A2, Tab 7, Schedule 1

8. EGDI is proposing an asymmetric ESM with a 100 bp deadband and 50/50 sharing thereafter. Assume that the risk of excessive forecasts under the auspices of EGDI's proposal is high and that, to protect ratepayers, the ESM allocates 90% of the first

100 bp of earnings over the allowed Return on Equity ("ROE") to ratepayers with 50/50 sharing to prevail for over-earnings in excess of 100 bp of ROE over the Board allowed return.

(a) Will EGDI operate under the auspices of its proposal in this scenario or will it revert to an annual cost of service filing?

Cost of Capital

I.A10d.EGDI.CME.8

Reference: Exhibit A2, Tab 5, Schedule 1
Exhibit E2, Tab 1, Schedules 1 and 2

9. Please list and provide copies of the sources of information which the Enbridge Inc. Treasury Dept. used to estimate the short-term debt, long Canada bond yields and utility bond and 30 year Government of Canada spreads which EGDI has used to derive the forecast ROEs for the years 2014 to 2018 inclusive under the auspices of the Board's formula.

Expert Reports

I.A1.EGDI.CME.9

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

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

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

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

(c) Please produce the retainer agreements.

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

Gas Volume Budget

I.C23.EGDI.CME.10

Reference: Exhibit C1, Tab 2, Schedule 1, page 1

11. The evidence indicates that EGDI's forecasts for each of the years 2014, 2015 and 2016 will be lower than the Board approved volumes for 2013. Please provide the following further information:

(a) The revenue requirement impact of increasing, proportionately. the General Service and Contract Market volumes for 2014, 2015 and 2016 to the level approved by the Board in 2013, namely, $11,504.4 10^6m^3.

Transactional Services

I.E36.EGDI.CME.11

Reference: Exhibit C1, Tab 3, Schedule 1

12. In connection with the Transactional Services ("TS") evidence, please provide the following information:

(a) List each of the services EGDI classifies as TS.

(b) Provide a schedule that shows the net amount EGD realized from each of these types of services over the years 2011, 2012 and 2013.

(c) Separate the TS between upstream transportation pipeline optimization activities and other transactional services.

(d) What will be the impact on ratepayers, if any, if all upstream transportation optimization activities are classified as upstream transportation cost reductions rather than as TS revenues?

Revenue Requirements and Deficiencies

I.B17.EGDI.CME.12

Reference: Exhibit F1, Tab 1, Schedule 1, page 3

13. The "Board Approved Revenue Requirement" for 2013 and "Revenue Requirements" for the years 2014, 2015 and 2016 are shown at line 10 of Table 1. Revenue at Existing Rates for each of those years is shown at line 1 of the Table. In connection with this evidence, please provide the following:

(a) Please provide the actual revenue (deficiency) / sufficiency calculation for 2013 using nine (9) months actual and three (3) months forecast information. If there is a revenue sufficiency for 2013, then please explain its causes.

(b) Please explain how the Revenue at Existing Rates in line 1, column (a) of $2,364.1M increases to $2,572.3M in 2014.

(c) Please explain how the Revenue at Existing Rates for 2014 of $2,572.3M at line 1, column (b) less the Revenue Sufficiency at line 11, column (b) of $9.7M operates to produce a Revenue at Existing Rates in 2015 of $2,635.8M at lien 1, column (c).

(d) Please explain how the Revenue at Existing Rates for 2015 of $2,635.8M at line 1, column (c) plus the Revenue Deficiency of $29.1M at line 11, column (c) operates to produce a Revenue at Existing Rates in 2016 of $2,683.4M at line 1, column (d).

Reference: Exhibit F1, Tab 1, Schedule 1, page 3
Exhibit F1, Tab 1, Schedule 3, Appendix A, pages 1 to 4

14. The evidence indicates that the revenue deficiencies for 2015 to 2018 inclusive are $29.1M, $119.7M, $166.1M and $215.7M respectively. We calculate the total rate increases EGDI is seeking over the four (4) years 2015 to 2018, before adjustments and updates, to be $530.6M, or, on average, about $132.65M per year.

    (a) Please list and briefly describe the causes of these escalating year-over-year revenue deficiencies for 2015 over 2014, 2016 over 2015, 2017 over 2016 and 2018 over 2017.

    (b) Do these amounts include or exclude the credit for Site Restoration Costs ("SRC")?

<u>Cost Allocation Methodology</u>

<u>I.C30.EGDI.CME.13</u>

Reference: Exhibit G1, Tab 1, Schedule 1
Exhibit G2, Tab 1, Schedules 1 to 7 inclusive

15. Please advise whether any changes have been made to the methods used to allocate costs. If so, then please describe each of the changes and their impacts.

<u>Proposed Rates</u>

<u>I.C31.EGDI.CME.14</u>

Reference: Exhibit H1, Tab 1, Schedule 1, pages 3 and 8
Exhibit H3, Tab 1, Schedule 1, Appendix A

16. Tables 1 and 2 in Exhibit H1, Tab 1, Schedule 1 show 2014 Average Rate Impacts excluding and including SRC. Estimated 2015 and 2016 Rate Impacts are shown in Exhibit H3, Tab 1, Schedule 1. In connection with this evidence and the preliminary Revenue Deficiency amounts for 2017 and 2018 of $166.1M and $215.7M respectively shown in Exhibit F, Tab 1, Schedule 3, Appendix A, please provide in one schedule the Rate Impacts for 2014 to 2018 inclusive in the format of Tables 1 and 2 in Exhibit H1, Tab 1, Schedule 1.

<u>Proposed Changes to Rate 100: Firm Contract Service</u>

<u>I.E42.EGDI.CME.15</u>

Reference: Exhibit H1, Tab 2, Schedule 2

17. Please provide a schedule which will show the existing charges currently paid by small, typical and large Rate 100 customers and how those charges will change, if at all, under the auspices of the changes EGDI is proposing.

Proposed Change to the Load Factor Requirement for Rate 110: Large Volume Load Factor Service

I.C42.EGDI.CME.16

Reference: Exhibit H1, Tab 2, Schedule 3

18. Please provide a schedule which will show the existing situation for customers served on Rate 110 and how the prices paid will change for those customers under the auspices of a rate with a 40% rather than a 50% Load Factor eligibility requirement.

19. For the 80 General Service customers who have a Load Factor greater than 40% and an annual volume greater than 340,000 m^3, please provide schedules which will show the likely impact on them of moving to proposed Rate 110 rather than continuing to take service under the auspices of EGDI's General Service rate. Please provide a similar schedule for the 300 General Service customers referenced in paragraph 9 of Exhibit H3, Tab 2, Schedule 3.

OTT01: 6011595: v1

1. Introduction and Executive Summary

1.1 Introduction

In June 2013, Enbridge Gas Distribution Inc. ("EGD," or "the Company") filed a customized incentive regulation ("Customized IR") proposal with the Ontario Energy Board ("OEB" or "the Board"). EGD's Customized IR plan would set gas distribution rates for EGD that recover the Company's projected costs of providing gas distribution services over the term of the plan.

Board staff asked Pacific Economics Group Research ("PEG") to provide a written assessment of the merits of EGD's Customized IR proposal. This assessment would address whether the proposed IR plan was consistent with sound principles for incentive regulation and the Board's IR criteria. It would also include a preliminary analysis of the empirical research that EGD and its advisor Concentric Energy Advisors ("CEA") provided in support of the IR proposal.

This report presents the findings of PEG's analysis. Chapter Two addresses the design and incentive consequences of EGD's Customized IR proposal. Chapter Three analyzes the empirical research presented in support of this proposal. Chapter Four presents concluding remarks.

1.2 Executive Summary

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.

2. EGD's IR proposal is based on a three-year forecast of the Company's costs, which falls short of the Board's minimum term of five years for a Custom IR plan. EGD says it cannot present a five year cost forecast because of the uncertainty of forecasting its 2017-18 investment

needs. EGD plans to adjudicate revenue requirements for these years within the term of its
proposed Customized IR proposal. Re-setting revenue requirements in the middle of an IR plan
is inconsistent with the rationale for incentive regulation, which is designed to be an alternative
3 to COSR that creates stronger performance incentives by extending the period between cost-
based rate reviews. Because re-setting rates within the term of a multi-year IR plan will impose
monetary and opportunity costs on the Company, the Board and intervenors, this provision of
EGD's IR proposal is not consistent with the Board's objective of creating incentives that
promote sustainable efficiency improvements.

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
4 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.

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
5 *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

EGD's proposed Z-factor language is also problematic. The Company's amended Z factor
would allow rate adjustments for cost increases or decreases demonstrably linked to an
6 unexpected, non-routine cause. This "unexpected cause" language could plausibly be interpreted
to mean *any* cost change that is not reflected in Company's cost forecasts, since the forecasts
themselves presumably reflect the expected causes. This amended Z factor language has the
potential to expand the frequency, contentiousness, and cost of Z factor proceedings.

EGD's proposal includes an AU factor and several new variance and deferral accounts,
which PEG does not oppose. We note, however, that these provisions protect EGD shareholders
7 against some of the most important risks the Company will face over the term of its IR plan.
These features of the proposal further shift the risk-reward balance under the plan towards
protecting EGD shareholders. It should also be recognized that if these mechanisms were part of

an IR plan that included an "inflation minus X" rate adjustment rather than a Customized IR approach, the plan would continue to offer substantial risk protection to EGD shareholders.

EGD's sustainable efficiency incentive mechanism ("SEIM") is incompatible with the
Board's objectives for incentive regulation. The SEIM inverts the design and rationale of
8 appropriate efficiency carry-over mechanisms and it would weaken, not strengthen, performance
incentives. It also creates a new risk and shifts that risk to customers. As currently designed, the
SEIM should be rejected.

PEG also concludes that EGD's IR proposal is more akin to a three-year IR than a five-
year IR plan. In the NGF, the Board found that three years is the minimum term that is expected
9 to give rise to productivity incentives, and its preference is for IR plans of five years. The
relatively shorter duration of the Company's IR proposal will have a negative impact on EGD's
ability to implement sustainable efficiency initiatives.

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
10 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.

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
11 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.

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
12 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.

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
13 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.

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
14 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.

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
15 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.

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.

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.

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.

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.