EB-2012-0459

ONTARIO ENERGY BOARD

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

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

Compendium for Examination
of John Todd and Michael Roger
by Enbridge Gas Distribution Inc.

March 25, 2014

EB-2012-0459

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

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

ASSOCIATION OF POWER PRODUCERS OF ONTARIO ("APPrO")

EXPERT PLAN

SEPTMBER 9, 2013

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AND

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E-mail: jwolnik@elenchus.ca

INTRODUCTION:

1. Enbridge Gas Distribution Inc. ("Enbridge") has filed an application with the Ontario Energy Board under section 36 of the *Ontario Energy Board Act, 1998*, as amended, for an Order or Orders approving or fixing rates for the sale, distribution, transmission and storage of gas as of January 1, 2014 (the "Application"). The Board has assigned file number EB-2012-0459 to the Application and has issued a Notice of Application dated July 22, 2013.

2. APPrO has been granted intervenor status and cost eligibility in respect of the Application, and hereby files this Expert Plan in accordance with the requirements of Procedural Order No. 1.

A. What are the issues for which the party intends to file expert testimony?

3. APPrO intends to engage an expert pursuant to Rules 13.01 and Rule 13A of the Board's *Rules of Practice and Procedure* to review the Application and give evidence in the proceeding in respect of Draft Issues List (Ex A1 Tab 4 S1) issue number 25 which states:

> *Is Enbridge's utility Cost Allocation Study, including the methodologies and judgments used and the proposed application of that study with respect to 2014 Fiscal Year rates, appropriate?*

4. Enbridge has proposed a major capital expansion project to their extra high pressure system referred to the "GTA Reinforcement" (Ex B2 Tab 3 S2 Attachment 2) which is not driven by the needs of and will provide very little benefit to the APPrO members serviced by Rate 125 and other unbundled customers. This and other significant reinforcement projects for non-contract customers (see for example, Ex B2 Tab 3 S1 Table 2 and Ex B2 Tab 3 S2 Attachment 1) results in a dramatic rate increase for Rate 125 customers who derive very little benefit from the proposed reinforcements. Specifically, Enbridge has forecasted that the Rate 125 will increase by **<u>over 30%</u>** in the next 5 years:

2014:	(0.8)% (Ex H1 Tab1 S1 page 3)
2015:	2.1% (Ex H3 Tab1 S1 Appendix A)
2016:	10.0% (Ex H3 Tab1 S1 Appendix A)
2017:	9.9% (Ex H3 Tab1 S2 Appendix A)

2018: 9.9 % (Ex H3 Tab1 S2 Appendix A)

B. Will the party be participating jointly with other parties in the commissioning of any expert evidence?

5. Rate 125 customers are large unbundled customers. APPrO represents all the customers in this rate class and no other intervening party represents these customers and therefore APPrO is not proposing to participate jointly with other parties in this proceeding.

6. APPrO takes its responsibility to carefully plan for and manage its costs and time commitments in respect of all Ontario Energy Board proceeding very seriously.

7. In respect of this Application, APPrO is proposing an expert that will focus on a single issue – cost allocation – that is of material consequence to the APPrO membership serviced under the Rate 125 customer class.

8. APPrO's expert will assist the Board impartially by giving evidence in respect of the above noted issue that is fair and objective and meets the requirements of Rules 13 and 13A of the Board's *Rules of Practice and Procedure*.

C. What is the estimate of costs for the expert (including an explanation of the assumptions regarding participation in various parts of the proceeding, including a joint expert conference)?

9. APPrO has issued a Request for Proposals to provide expert support as part of this proceeding (the "**RFP**"). A draft of this RFP is attached as Appendix "A". Due to the short timeframes specified in Procedural Order No. 1, APPrO is not in a position to estimate the costs for the expert because APPrO is still waiting for responses to its RFP. The purpose of the RFP is to ensure a qualified, independent and cost-effective cost allocation expert is retained for this proceeding. APPrO will undertake to provide the Board with an estimate of the costs of the expert (including an explanation of the assumptions regarding participation in various parts of the proceeding, including a joint expert conference) within 5 business days of its selection of a winner of the aforementioned RFP process.

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 9TH DAY OF SEPTEMBER, 2013

BORDEN LADNER GERVAIS LLP

Per:

Original signed by John A.D. Vellone
John A.D. Vellone
Counsel to APPrO

APPENDIX "A"

Please see attached.

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Borden Ladner Gervais

SENT BY EMAIL & COURIER

September 9, 2013

[Contact Details]

Dear [ ]:

Re: The Association of Power Producers of Ontario ("APPrO") is seeking the services of a cost allocation expert.

Enbridge Gas Distribution Inc. ("Enbridge") filed an application dated July 3, 2013 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act*, S.O. 1998, c.15, Schedule B for an order or orders approving rates for a five year period commencing January 1, 2014 (the "Application"). The Board has assigned file number EB-2012-0459 to the Application and has issued a Notice of Application dated July 22, 2013.

We are acting as counsel for APPrO in respect of the Application.

APPrO wishes to retain the services of an independent cost allocation expert in this proceeding to review the Application, assist in the preparation of written interrogatories, review of the interrogatory responses, and, if necessary, to prepare and defend evidence in respect of the following issue:

> *Is Enbridge's utility Cost Allocation Study, including the methodologies and judgments used and the proposed application of that study with respect to 2014 Fiscal Year rates, appropriate?*

APPrO is a non-profit organization representing more than 100 companies involved in the generation of electricity in Ontario, including generators and suppliers of services, equipment and consulting services. APPrO members produce power from natural gas, as well as hydro, gas, coal, nuclear, wind, waste wood and other sources.

Among APPrO's members are gas-fired generators in Enbridge's franchise area. These generators take service from Enbridge primarily under Rate 125. The evidence filed by Enbridge indicates that rate 125 is forecasted to increase minimally in the first year, followed by significant increases over the balance of the five year period proposed by Enbridge (see below Section 3).

All customers in the Rate 125 rate class are power generators and not represented by any other consumer group.

APPrO is seeking:

A written proposal with the following information:

- Names and a CV listing the credentials of the individual or team you would assign to this project.
- Estimate of the rates you would charge for this project with an estimate of anticipated expense total for the proceeding for counsel and consultation services which may be required. For the purposes of providing an estimate of anticipated expense total, please state your all of your assumptions (including number of hours assumed in respect of each of the areas where APPrO requires support as set out in Section 4 below).
- References (minimum #2).
- A list of all regulatory or court proceedings that you have appeared before, the issue you appeared in respect of, for whom did you appear, and what role you took (qualified expert, advisor, etc.).

1. Background

- APPrO members produce 95% of the power generation in the Province of Ontario, including gas-fired power generators.
- Within their franchise, Enbridge provides service to most large gas-fired power generators under Rate 125.
- Because large power generators require high pressure and their loads are large, service from the utility is always provided from its extra high pressure (XHP) mains.
- Rate 125 is primarily derived based on the allocation of the cost of service of the XHP system, plus metering costs.
- The XHP main costs are allocated on the basis of peak day demand of Rate 125 customers to the total current peak day demand of all customer rate classes.

2. Summary of Enbridge's Recent and Current XHP Main Projects

- Enbridge is seeking to add approximately $700 million to their XHP system in 2014 and 2015, including the GTA Reinforcement Project (Ex B2 T3 S2 Attachment 2), the Ottawa Reinforcement Project (Ex B2 T3 S2 Attachment 1) and several other smaller projects.
- The GTA Reinforcement is not driven by the needs of unbundled contract customers and will provide very little benefit to the APPrO members serviced by Rate 125.

3. APPrO Member's Concern

- This and other significant reinforcement projects for non-contract customers (see for example, Ex B2 Tab 3 S1 Table 2 and Ex B2 Tab 3 S2 Attachment 1) results in a dramatic rate increase for Rate 125 customers who derive very little benefit from the proposed reinforcements. Specifically, Enbridge has forecasted that the Rate 125 will increase by over 30% in the next 5 years:

2014:	(0.8)% (Ex H1 Tab1 S1 page 3)
2015:	2.1% (Ex H3 Tab1 S1 Appendix A)
2016:	10.0% (Ex H3 Tab1 S1 Appendix A)
2017:	9.9% (Ex H3 Tab1 S2 Appendix A)
2018:	9.9 % (Ex H3 Tab1 S2 Appendix A)

4. Cost Allocation Expert Assistance Required

- APPrO is concerned that Enbridge's current cost allocation methodology over allocates XHP main costs to Rate 125 which is driving the significant rate increases for this rate class with little to no benefit.

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- APPrO requires the support of an independent cost allocation expert to assess Enbridge's current cost allocation methodology and, if possible, to develop a more equitable cost allocation methodology. More specifically to:
  - Review the cost allocation evidence in the Application, which is available online at:
    - http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/401940/view/EGDI_Appl_ExG_Cost%20Allocation_20130628.PDF
    - http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/401941/view/EGDI_Appl_ExH_Rate%20Design_20130728.PDF
  - Provide support for the drafting of interrogatory questions to Enbridge in the area of cost allocation;
  - Assess the reasonableness of the current cost allocation methodology, especially in light of the significant expansion projects being proposed;
  - Evaluate other potential cost allocation methodologies and their relative impact on Rate 125 and Enbridge's other rate classes;
  - Make a recommendation for any proposed changes to Enbridge's cost allocation methodology;
  - Prepare expert testimony to support the recommendations;
  - Respond to any interrogatory requests from Enbridge and other intervenors;
  - Attend an expert pre-hearing conference, if required by the Board;
  - Provide any support that may be required for cross examination questions of Enbridge;
  - Appear at the Enbridge hearing for cross examination if required;
  - Respond to any undertakings; and
  - Provide support as may be required for APPrO argument.

All experts before the Ontario Energy Board are required to comply with Rule 13A of the Board's *Rules of Practice and Procedure*. We recommend that you refer to your obligations under Rule 13A, which for ease of reference is excerpted as Attachment 1 to this document.

5. Application Timeframe

The Board has issued a Procedural Order No. 1 and is current awaiting written submissions on a preliminary issue raised by several other intervenors. In addition, the Board has required APPrO and other cost eligible intervenors to file an expert plan by September 9, 2013.

As of yet, no procedural steps have been set aside from the preliminary issue but it is anticipated that the IR support will be required by mid/late September and the hearing will likely occur during October/November.

6. Requirements

Required areas of expertise:

- Knowledge of cost allocation methods, principles and practice
- Knowledge and experience in natural gas system:
  - rate design
  - general pipeline system operation and design principles

Desirable but not necessarily required expertise:

- Knowledge of APPrO member business objectives and APPrO strategic objectives
- Previous experience working with APPrO
- Prior appearances as an expert before the OEB or other energy regulatory authority

Borden Ladner Gervais

7. Next Steps

Interested parties may submit proposals by mail, fax or email, but they must be received by 5:00:00 pm on Friday, September 20, 2013 marked “Enbridge Custom IR Case – Cost Allocation Expert -- CONFIDENTIAL” and addressed to APPrO’s legal counsel:

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Suite 4100, Scotia Plaza, 40 King Street West
Toronto ON M5H 3Y4

Tel: (416) 367-6730
Facsimile: (416) 361-2758
Email: jvellone@blg.com

With a copy to:

Mr. David Butters
President
The Association of Power Producers of Ontario (APPrO)
Suite 1602, 25 Adelaide St. E.
Toronto, ON M5C 3A1

Tel. 416-322-6549
Fax 416-481-5785

Any questions may be addressed to Mr. Vellone prior to September 20th.

Sincerely,

John A.D. Vellone
Counsel to APPrO

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Borden Ladner Gervais

December 18, 2013

DELIVERED BY RESS, COURIER AND E-MAIL

Ms. Kristen Walli, Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2701
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: APPrO Expert Evidence
Enbridge EB-2012-0459

Pursuant to the Decision on Need for a Preliminary Issue and Procedural Order No. 2 dated October 3, 2013, please find enclosed the evidence of Mr. John Todd and Mr. Mike Roger of Elenchus Research Associates Inc. being filed by the Association of Power Producers of Ontario ("**APPrO**") in respect of the above noted proceeding.

APPrO previously filed its Expert Plan on September 9, 2013 (the "**APPrO Expert Plan**"). By letter dated October 3, 2013, APPrO provided an update to the APPrO Expert Plan to inform the Board that it had chosen Mr. John Todd and Mr. Mike Roger of Elenchus Research Associates Inc. as its cost allocation experts for this proceeding.

Yours Truly,

BORDEN LADNER GERVAIS LLP

Original signed by John A.D. Vellone

John A.D. Vellone

Encl.

Copy: David Butters, APPrO
John Wolnik, John Todd, Mike Roger, Elenchus
Parties to EB-2012-0459

TOR01: 5433465: v1

34 King Street East, Suite 600
Toronto, Ontario, M5C 2X8
elenchus.ca

Proceeding EB-2012-0459

Enbridge Gas Distribution Inc.

Cost Allocation Methodology

Evidence Prepared by
John Todd and Michael Roger
Elenchus Research Associates Inc.

On Behalf of APPrO

December 18, 2013

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EXECUTIVE SUMMARY

This report presents our views with respect to issues raised by the Association of Power Producers of Ontario ("APPrO") related to the Cost Allocation Methodology ("CAM") used by Enbridge Gas Distribution Inc. ("Enbridge") to apportion its revenue requirement among its customer classes.

In our opinion, it would be appropriate to refine Enbridge's CAM in order to better align the costs recovered from the Rate 125 class with the costs they cause as determined using standard cost causality principles as generally applied in cost allocation studies. There are two issues of concern:

1. It should be recognized that Enbridge's Extra High Pressure (XHP) facilities include both higher capacity facilities of the type that can be used to serve all customers, including Rate 125 customers, and lower capacity facilities that do not have sufficient capacity to serve Rate 125 customers. Just as distribution assets are allocated only to those customers that can be served using those assets, so too should the lower capacity XHP assets and expenses be allocated only to customer classes that can be served with those facilities. To address this inequity, Enbridge's XHP facilities as traditionally defined should be separated into two categories that reflect the evolution of the Enbridge system. A refined definition of XHP assets would more accurately reflect the requirements of Enbridge's current customer classes, including Rate 125, and the costs they cause.
2. The CAM should also be modified to reflect the fact that Enbridge's economic feasibility test, which is used to determine the amount of capital contribution required, is based on a capital expenditure amount that not only ensures that the system is reinforced as required to meet the demand of a new Rate 125 customer, but also adds sufficient capacity to ensure that the total available excess capacity in the system for future growth is not diminished. In essence, Rate 125 customers are precluded from utilizing any of the current or future spare capacity in the Enbridge system. Given that Rate 125 customers must pay

sufficient contribution when connecting to the system to maintain the spare capacity in the system, it amounts to double charging this rate class to also allocate the costs associated with unutilized capacity (e.g., sizing reinforcement projects to accommodate future growth) to this customer class. Conceptually, this inequity could be addressed by modifying the CAM so that the costs associated with excess capacity would not be allocated to Rate 125. Since the financial requirement for Rate 125 customers to maintaining the appropriate level of excess capacity in the Enbridge system is embedded in the economic feasibility test when they connect to the system, it appears inconsistent also to consider the costs associated with excess capacity to be included in rates.

Hence, our recommendations are that:

- Enbridge's CAM should distinguish between high and low capacity XHP assets so that these assets can be allocated in a manner that better reflects cost causality principles. Enbridge should allocate to Rate 125 customers only costs of XHP assets that meet the physical specification of facilities that can be used to supply services to them.
- In order to avoid Rate 125 customers paying in two ways for the excess capacity required in the Enbridge system to accommodate future growth efficiently, Enbridge should be directed either to amend its economic feasibility test as it applies to Rate 125 customers or to modify its cost allocation methodology so that Rate 125 customers are not required to pay for excess capacity in the system in two ways.

1 INTRODUCTION

The Association of Power Producers of Ontario ("APPrO") has retained John Todd and Michael Roger (Todd/Roger) of Elenchus Research Associates Inc. in order to assist the Ontario Energy Board ("OEB") in the Enbridge Gas Distribution Inc. ("Enbridge") application on its 2014 to 2018 Revenue Requirement, proceeding EB-2012-0459, by presenting expert opinion evidence on the topic of the Cost Allocation Methodology ("CAM") used by Enbridge to apportion its revenue requirement to customer classes. In this proceeding, Enbridge's CAM has been described in Exhibits G1 and G2.

APPrO's specific concerns with Enbridge's current cost allocation methodology relate to the methodology used to allocate XHP main costs to Rate 125 and to the way in which costs associated with Enbridge's excess capacity are recovered from this rate class. APPrO has noted that the GTA reinforcement project alone is expected to increase rates to Rate 125 by 23.8%[1], when little of this capacity is being caused by or is available to these customers. Most of the capacity that is being added is to facilitate a shift in gas supplies to accommodate purchases at Dawn and Niagara, to provide capacity to accommodate the 10 year growth requirements of its bundled customers and to provide ex-franchise transmission services[2]. Other reinforcement projects will further increase rates although, by definition, these costs cannot be caused by Rate 125 customers.

Based on these concerns, APPrO requested that we "...assess Enbridge's current cost allocation methodology and, if possible, develop a more equitable cost allocation methodology".[3]

This report includes our assessment and recommendations with respect to Enbridge's CAM. Our recommendations are based on generally accepted cost causality principles.

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1 EB-2012-0451 Exhibit A Tab 3 Schedule 9 Page 15

2 EB-2012-0451 Exhibit A Tab 3 Schedule 1

3 The written instructions provided to Elenchus in relation to the proceeding are included as Appendix A to the APPrO Expert Plan dated September 9, 2013.

The evidence presented in this report is divided into 4 main sections. Section 2 describes cost causality principles and how these principles are used in the utility industry, section 3 presents a summary of relevant factors, section 4 describes our proposed refinements to Enbridge's CAM and section 5 lists our recommendations. Appendix A contains the CVs for John Todd and Michael Roger.

John Todd and Michael Roger have been experts dealing with cost allocation, rate design and rate regulation issues for over 30 years. Mr. Todd has testified before regulatory agencies across Canada on a wide range of matters related to rate setting principles, policies and procedures including cost allocation and rate design issues. Mr. Roger worked for over 32 years at Ontario Hydro, Ontario Power Generation and Hydro One and spent most of his career dealing with Cost Allocation and Rate Design issues for wholesale and retail electricity customers in Ontario. He has also testified on numerous occasions at OEB proceedings. John's and Michael's vast experience with Cost Allocation issues were applied in reviewing Enbridge's Cost Allocation Methodology evidence and form the basis for their recommendations to the OEB on Enbridge's CAM.

2 PRINCIPLES OF COST ALLOCATION

2.1 ONTARIO APPROACH

The OEB regulates the natural gas and electricity sectors in Ontario.

Union Gas Limited, Enbridge Gas Distribution Inc. and Natural Resource Gas Limited are the regulated natural gas distribution companies operating in Ontario. They are required to submit their revenue requirements for approval by the OEB to recover their operating and capital costs through bundled and unbundled natural gas rates in a just and reasonable manner from Ontario natural gas customers. The OEB also approves all major natural gas facility projects including the manner in which the cost of the proposed facilities will be recovered from customers.

There are widely accepted principles that provide guidance to regulators in determining rates that are just and reasonable. These are often referred to as Generally Accepted Regulatory Principles ("GARP"). The seminal work of James C. Bonbright et al., which sets out ten "attributes of a sound rate structure"[4], is a primary reference used by regulators and regulatory experts in identifying the key ratemaking principles. Although the broad principles have been restated over the years in many different ways in the literature on economic regulation[5] the basic concepts remain at the heart of economic regulation.

We note that the OEB has explicitly endorsed a version of the Bonbright Principles, as stated in the Staff Discussion Paper for Rate Design for Recovery of Electricity Distribution Costs[6]. The Board identified three rate design principles for the purposes of that process. These principles, which encompass the relevant "Bonbright attributes of a sound rate structure" identified in the March 2007 Staff Discussion Paper, are:

1) full cost recovery;
2) fairness; and
3) efficiency.

The record clearly shows that it is appropriate to use these Generally Accepted Regulatory Principles as the touchstone for determining just and reasonable rates for Enbridge's customers.

Cost allocation is an important step in the overall rate making process and it is guided by the aforementioned Bonbright Principles. In the context of cost allocation, the most essential element of these principles is that costs should be allocated to customer classes in a manner that reflects cost causality. The importance of this approach within

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4 Bonbright, James C., Albert L. Danielson and David R. Kamerschen, (1988) Principles of Public Utility Rates (Second Edition), Public Utilities Reports, Inc., pages 383-384.

5 A particularly thorough and relatively recent restatement of the Bonbright principles made by a regulator appears in Newfoundland and Labrador Board of Commissioners of Public Utilities, in the Matter of an Application by Newfoundland and Labrador Hydro for a General Rate Review, Decision and Order of the Board, Order No. P.U. 7 (2002-2003), June 7, 2002, pages 28-29.

6 Ontario Energy Board, Staff Discussion Paper, Rate Design for Recovery of Electricity Distribution Costs, EB-2007-0031, March 31, 2008 (revised June 6, 2008).

the OEB's regulatory regime was clearly stated in the Report of the Board EB-2007-0667.

The establishment of class-specific revenue requirements (or cost responsibility) through cost causality determinations is a fundamental rate-making principle. Cost allocation is key to implementing that principle. Cost allocation policies reasonably allocate the costs of providing service to various classes of consumers and, as such, provide an important reference for establishing rates that are just and reasonable.[7]

In our opinion, the applicability of the concept of allocating and recovering costs in a manner that reflects cost causality is a core principle that guides the setting of just and reasonable rates in all applications of economic regulation. Certainly, the cost causality principle is not the sole determinant of just and reasonable rates; however, significant deviations from this principle should result from an explicit determination of the appropriateness of any departure from pure cost causality. By definition, such departure creates cross-subsidies among customers, which need to be accounted for when balancing relevant rate making principles.

Furthermore, in our opinion, it would be inappropriate to establish a charge without first determining the causal costs in play. Those costs would serve as a reference point in determining whether any deviation from strict cost causality is appropriate and necessary, considering other rate making principles or policy considerations. In our opinion, it would be inconsistent with GARP to accept rates as just and reasonable when they embed cross-subsidies that have not been quantified and have not been explicitly recognized and accepted by the regulator.

2.2 COST ALLOCATION METHODOLOGY

In order to determine cost based rates, a cost allocation study is performed by a utility to fairly allocate shared assets and expenses to the customer groups served by the utility. Traditionally three steps are followed in a cost allocation study: Functionalization, Categorization or Classification, and Allocation.

[7] Ontario Energy Board, Report of the Board, Application of Cost Allocation for Electricity Distributors, EB-2007-0667, November 28, 2007.

Assets and expenses that are identified with a particular customer class and that are not shared with other customer classes are “Directly” allocated to that particular customer class.

Functionalization of assets and expenses is the process of grouping assets and expenses of a similar nature, for example, generation, transmission, distribution, customer service, meter reading, etc. Hence, as a first step in a cost allocation study, each account in the utility’s system of accounts is functionalized. That is, the function(s) served by the assets or expenses contained in each account is identified so that the costs can be attributed appropriately to the identified functions.

Categorization or Classification is the process by which the functionalized assets and expenses are classified as commodity, capacity and/or customer related. Hence, the costs associated with each function are attributed to these categories based on the principle that the quantum of costs is reflective of the quantum of volume, system demand, or number of customers.

Allocation, which is the final step, is the process of attributing the commodity demand, capacity and customer related assets and expenses to the customer classes being served by the utility. This allocation is accomplished by identifying allocators related to commodity, capacity or customer counts that are reflective of the relationship between different measures of these cost drivers and the costs that are deemed to be caused by each customer class.

It is in this third step that customers are grouped based on common characteristics, or utility asset utilization reflecting cost causality.

3 SUMMARY OF RELEVANT FACTORS

3.1 EXTRA HIGH PRESSURE (XHP) SYSTEM

In response to APPrO IR # 6[8], Enbridge stated that “Pipes of any size which operate at a pressure greater than 1207 kPa (175 psi) are included in the XHP system”. Enbridge further states in its response to APPrO’s IR # 10 b)[9]:

> *“The minimum pipe size capable of serving an embedded Rate 125 customer is 6 inches in diameter. A 4 inch diameter pipeline could provide service in limited circumstances only.”*

3.2 REINFORCEMENT PROJECTS

There are two major reinforcement projects included in Enbridge’s Cost Allocation Methodology: Ottawa and GTA projects. The costs related to these two projects and other reinforcement projects are being recovered from all customers including Rate 125 customers.

3.2.1 OTTAWA REINFORCEMENT PROJECT

As described in Exhibit B2, Tab 3, Schedule 2, Attachment 1, page 2, the purpose and need of this project is due to strong customer growth in the area. The project will increase capacity in the distribution system in order to meet forecast loads and provide additional security of supply and operational flexibility.

This project is expected to satisfy the peak load increase forecast over the next 10 years of 117 10^3m^3/hr[10]. Any future incremental requirement to serve current or future Rate 125 customers will not be met by utilizing the capacity provided through this reinforcement project since the facility design and the feasibility test for the new Rate 125 customers will maintain the level of spare capacity that would have existing if they had not connected to the system.

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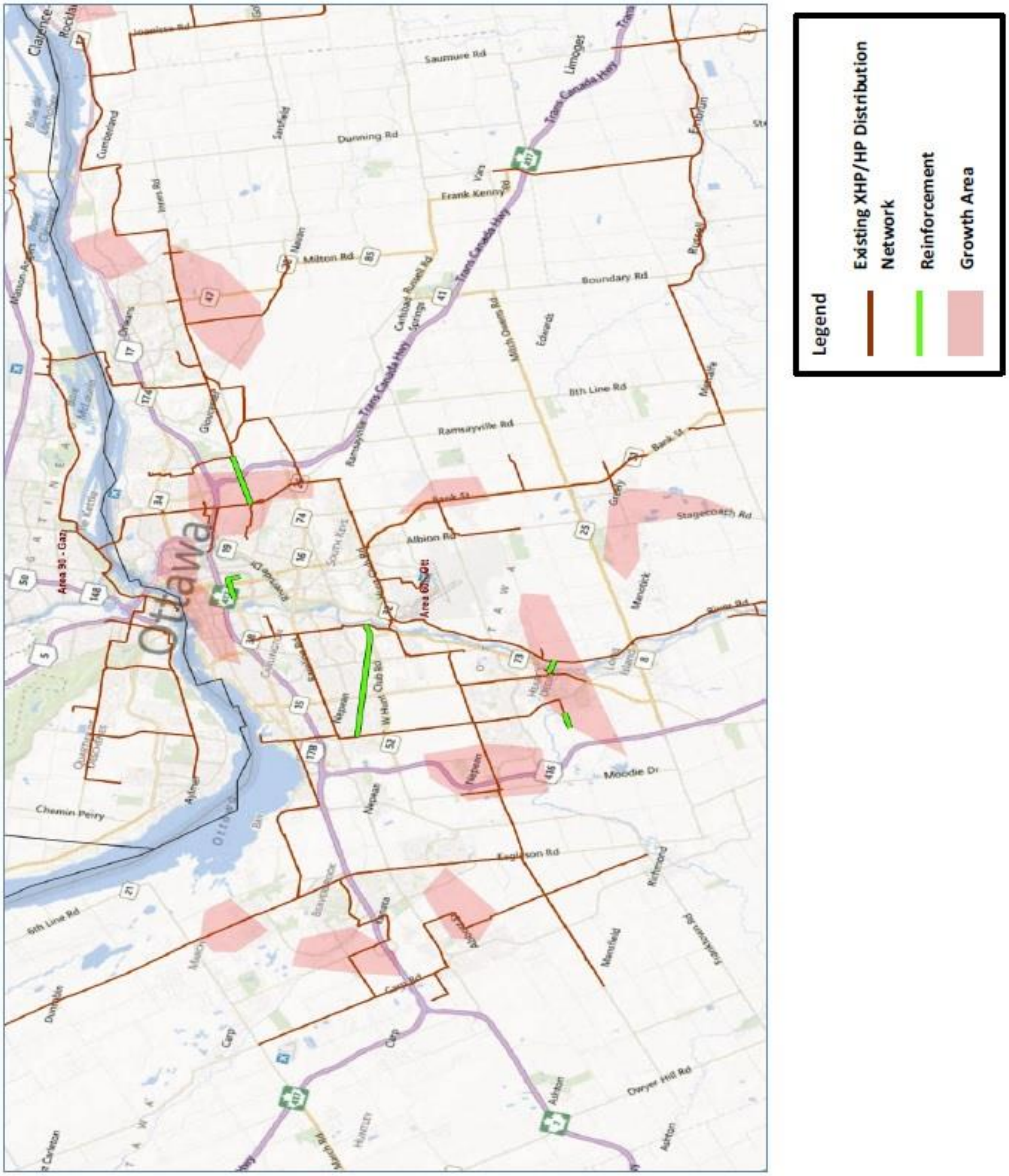
[8] Exhibit I.C30.EGDI.APPrO.6
[9] Exhibit I.C30.EGDI.APPrO.11
[10] Proceeding EB-2012-0099, Exhibit A, Tab 3, Schedule 2, page 1, paragraph 2

The map below from Exhibit B2, Tab 10, Schedule 1, page 49, shows the Ottawa area the existing XHP/HP Distribution Network, Reinforcement projects and Growth Areas.



3.2.2 GTA Reinforcement Project

In Exhibit B2, Tab 3, Schedule 2, Attachment 2, page 3, it is stated that the GTA project will meet customer growth requirements, reduce operational risks and enhance safety and reliability, provide entry point diversity by reducing the dependence of Parkway Station and finally improve supply chain diversity, reduce upstream supply risks and reduce gas supply costs over the 2015 to 2025 period.

The advance capacity of the GTA project in 2013/2014 is 253.1 10^3m^3/hr, (2024/2025 peak load 3186403 minus 2013/2014 peak load 2933273)[11]. This capacity has been identified as being required to satisfy the ten-year future needs of bundled customers[12]. This project is expected to have a reserve capacity of 160 TJ/day in 2015 and 130 TJ/d as of 2025[13].

The map below from Exhibit B2, Tab 10, Schedule 1, page 41, shows the GTA area, the existing XHP/HP Distribution Network, Reinforcement projects and Growth Areas.

The subsequent map, which appeared as ED-2012-0451, Exhibit A, Tab 3, Schedule 1, Attachment Figure 1, shows the full extent of the GTA Reinforcement Project.

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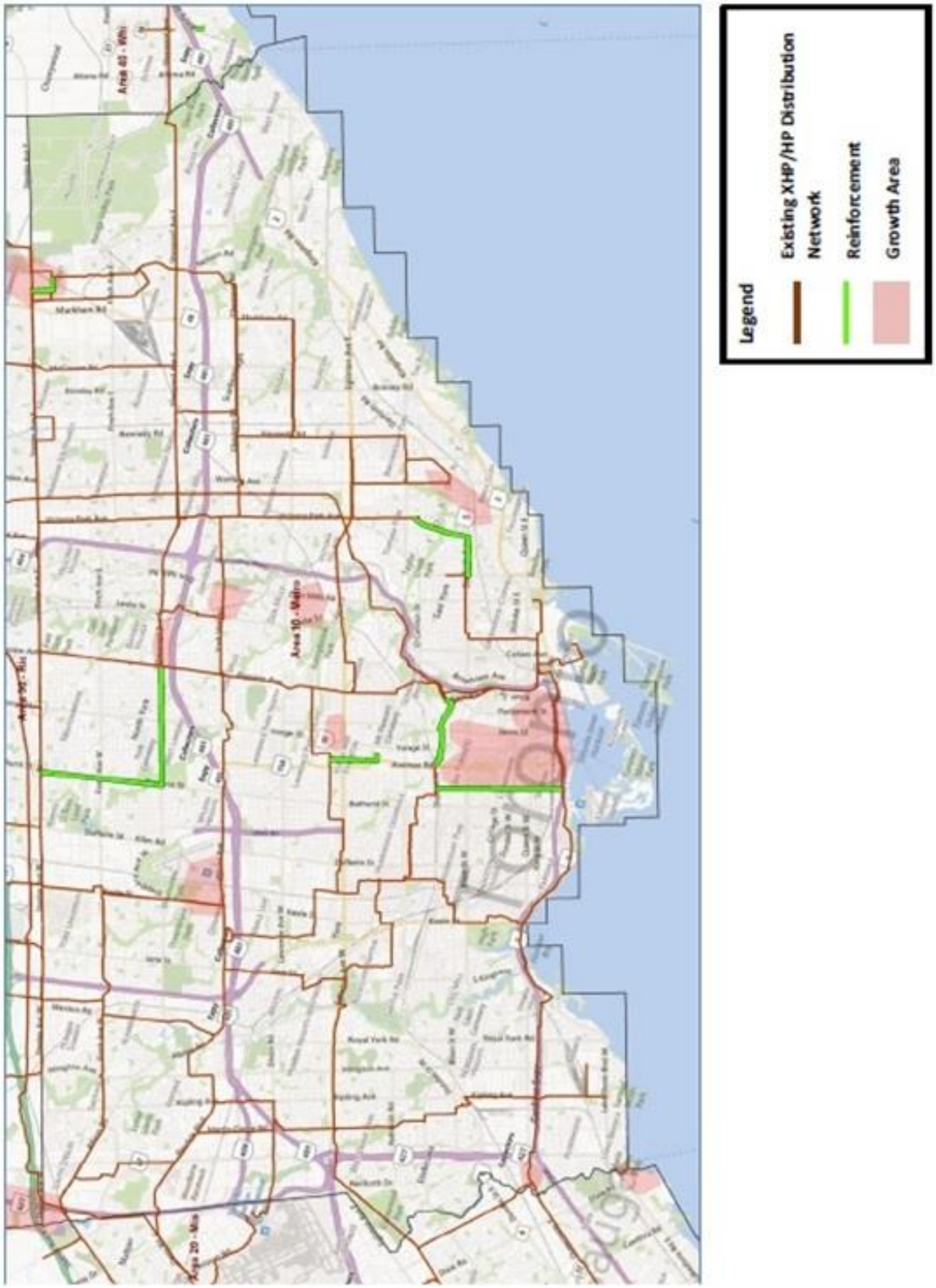
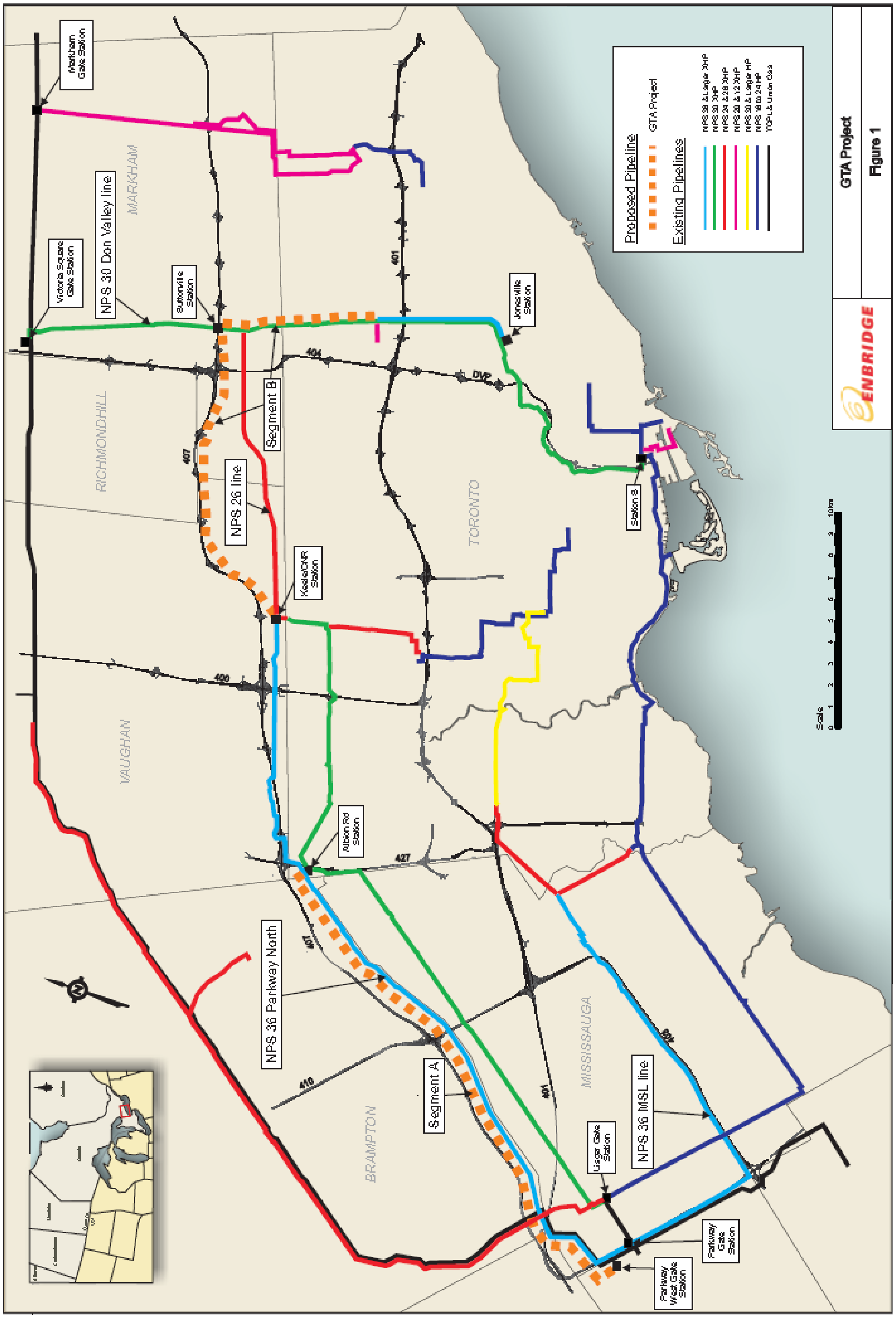
11 Proceeding EB-2012-0451, Exhibit I.A4.EGD.ED.5
12 EB-2012-0451 Exhibit I.A1.EGD.APPrO.5
13 Proceeding EB-2012-0451, Exhibit I.A1. EGD.APPrO.1, page 4, section i)


Legend
Existing XHP/HP Distribution Network
Reinforcement
Growth Area

Filed: 2012-12-21
EB-2012-0451
Exhibit A
Tab 3
Schedule 1
Attachment
Figure 1



4 ENBRIDGE'S CAM

Enbridge's CAM follows the traditional three steps approach of Functionalization, Classification and Allocation of costs used by utilities to apportion costs amongst its customer classes.

We reviewed Enbridge's CAM and agree with the basic approach utilized by Enbridge. We note, however, no cost allocation model can ever be viewed as perfect. Over the years both Enbridge and other parties have identified appropriate refinements based on a detailed examination of the consistency of specific aspects of the CAM with the fundamental principles of cost allocation. Subject to issues of availability of data and practicality, there is a predisposition to adopt refinements that result in an allocation that better reflects causal costs.

APPrO identified two specific areas in Enbridge's CAM that we were asked to examine. To our knowledge, these specific issues have not previously been examined in the context of Enbridge's CAM. Based on our review of these issues, we have concluded that two refinements to the CAM would result in an allocation that would better reflect cost causality principles. These refinements relate to:

1. The allocation of XHP assets and expenses; and
2. The consistency of the approach to recovering costs related to the excess capacity in the Enbridge system as embedded in the current CAM and in the economic feasibility test as it is applied to Rate 125 customers.

In our view, the proposed refinements provide appropriate updating of Enbridge's CAM to reflect the evolution of the Enbridge system and the requirements of the customers currently served under Rate 125.

4.1 ALLOCATION OF XHP ASSETS AND EXPENSES

AS noted above, XHP assets are extra high pressure assets used by Enbridge to supply its customers and include "Pipes of any size which operate at a pressure greater than 1207 kPa (175 psi)"[14]. As stated by Enbridge in its response to APPrO's IR # 10 b)[15]:

> *"The minimum pipe size capable of serving an embedded Rate 125 customer is 6 inches in diameter. A 4 inch diameter pipeline could provide service in limited circumstances only."*

In response to APPrO's IR # 10 a)[16], Enbridge agrees that based on cost causality principles, customer classes should be allocated costs based on the costs that the customer class imposes on Enbridge's system.

Not all current assets and expenses defined as XHP in Enbridge's Functionalization step in its CAM are able to provide service to Rate 125 customers, as confirmed by Enbridge in response to APPrO's IR # 10 b)[17].

Rate 125 customers are Enbridge's largest customers. They must have a Contract Demand greater than 600,000 m^3/d[18].

In order to better reflect cost causality, the XHP function should be further broken down into those XHP assets with size and pressure characteristics that are consistent with the volumetric requirements of Rate 125 customers and the rest of the XHP assets that do not provide sufficient capacity to adequately serve Rate 125 customers. In the Allocation step of the CAM, Enbridge should allocate to rate 125 customers only those XHP assets and expenses that are capable of supplying services to them.

The result of this change, as stated in Enbridge's response to APPrO's IR # 10 c)[19], is that by allocating only pipelines with diameters of 6 inches or more, the Capacity TP allocated to rate 125 customers decreases from $9.96 million to $9.02 million for 2014.

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14 Exhibit I.C30.EGDI.APPrO.6
15 Exhibit I.C30.EGDI.APPrO.11
16 Ibid.
17 Ibid.
18 Exhibit H2 Tab 2 Schedule 1 Rate 125 Page 1 of 6
19 Exhibit I.C30.EGDI.APPrO 10

Base on OEB approvals for the most recent four out of the five Rate 125 customers, the size of XHP assets utilized by Enbridge to serve these customers are shown in the Table below.

Rate 125 Customer	Proceeding #	MW	Peak Day 10^3m^3/d	Pipeline Size
Goreway	EB-2005-0539	839	5,400	24 inch[20]
Portlands	EB-2006-0305	550	2785.9	NPS 20 and NPS 36[21]
Thorold	EB-2008-0065	236	2037.7	NPS 12[22]
York Energy	EB-2009-0187	393	3264.0	16 inch[23]

It is also noteworthy that 3 of the above 4 Rate 125 customers are serviced off dedicated pipelines separate and distinct from the balance of the XHP system.

We are of the view that Enbridge's CAM should be modified so as to allocate XHP assets based on cost causality principles to Enbridge's customers by:

1. Separating XHP assets into two sub accounts: XHP assets able to reasonably satisfy the minimum volumetric requirements of Rate 125 customers and the remaining XHP assets, and
2. Allocating XHP assets that can supply Rate 125 customers to all of Enbridge's customer classes and allocation the remaining XHP assets to Enbridge's customer classes excluding Rate 125 customers.

[20] Notice of Application and Hearing, February 14, 2006
[21] Decision and Order, June 1, 2007
[22] Decision and Order, October 28, 2008
[23] Decision and Order, April 5, 2010

4.2 Treatment of Costs Related to Excess Capacity

The costs associated with the Ottawa Reinforcement, the GTA Reinforcement, the Allison Reinforcement, the Harmony Conlin Reinforcement and the York Region Reinforcement Project are being included in Enbridge's revenue requirement for the period 2014 to 2018 and are being recovered from Enbridge's customers based on Enbridge's CAM.

Excess capacity means that portion of XHP distribution capacity that is being added by Enbridge as a result of a reinforcement project. The excess capacity that is being added is usually the result of economies of scale of pipeline construction and is based on a long term market forecast for an area.

It is our understanding that when a new Rate 125 customer applies for service, Enbridge provides for 100% of the capacity required by the customer to be added to the system to ensure that the excess capacity that might exist in the system to accommodate the growth of small volume customers is not used up by the new Rate 125 customer. The cost of this new capacity is incorporated into the economic feasibility tests used by Enbridge. If the expansion costs and the ongoing operating and maintenance costs result in a profitability index (PI) less than 1.0, then the customer is required to pay a contribution in aid of construction (CIAC) by an amount that would result in a PI = 1.0. Since Rate 125 customers are only served off the XHP system, the full costs of the capacity required to serve the new customer are recovered in the existing rate or are paid as a CIAC.

Enbridge has proposed a number of major XHP reinforcement projects in the GTA, Ottawa and other regions for the benefit of small volume customers. The capacity that is being added is in excess of the capacity that is required for the test year. Under the CAM, this excess capacity is not distinguished from the utilized capacity and is allocated to all rate classes, including Rate 125, using the peak day demand allocator.

Since Rate 125 must pay for all the incremental XHP system capacity that is required to serve their load, they are unable to access any of the excess capacity that results from the planned reinforcement projects. The effect of the CAM therefore is to recover a portion of the costs associated with the excess capacity from Rate 125 even though the economic feasibility test ensures that they are paying enough to cover the cost of maintaining the amount of excess capacity in the system.

In essence, Rate 125 customers are not able to access any excess system capacity that exists at the time they come on line, and 100% of the capacity required to meet their Contract Demand requirements[24] is included in the economic test when they come on line.

It is our view that requiring Rate 125 customer to pay for the reinforcement projects identified above, as per the current Enbridge CAM, would in effect recover the same costs from rate 125 customers that were already recovered by way of rates and the contribution in aid of construction which maintains the existing capacity of Enbridge's distribution system when Rate 125 customers are connected.

In Proceeding EB-2012-0433/EB-2012-0451/EB-2013-0074, in Transcript Volume 4, of September 19, 2013, on page 115 line 16 to page 116 line 1, the following oral testimony evidence was provided:

> *MS. GIRIDHAR: So, Mr. DeRose, I think we should clarify that when we seek contributions from our large industrial or power generation customers, the notion there is that they're paying for capacity that they're taking away from the system. We have no requirement for them to pay for future growth of other customers being added on the system.*
>
> *The reality is that the addition of customers since that time has created additional constraints on infrastructure that's jointly used by all of our customers, including Portlands. So the suggestion that somehow Portlands should pay for the capacity required to meet the needs of other customers doesn't really, you know, ring true for us.*

In the same Proceeding, in Transcript Volume 4, of September 19, 2013, on page 114 line 21 to page 115 line 3, the following oral testimony evidence was provided:

> *MR. FERNANDES: So the answer is that the Portlands project was specific to Portlands as an electrical generator. And the requirement then was to replace the lost capacity on the system in order to ensure that the other ratepayers were not impacted by them coming on the system.*
>
> *So Portlands paid a substantial contribution in aid of construction for those facilities. So it would have been inappropriate for to us build more capacity than what Portlands required, because they were substantially paying for that capacity.*

---

[24] EB-2012-0451 Exhibit1.A1.EGD.APPrO.2

It is our view that in order to avoid Rate 125 customers paying in two ways for the excess capacity required in the Enbridge system to accommodate future growth efficiently, Enbridge should be directed either to amend its economic feasibility test as it applies to Rate 125 customers or to modify its cost allocation methodology so that Rate 125 customers are not required to pay for excess capacity in the system in two ways.

Given that some existing Rate 125 customers have paid CIAC that includes the cost of maintaining the pre-existing level of excess capacity in the system, the only practical approach to treating all Rate 125 customers equitably may be to modify the cost allocation model so that Rate 125 customers are not allocated the costs of excess capacity required to accommodate future load growth in the Enbridge system.

5 RECOMMENDATIONS

We recommend that Enbridge's CAM should be refined as follows in order to better reflect cost causality principles.

First, the XHP function should be further broken down into those assets and expenses that can reasonably serve rate 125 customers and the rest of the XHP assets that cannot serve Rate 125 customers. In the Allocation step of the CAM, Enbridge should allocate to rate 125 customers only those XHP assets and expenses that can be used to reasonably supply services to them as well as other customers who can be served by those facilities.

Second, Enbridge should be directed either to amend its economic feasibility test as it applies to Rate 125 customers or to modify its cost allocation methodology so that Rate 125 customers are not required to pay for excess capacity in the system in two ways.

RATE 125

1. Rate 125 was first introduced and approved by the Ontario Energy Board in the context of Enbridge Gas Distribution's 2000 Rate Case (RP-1999-001) in order to respond to opportunities for natural gas fuelled cogeneration and power generation in anticipation of the deregulation of the electricity market in Ontario. Rate 125 provides unbundled distribution service from Enbridge Gas Distribution's city gate to the customer's premise.

2. At its inception, the applicability section of Rate 125 stipulated a minimum annual volume of 200 million cubic metres, a minimum contract demand of 609 thousand cubic metres per day, and a minimum load factor requirement of 90 percent. In its 2001 Rate Case (RP-2000-0040), Enbridge Gas Distribution subsequently applied and received approval from the Board to remove the minimum load factor requirement of 90 percent. This amendment was requested on the ground that the rate was originally designed for cogeneration projects and as further developments of the electricity market unfolded, Rate 125 was too restrictive for gas fired power plants that intended to sell all or most of their output to the power grid. These plants would have no assurance regarding their operating profile as this will ultimately depend on each plant's success in bidding to supply power into the Ontario grid.

3. The approach undertaken in the derivation of Rate 125 was based on the ratemaking principles considered by the Board for the approval of all other customer rate classes. These principles included the use of postage stamp rates, class rate-making, and the use of an embedded average cost approach. The costs allocated to Rate 125 include return and taxes, operating and maintenance costs, and depreciation associated with extra high pressure mains, meters, and services. No

costs were allocated for the high pressure or low pressure distribution network. A typical customer under this rate would require service off the Company's extra high pressure (i.e. transmission pressure) network. The level of Rate 125 was set such that it entirely recovers its fully allocated costs.

4. In subsequent discussions, potential Rate 125 customers expressed a desire for more flexibility in the rate, given the uncertainties of the deregulated electricity market and the distinctive nature of merchant power plants. The specific areas that were discussed related to the existing terms and conditions pertaining to the requirement for system wide unaccounted for gas in the case of dedicated lines, as well as the consideration for the establishment of authorized demand overrun provision within Rate 125. Consideration of these issues took place and Enbridge Gas Distribution filed an amended Rate 125 schedule on October 8, 2002 as part of its 2003 Rate Case proceeding. There are no customers currently taking service on Rate 125.

5. Under the current Rate 125, customers are required to balance deliveries and consumption within a 2% tolerance. Any imbalance in excess of 2% is cashed out based on the price of gas on the day. In this proceeding, based on stakeholder feedback, Enbridge Gas Distribution is expanding the scope of Rate 125 from a pure unbundled distribution rate to include a default balancing provision. The service allows a certain degree of imbalance between the customer's deliveries and consumption on a daily basis. The provision is default in the sense that a customer who is always in balance within +/- 2%, would only incur fixed distribution charges and no balancing charges. Failure to remain within expanded balancing limits will still trigger cashout provisions.

Witness: M. Giridhar
E. Overcast

6. Enbridge Gas Distribution has reviewed potential alternatives for providing a limited balancing service. In all instances the Company would require the use of storage assets and pipeline capacity to provide load balancing service in the franchise area. However, depending on the level of incremental assets and their characteristics, there would be different trade-offs between cost and quality and between flexibility and restrictions. In a low cost offering that utilizes system diversity and few incremental assets, some restrictions on balancing may be required to minimize cost consequences on bundled customers and the probability of system outages. On the other hand, if there is full reservation of capacity for power generation customers and no reliance on system diversity, restrictions may be reduced significantly without compromising system integrity, albeit at a higher cost. The table below lays out the options and the associated tradeoffs.

Load Balancing Options

Option	Cost	Enhanced Storage	Enhanced Transport	Use of System Diversity	Service Restrictions	Imbalance Charges	Nature of Service
1	Low	Yes	None	High	Seasonal and OFO	Variable	Default
2	Medium	Yes	Partial	Low	Some	Fixed/Variable	Contracted
3	High	Yes	Full reservation of capacity	None	Low	Fixed/Variable	Contracted

7. Option 1 in the above table provides a lower quality and lower cost service. The service relies on high deliverability storage but no incremental pipeline capacity to

APPrO INTERROGATORY #14

INTERROGATORY

Reference: Exhibit G2, Tab 1, Schedule 1

Preamble: APPrO would like to better understand the XHP system capacity allocators used in Enbridge's Cost Allocation Methodology

Issue: 30. Is Enbridge's utility Cost Allocation Study, including the methodologies and judgments used and the proposed application of that study with respect to 2014 Fiscal Year rates, appropriate?

Questions:

a) In Exhibit G2, Tab1, Schedule 1, page 27 Appendix B, it shows that the allocation factor used for TP Demand is "Peak throughput on the transmission pressure system".
   i. Please confirm that the allocators used for TP Demand are those shown as "2.1 Delivery Demand TP" in Exhibit G2, Tab 6, Schedule 3, page 1 and that these allocators reflect peak daily throughput.
   ii. Please confirm that distribution mains are designed and modeled from a network analysis perspective, on a peak hour basis. If not please explain in full.
   iii. For each rate class or groups of rate classes, please explain in detail the methodology used to determine the peak daily demand. Please explain how the peak hour load is converted to a peak daily load for calculation of the peak daily load.
   iv. For heat sensitive loads, please confirm that the peak hour and peak daily loads have been adjusted to reflect Enbridge's current approved design day temperature standard for each region.
   v. Please provide the typical hourly load profile graph over a 24 hour period of Enbridge's heat sensitive market by rate class and in aggregate on a design day. On this graph, please illustrate the peak hourly demand, average hourly demand, and the Delivery Demand TP ÷ 24.

b) TP Demand
   i. Please re-run the Cost Allocation Methodology for the period 2014 to 2018 by allocating the TP Demand to customer classes using the peak hour load and not the peak daily throughput and provide the results of the model run in the

Witnesses: A. Kacicnik
M. Kirk

same format as shown for the exhibits from Exhibit G2, Tab 2, Schedule 1 to Exhibit G2, Tab 6, Schedule 1.

ii. Based on the results of a) above please provide the rates and proposed rate increases to all customers for the years 2014, 2015, 2016, 2017 and 2018

c) Please re-run the Cost Allocation Methodology for the period 2014 to 2018 incorporating the Cost Allocation Methodology changes outlines in the above interrogatories and provide the results of the model run in the same format as shown for the exhibits from Exhibit G2, Tab 2, Schedule 1 to Exhibit G2, Tab 6, Schedule:

i. Allocating to rate 125 customers only those XHP system assets that are reasonably capable to supply service to them
ii. Allocating the costs of Advance Capacity to those distribution customers that directly benefit from the use of such Advance Capacity
iii. Allocating the costs of Reserve Capacity to those distribution customers that directly benefit from the use of such Reserve Capacity
iv. Allocating the TP Demand to customer classes using the peak hour load and not the peak daily throughput

d) Based on the results of c) above please provide the rates and proposed rate increases to all customers for the years 2014, 2015, 2016, 2017 and 2018

RESPONSE

a)

i. Confirmed.

ii. Confirmed.

iii. From the top down (i.e., system total) perspective, design peak day demand is forecast utilizing a regression analysis. For each of the three weather zones contained within Enbridge's franchise area a separate regression equation is developed. Within each regression equation actual peak day demand (i.e., as measured at gate station entry points into the system excluding flows/demand of unbundled customers) is expressed as a function of weather variables and the number of customers. The peak day demand forecast by weather zone is then determined by utilizing design weather conditions and projected customer numbers as inputs to these regression equations. The total (i.e., system wide) design peak day demand for bundled customers is determined by summing the design peak day demand forecasts produced by each regression equation.

From the network analysis perspective, it is important to note that the Company does not measure peak hourly or daily consumption for the vast majority of its customers. The peak load is derived from actual customer consumption volumes extracted from Enbridge's billing system. An extract of 24 months of actual customer consumption volumes and corresponding temperature readings are used in a mathematical regression to determine the base load and heat load for various customer sectors. The base load and heat load are aggregated to sector (i.e., residential, apartment, commercial, and industrial) and to each region. The sum of the base load and heat load then results in peak consumption estimates for the forecast period.

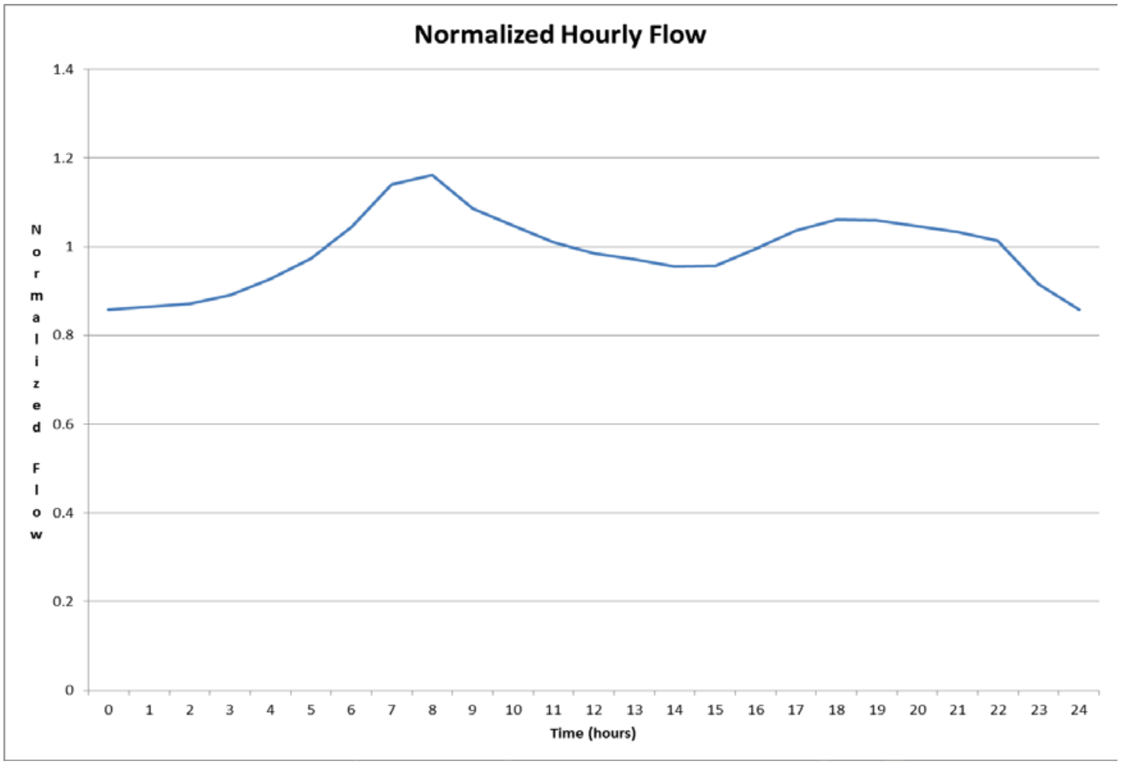
For unbundled customers, the sum of the customers' contract demands or billing contract demands is used as peak day demand.

iv. Confirmed. The forecast peak daily demand is adjusted for bundled customers to meet the design day criteria. This is not the case for unbundled customers, whose contract demand or billing contract demand is not adjusted with respect to the design day criteria.

Note that for bundled customers, the design peak day demand represents peak hourly demand times 20 (rather than 24). This accounts for the varying level of bundled customers' volume/demand within a day, since consumption for these customers varies over a 24 hour period.

v. Below is a graph depicting a typical normalized 24-hour gate station load profile showing the heat sensitivity of the load:

Witnesses: A. Kacicnik
M. Kirk



b), c) and d)

TP Capacity costs are allocated to rate classes based on the contribution of each rate class to the peak demand day. As mentioned in part a) iv), the forecast peak daily demand is adjusted for bundled customers to meet the design day criteria. For unbundled customers, the sum of the customers' contract demands or billing contract demands is used as peak day demand.

The following table shows contract parameters for Rate 125 customers on an aggregated basis.

	CD & Billing CD	CD	Maximum Hourly Demand
Rate 125	9,935,357*	15,626,561	651,107

*See Exhibit G2, Tab 6, Schedule 3, Page 1, Line 4, Column 8

As proposed in the evidence, Rate 125 customers, based on the sum of contract demand and billing contract demand, represent approximately 8.6% of the Delivery Demand TP for 2014.

	Peak Day Demand	% of Peak Day Demand
Bundled	105,004,800*	91.4%
Rate 125 (CD & Billing CD)	9,935,357	8.6%
Total Peak Day Demand	114,940,157**	100.0%

* See Exhibit G2, Tab 6, Schedule 3, page 1, Line 1.4 for Bundled Peak Delivery, and Exhibit D3, Tab 3, Schedule 3, page 1, Line 1 (3,961,350 GJs or 105,100 103m3)

** See Exhibit G2, Tab 6, Schedule 3, page 1, Line 2.1 (difference of 15.6 is Rate 300)

Should the contract demand be used, then Rate 125 customers would represent approximately 13.0% of the Delivery Demand TP for 2014.

	Peak Day Demand	% of Peak Day Demand
Bundled	105,004,800	87.0%
Rate 125 (CD)	15,626,561	13.0%
Total Peak Hourly Demand	120,631,361	100.0%

Should the peak hour load be used to derive the Delivery Demand TP allocator then Rate 125 customers would represent approximately 11.0% of the Delivery Demand TP for 2014.

	Peak Hourly Demand	% of Peak Hourly Demand
Bundled	5,250,240*	89.0%
Rate 125	651,107	11.0%
Total Peak Hourly Demand	5,901,347	100.0%

* Bundled Design Peak Day of 105,004,800 divided by 20 equals 5,250,240

Witnesses: A. Kacicnik
M. Kirk

Note that if the peak hour load is used to derive the Delivery Demand TP allocator then the billing contract demand cannot be used to derive the Delivery Demand TP allocator for Rate 125 customers since the concept of billing contract demand is a daily value.

Also note that the maximum hourly demand is about 1/15 of Rate 125 contract and billing demand.

The as-proposed-for allocators (using the Board approved methodology) result in the amount allocated to unbundled customers which is less than it would be if Delivery Demand TP were allocated using the peak hour load.

It can be inferred from the information above that the rates and proposed rate increases would be higher for Rate 125 under such an approach versus using the Board approved methodology. Consequently and also given that it would be an onerous exercise to do so, the Company respectfully declines to re-run its cost allocation methodology as suggested by the question.

Witnesses: A. Kacicnik
M. Kirk

ALLOCATION FACTORS
Year Ended December 31, 2014

	Col. 1 FACTOR TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col. 10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300 Firm	Col. 14 RATE 300 Int	Col. 15 Direct Purchase
COMMODITY RESPONSIBILITY															
1.1 Annual Sales	7,351.1	4,131.1	2,942.6	0.5	0.0	92.1	0.9	0.0	1.2	22.0	37.3	123.4	0.0	0.0	0.0
1.2 Bundled Annual Deliveries	11,125.9	4,621.3	4,568.1	0.6	0.0	617.6	471.0	0.0	56.5	163.0	462.9	164.9	0.0	0.0	0.0
1.3 Total Annual Deliveries	11,155.9	4,621.3	4,568.1	0.6	0.0	617.6	471.0	0.0	56.5	163.0	462.9	164.9	0.0	30.0	0.0
1.4 Bundled Peak Delivery	105,004.8	54,021.7	45,223.8	1.9	0.0	2,287.4	1,535.8	0.0	5.0	431.7	302.7	1,194.9	0.0	0.0	0.0
1.5 System Gas Sales	7,351.1	4,131.1	2,942.6	0.5	0.0	92.1	0.9	0.0	1.2	22.0	37.3	123.4	0.0	0.0	0.0
DISTRIBUTION CAPACITY RESPONSIBILITY															
2.1 Delivery Demand TP	114,955.7	54,021.7	45,223.8	1.9	0.0	2,287.4	1,535.8	9,935.4	5.0	431.7	302.7	1,194.9	15.6	0.0	0.0
2.2 Delivery Demand HP	103,924.2	54,021.7	45,223.8	1.9	0.0	2,287.4	1,535.8	0.0	5.0	431.7	302.7	0.0	15.6	98.7	0.0
2.3 Delivery Demand LP	103,035.7	54,021.7	45,223.8	1.9	0.0	2,287.4	647.3	0.0	5.0	431.7	302.7	0.0	15.6	98.7	0.0
2.4 Cust. Rel Plant	2,059,618	1,899,632	159,576	8	0	191	27	5	41	102	34	0	1	1	0.0
STORAGE RESPONSIBILITY															
3.1 Deliverability	57.9	32.6	24.3	0.0	0.0	0.4	0.2	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0
3.2 Space	2,754.8	1,324.7	1,274.6	0.0	0.0	34.3	8.7	0.0	0.0	29.2	45.8	37.7	0.0	0.0	0.0
CUSTOMER RESPONSIBILITY															
4.1 Meters	419,420.0	231,637.1	182,049.6	44.4	0.0	1,653.4	225.6	2,283.5	362.6	862.8	284.1	0.0	8.6	8.4	0.0
4.2 Sales Stations	190,084.1	14,306.0	161,030.8	151.9	0.0	5,743.6	1,104.2	0.0	2,816.3	2,487.3	2,182.6	0.0	131.5	129.9	0.0
4.3 Services	2,309,110.0	2,051,935.6	249,682.5	19.1	0.0	1,974.4	730.1	447.7	376.3	1,028.4	2,820.2	0.0	12.7	82.9	0.0
4.4 Rental Equipment	0.3	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4.5 Total Customer Count	2,059,618	1,899,632	159,576	8	0	191	27	5	41	102	34	0	1	1	0.0
4.6 Comm/Ind. Customer Count	159,986	0	159,576	8	0	191	27	5	41	102	34	0	1	1	0.0
4.7 Contracts	402	0	0	0	0	191	27	5	41	102	34	0	1	1	0.0
4.8 Chart Readings non AMR per Year	67,035	0	65,712	36	0	156	0	0	36	0	365	0	365	365	0.0
4.9 Chart Readings AMR per Year	2,492	0	2,095	5	0	173	33	5	36	104	41	0	0	0	0.0
4.10 Meter Readings per Year	12,311,940	11,397,792	914,148	0	0	0	0	0	0	0	0	0	0	0	0.0
4.11 Direct Purchase Customers	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1.0
5. Rate Base	4,136.8	2,858.8	1,148.1	1.8	0.0	39.3	15.2	38.3	2.0	11.3	11.9	8.8	0.3	1.1	0.0

ALLOCATION PERCENTAGES
Year Ended December 31, 2014

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
	FACTOR TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300	RATE 300 Int	Direct Purchase
COMMODITY RESPONSIBILITY															
1.1 Annual Sales	1.0000	0.5620	0.4003	0.0001	0.0000	0.0125	0.0001	0.0000	0.0002	0.0030	0.0051	0.0168	0.0000	0.0000	0.0000
1.2 Bundled Annual Deliveries	1.0000	0.4154	0.4106	0.0001	0.0000	0.0555	0.0423	0.0000	0.0051	0.0147	0.0416	0.0148	0.0000	0.0000	0.0000
1.3 Total Annual Deliveries	1.0000	0.4142	0.4095	0.0001	0.0000	0.0554	0.0422	0.0000	0.0051	0.0146	0.0415	0.0148	0.0000	0.0027	0.0000
1.4 Bundled Peak Delivery	1.0000	0.5145	0.4307	0.0000	0.0000	0.0218	0.0146	0.0000	0.0000	0.0041	0.0029	0.0114	0.0000	0.0000	0.0000
1.5 System Gas Sales	1.0000	0.5620	0.4003	0.0001	0.0000	0.0125	0.0001	0.0000	0.0002	0.0030	0.0051	0.0168	0.0000	0.0000	0.0000
DISTRIBUTION CAPACITY RESPONSIBILITY															
2.1 Delivery Demand TP	1.0000	0.4699	0.3934	0.0000	0.0000	0.0199	0.0134	0.0864	0.0000	0.0038	0.0026	0.0104	0.0001	0.0000	0.0000
2.2 Delivery Demand HP	1.0000	0.5198	0.4352	0.0000	0.0000	0.0220	0.0148	0.0000	0.0000	0.0042	0.0029	0.0000	0.0002	0.0010	0.0000
2.3 Delivery Demand LP	1.0000	0.5243	0.4389	0.0000	0.0000	0.0222	0.0063	0.0000	0.0000	0.0042	0.0029	0.0000	0.0002	0.0010	0.0000
2.4 Cust. Rel Plant	1.0000	0.9223	0.0775	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
STORAGE RESPONSIBILITY															
3.1 Deliverability	1.0000	0.5628	0.4191	0.0000	0.0000	0.0064	0.0032	0.0000	0.0000	0.0000	0.0000	0.0085	0.0000	0.0000	0.0000
3.2 Space	1.0000	0.4809	0.4627	0.0000	0.0000	0.0125	0.0031	0.0000	0.0000	0.0106	0.0166	0.0137	0.0000	0.0000	0.0000
CUSTOMER RESPONSIBILITY															
4.1 Meters	1.0000	0.5523	0.4341	0.0001	0.0000	0.0039	0.0005	0.0054	0.0009	0.0021	0.0007	0.0000	0.0000	0.0000	0.0000
4.2 Sales Stations	1.0000	0.0753	0.8472	0.0008	0.0000	0.0302	0.0058	0.0000	0.0148	0.0131	0.0115	0.0000	0.0007	0.0007	0.0000
4.3 Services	1.0000	0.8886	0.1081	0.0000	0.0000	0.0009	0.0003	0.0002	0.0002	0.0004	0.0012	0.0000	0.0000	0.0000	0.0000
4.4 Rental Equipment	1.0000	0.2000	0.8000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.5 Total Customer Count	1.0000	0.9223	0.0775	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.6 Comm/Ind. Customer Count	1.0000	0.0000	0.9974	0.0001	0.0000	0.0012	0.0002	0.0000	0.0003	0.0006	0.0002	0.0000	0.0000	0.0000	0.0000
4.7 Contracts	1.0000	0.0000	0.0000	0.0000	0.0000	0.4751	0.0672	0.0124	0.1020	0.2537	0.0846	0.0000	0.0025	0.0025	0.0000
4.8 Chart Readings non AMR per Year	1.0000	0.0000	0.9803	0.0005	0.0000	0.0023	0.0000	0.0000	0.0005	0.0000	0.0054	0.0000	0.0054	0.0054	0.0000
4.9 Chart Readings AMR per Year	1.0000	0.0000	0.8407	0.0020	0.0000	0.0694	0.0132	0.0020	0.0144	0.0417	0.0165	0.0000	0.0000	0.0000	0.0000
4.10 Meter Readings per Year	1.0000	0.9258	0.0742	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.11 Separation Expense Allocator	1.0000	0.7750	0.2250	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.12 Direct Purchase Customers	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.0000
5. Rate Base	1.0000	0.6911	0.2775	0.0004	0.0000	0.0095	0.0037	0.0093	0.0005	0.0027	0.0029	0.0021	0.0001	0.0003	0.0000