EB-2017-0087

Union Gas Limited

Application for natural gas distribution, transmission and storage rates effective January 1, 2018.

IGUA Compendium for Argument

GOWLING WLG

ONTARIO ENERGY BOARD NOTICE
TO CUSTOMERS OF UNION GAS LIMITED

Union Gas Limited applied to raise its natural gas rates effective January 1, 2018

Learn more. Have your say.

Union Gas Limited applied to the Ontario Energy Board to raise its natural gas rates effective January 1, 2018. If the application is approved, a typical residential customer of Union Gas Limited in the south (Windsor to Hamilton) would see an increase of approximately $9.60 per year. Residential customers in all the other areas served by Union Gas Limited would see an increase ranging from $10.75 to $14.00 per year. Other customers, including businesses, may also be affected.

The requested rate increase is set using a formula previously approved by the Ontario Energy Board for the period 2014 to 2018. The formula is tied to inflation and other factors intended to promote efficiency.

Union Gas Limited is also requesting approval to make certain changes to the Rate M12 Schedule "C" as it applies to the proposed M12-X service and other services. Union Gas Limited's application also includes costs for the Panhandle Reinforcement Project.

THE ONTARIO ENERGY BOARD WILL HOLD A PUBLIC HEARING

The Ontario Energy Board (OEB) will hold a public hearing to consider Union Gas' request. We will question the company on its case for a rate change. We will also hear questions and arguments from individual customers and from groups that represent Union Gas customers. At the end of this hearing, the OEB will decide what, if any, rate changes will be allowed.

The OEB is an independent and impartial public agency. We make decisions that serve the public interest. Our goal is to promote a financially viable and efficient energy sector that provides you with reliable energy services at a reasonable cost.

BE INFORMED AND HAVE YOUR SAY

You have the right to information regarding this application and to be involved in the process.

- You can review Union Gas' application on the OEB's website now.
- You can file a letter with your comments, which will be considered during the hearing.
- You can become an active participant (called an intervenor). Apply by **October 23, 2017** or the hearing will go ahead without you and you will not receive any further notice of the proceeding.
- At the end of the process, you can review the OEB's decision and its reasons on our website.

The OEB intends to consider cost awards in this proceeding that are in accordance with the *Practice Direction on Cost Awards* and only in relation to updates to the Rate M12 Schedule "C" and the Panhandle Reinforcement Project.

LEARN MORE

Our file number for this case is **EB-2017-0087**. To learn more about this hearing, find instructions on how to file letters or become an intervenor, or to access any document related to this case, please enter the file number **EB-2017-0087** on the OEB website: **www.oeb.ca/participate**. You can also phone our Consumer Relations Centre at 1-877-632-2727 with any questions.

ORAL VS. WRITTEN HEARINGS

There are two types of OEB hearings – oral and written. The OEB intends to proceed by way of a written hearing in this case. If you think an oral hearing is needed, you can write to the OEB to explain why by **October 23, 2017**.

PRIVACY

If you write a letter of comment, your name and the content of your letter will be put on the public record and the OEB website. However, your personal telephone number, home address and email address will be removed. If you are a business, all your information will remain public. If you apply to become an intervenor, all information will be public.

This rate hearing will be held under section 36 of the Ontario Energy Board Act, S.O. 1998 c.15 (Schedule B).

Ontario

Ontario Energy Board Commission de l'énergie de l'Ontario

GOWLING WLG

October 19, 2017

Ian A. Mondrow
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VIA RESS AND COURIER

Ms. Kirsten Walli
ONTARIO ENERGY BOARD
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: EB-2017-0087 – Union Gas Limited (Union) 2018 Rates Application.

Industrial Gas Users Association (IGUA) Request for Intervention.

We write as legal counsel to IGUA to request that IGUA be granted intervenor status in the captioned proceeding.

Description of IGUA

IGUA is an association of industrial companies located in the Canadian provinces of Ontario and Québec, who use natural gas in their industrial operations. IGUA was first organized in 1973 and it provides a coordinated and effective public policy and regulatory voice for those industrial firms depending on natural gas as a fuel or feedstock. IGUA has become the recognized voice representing the industrial user of natural gas before regulatory boards and governments at both the provincial and national levels.

The Association's activities are guided by a 15 member Board of Directors, constituted to assure that each industrial sector and geographic region is represented. The Board of Directors has regularly scheduled meetings at least six times each year. A full time President and other staff are based in a permanent office in Ottawa.

Through regulatory intervention, government advocacy, marketing, promotion, partnerships, education and outreach, IGUA successfully represents industrial gas users. Our mission is to be the voice of our members within the natural gas industry through intervention, advocacy, and partnerships.

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Nature and Scope of IGUA's Intended Participation

IGUA was an active participant in Union's cost of service and IRM proceedings which established the current (2014-2018) rate plan under which this application is proceeding. IGUA intends to review the current application in general (subject to further consideration of the Board's Notice of hearing direction limiting the scope of cost eligibility), but at this time anticipates a focus on one issue in particular; the rate impacts of the Panhandle Reinforcement Project.

IGUA has members served on Union's St. Clair system who will be particularly impacted in 2018 by Union's proposal for 2018 recovery of costs of the Panhandle Reinforcement Project in accord with the Board's findings in EB-2016-0186. IGUA now has information sufficient to quantify the rate impacts on its members of this recovery proposal. IGUA proposes to file evidence of those impacts and the implications to its members of an alternative approach to allocation of the subject costs as previously proposed by Union. IGUA will argue in this proceeding that the Panhandle Expansion Project rate impacts are too significant to further defer a re-examination of the appropriate and equitable approach to allocation of these costs.

Written or Oral Hearing

IGUA will have a better view of whether a written hearing would be appropriate in this application, or whether an oral hearing would be advisable, following the finalization and filing of its proposed evidence and the anticipated interrogatory process in respect of that evidence and Union's pre-filed evidence. IGUA respectfully suggests that the Board contemplate a schedule which includes provision for a brief oral hearing, if ultimately deemed appropriate.

Intention to Seek an Award of Costs

IGUA also hereby requests that it be determined eligible for recovery of its reasonably incurred costs of its intervention herein.

As a party primarily representing the direct interests of industrial consumers (i.e. ratepayers) in relation to regulated services, IGUA has in the past been determined to be eligible for cost awards pursuant to section 3.03(a) of the Board's *Practice Direction on Cost Awards*.

While we have noted the Board's direction in the Notice of Hearing limiting the scope of cost recovery to updates to Rate M12 Schedule "C" and the Panhandle Reinforcement Project, IGUA reserves its position on seeking costs in respect of additional issues which, based on a full record, are demonstrably material and appropriate for review and determination, with input from affected customers, as part of this proceeding.

GOWLING WLG

Request for Written Evidence and Contact Information

IGUA requests that copies of written evidence and all circulated correspondence related to this matter be directed to it as follows:

Ian Mondrow, Partner
GOWLING WLG (CANADA) LLP
Suite 1600, 1 First Canadian Place
100 King Street West
Toronto, Ontario
M5X 1G5

Phone:	416-369-4670
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Dr. Shahrzad Rahbar
President
INDUSTRIAL GAS USERS ASSOCIATION
260 Centrum Boulevard, Suite 202
Orleans, Ontario
K1E 3P4

Office:	613-236-8021
Mobile:	613-983-2927
E-Mail:	srahbar@igua.ca

We have an electronic copy of the prefiled materials and do not require a hard copy.

Yours truly,

Ian A. Mondrow

c: A. Stiers (Union)
C. Smith (Torys)
S. Rahbar (IGUA)
K. Viraney (Board Staff)

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Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2017-0087

Union Gas Limited

Application for natural gas distribution, transmission and storage rates effective January 1, 2018

PROCEDURAL ORDER NO. 3

November 29, 2017

Union Gas Limited (Union Gas) filed an application dated September 26, 2017 with the Ontario Energy Board (OEB) pursuant to section 36 of the *Ontario Energy Board Act, 1998* (Act), for an order or orders approving rates for the distribution, transmission and storage of natural gas, effective January 1, 2018. The Industrial Gas Users Association (IGUA) filed evidence requesting a change to the current cost allocation methodology used to allocate Panhandle Reinforcement project costs.

The OEB has previously directed that IRM rate changes are supposed to be mechanistic in the current IRM framework. Cost allocation changes are outside of the scope of this proceeding accordingly the evidence of IGUA will not be considered.as part of the evidentiary record.

The Union Gas 2013 application for a multi-year Incentive Ratemaking (IRM) framework, EB-2013-0202, established the IRM framework for Union Gas' current application for 2018 rates. The framework sets rates on an annual basis using a price cap and other adjustments. With respect to cost allocation, the OEB- approved settlement stated:

> Subject to direction otherwise from the Board, Union will allocate the net revenue requirement using 2013 Board-approved cost allocation methodologies. Any party, including Union, may take any position with respect to the proposed allocation for any particular capital project during review of the project, or its rate impacts, by the Board[1];

[1] EB-2013-0202 Settlement Agreement, Union Gas Limited, Page 21, July 31, 2013

In the Panhandle Reinforcement Leave to Construct application, EB-2016-0186, Union proposed to allocate the Panhandle System demand costs in proportion to the firm Union South in-franchise Panhandle System Design Day demands. The OEB-approved cost allocation methodology allocates costs based on the combined Panhandle and St. Clair System. With the addition of significant Panhandle System project costs, Union submitted that the use of the combined system for cost allocation purposes no longer reflected the costs to serve the customers. The OEB Decision determined that a change in cost allocation cannot be adequately considered during the IRM term and such changes should be reviewed in Union's next rebasing proceeding. Neither IGUA nor any other party requested a review of this decision.

Union's IRM term is ending in 2018 and it was expected to file a rebasing proceeding for 2019 rates. The Union and Enbridge Gas Distribution Inc. (Enbridge) merger application proposed a 10-year adjustment to rates using a price cap index[2]. In response to an interrogatory[3], Union has indicated that it intends to address concerns with the cost allocation of all Panhandle System and St. Clair System costs in its 2019 price cap index rates application.

As an approved intervenor in the current proceeding, the Industrial Gas Users Association (IGUA) filed evidence providing an overview of the rate impact on IGUA members as a result of the current cost allocation methodology. IGUA noted that a number of its members were T2 customers who would have a rate increase of 16.2% in 2018. The aggregate difference between using the existing allocation methodology and Union's proposed allocation methodology in the Panhandle Reinforcement leave to construct application will be approximately $926,000 in 2018 for the four specifically identified IGUA members. IGUA submitted that this was a material impact for, and a significant concern of IGUA's Sarnia area members.

The OEB is of the opinion that cost allocation issues can be better addressed prior to Union entering another price cap rate mechanism framework. It would not be appropriate to address cost allocation changes in the last year of the current IRM framework where rate changes are supposed to be mechanistic. Furthermore, the merger Application of Union and Enbridge has not yet been approved, and it is possible that Union and Enbridge could be required to file evidence dealing with some components of rebasing applications. The OEB is of the opinion that any cost allocation changes are appropriate to be considered for the setting of 2019 rates. In addition, the Notice in the current proceeding did not include any specific reference to cost allocation as an issue.

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[2] Union and Enbridge MAADs and Rate Framework Applications, EB-2017-0306 and EB-2017-0307
[3] Union response to interrogatory, Exhibit B.IGUA.4, part c, November 21, 2017

The OEB has reviewed the evidence of IGUA and has determined that the issue raised by IGUA in its evidence is thus out of scope and will not be addressed in this proceeding. Accordingly, further examination of the evidence submitted by IGUA through interrogatories is not required for the determination of the application. The OEB reminds all parties that it will not provide for costs related to review of IGUA's evidence or for preparing interrogatories on that evidence.

All filings to the Board must quote the file number, **EB-2017-0087** and be made electronically in searchable/unrestricted PDF format through the OEB's web portal at https://www.pes.ontarioenergyboard.ca/eservice/. Two paper copies must also be filed. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.oeb.ca/OEB/Industry. If the web portal is not available, parties may email their documents to the address below.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Khalil Viraney at Khalil.Viraney@oeb.ca and Board Counsel, Michael Millar at Michael.Millar@oeb.ca.

ADDRESS

Ontario Energy Board
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Attention: Board Secretary

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Fax: 416-440-7656

DATED at Toronto, November 29, 2017

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

GOWLING WLG

December 6, 2017

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VIA RESS AND COURIER

Ms. Kirsten Walli
ONTARIO ENERGY BOARD
P.O. Box 2319, 27th Floor
2300 Yonge Street
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M4P 1E4

Dear Ms. Walli:

Re: EB-2017-0087 – Union Gas Limited (Union) 2018 Rates Application.

Industrial Gas Users Association (IGUA) Request for Board Review of P.O. No. 3.

On behalf of IGUA we write to request that the Board review part of Procedural Order No. 3 herein (P.O. 3), pursuant to Rule 41.01 of the Board's *Rules of Practice and Procedure* (Rules). Rule 41.01 permits the Board to vary P.O. 3. IGUA believes that the Board has adopted an erroneous assumption in respect of IGUA's position in this matter and that the clarification provided in this letter might assist the Board and would justify variance of P.O. 3.

The Board issued P.O. 3 on November 29th indicating that it would not consider the evidence filed by IGUA herein as part of the evidentiary record in this proceeding. The basis for the Board's determination in respect of IGUA's evidence was that cost allocation changes are outside of the scope of this proceeding.

IGUA's evidence was intended to provide the Board and interested parties with information on the impact on IGUA's members of the allocation of Panhandle Reinforcement costs to rate classes as proposed in the current proceeding (Status Quo Allocation) compared to the impact that would result from adoption of the allocation methodology proposed by Union in the application for leave to construct the Panhandle Reinforcement [EB-2016-0186] (Union Proposed Allocation).[1] IGUA's evidence does not advocate a particular remedy associated with the information provided.

We concede that our October 19, 2017 letter filed herein on behalf of IGUA requesting intervenor status indicated that *"IGUA will argue in this proceeding that the Panhandle Expansion Project rate impacts are too significant to further defer a re-examination of the appropriate and equitable approach to allocation of [Panhandle Reinforcement] costs"*. We also acknowledge the direction provided in P.O. 3 that the Board is not prepared in the current proceeding to engage in re-examination of such allocation.

[1] IGUA Evidence, paragraph 1.

However, and with respect, IGUA should not be precluded from exploring other possible options for the Board to consider in addressing what would be a very significant and negative impact on its members, who are Union customers, resulting from the proposed recovery in 2018 by Union of the test year revenue requirement associated with the Panhandle Reinforcement.

We note that:

1. Union's evidence during the Panhandle Reinforcement leave to construct proceeding is that the largest rate impact of the Panhandle Reinforcement investment would be in 2018.[2]

2. Union has now indicated in this proceeding that it intends to address concerns with the cost allocation of all Panhandle System and St. Clair System costs in its 2019 Rates application.[3] This information was not available at the time that we filed IGUA's request for intervenor status herein and indicated IGUA's intention to argue against further deferral of re-examination of the allocation of Panhandle Expansion costs.

3. There is a $3.6 million difference in Panhandle Reinforcement cost allocation results for Union's T2 customers under application of the Status Quo Methodology as compared to the Union Proposed Methodology.[4]

4. Almost $1 million of this difference accrues to IGUA's 4 Sarnia area members whose evidence has been filed by IGUA and in respect of whose gas delivery needs Union does not rely on the Panhandle system at all.[5]

5. The Board's Notice of Hearing herein indicated that Panhandle Costs would be an issue in this proceeding (and subject to cost recovery eligibility).

6. P.O. No. 1 herein provided parties (including IGUA) with the opportunity to file evidence on issues in this proceeding.

IGUA understands the Board's direction that it will not entertain discussion of alternative methodologies for allocation of these costs in this proceeding. However, IGUA wishes to be able to explore in settlement discussions, and ultimately argue if required, for alternative forms of relief. For example, IGUA may wish to argue that where there is a negative impact on rate classes in the test year from adoption of one allocation methodology as compared to the other, a portion of the test year revenue requirement resulting from the Panhandle Reinforcement project costs be deferred pending the anticipated imminent review by the Board of the cost allocation methodology as part of Union's 2019 rates proceeding. There may be other reasonable mechanisms that IGUA or others could propose to address what IGUA will submit is a material inequity in the test year arising from the Status Quo Methodology, and pending the imminent review by the Board of the cost allocation methodology for Panhandle and St. Clair system costs.

[2] EB-2016-0186, Exhibit A, Tab 8, page 18, lines 2-5.
[3] Exhibit B.IGUA.4, part c).
[4] Exhibit B.IGUA.2, Attachment 1, line 15.
[5] IGUA Evidence, paragraph 29.

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IGUA's evidence is both relevant and probative of the equity of considering alternative test year treatments for recovery of Panhandle Reinforcement costs. While IGUA accepts the Hearing Panel's direction that the Panel will not entertain arguments for changes in cost allocation in this proceeding, we submit that it would be unfair for IGUA to be denied the opportunity to put forward its strongest case for potential alternatives (other than a re-examination of cost allocation at this time) to address what it asserts is an inequity in the test year that should be considered and addressed in some fashion in this proceeding. With respect, while IGUA accepts the Panels determination on the permitted scope of the Panhandle Cost issue in this proceeding, striking IGUA's evidence from the record herein is neither necessary to implement that direction nor fair to IGUA.

IGUA therefore requests that, in light of the foregoing clarifications, the Hearing Panel review P.O. 3 and vary its order to allow IGUA's evidence to remain on the record, with the caveat to IGUA and other parties that further exploration of alternative Panhandle Reinforcement cost allocation methodologies (beyond the impact in the test year of those alternatives) will not be permitted in this proceeding.

We note that the Settlement Conference herein is scheduled to commence next Wednesday, December 13th. In the event that the Board varies P.O. 3 as requested, and parties have questions regarding IGUA's evidence, IGUA is prepared to make best efforts to answer such questions as quickly as possible so that any discussions thereon at the Settlement Conference can proceed on the most complete information reasonably available.

On behalf of IGUA, we appreciate the Board's consideration of this request.

Yours truly,

Ian A. Mondrow

c: A. Stiers (Union)
C. Smith (Torys)
S. Rahbar (IGUA)
K. Viraney (Board Staff)
Intervenors of Record

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EB-2017-0087

ONTARIO ENERGY BOARD

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 Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act*, *1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2018.

SETTLEMENT PROPOSAL

December 21, 2017

The current approved authorized overrun Kirkwall to Dawn fuel ratio for Rate C1 is 0.157%. Union's proposal is to set the Rate C1 Kirkwall to Dawn authorized overrun fuel ratio and to introduce an M12 Kirkwall to Dawn authorized overrun fuel ratio at 0.778%. This proposed fuel ratio is consistent with the authorized overrun fuel ratio in the winter months for westerly transportation from Parkway to Kirkwall or Dawn, under both Rate C1 and Rate M12-X.

Union is proposing to remove the VT3 Westerly Parkway to Kirkwall and Parkway to Dawn fuel ratio and fuel rate from the Rate M12 Schedule "C" as Union no longer offers this service under Rate M12. The last Rate M12 contract for Parkway to Dawn service expired in 2014. Union only offers transportation from Parkway to Kirkwall and Dawn under Rate C1 or as part of the M12-X service. There is no impact of removing this service option as Union currently offers and will continue to offer long-term westerly transportation from Parkway to Kirkwall or Dawn under Rate C1 and as part of the Rate M12-X service.

The following Parties agree with the settlement of this issue: BOMA, CME, CCC, Energy Probe, FRPO, IGUA, Kitchener, LPMA, SEC, VECC, SNNG, Union.

Evidence references: A/T1/pp. 14-15; B.Staff.5; B.Staff.6; BOMA.1; BOMA.3; FRPO.3; FRPO.4; FRPO.5; FRPO.6; VECC.2.

2. THE PANHANDLE REINFORCEMENT PROJECT

(Partial Settlement)

The Panhandle Reinforcement Project was approved by the OEB on February 23, 2017 with a capital cost of $264.5 million. The Panhandle Reinforcement Project was placed into service commercially on November 1, 2017 and operationally on November 11, 2017.

The Parties agree to include in 2018 rates the Panhandle Reinforcement Project net revenue requirement calculated in accord with the Board's Decision and Order in Union's Panhandle Reinforcement Project Leave to Construct application (EB-2016-0186), subject to an update to the capital cost to reflect Union's latest total forecast capital cost of $242.8 million, as provided in Exhibit B.BOMA.4, and subject to the issue of final allocation of Panhandle Reinforcement Project costs to rates, including in respect of the 2018 test year, as outlined below. The Parties also agree that any variance between actual and forecast net delivery revenue requirement (positive or negative) will continue to be captured in the Panhandle Reinforcement Project Costs Deferral Account (No. 179-156). These costs will be disposed of through a future proceeding.

There is no agreement as to the final allocation of Panhandle Reinforcement Project costs for 2018. As the Board has noted in its December 11, 2017 Decision on Motion to Vary Part of Procedural Order No. 3, IGUA has suggested potential remedies to what it views as an inequity arising from the Board approved cost allocation of Panhandle Reinforcement Project costs which potential remedies would not involve changes to cost allocation methodology in this proceeding. The parties agree that no further evidence is required in respect of this issue, and it should proceed to argument.

The following Parties agree with the settlement of this issue: BOMA, CME, CCC, Energy Probe, FRPO, IGUA, Kitchener, LPMA, SEC, VECC, SNNG, Union.

Evidence references: A/T1/pp. 8-11; B.Staff.4; B.Staff.8; B.BOMA.4; B.BOMA.5; B.BOMA.6; B.CME.1; B.Energy Probe.10; B.IGUA.1; B.IGUA.2; B.IGUA.3; B.IGUA.4; B.VECC.1.

Ontario

Ontario Energy Board
Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2017-0087

UNION GAS LIMITED

Decision on Motion to Vary Part of Procedural Order No. 3

BEFORE: **Michael Janigan**
Presiding Member

Susan Frank
Member

December 11, 2017

1 INTRODUCTION AND SUMMARY

Union Gas Limited (Union Gas) filed an application dated September 26, 2017 with the Ontario Energy Board (OEB) pursuant to section 36 of the *Ontario Energy Board Act, 1998* (Act), for an order or orders approving rates for the distribution, transmission and storage of natural gas, effective January 1, 2018. Union Gas is currently under an Incentive Ratemaking (IRM) framework for its annual rate adjustment.

The Industrial Gas Users Association (IGUA) filed evidence on November 27, 2017. The evidence provided an overview of the rate impact on IGUA members as a result of the current cost allocation methodology used to allocate Panhandle Reinforcement project costs.

In its evidence, IGUA noted that a number of its members acquiring gas supply services from Union Gas under Rate T2 would experience significant rate increases as a result of the current cost allocation methodology used to allocate Panhandle Reinforcement costs.

In the Panhandle Reinforcement Leave to Construct application[1], Union Gas proposed to allocate the Panhandle System demand costs related to the project, in proportion to the firm Union Gas South in-franchise Panhandle System Design Day demands, updated to include the incremental firm Project Design Day demands. Union Gas' proposed cost allocation was different from the OEB-approved cost allocation methodology. The existing methodology allocates costs based on the combined Panhandle and St. Clair System. With the addition of significant project costs related only to the Panhandle System and no change to the cost of the St. Clair System, the use of the combined system for cost allocation purposes no longer reflected the costs to serve the customers on each respective transmission system according to Union Gas. Union Gas submitted that its proposed interim allocation of project costs better reflected the principles of costs causality during the remainder of the IRM term.

The OEB in its leave-to-construct Decision[2] determined that a change in cost allocation cannot be adequately considered during the IRM term and such changes should be reviewed in Union Gas' next rebasing proceeding, which at the time was expected to be in 2019.

[1] EB-2016-0186
[2] EB-2016-0186 Decision and Order, February 23, 2017, page 11

In Procedural Order No. 3 issued on November 29, 2017, the OEB determined that cost allocation changes were outside of the scope of this proceeding and accordingly the evidence of IGUA would not be considered as part of the evidentiary record. The OEB noted that it would not be appropriate to address cost allocation changes in the last year of the current IRM framework where rate changes are supposed to be mechanistic.

By a letter dated December 6, 2017, IGUA requested a review under Part VII of the OEB's *Rules of Practice and Procedure* for a part of Procedural Order No. 3. Although IGUA accepted the OEB's determination that it would not be making changes to cost allocation methodology in this proceeding, it submitted that it should not be precluded from exploring other possible options for the OEB to consider in addressing what would in its view be a very significant and negative impact on IGUA members. For example, IGUA suggested that it might ultimately argue in favour of deferring a portion of the Panhandle associated revenue requirement until the OEB's consideration of cost allocation issues in 2019 rates.

IGUA expressed a desire to be able to explore in upcoming settlement discussions, and ultimately argue if required, for alternative forms of relief. IGUA argued that the most significant impacts of the Panhandle costs will fall in 2018 (i.e. the year covered by the current application), and that the amounts are material at both a class level and for certain individual customers. IGUA further submitted that its evidence is both relevant and probative of the equity of considering alternative test year treatments for recovery of Panhandle Reinforcement costs. While IGUA accepted the determination of the OEB that cost allocation with respect to Panhandle Reinforcement costs would not be addressed in this proceeding, IGUA submitted that striking its evidence from the record was neither necessary to implement that direction nor fair to IGUA.

2 OEB FINDINGS

The OEB has considered the arguments presented in IGUA's letter of December 6, 2017 and has determined that, pursuant to Rule 43.01, it will dismiss this request for a review. As detailed in Procedural Order No. 3, the OEB has already determined that it will not be examining cost allocation issues in this proceeding. Although IGUA has suggested potential remedies that would not involve direct changes to cost allocation methodology in this proceeding (such as a deferral), the OEB does not believe that the proposed IGUA evidence is necessary to advance such arguments. The record already contains information regarding the different impacts that would result (at a class level) using the status quo cost allocation versus the cost allocation methodology proposed by Union Gas in the leave-to-construct application[3]. Detailed information regarding the impacts on specific customers is not necessary for the purposes of this proceeding.

[3] Panhandle Reinforcement Leave-to-Construct Application EB-2016-0186

3 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. It will not review part of Procedural Order No. 3 and will not vary its decision to include IGUA's evidence on the record.

All filings to the OEB must quote the file number, EB-2017-0087 and be made electronically in searchable / unrestricted PDF format through the OEB's web portal at https://www.pes.ontarioenergyboard.ca/eservice/. Two paper copies must also be filed. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

ADDRESS
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4
Attention: Board Secretary

E-mail: boardsec@oeb.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

DATED at Toronto, **December 11, 2017**

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Reference: EB-2016-0186 Decision and Order, pp.8-11.

In the Panhandle Reinforcement Project Leave to Construct application the Board determined that it would not approve Union's proposal for a revised (Panhandle System design day demand) cost allocation methodology for Panhandle Reinforcement Project cost recovery. In addressing this cost allocation proposal, and a proposal to depreciate the project over a 20 year period in lieu of a more conventional useful life period, the Board stated:

A comprehensive review is required for parties to test, and the OEB to assess, the merits and implications of these two proposals, and this should be at Union's next cost of service or customer IR Application.

While these proposals may have merit, they cannot be adequately considered during the IRM term, for one project in isolation

A proper review of these issues will need to include the full range of possible amortization periods, and the impacts on all customer classes of a change to the cost allocation methodology.

a) Please confirm that Union is proposing to defer a cost of service review for a period of at least 10 years, as part of its now filed MAADs application (EB-2017-0306).

b) Please confirm that Union has no current plan to undertake a full cost allocation study.

c) Please indicate whether Union still believes it to be appropriate to allocate Panhandle Reinforcement costs on the basis of Panhandle System design day demands.

d) Please discuss the impacts on all customer classes of allocation of Panhandle Reinforcement costs on the basis of Panhandle System design day demands, compared to the currently proposed combined Panhandle/St. Clair design day demands allocation approach.

e) Which approach to allocation of Panhandle Reinforcement costs – Panhandle System design day demands or combined Panhandle/St. Clair systems design day demands - does Union believe better reflects "user pay", "cost causality" and equity/fairness principles of ratemaking. Please explain Union's views provided in response.

Response:

a) The MAADs application in EB-2017-0306 includes a 10 year deferred rebasing period.

b) Confirmed.

c) As proposed in EB-2016-0186, Union believes the allocation of the Panhandle Reinforcement Project ("Project") costs in proportion to Panhandle System design day demands is an appropriate interim allocation for the remainder of the 2014-2018 IRM term. Union proposed this allocation to more appropriately reflect cost causation principles by allocating the Project costs to rate classes that use the Panhandle System and drove the need for the Project.

   The OEB-approved cost allocation methodology of Ojibway/St. Clair demand costs is based on the combined Panhandle System and St. Clair System. Union maintains the OEB-approved cost allocation methodology is no longer appropriate for the Panhandle System and St. Clair System costs because the addition of the Project costs creates a large difference in the cost per unit of demand between the Panhandle System and St. Clair Systems and no longer reflects the costs to serve the St. Clair System or ex-franchise Rate C1 and Rate M16 customers.

   In the EB-2016-0186 Decision, the OEB did not approve Union's proposed interim cost allocation for the Project and deferred the review of a change in cost allocation until Union's next cost of service or custom IR application. Subsequent to the OEB Decision, Union and Enbridge Gas Distribution filed a MAADs application including a 10 year deferred rebasing period (EB-2017-0306). Union intends to address concerns with the cost allocation of all Panhandle System and St. Clair System costs in its 2019 Rates application.

d) Please see Exhibit B.IGUA.2, Attachment 1 for the unit rate impact and Exhibit B.IGUA.3, Attachment 1 for the total cost allocation impact of allocating the Project costs based on the current approved cost allocation of the combined Panhandle System and St. Clair System design day demands as included in 2018 Rates compared to the Panhandle System design day demands only.

   The Panhandle System and St. Clair System have significantly different proportions of design day demands by rate class as compared below:

Table 1
Comparison of the St. Clair and Panhandle System Design Day Demands

Line No.	Rate Class	Design Day Demands St. Clair System (1) (%)	Design Day Demands Panhandle System (2) (%)	OEB-Approved Cost Allocation As-Filed (3) (%)	Difference (%)
		(a)	(b)	(c)	(d) = (c-b)
1	Rate M1	7%	40%	21%	-19%
2	Rate M2	2%	14%	7%	-7%
3	Rate M4	0%	14%	7%	-7%
4	Rate M5	-	0%	0%	0%
5	Rate M7	-	4%	2%	-2%
6	Rate T1	9%	5%	6%	1%
7	Rate T2	82%	23%	42%	19%
8	Total In-franchise	100%	100%	85%	-15%
9	Rate C1	-	-	13%	13%
10	Rate M16	-	-	3%	3%
11	Total Ex-franchise	-	-	15%	15%
12	Total	100%	100%	100%	-

Notes:

(1) Percentages by rate class derived from Exhibit B.CME.1, Attachment 1, line 15.

(2) Percentages by rate class derived from Exhibit B.CME.1, Attachment 1, line 14 + line 16.

(3) Percentages by rate class derived from Exhibit B.CME.1, Attachment 1, line 18.

The use of the OEB-approved cost allocation methodology, as compared to the Panhandle System design day demands results in a greater allocation of Project costs to Rate T2 because of the higher Rate T2 demands on the St. Clair System (Table 1, line 7). Using the approved cost allocation based on the combined system design day demands results in an allocation to Rate T2 that is not representative of the use of the Panhandle System by Rate T2 customers, as the design day demands of the St. Clair System do not drive the Project costs. The greater allocation of Project costs to Rate T2 is offset by a lower allocation to Rate M1 (Table 1, line 1).

The use of the OEB-approved cost allocation methodology also allocates significant costs to ex-franchise Rate C1 and Rate M16, which results in a rate increase of over 200% for Rate C1 transportation services between Dawn and Ojibway, St. Clair and Bluewater as well as Rate M16 transportation to/from storage pools located west of Dawn. These transportation services had no impact on the need for the Project, as the ex-franchise demands flow easterly to Dawn and are counter flow to the westerly peaking Panhandle design day demands.

e) Allocating the Project costs using only the Panhandle System design day demands better reflects the principle of cost causality by rate class than the current approved cost allocation methodology which uses the combined Panhandle System and St. Clair System design day demands as explained in part c) and part d).

Ontario Energy Board

EB-2010-0219

Report of the Board

Review of Electricity Distribution Cost Allocation Policy

March 31, 2011

EXECUTIVE SUMMARY

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.

As indicated in the Board's September 2 letter, this consultation was intended to be limited in scope, with a more comprehensive review becoming more feasible in the next two to three years as smart meter data increases in volume and better cost allocators for the cost allocation model ("CA Model") becomes available. The focus of this consultation was therefore to determine the need for and nature of any update and refinement to the following elements of the Board's electricity distribution cost allocation policy as follows:

- To take into account the creation of the microFIT rate class;
- To refine the following specific components of the cost allocation methodology:
  – Cost allocation to unmetered loads (i.e., unmetered scattered loads, street lighting and sentinel lighting);
  – Treatment of the transformer ownership allowance;
  – Allocation of miscellaneous revenues;
  – Weighting factors for services and billing costs; and
  – Allocation of host distributor costs to embedded distributor(s).
- To review options for allocating costs to load displacement generation;
- To refine the three widest Target Ranges, which are associated with the following rate classes: General Service 50 to 4,999 kW, Street Lighting, and Sentinel Lighting; and
- To address accounting changes and the transition to International Financial Reporting Standards ("IFRS").

The Board retained the services of Elenchus Research Associates, Inc. ("Elenchus") to prepare a report that included background, options and recommendations on the above-listed matters (the "Elenchus Report"). A stakeholder meeting was held on November 18, 2010 during which participants had an opportunity to engage Elenchus in a discussion on the content of its report. On December 2, 2010, the Board received written comments on the Elenchus Report from 17 stakeholder groups.

Informed by the Elenchus Report and the stakeholder comments, and as further explained in this Report, the Board has made revisions to its policy and plans to undertake separate consultations in certain areas as follows:

MicroFIT Customers

The Board will provide an update to the default province-wide microFIT charge in November of each year. All distributors filing a cost of service application should provide information on the nine cost elements identified in the Board's EB-2009-0326

Decision and Order. This information, along with the most recent information on record for distributors that are not filing a cost of service application in that year, will be used to derive the annual microFIT charge update.

Distributors will be expected to request a change to their microFIT charge to the updated default province-wide microFIT charge as part of their annual incentive regulation application or cost of service application.

Distributors filing a cost of service application may request a distributor-specific microFIT charge but must demonstrate that the experience it has gained provides sufficient and adequate evidence for it. A microFIT administrative costs worksheet will be added to the CA Model for the purpose of collecting data from distributors for the Board's annual update to the default charge and to provide a tool for distributors wishing to apply for a distributor-specific microFIT charge.

Distributors wishing to seek approval for a distributor-specific microFIT charge may consider adjusting the weighting factors for the nine cost elements identified in the Board's EB-2009-0326 Decision and Order. Those distributors may also consider whether additional cost elements should be included in the determination of their proposed microFIT charge.

Load Displacement Generation

Additional research and further consultation on this topic will be required before a standard methodology is established. The Board believes that these issues warrant attention in the short term, and will to that end initiate a separate consultation in the near future. In the meantime, the Board will entertain applications by distributors requesting, as part of their next cost of service application, to have their existing interim standby rates declared final.

Miscellaneous Revenues

The Board expects distributors that have the relevant information to allocate the major components of miscellaneous revenues to customer classes in the same proportions as the corresponding cost drivers are allocated to customer classes. The remaining miscellaneous revenues should be allocated to the customer classes in the same proportion as composite operations, maintenance and administrative ("OM&A") expenses.

Treatment of Unmetered Load

As part of their next cost of service application, the Board expects each distributor to include a separate unmetered scattered load ("USL") class in their CA Model and on their proposed Tariff of Rates and Charges. A distributor that does not believe that it is necessary to create a separate USL rate class would have to demonstrate to the Board the benefits of not creating such a class.

There is a need to clarify some aspects of the terminology surrounding the USL and Street Lighting classes (e.g., definition of a customer, an account, a device) and the associated modeling methodology. This matter will be addressed as part of a separate consultation process that will be initiated by the Board.

Weighting Factors for Services and Billing Costs

The Board expects each distributor to assess the circumstances specific to their service area and ensure that the weighting factors they use appropriately reflect them. A new worksheet will be added to the CA Model to facilitate the customization of the weighting factors.

Transformer Ownership Allowance

The treatment of transformer ownership allowance in the CA Model will be streamlined to be consistent with the methodology outlined in Chapter 2 of the Filing Requirements for Transmission and Distribution Applications.

Allocation of Host Distributor Costs to Embedded Distributor(s)

The Board is of the view that the methodology outlined in Schedule 10.7 of the 2006 Electricity Distribution Rate ("EDR") Handbook, as updated in proceeding EB-2007-0900, provides an appropriate basis for estimating the costs to be allocated to an embedded distributor rate class.

The Board is also of the view that it is appropriate to use a threshold approach whereby any host distributor with embedded distributor(s) that exceed(s) the threshold(s) should treat its embedded distributor(s) as a separate customer class. Before determining what the threshold(s) should be, the Board will undertake further analysis. This analysis will require the collection of additional data on embedded loads from distributors and the Board will issue a letter shortly to all rate-regulated electricity distributors providing further details on this upcoming information request.

Changes to Revenue-to-Cost Ratio Ranges

The pace at which revenue-to-cost ratios should be adjusted to a Board-approved ratio should only be affected by concerns regarding its impact on any rate classes.

The Board's range for the General Service 50 to 4,999 kW and the Sentinel Lighting classes are revised to 0.8 to 1.2; all other Board ranges remain unchanged at this time. The Board's policy remains that distributors should endeavour to move their revenue-to-cost ratios closer to one if this is supported by improved cost allocations.

Accounting Changes and the Transition to IFRS

Until the changes have been finalized, it would be premature to attempt to implement IFRS-related changes to the CA Model. While no changes to the structure of the CA Model are anticipated to be required as a result of the transition to IFRS, the Board will ensure that the CA Model can accommodate an increased number of accounts in the event they are required.

Implementation

The Board's electricity distribution cost allocation policy is intended to continue to be evolutionary in nature, with the expectation that the degree of precision will continue to be enhanced as more experience is gained and additional information becomes available.

In order to implement the changes to the CA Model required from the policy changes set out in this Report, a cost allocation working group ("CA Working Group") will be established to identify and propose to Board staff the necessary revisions to the CA Model and provide input to Board staff on the development of the supporting documentation. Informed by Board staff and the CA Working Group's recommendations, the Board will issue a revised CA Model.

The revisions to the Board's cost allocation policy set out in this Report will be implemented through cost of service applications starting with the 2012 rate year. The Board's revised CA Model is not expected to be available before the April 29, 2011 filing deadline for those distributors requesting cost of service rates effective January 1, 2012. The Board notes, however, that it expects the current CA Model to be able to accommodate most of the policy changes set out in this Report. The Board anticipates that the CA Model changes will result in a more "user-friendly" platform with some additional flexibility. Accordingly, the Board expects that, in most cases, a distributor that is required to file its application before the issuance of the revised CA Model will be able to comply with the policy by applying it to the current CA Model. If necessary, a distributor in this situation may update its cost of service application with the revised CA Model once it becomes available.

1 INTRODUCTION

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.

On November 28, 2007, the Ontario Energy Board (the "Board") issued its *Report of the Board: Application of Cost Allocation for Electricity Distributors* (the "2007 Report"). The 2007 Report set out the Board's current policies in relation to specific cost allocation matters for electricity distributors, and represented the culmination of a consultation process that had begun several years earlier. It addressed a number of issues, most significantly the relationship between the class revenue and the class total allocated costs (the "revenue-to-cost ratio"). The 2007 Report also discussed the treatment of the monthly service charge, metering credits for the unmetered scattered load class, transformer credits for customer-owned transformers, and charges for the provision of standby power for customers with load displacement generation.

In its 2010-2013 Business Plan, the Board indicated that it would review its electricity distribution cost allocation policy and revise it as required (the "Review"). In September 2010, the Board initiated a consultation process for that purpose. All materials in relation to this consultation are available on the Board's web site.

Informed by a consultant's report and stakeholder comments, this Report sets out the Board's updated approach in relation to its electricity distribution cost allocation policy.

Implementation details relating to certain elements of the Board's approach as set out in this Report are being assigned to a Stakeholder Cost Allocation Working Group (the "CA Working Group") that will provide input to Board staff. Further detail is set out in Chapter 3 of this Report. Informed by Board staff and the CA Working Group's recommendations, a revised Cost Allocation Model (the "CA Model") will be released.

This Report sets out information on two further separate consultation processes to be initiated by the Board as well as information on the next step to establish threshold(s) above which a host distributor will be expected to establish a separate rate class for its embedded distributor(s). Except for these three matters, the revisions to the Board's cost allocation policy set out in this Report will be implemented through cost of service applications starting with the 2012 rate year. The Board's revised CA Model is not expected to be available before the April 29, 2011 filing timeline applicable to distributors requesting cost of service-based rates effective January 1, 2012. Changes to the CA Model to reflect the revised policies set out in this Report are expected to result in a more "user-friendly" platform with some additional flexibility. However, the Board anticipates that the current CA Model can accommodate most of those policy changes, and as a result most distributors should be able to comply with the revised policies by applying them to the current CA Model if their filings are due before the revised CA Model is issued. If necessary, a distributor that files its cost of service

Principles of Public Utility Rates

Second Edition

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the competing objectives of ratemaking that are difficult to resolve, thus making the climb to the peak of Mount Pareto slippery. While our preference as economists is to make greater use of the criterion of service at cost as the standard by which alternative rate structures are compared, we realize that to expect this bias of others would be hopelessly naïve. We do believe, however, that the ratemaker should utilize the cost standard as a benchmark, with assessments of the efficiency advantages (or disadvantages) of particular rate structures playing a subsidiary role; social and fairness standards also may be appropriate within the limits of authority that a regulating body may be able to exercise. As the French thinker Blaise Pascal noted: "We know the truth not only by reason, but also by the heart."

CRITERIA OF A DESIRABLE RATE STRUCTURE

Throughout this study we have stressed the point that, while the ultimate purpose of rate theory is that of suggesting criteria of reasonable rates and rate relationships, an intelligent choice of these depends primarily on the accepted *objectives* of ratemaking policy and secondarily on the need to minimize undesirable side effects of rates otherwise best designed to attain these objectives. However, no rational discussion of the relative merits of cost of service and value of service, for example, as standards of desirable rates or rate relationships is possible without reference to the question of what desirable results the ratemaker hopes to secure, and what undesirable results are to be minimized, by a choice between or mixture of the two standards. This was recognized explicitly in the Electric Utility Rate Design Study sponsored by the National Association of Regulatory Utility Commissioners (NARUC) and undertaken by the Electric Power Research Institute (EPRI) (See Malko, Smith and Uhler, 1981, p. 1-6). Not only this: the very *meaning* to be attached to ambiguous, proposed standards such as those of "cost" and "value" — an ambiguity not completely removed by the addition of familiar adjuncts, such as out-of-pocket costs, or marginal costs, or average costs — must be determined in the light of the purposes to be served by the public utility rates as instruments of economic policy. This is a commonplace; but it is a commonplace which, so far from being taken for granted, needs repeated emphasis.

In this section we first outline a set of attributes to be sought in the development of a sound rate structure. While we know that regulation will not guarantee good economic performance, we should at least like it to arrest or curb egregiously bad performance. For instance, regulation should allow a fair rate of return, but not guarantee or protect a regulatee against mismanagement or adverse business conditions. Sound rate relationships are essential to the attainment of these desirable ends, but criteria are required to judge whether, and to what extent, these objectives have been attained. In our attempt to put the competing criteria into an explicit form we recognize that we are violating the sage advice of Charlie Brown that: "No problem is so big that it can't be run away from."

Attributes of a Sound Rate Structure

What are the attributes to be sought in the development of a sound rate structure? Many different answers have been suggested in the technical economics literature and in the reported opinions by courts and commissions. A number of writers have summarized their answers in the form of a list of desirable attributes of a rate structure, comparable to the canons of taxation found in Adam Smith's *Wealth of Nations* (1937 — originally 1776) and subsequent treatises on public finance. In very general terms (see e.g., Federal Energy Regulatory Commission, Order No. 436, October 9, 1985) optimal rates: should provide clear, efficient, effective, informative, and cost-effective market signals about the present and the future cost of service to buyers and sellers, (which requires that prices track costs); should embody strong incentives for optimal present and future cost and service quality configuations; should give buyers and sellers optimal flexibility in selecting sellers and buyers respectively; should allow utilities to serve as agents of progress; should maintain or improve distributive equity, and should allow for the attainment and maintenance of a flexible (non *ad hoc*) regulatory framework with a modicum of necessary delay and obfuscation (and even a willingness of a commission to dissolve itself under the appropriate competitive or contestable conditions!). But this is a pretty general menu, and more specific direction is needed when applying them to an empirical world. As someone once said, "the real world is only a special case of the theoretical world, and not a very interesting one at that." But many practical-minded people would disagree, so let us push on to greater specificity.

The list that follows is fairly typical, although we have derived it from a variety of sources, instead of relying on any one presentation. Of the ten proposed attributes enumerated in this section, the first three relate to the provision of adequate stable and predictable revenues and rates; the next five are based on cost, efficiency, and equity considerations, and the remaining two deal with matters of practicality and acceptability. However, the sequence in which the ten attributes are presented is not meant to suggest any order of importance. Moreover, there is, perforce, some inconsistency and redundancy in any such listing. We are simply trying to identify the desirable characteristics of utility performance that regulators should seek to compel through edict.

Revenue-related Attributes:

1. Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety.

2. Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.

3. Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers and with a sense of historical continuity. (Compare "The best tax is an old tax.")

Cost-related Attributes:

4. Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).

5. Reflection of all of the present and future private and social costs and benefits occasioned by a service's provision (i.e., all internalities and externalities).

6. Fairness of the specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity in three

dimensions: (1) *horizontal* (i.e., equals treated equally); (2) *vertical* (i.e., unequals treated unequally); and (3) *anonymous* (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).

7. Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).

8. Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

Practical-related Attributes:

9. The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.

10. Freedom from controversies as to proper interpretation.

Lists of this nature are useful in reminding the ratemaker of considerations that might otherwise be neglected, and also useful in suggesting important reasons why problems of practical rate design do not yield readily to scientific principles of optimum pricing. But they are unqualified to serve as a base on which to build these principles because of their ambiguities (how, for example, does one define "undue discrimination"?), their overlapping character, their inconsistencies, and their failure to offer any basis for establishing priorities in the event of a conflict. For such a basis, we must start with a simpler and more fundamental classification of ratemaking functions and objectives.

Some of these attributes in the aforementioned list are based directly on the primary functions of public utility rates first presented in Chapter 4, and the related objectives to be sought in the establishment of a cost-based standard of ratemaking (Chapter 5). These objectives provided the basis for development of the criteria of a fair return (Chapter 10). These same objectives, derived from the four primary functions, can now be used to specify the criteria of a sound rate structure discussed in the following section.

The Primary Criteria Are Based on the Objectives of Regulation

General principles of public utility rates and rate differentials are necessarily based on simplified assumptions both as to the objectives of ratemaking policy and as to the factual circumstances under which these objectives are sought to be attained. Attempts to make these stated principles subserve all special objectives and cover all specific conditions would be hopeless. Writers on the theory of rates are therefore at liberty to base their analyses on the acceptance of those objectives which are of wide application and the attainment of which may be aided by whatever tests or measures of sound rate structure the analyses suggest.

Among these objectives, the following three may be called primary, not only because of their widespread acceptance, but also because most of the more detailed objectives discussed in the literature are ancillary thereto: (1) the revenue-requirement, production-motivation, or financial-need objective; (2) the optimum-use, demand control, or consumer-rationing objective; and (3) the compensatory income transfer function or fair-cost-apportionment objective. Based on these objectives we propose the following three primary criteria by which to judge the soundness and desirability of a rate structure for public utility enterprises. As outlined below, these objectives are related closely to five of the ten attributes specified above.

Criterion 1 - Capital Attraction
(Attribute 1): based on the revenue-requirement objective, with due regard to potential problems of socially undesirable levels of rate base, product quality, and safety; it takes the form of a fair-return standard with respect to private utility companies;

Criterion 2 - Consumer Rationing
(Attributes 4 and 5): based on the consumer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between the private and social costs incurred and benefits received;

Criterion 3 - Fairness to Ratepayers
(Attributes 6 and 7): fair-cost-apportionment objective, which invokes the principle that the burden of meeting total revenue requirements must be distributed *fairly* and without arbitrariness, capriciousness, and inequities among the beneficiaries of the service and so as, if possible, to avoid undue discrimination.

The objectives specified above correspond to three of the four primary functions of utility rates set forth in Chapter 4. The efficiency-incentive function, or that of encouraging managerial efficiency, is omitted because of its more direct bearing on the desirable criteria for a fair rate of return. Some writers, especially the older ones, e.g., Wallace (1941, pp. 475-478) would add a fifth objective: that of benefitting specific classes of ratepayers, such as customers of sub-standard income or a depressed industry. This objective comes under the heading of social principles of ratemaking as we have used the term in Chapter 8.

In actual rate cases, these three objectives of reasonable rates and rate relationships, and particularly the last two, are by no means always sharply distinguished. But the distinction may be illustrated by the imagined example of a request, submitted to a regulating commission by a group of ratepayers, that an electric (gas or tele-communications) company be ordered forthwith to abandon its present, somewhat elaborate, schedule of class rates, block rates, and two-part or three-part tariffs in favor of a uniform kilowatt-hour (therm or message minute) rate for all customers throughout its franchise territory. Almost certainly this proposal would be held subject to the threefold objection:

(a) that no uniform rate, however high, could be made to yield a fair return on the company's invested capital;

(b) that, even if it could do so, rate uniformity despite lack of cost uniformity in the supply of different types of service would impose *unfair* and discriminatory burdens on the consumers of the less costly services; and

(c) that, quite aside form its unfairness, the uniform rate would result in a serious underutilization of plant capacity because it would cut down the demand for services (especially, for off-peak services) that could be supplied at incremental costs materially below average unit costs, while stimulating a wasteful on-peak demand for services that can be supplied only at incremental costs higher than average costs and it does not reflect any differential social costs and benefits in different areas.

Some writers who confine their attention to what they call the "economic" principles of public utility rates have ignored the third criterion of a sound rate structure in their development of their principles of public utility rates on the ground that fairness questions are beyond the competence of professional economists (on the general issue of fairness, see Zajac, 1985, and Baumol, 1986). Instead, they have centered attention on the second criterion, often with special reference to its application under the constraint of a revenue-requirement constraint. But a refusal to recognize fairness issues as relevant to the design of a sound rate structure would so far remove the analysis from the objectives of Chapter 5 and divorce theory from practice that these issues will not be completely ignored in the discussion that follows.

Stability and Predictability of Rates: A Secondary Criterion

Attributes 2 and 3 on stability and predictability have been neglected relative to those associated with the three primary criteria, and deserves further consideration. In ratemaking, the attribute of *predictability*, is more important than *stability* per se. Time-of-use rates, for example, are not stable (in a strict sense), but are predictable and, most would agree, desirable. One could certainly argue that ratepayers should be given the information they need to *predict* rates accurately. However, this does not imply a necessary need to keep rates stable at the expense of otherwise efficient pricing. For instance, in the case of rate base valuation, most jurisdictions opted for the rate stability associated with original costs (also for the popular understanding and administrative practicality) even though this method has an economic cost in terms of ideal resource allocation and use during periods of changing price levels. In that case, the presumably intelligent choice between the merits and demerits of the alternatives led decisionmakers to conclude that the price society pays for this stability is reasonable.

Stability, like freedom, is not free. Utility regulation can and does affect the social cost of risk bearing (Schmalensee, 1979, p. 36-37). The bearers of risks have real costs imposed on them. Economic efficiency calls for the one's best able to bear risk to do so. Ideally, the regulatory process only redistributes and does not increase total risks. Erratic regulation can increase a firm's real costs, including capital costs. Stabilized rates (returns) shift risks from ratepayers (shareholders) to shareholders (ratepayers). Utilities need revenue stability to mitigate the sunk costs of their highly specialized systems that make them prime candidates for expropriation or opportunism. However, as Yandle (1987) puts it: "You can fleece a sheep many times, but you can only skin him once."

A monolithic critic might ask: why place such great importance on revenue and rate stability and predictability when no such constraints operate in the unregulated sector (especially in light of the business cycle)? The answer to this question is provided in great detail in the next two chapters. For the moment, let it suffice to note five major considerations. First, some users have a strong preference for rate stability in planning even if it means some sacrifice in the (higher) level of initial rates. This is especially true of customers who use the utility in the production of other goods and services and who fear that rivals may obtain advantages by acquiring the service more cheaply and reliably elsewhere (Baldwin, 1987, p. 225). Second, there are transaction costs involved in the determination, administration, and publicity of a rate structure; these include advertising, publishing and distributing price lists, issuing new catalogs, etc. Third, since the greater asset-specificity in regulated markets provides more scope for opportunistic behavior, assurances of predictable revenues are appropriate in a regulated industry. Fourth, rate stability and more particularly predictability, are needed to allow the users to secure a rational control of demand. We want to make sure that regulation does not increase, but only redistributes the total and real risk. Therefore, a fourth criterion, although of a somewhat lower rank than the three primary ones discussed earlier, is that of stability and predictability of specific rates and of revenues.

Some Simplifying Assumptions

In the remainder of this Part Four, except for the sections in Chapter 17, the principles governing the development of a sound rate structure will be discussed under the assumption that rates are designed primarily to subserve the four primary objectives of rate-making policy specified earlier. But in order to avoid extreme complexities, the following four explicit assumptions are made, all of which are implicit in much of the literature on public utility rates. Some of these are reiterations of the criteria, whereas others are additional assumptions required for clarity.

In the first place, we shall impute an unqualified priority to the fair-return standard of reasonable rate levels despite the fact, noted in Chapter 10, that no such priority is accorded either by legal doctrine or by ratemaking practice. That is to say, we shall assume that the rates of any given utility enterprise, taken as a whole, must be designed as far as possible to cover costs as a whole including (or plus) a fair return on capital investment.

In the second place, we shall assume the availability of a wide range of alternative rate structures, any one of which could be made to yield the allowed fair return on whatever capital investment is required in order to supply the services demanded. This assumption, which implies that the utility enterprise in question enjoys a substantial degree of monopoly power, permits us to center attention on a choice among rate structures, any one of which would be equally fair to investors and equally effective in maintaining corporate credit.

In the third place, throughout this handbook, we operate under a general presumption that pricing at marginal cost would lead to a revenue shortfall; i.e., the firm operates in the range of declining unit costs. However, there is evidence now to suggest that there are certain aspects of utility operations, such as the generation of electricity, which are in the range of increasing unit costs. Thus, the possibility exists that a company could find itself overall in the increasing cost range. This nontrivial possibility should be kept in mind in discussions of the problem of revenue reconciliation.

And in the fourth place, except for incidental references, we shall rule out all of those social principles of ratemaking, discussed in Chapter 8, which may justify the sale of some utility services at less than even marginal costs. While the rate structure may be used as a tool for redistributing income, economists in general prefer alternative fiscal policies, such as taxation and direct subsidies. This is so primarily because of the limited span over which any single regulatory body may exercise control. Thus, the positive realities impinge on our normative analyses.

IMPORTANCE AND LIMITATIONS OF THE PRINCIPLE OF COST OF SERVICE

Cost-of-service as a Basic Standard

Without doubt the most widely accepted measure of reasonable public utility rates and rate relationships is cost of service. For example, based on their extensive researce associated with the Electric Power Research Institute (EPRI) rate design study, Malko, Smith and Uhler (1981, Chapter 4) conclude that "In general, cost-based rates satisfy the commonly held multidimensional, sometimes conflicting, pricing objectives better than noncost-based rates". In the literature, the cost-of-service measure is generally given a dominant position even by writers who insist upon, or reluctantly concede, the necessity for deviations from cost in the direction of value-of-service principles or of various social objectives of ratemaking. However, Stanley (1984) argues that because of the interdependency among ratepayers of basic service and the deterrence effects of the connection charges — e.g., access to the telephone network — the optimal price would be set *below* marginal cost with subsidization by nonbasic services such as the Yellow Pages, Touch-Tone service, long-distance service, etc. Be that as it may, in actual practice there is usually an obvious, marked

Filed: 2017-11-21
EB-2017-0087
Exhibit B.IGUA.2
Attachment 1
Page 1 of 2

UNION GAS LIMITED
Summary of 2018 Proposed Rates

Line No.	Particulars	Current Approved Rates (1) (cents / m³)	As Filed (2) 2018 Capital Pass-Throughs ($000's)	As Filed (2) Proposed Rates (cents / m³)	As Filed (2) Rate Change (%)	Updated for Exhibit B.IGUA.2 2018 Capital Pass-Throughs ($000's)	Updated for Exhibit B.IGUA.2 Updated Rates (cents / m³)	Updated for Exhibit B.IGUA.2 Updated Rate Change (%)
		(a)	(b)	(c)	(d) = (c-a)/a	(e)	(f)	(g) =(f-a)/a
	North Delivery							
1	Rate 01	17.5559	(8,971)	18.0596	2.9%	(8,971)	18.0596	2.9%
2	Rate 10	6.1303	(1,090)	6.3664	3.9%	(1,090)	6.3664	3.9%
3	Rate 20	2.2403	(911)	2.2421	0.1%	(911)	2.2421	0.1%
4	Rate 25	2.7201	(285)	2.7076	-0.5%	(285)	2.7076	-0.5%
5	Rate 100	0.8392	(778)	0.8380	-0.1%	(778)	0.8380	-0.1%
6	Total North Delivery		(12,034)			(12,034)		
	South Delivery & Storage							
7	Rate M1	14.1538	(5,197)	14.8650	5.0%	(1,566)	14.9943	5.9%
8	Rate M2	5.4475	2,787	5.9089	8.5%	4,021	6.0232	10.6%
9	Rate M4	4.2933	1,970	4.8857	13.8%	3,207	5.2502	22.3%
10	Rate M5A	2.9291	(671)	3.0125	2.8%	(649)	3.0174	3.0%
11	Rate M7	3.9255	739	4.5554	16.0%	1,073	4.8359	23.2%
12	Rate M9	1.6844	149	1.7259	2.5%	149	1.7259	2.5%
13	Rate M10	6.7289	3	7.1737	6.6%	3	7.1737	6.6%
14	Rate T1	2.2725	1,378	2.5070	10.3%	1,201	2.4720	8.8%
15	Rate T2	1.1308	11,379	1.3139	16.2%	7,821	1.2360	9.3%
16	Rate T3	2.4820	1,091	2.5708	3.6%	1,091	2.5708	3.6%
17	Total South Delivery & Storage		13,628			16,351		
18	Total In-Franchise Delivery		1,594			4,317		

Notes:
(1) EB-2017-0278, Appendix A, rates effective October 1, 2017 (excluding Price Adjustments and Cap-and-Trade unit rates).
(2) Rate Order, Working Papers, Schedule 3, columns (k), (o), and (p), respectively.

UNION GAS LIMITED
Summary of 2018 Proposed Rates

Line No.	Particulars	Current Approved Rates (1) (cents / m³)	As Filed (2) 2018 Capital Pass-Throughs ($000's)	As Filed (2) Proposed Rates (cents / m³)	As Filed (2) Rate Change (%)	Updated for Exhibit B.IGUA.2 2018 Capital Pass-Throughs ($000's)	Updated for Exhibit B.IGUA.2 Proposed Rates (cents / m³)	Updated for Exhibit B.IGUA.2 Rate Change (%)
		(a)	(b)	(c)	(d) = (c-a)/a	(e)	(f)	(g) =(f-a)/a
	North Transportation & Storage							
1	Rate 01	9.5289	6,081	9.9568	4.5%	6,081	9.9568	4.5%
2	Rate 10	7.5561	1,562	7.9375	5.0%	1,562	7.9375	5.0%
3	Rate 20	6.5571	405	6.6286	1.1%	405	6.6286	1.1%
4	Rate 25	1.6229	(6)	1.5784	-2.7%	(6)	1.5784	-2.7%
5	Rate 100	-	25	-		25	-	0.0%
6	Total North Transportation & Storage		8,066			8,066		
7	Gas Supply Admin Charge		(100)			(100)		
8	Total In-Franchise		9,560			12,283		
	Ex-Franchise							
9	Rate M12		114,965		14.0%	114,965		14.0%
10	Rate M13		(2)		1.1%	(2)		1.1%
11	Rate M16		441		63.7%	(26)		-2.0%
12	Rate C1		4,670		5.9%	2,415		1.1%
13	Total Ex-Franchise		120,074			117,351		
14	Total In-Franchise & Ex-Franchise		129,633			129,633		

Notes:
(1) EB-2017-0278, Appendix A, rates effective October 1, 2017 (excluding Price Adjustments and Cap-and-Trade unit rates).
(2) Rate Order, Working Papers, Schedule 3, columns (k), (o), and (p), respectively.

UNION GAS LIMITED
Panhandle Reinforcement Project 2018 Revenue Requirement Allocation to Rate Classes

		As Filed			Updated for Exhibit B.IGUA.1		
Line No.	Particulars	Total Revenue Requirement ($000's) (1)	Incremental Project Revenue ($000's) (2)	Net Revenue Requirement ($000's)	Total Revenue Requirement ($000's) (3)	Incremental Project Revenue ($000's) (4)	Net Revenue Requirement ($000's)
		(a)	(b)	(c) = (a - b)	(d)	(e)	(f) = (d - e)
1	Rate M1	2,563	648	1,915	6,794	1,248	5,546
2	Rate M2	1,314	221	1,092	2,751	425	2,326
3	Rate M4	1,585	237	1,348	3,021	437	2,585
4	Rate M5	(40)	3	(43)	(14)	7	(21)
5	Rate M7	489	73	415	876	126	750
6	Rate M9	(2)	-	(2)	(2)	-	(2)
7	Rate M10	(0)	-	(0)	(0)	-	(0)
8	Rate T1	1,209	180	1,029	1,002	150	851
9	Rate T2	8,837	1,295	7,542	4,695	711	3,984
10	Rate T3	(7)	-	(7)	(7)	-	(7)
11	Subtotal - Union South	15,948	2,658	13,290	19,116	3,104	16,012
12	Excess Utility Space	(35)	-	(35)	(35)	-	(35)
13	Rate C1	2,706	368	2,338	82	-	82
14	Rate M12	(191)	-	(191)	(191)	-	(191)
15	Rate M13	0	-	0	0	-	0
16	Rate M16	528	77	451	(16)	-	(16)
17	Subtotal - Ex-franchise	3,009	445	2,564	(159)	-	(159)
18	Rate 01	(941)	-	(941)	(941)	-	(941)
19	Rate 10	(131)	-	(131)	(131)	-	(131)
20	Rate 20	(99)	-	(99)	(99)	-	(99)
21	Rate 100	(77)	-	(77)	(77)	-	(77)
22	Rate 25	(29)	-	(29)	(29)	-	(29)
23	Subtotal - Union North	(1,277)	-	(1,277)	(1,277)	-	(1,276)
24	Gas Supply Admin	(3)	-	(3)	(3)	-	(3)
25	In-franchise (line 11 + line 23 + line 24)	14,668	2,658	12,010	17,836	3,104	14,733
26	Ex-franchise (line 17)	3,009	445	2,564	(159)	-	(159)
27	Total	17,677	3,104	14,574	17,677	3,104	14,574

Notes:
(1) Rate Order, Appendix G, p. 7, column (a).
(2) Rate Order, Appendix G, p. 7, column (b).
(3) EB-2016-0186, Exhibit A, Appendix B, Schedule 4, column (a).
(4) Allocation of Incremental Project Revenue to rate classes based on 2013 Panhandle System design day demands updated to include the 2018 demands of the Panhandle Reinforcement Project.

3.1 Proposed Project Cost Allocation

Union is proposing to allocate the Panhandle System demand costs related to the Project in proportion to the firm Union South in-franchise Panhandle System Design Day demands, updated to include the incremental firm Project Design Day demands. This allocation methodology is consistent with the use of the Panhandle System on Design Day.

The proposed cost allocation factor is based on the 2013 Board-approved in-franchise Panhandle System firm Design Day demands of 12,102 $10^3m^3/d$ updated to include the incremental Project firm Design Day demands in 2017 and 2018. The incremental firm Design Day demands of the Project are 1,492 $10^3m^3/d$ (or 58 TJ/d) in 2017 and 392 $10^3m^3/d$ (or 15 TJ/d) in 2018, for total incremental demands of 1,884 $10^3m^3/d$ (or 73 TJ/d) by 2018. A summary of the proposed Project cost allocation factors are provided in Table 8-1. The detailed calculation of the proposed 2017 and 2018 Project cost allocation factors by rate class is provided at Exhibit A, Tab 8, Schedule 2, lines 19-25.

Union will maintain the allocation of existing Panhandle System demand costs in proportion to the 2013 Board-approved allocation methodology as provided at Section 3.2.

Table 8-1
Proposed Project Cost Allocation Factors

Line No.	Particulars $(10^3m^3/d)$	2013 Panhandle Design Day Demands	Incremental 2017 Project Design Day Demands	Total 2017 Allocation Factor	Incremental 2018 Project Design Day Demands	Total 2018 Allocation Factor
		(a)	(b)	(c) = (a+b)	(d)	(e) = (c+d)
1	Rate M1	5,567	28	5,595	28	5,623
2	Rate M2	1,870	24	1,894	21	1,915
3	Rate M4	929	696	1,625	343	1,968
4	Rate M5	30	-	30	-	30
5	Rate M7	131	439	570	-	570
6	Rate T1	524	154	678	-	678
7	Rate T2	3,051	151	3,202	-	3,202
8	Total	12,102	1,492	13,594	392	13,986

Union is proposing a cost allocation for the Project that is different than the Board-approved cost allocation methodology because the existing methodology allocates costs based on the combined Panhandle System and St. Clair System. With the addition of the significant Project costs related only to the Panhandle System and no change to the cost of the St. Clair System, the use of the combined system for cost allocation purposes no longer reflects the costs to serve the customers on each respective transmission system. The 2018 Project costs of approximately $27.2 million represents a significant increase over the 2013 Board-approved total combined system costs of $7.1 million.

Union's proposed interim allocation of Project costs based on the Panhandle System Design Day demands better reflects the principles of cost causality during the remainder of the IRM term than the current Board-approved methodology.

Filed: 2013-07-31
EB-2013-0202
Exhibit A
Tab 2
Settlement Agreement

EB-2013-0202

UNION GAS LIMITED

SETTLEMENT AGREEMENT

July 31, 2013

The draft UFG accounting order can be found at Appendix F.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

6.6 Major Capital Additions

The parties agree to Y factor treatment for major capital projects that meet the criteria in sections (i) through (viii) below. If the two major facility expansion projects set out below meet the criteria and are approved by the Board in their respective leave to construct applications and, provided they continue to meet the requisite criteria, the net delivery revenue requirement impacts of those projects will be treated as Y-factors in each year of the IRM term beginning with the first year that each project comes into service:

1. The facilities included in the Parkway West Project as that term is used in EB-2012-0433. The current forecast of the net delivery revenue requirement impacts are shown in Appendix G. Rate recovery would, assuming the current forecast of 2015 as the in-service year, commence with rates effective January 1, 2015;
2. The facilities included in the Brantford-Kirkwall Pipeline and Parkway D Compressor Station Projects as those terms are used in EB-2013-0074. The current forecast of the net delivery revenue requirement impacts is shown in Appendix G. Rate recovery would, assuming the current forecast of 2016 as the in-service year, commence with rates effective January 1, 2016.

Y-factor treatment also applies to additional capital projects that result in net delivery revenue requirement impacts over the IRM term which meet the requisite criteria specified below.

The criteria that must be met for any capital project to quality for Y factor treatment are as follows:

i) A minimum increase, or a minimum decrease, of $5 million in net delivery revenue requirement for a single new project (the "Rate Impact Threshold"). For the purposes of making this determination, capital costs are those costs relating to that capital project as defined under the applicable accounting rules. For the purpose of determining whether the Rate Impact Threshold is met, the net delivery revenue requirement associated with the capital project for each of the years from the in-service year until 2018 shall be calculated; should the net delivery revenue requirement exceed the Rate Impact Threshold in any year, the project would meet the Rate Impact Threshold criterion. The rate adjustment for each year will be based on the forecast net delivery revenue requirement impacts for each specific year, subject to true-up to actual as discussed in subparagraph (viii) below.

   In determining net delivery revenue requirement for any year, the following parameters will be applied:

   - Depreciation expense will be calculated using 2013 Board-approved depreciation rates;
   - Required return assumes a capital structure of 64% long-term debt and 36% common equity;

- The incremental long-term debt cost will be calculated based on expected financing costs for the incremental borrowing required by the project, at market rates in effect at the time the project is approved;
- The return will be calculated using the 2013 Board-approved return on equity of 8.93%;
- Income and other taxes related to the equity component of the return will be calculated using the 2013 Board-approved tax rate of 25.5%;
- Incremental delivery revenues associated with the project will be calculated as an offset to the delivery revenue requirement;
- For the in-service year, all components of the calculation except taxes (but including, without limitation, depreciation, cost of debt, and return) will be calculated only for the period from the month of in-service to the end of the year; and,
- Union agrees to make no changes to these parameters during the IRM term.

ii) The capital cost of the project, using the same capitalization policies as were in place for the purposes of the approved EB-2011-0210 revenue requirement, must exceed $50 million. Provided, however, that in the event that Union is required to change its accounting standard from USGAAP to any other standard (including IFRS), and as a result its capitalization policies must change, the capitalization policies under the new accounting standard shall apply;

iii) The project is outside the base rates on which this incentive regulation framework is set;

iv) The project must be needed to serve customers and/or to maintain system safety, reliability or integrity, and cannot reasonably be delayed, and is demonstrated to be the most cost effective manner of achieving the project's objective relative to the reasonably available alternatives;

v) The project will be identified to stakeholders and the Board as soon as possible, including in that year’s stakeholder review session where practical (see Section 12.2);

vi) The project will be subject to a full regulatory review equivalent to a leave to construct proceeding, in which the applicant must demonstrate need, safety or reliability purposes, and economic viability prior to inclusion in rates. For any project that requires leave-to-construct approval of the Board, the full regulatory review will be conducted in that proceeding. For any project that does not require leave-to-construct approval of the Board, Union commits to filing its annual rate adjustment application with the Board by July 1 of the year prior to rate impacts of the project going into effect, to allow sufficient time for a full regulatory review of the project in its rates application;

vii) Subject to direction otherwise from the Board, Union will allocate the net revenue requirement using 2013 Board-approved cost allocation methodologies. Any party, including Union, may take any position with respect to the proposed allocation for any particular capital project during review of the project, or its rate impacts, by the Board; and,

viii) The project will include a deferral account request to capture any differences between the forecast annual net delivery revenue requirement and the actual net delivery revenue requirement for each year of the IRM term for which the project is included in rates. The true-up will occur annually during the period the project is subject to Y factor treatment. If, at the end of the 2018 year, the actual net delivery revenue requirement has not exceeded the $5 million minimum for every year the project has been in service, then the project will be deemed not to have qualified, and all amounts collected thereon shall be refunded/debited to ratepayers through an end of IRM term true-up deferral account mechanism.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

7 **DEFERRAL AND VARIANCE ACCOUNTS**

(Complete Settlement)

The parties agree that the Deferral and Variance Accounts described and listed in Appendix H will continue during the term of the IRM. It is understood and agreed that Union will make no changes in the manner in which it administers and clears the Deferral and Variance Accounts during the course of the IRM without first fully disclosing the proposed changes to the parties, and then obtaining prior Board approval for such proposals. Moreover, it is understood and agreed that Union will administer the pass through items of expenses and savings in a manner that is compatible with the principle that neither Union nor its ratepayers should gain or lose on such pass through items.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

Ontario Energy Board
Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2016-0186

UNION GAS LIMITED

Application for approval to construct a natural gas pipeline in the Township of Dawn Euphemia, the Township of St. Clair and the Municipality of Chatham-Kent and approval to recover the costs of the pipeline.

BEFORE: **Allison Duff**
Presiding Member

Cathy Spoel
Member

Paul Pastirik
Member

February 23, 2017

LPMA submitted that the Project met the OEB's economic test in Stage 2. Although LPMA did not agree with all the assumptions used to calculate the NPV of the stage 2 benefits, LMPA agreed that the NPV is well in excess of the $212 shortfall in the Stage 1 NPV calculation.

Findings

The OEB finds that the Project meets the OEB's economic tests. The OEB finds that the Stage 2 benefits sufficiently exceed the Stage 1 net cost, and result in a positive NPV.

Union's Stage 1 NPV was negative $212 based on a 5-year forecast and 20-year term. The NPV changed slightly to negative $207 based on a 40-year term. With a 40-year term, the NPV for Alternative 2 changed from negative $207 to negative $201. The OEB finds the Stage 1 NPVs for the Project to be similar to Union's Alternative 2, despite a change in term.

The OEB agrees with LPMA that not all of Union's assumptions in its Stage 2 analysis may be adequately justified, but the OEB finds the $805 M in estimated benefits so large that even with some adjustments the benefits will exceed the net cost estimate in Stage 1.

Based on Union's forecast five-year demand, the OEB finds that Union has demonstrated that the economic tests required by the OEB's filing guidelines have been met.

3.3 Potential rate impacts to customers

Based on Union's proposed costs and rate recovery, the average total bill impact for Union South customers ranged from 1.2% for residential rate M1 to 5.8% for small rate M4[4].

Union's cost estimate included depreciation expense based on a 20-year depreciation period, which is shorter than the 50 years in the OEB's approved depreciation rates for these assets. The depreciation expense to be recovered from customers would be lower by $3.5 M in 2017 and $7.4 M in 2018 if depreciated over 50 years.[5]

Union submitted that a shorter amortization period was warranted given the uncertainties with Ontario's Cap and Trade program and the introduction of the government's Climate Change Action Plan (CCAP). Union submitted that these new

[4] Exhibit A, Tab 8, Schedule 6, p.2
[5] Exhibit J1.3

initiatives add significant risk to the return of any capital invested in natural gas infrastructure over the medium to long term. Union submitted that a 20-year period better aligns the recovery of the asset costs with the timing of government restrictions and potential elimination of natural gas heating of homes and businesses.

All but one of the intervenors disagreed with Union's proposal for a 20-year amortization period. They noted that the settlement agreement entered into at Union's most recent cost of service proceeding refers to OEB-approved 2013 depreciation rates. These intervenors argued that the terms of the settlement proposal prohibit the use of different depreciation rates, and that depreciation was not identified as a Y-factor in the settlement proposal. These intervenors also argued that if a change was to be considered by the OEB it should be during a rebasing year, not during the IRM term, based on a comprehensive review of all assets.

LPMA supported Union's proposal, submitting that a 20-year period reduced the risk for Union resulting from Cap and Trade and CCAP, and reduced the total net present cost to customers.

Union proposed two changes to the cost allocation methodology approved by the OEB when rates were established in 2013. The proposed cost allocation would determine how the Project costs would be recovered until 2019, the end of Union's current IRM term.

First, Union proposed to base the allocation on the Panhandle System's design day demand plus incremental design day demands of the Project. In 2013, the OEB had approved a cost allocation methodology based on design day demands from the combined Panhandle and St. Clair Systems.

Second, Union proposed to exclude ex-franchise Rate C1 and M16 firm contracted demands from the cost allocation. In 2013, the OEB had approved a cost allocation methodology that included in-franchise and ex-franchise rate classes.

Union's position is that using the combined Panhandle and St. Clair Systems to allocate costs no longer reflects the costs to serve customers on their respective parts of these Systems. In addition, Union submitted that C1 and M16 ex-franchise customers are not driving the need for the Project because their gas flows counter to the flow of design day volumes. Union's proposed allocation would result in a re-allocation of 15% of the Project costs to in-franchise customers, rather than allocating them to C1 and M16 customers. A full comparison of the current OEB-approved and the proposed allocation follows.[6]

Line No.	Rate Class	Design Day Demands St. Clair System (%) (a)	Design Day Demands Panhandle System (%) (b)	Project Cost Allocation Factors OEB-Approved Allocation (%) (c)	Project Cost Allocation Factors Proposed Allocation (%) (d)
1	Rate M1	7%	40%	21%	40%
2	Rate M2	2%	14%	7%	14%
3	Rate M4	0%	14%	7%	14%
4	Rate M5	-	0%	0%	0%
5	Rate M7	-	4%	2%	4%
6	Rate T1	9%	5%	6%	5%
7	Rate T2	82%	23%	42%	23%
8	Total In-franchise	100%	100%	85%	100%
9	Rate C1	-	-	13%	-
10	Rate M16	-	-	3%	-
11	Total Ex-franchise	0%	0%	5%	0%
12	Total	100%	100%	100%	100%

All Intervenors except two disagreed with Union's proposal to change the cost allocation methodology for the Project. These intervenors submitted that a change to cost allocation should only be considered in a rebasing year, not during an IRM term, as changes to one part of cost allocation affect all other customers. LPMA, VECC and OEB staff indicated that they were not opposed to Union's proposal, but suggested further review of the impacts are required.

APPrO and IGUA supported Union, arguing that Union's cost allocation proposals were in line with the principle of cost causality and consistent with how the Panhandle System is used.

Findings

The OEB will not approve Union's proposals for a 20-year depreciation period and a revised cost allocation methodology. The OEB finds that both proposals should be deferred to Union's next cost of service or custom IR application. It would be inconsistent to change the depreciation term and cost recovery for one project, while Union's other assets are depreciated and recovered on different bases. A comprehensive review is required for parties to test, and the OEB to assess, the merits

[6] Exhibit J1.2 Attachment 2, page 3

and implications of these two proposals and this should be at Union's next cost of service or custom IR application.

While these proposals may have merit, they cannot be adequately considered during the IRM term, for one project in isolation. A leave-to-construct application requesting a capital pass-through mechanism for cost recovery over 14 months is not the appropriate forum to consider deviations from principles embedded in current OEB-approved rates.

A proper review of these issues will need to include the full range of possible amortization periods, and the impacts on all customer classes of a change to the cost allocation methodology

Given these findings, it is not necessary for the OEB to comment on whether Union's proposal is consistent with the settlement agreement.

3.4 Facilities and non-facilities alternatives to the Project

Exhibit A, Tab 6 of Union's evidence describes the alternatives to the Project that were considered by Union. Union defined an acceptable alternative as one which allows Union to maintain minimum inlet pressures on a design day and meet design day requirements to supply its downstream distribution systems. The alternatives considered by Union are intended to serve the five-year forecasted demand growth from 565 TJ/d to 671TJ/d by 2021, and further consideration for expected future growth beyond 2021.

Union's Alternative 1

This alternative involves construction of a new 30 or 36 inch pipeline from Dawn alongside the existing Panhandle pipeline which would continue to be used.

Union forecast the cost of this alternative at an NPV of negative $224 M which is $12M more expensive than the Project's estimate of negative $212 M. The Project also has the advantage of eliminating the need for additional land and easements and ongoing maintenance costs to preserve the integrity of the existing pipeline.

Union's Alternative 2

This alternative involves contracting for an additional 34 TJ/d of gas supply at Ojibway and installing incremental pipeline and station facilities along the Panhandle System to serve the remainder of the demand from Dawn.

Union's forecast of the NPV for this alternative was negative $207 M. When comparing this to the Project's NPV of negative $212 M, Union did not consider this small differential to be worth the added risk of this alternative. Union's evidence is that