UNION GAS LIMITED

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VT INCEPIT FIDELIS SIC PERMANET

Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2011-0210

VOLUME:	**1**	
DATE:	**July 10, 2012**	
BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

cross-reference, if it is of assistance, and incorporate the specific figures in the aspects of the agreement.

So for example, with respect to issue 1.4, perhaps just so that we're all clear as to how we can be of assistance, issue 1.4 refers to the proposed test year rate base. And there is a reference to appendix B1, schedule 1, and the reduction of 1.6 million.

If you turn, members of the Board, to appendix B, schedule 1, the second item from the bottom of the page is the approximately 1.7 million. So that is the $1.689 million that is referred to in that item.

So I just want to make sure that I do exactly what the Board wants us to do.

MS. HARE: No, we understand the numbers are there, but we want the body of the settlement agreement to be a standalone.

MR. SMITH: I see.

MS. HARE: Okay?

MR. SMITH: Okay. Well, we can certainly do that.

MS. HARE: You can do that?

Now, we have a few questions, and not many. Okay?

MR. SMITH: Yes. It may be, before we take the specific questions -- one thing that I thought might be of additional assistance to the Board is to review the specific approvals requested by Union in relation to --

MS. HARE: Yes, that would be helpful.

MR. SMITH: -- in respect of phase 1. And we do have, the specific approvals are set out at Exhibit A1, tab 3, schedule 1. But we had copies made of that schedule, which we can distribute, if that is of assistance.

MS. HARE: Thank you.

So that would be given an exhibit number, Mr. Millar.

MR. SMITH: I don't think it needs to be given an exhibit number, Madam Chair, in that it is at Exhibit A1, tab 3, schedule 1, if that might be more efficient.

MS. HARE: Okay. That's fine. Thank you.

MR. SMITH: So if we look at Exhibit A1, tab 3, schedule 1, I would just propose to walk through the specific approvals, at least as they relate to phase 1.

So item 1 asks for approval to charge rates from January 1, 2013, to recover a $71.4 million delivery-related deficiency. And as the Board will have seen at the settlement agreement, appendix B, schedule 1, that figure has been revised as a result of the settlement agreement to a figure of 56.580 million.

With respect to item number 2, the parties have not reached an agreement, so that remains outstanding.

Item 3 asks for approval to adopt the Board's revised formula for return on equity, and that matter has been resolved and it is addressed at issue 4.3 of the settlement agreement, and that can be found at page 16 and over at 17. And the parties have agreed that Union's return on equity will be established using the formula as determined in the Board's report, and, obviously, the final rate of return on rate base will be determined using the September 2012 actual figures and forecast bond yields.

Item number 4 asks for approval to adopt USGAAP for rate-making purposes, and the Board will recall that that was the subject of a preliminary issue heard in advance of interrogatories, and Union was granted approval to file on the basis of USGAAP.

Item number 5 asks for approval in respect to a change to the weather methodology. There was no settlement in respect of that issue and it will be addressed, I believe, by Union's first panel.

Item number 6, an approval to update bad debt expense as part of the quarterly rate adjustment mechanism process, Union, as reflected in issue 3.12, is no longer seeking that approval from the Board. That is a risk that Union has traditionally borne and is prepared to bear going forward.

Item number 7 asks for approval of the change in the provision for depreciation, amortization and depletion, and that issue is resolved, as well, at issue 3.4, which can be found on page 11 of the settlement agreement. And the parties accept the provisions for depreciation, amortization and depletion proposed by Union based on its 2011 depreciation study.

Item number 9 -- sorry, item number 8, thank you, relates to approval to recover the costs of Union's community investments. That approval is no longer being sought. As the Board will have seen under item 3.1, relating to the overall O&M budget, the parties have reached an agreement with respect to the O&M budget, which calls for a reduction of $9.55 million. Certain specific adjustments have been agreed to, and one of them relates to community investment, and that can be found on page 9 of the settlement agreement.

Approval of the change to the system integrity space requirement included in delivery rates, that issue is dealt with at issue 3.16 of the settlement agreement, and the parties accept Union's proposed system integrity space value and its allocation for 2013. There will, I expect, be some cross-examination in relation to system integrity space and its actual uses, but that will not have an impact on rate base or cost of service. It is a revenue item, and I hope that explains the wording in 3.16.

Item number 10 seeks approval of funding for the Energy Technology and Innovation Canada Program, or ETIC, and that, like community investment, is resolved, in that Union is not seeking that approval and it was the subject of the 2013 O&M budget. ETIC is identified on page 9.

Finally, approval to continue to sell gas to consumers, that is an approval that Union will be seeking in this proceeding. It is actually not on the issues list and it was not the subject of settlement, but it is something that Union has done historically and will be seeking the continued approval from the Board.

MS. HARE: Just going back to number 10, if I understand what you said, that is part of the envelope for OM&A?

MR. SMITH: Well, yes, but a bit more than that, in that there was an agreed-upon reduction of $9.55 million.

MS. HARE: Right.

MR. SMITH: And ETIC is part of that. Union has removed from its O&M budget, for rate-making purposes, the entire amount relating to ETIC, which is $5 million, and that is why I say we're not seeking that approval.

MS. HARE: Okay. On issue - the way you have it listed now - 11, approval to continue to sell gas to customers --

MR. SMITH: Yes.

MS. HARE: -- you said that is not on the issues list. Is that an issue that has been raised by parties?

MR. SMITH: It was not -- I am not aware of any interrogatories in relation to that issue.

MS. HARE: Okay. I am a bit confused. Why is this an issue?

MR. SMITH: No. I don't think it is an issue, Madam Chair. I apologize.

MS. HARE: All right.

MR. SMITH: I don't think it is an issue. I don't think anybody will have an issue with this at the end of the day.

MS. HARE: You just want confirmation that --

MR. SMITH: That we will be seeking that approval.

MS. HARE: Okay, I will write that one up.

[Laughter]

MS. HARE: Okay, that was very helpful, Mr. Smith. I have one question. 3.11, which is indicated as a partial settlement on page 13, my page 13 --

MR. SMITH: Yes.

MS. HARE: -- my understanding of the way this is written up is that there is agreement to the numbers --

MR. SMITH: Yes.

MS. HARE: -- but there is not agreement as to whether or not you should file the income tax returns; is that correct?

MR. SMITH: That's correct.

MS. HARE: So you would like a Board decision on whether or not you are compelled to file the income tax returns? That's the issue? I just want to understand.

MR. SMITH: I'm not sure that I want such a decision -

[Laughter]

MR. SMITH: -- in that we have not filed them, but I - we have agreed that parties may ask for the income tax returns. I expect that they will, and I expect we will have a disagreement as to whether or not they ought to be filed.

MR. SHEPHERD: Madam Chair, I wonder if I could interject on that, because it was Schools and Board Staff who asked for them.

This provision is in there so that the decision to settle the issue is not a precedent for the fact that they refused to file them. We actually don't expect to ask for the tax returns because, if they were filed, you couldn't do anything with them, since we've already settled the issue.

But we didn't want to be precluded later with Union saying, Well, you didn't get them last time; you're not going to get them this time. So they have agreed next time we can ask for them again, and then have the dispute.

I think that -- Board Staff can tell me whether they want to pursue it, but I don't think we want to actually pursue it, because I think we would be wasting the Board's time.

MR. MILLAR: I don't expect we will pursue it either, and Mr. Shepherd has accurately conveyed -- obviously, Board Staff is not party to the settlement, so we didn't really have a hand in drafting this, but that is my understanding, as well.

MR. THOMPSON: We might pursue it when the cost of capital panel comes, but -- undecided at the moment, but it is still an open item, as far as we're concerned.

MS. HARE: Okay. My puzzled face is whether or not this is actually a partial settlement or not, then.

MR. SMITH: Well, there is...

MS. HARE: There are two components. One part is settled; the numbers are settled. The second part is not settled.

MR. SMITH: Well, correct. I mean, the request to file the income tax returns -- as I understand Mr. Thompson's comment, he may ask that the income tax returns be filed. With respect to Mr. Shepherd's comments and Mr. Millar's comments, I am perfectly comfortable with that.

It is a matter somewhat of belts and suspenders, in

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UNION GAS LIMITED

SPECIFIC APPROVALS REQUESTED – PHASE I

1. Approval to charge rates effective January 1, 2013 to recover a $ 71.4 million delivery-related revenue deficiency (described at Exhibit F3, Tab 1, Schedule 1).
2. Approval of Union's proposed change in capital structure, increasing Union's common equity component from 36% to 40% (described at Exhibit E1, Tab 1).
3. Approval to adopt the Board's revised formula (EB-2009-0084) for return on equity (Described at Exhibit F1, Tab1).
4. Approval to adopt US GAAP for rate making purposes (described in Exhibit A2, Tab 4).
5. Approval to change the methodology used to calculate weather normal to a 20-year declining trend methodology (described at Exhibit C1, Tab 5).
6. Approval to update bad debt expense as part of the Quarterly Rate Adjustment Mechanism process (described at Exhibit D1, Tab 2, p. 2).
7. Approval of the change in the provision for depreciation, amortization and depletion as recommended by Foster Associates, Inc. (described at Exhibit D1, Tab 6).
8. Approval to recover the costs of Union's community investments (described at Exhibit D1, Tab 8).
9. Approval of the change to the system integrity space requirement included in delivery rates (described at Exhibit D1, Tab 9).

10. Approval of funding for the Energy Technology and Innovation Canada program (described at Exhibit D1, Tab 10).
11. Approval to continue to sell gas to consumers.

UNION GAS LIMITED

SPECIFIC APPROVALS REQUESTED – PHASE II

1. Approval of the proposed Cost Allocation Study methodology changes (described at Exhibit G1, Tab 1):
    a. To change the methodology used to functionalize, classify and allocate the cost of assets at the Oil Spring East storage pool.
    b. To change the methodology used to allocate the cost of Tecumseh metering and regulating equipment at the Dawn facility.
    c. To change the methodology used to allocate the cost of system integrity.
    d. To change the methodology used to allocate North distribution customer station plant.
    e. To change the methodology used to classify and allocate distribution maintenance O&M (meter and regulator repairs).
    f. To change the methodology used to allocate distribution maintenance O&M (equipment on customer premises).
    g. To change the methodology used to classify and allocate purchase production general plant.
2. Approval of the methodology used to allocate the cost of the following new services (described at Exhibit G1, Tab 1):
    a. Dawn to Dawn-TCPL

   b. Dawn to Dawn-Vector

   c. M12 Firm All Day (F24-T)

3. Approval of the rates proposed in Exhibit H3, Tab 2 (described at H1, Tab 1)

4. Approval of the following specific Rate Design proposals:

   a. Approval to decrease the volume breakpoint between small volume general service rates M1 and 01 and large volume general service rates M2 and 10 to 5,000 m^3 a year (described at Exhibit H1, Tab 1).

   b. Approval for harmonization of general service rate structures between North and South operating areas (described at Exhibit H1, Tab 1).

   c. Approval to decrease eligibility for the M4 and M5A rate classes to a daily contracted demand of 2,400 m^3 and a minimum annual volume of 350,000 m^3 (described at Exhibit H1, Tab 1).

   d. Approval for an M4 interruptible service offering (described at Exhibit H1, Tab 1).

   e. Approval to decrease eligibility for the M7 rate class to a combined firm, interruptible and seasonal daily contract demand of 60,000 m^3 (described at Exhibit H1, Tab 1).

   f. Approval to decrease T1 annual eligible volume to 2,500,000 m^3 (described at Exhibit H1, Tab 1).

   g. Approval for a T2 large market rate class service offering (described at Exhibit H1, Tab 1).

h. Approval to modify the fuel ratio design for the Dawn to Dawn-Vector transportation service to recover UFG transportation activity in the winter period (described at Exhibit H1, Tab 1).

5. Approval of Union's response to the Board directive to review the M12 and C1 rate-making methodology (described at Exhibit H1, Tab 1).
6. Approval to modify the Rate M1 and Rate M2 rate schedules to set the additional meter charge equal to the Monthly Customer Charge approved for each of the rate classes (described at Exhibit H1, Tab 1).
7. Approval of modification to Schedule "C" of the M12 rates schedule to clarify the applicability of the VT1 Easterly, VT3 Westerly and M12-X Westerly monthly fuel ratios and fuel rates (described at Exhibit H1, Tab 1).
8. Approval of the methodology used to allocate costs and set rates for the Kirkwall-Dawn westerly service.
9. Approval to add the F24-T service to the C1 rate schedule (described at Exhibit H1, Tab 1).
10. Approval of modification to the M12, M13, M16, and C1 rate schedules including Schedule A, Schedule A-2013 and Schedule C (described at Exhibit H1, Tab 1 and Tab 2).
11. Approval to update the utility/non-utility allocator used to calculate margin sharing for short-term storage services to 59:41 to reflect the updated cost study.

12. Approval of changes to the Distributor Consolidated Billing fee to $0.57 per month per customer (described at Exhibit H1, Tab 3).

13. Approval to close the following deferral accounts after 2012 year-end balances are disposed of (described at Exhibit H1, Tab 4):

    a. Late Payment Penalty Litigation (No. 179-113)

    b. Harmonized Sales Tax (No. 179-124)

14. Approval to modify the wording of the following deferral accounts (described at Exhibit H1, Tab 4):

    a. Short-term Storage and Other Balancing Services (No. 179-70)

    b. Average Use Per Customer (No. 179-118)

    c. Inventory Revaluation Account (No. 179-109)

15. Approval to create the following deferral account:

    a. Energy Technology and Innovation Canada (described at Exhibit D1, Tab 10)

The 2013 revenue deficiency includes the impact of increasing Union's return on equity ("ROE") from 8.54% to 9.58%. The pre-tax impact of the ROE increase is $19.0 million. The ROE of 9.58%[1] was calculated using the formula approved by the Board in EB-2009-0084. Final 2013 rates will be based on the Board's approved ROE once the September 2012 actual and forecast bond yields are available. The primary drivers of the 2013 revenue deficiency are described in more detail at Exhibit F1, Tab 1.

2008-2012 INCENTIVE REGULATION EXPERIENCE

As indicated above, Union's regulated distribution, transmission and storage rates were determined under an IR mechanism for 2008 to 2012. Under the IR framework regulated rates were calculated using the price cap formula, defined as PCI = I – X + Z + Y + AU, where PCI is the price cap index, I is the inflation factor, X is the productivity factor, Z represents certain non-routine adjustments, Y represents certain predetermined pass-through items and AU is a volume adjustment reflecting changes in average gas use in the General Service rate classes. Table 2 shows the changes to approved revenues between 2008 and 2012 as a result of the application of the price cap formula.

[1] As per the Board's March 3, 2011 notice that provides the cost of capital parameter updates for 2011 cost of service applications for rates effective May 1, 2011.

Table 2
Changes to Approved Revenues
(2008–2012)

Line No.	Particulars ($ millions)	2008	2009	2010	2011	2012
		(a)	(b)	(c)	(d)	(e)
1	Opening Approved Revenue	955,690	955,690	955,690	955,690	955,690
2	PCI-X factor	1,904	(540)	7,404	(2,095)	(2,947)
3	Storage Premium Adjustment	(544)	4,807	10,158	15,509	15,509
4	Y factors	6,354	(1,168)	4,070	36,887	42,951
5	Z factors	-	(880)	(4,967)	(7,031)	(6,899)
6	Closing Approved Revenue	963,404	957,909	972,355	998,960	1,004,304
7	Approved Revenue Less Y factors	957,050	959,077	968,285	962,073	961,353

Table 2 shows that, over the IR term, rate increases as a result of removing the long-term storage premium from rates were largely offset by rate reductions associated with low inflation relative to the fixed productivity factor of 1.82% and tax rate decreases. Customers have enjoyed the benefits associated with flat delivery rates for the extended five-year period with rates increasing by only 0.6%, net of pass-through items, relative to 2007 Board-approved rates. One of the primary drivers to the 2013 deficiency is the fact that, although revenue increased over the IR term, rate increases as determined by the PCI formula were not sufficient to offset cost increases.

At the same time as ratepayers were enjoying relatively flat rates, they also benefited from earnings sharing over the IR term. Under the terms of the current IR framework, Union shares 50/50 with ratepayers earnings in excess of 200 bps above the ROE, calculated annually using the Board's ROE formula underpinning 2007 Board-approved rates. Earnings in excess of 300 bps above the benchmark ROE are shared 90/10 in favour of ratepayers. Table 3 compares Union's Actual ROE to the Benchmark ROE for the years 2008 to 2012.

Table 3
Actual ROE Compared to Benchmark ROE (2008-2012)

Line No.		2008 (a)	2009 (b)	2010 (c)	2011 (d)	2012 (e)
1	Actual ROE (%)	13.35	11.22	10.91	9.8	8.06
2	Benchmark ROE (%)	8.81	8.47	8.54	8.10	8.10
3	Difference (%)	4.54	2.75	2.37	1.70	(0.4)
4	Sufficiency/(Deficiency) ($ millions)	82.3	51.6	44.1	30.4	(0.8)

The primary drivers of earnings sharing over the IR term were sustainable productivity gains associated with initiatives Union undertook between 2008 and 2011 (Exhibit A2, Tab 5); unsustainable productivity gains revenue associated with the optimization of Union's upstream capacity through the use of TransCanada Pipelines ("TCPL") Firm Transportation Risk Alleviation Mechanism ("FT RAM") credits; declining unaccounted-for-gas ("UFG") volumes; and, favourable weather.

Union is not projecting an earnings sufficiency beyond 2011. First, as indicated above, although rates did increase as a result of the removal of long-term storage premium from rates, these increases were largely offset by rate reductions associated with low inflation relative to the fixed productivity factor of 1.82% and tax rate decreases. Second, the ability to achieve incremental productivity gains beyond 2012 is limited and uncertain. Over the IR term, Union was able to achieve sustainable productivity gains at a relatively low cost. Going forward, productivity gains will be harder to achieve and will require significant investment. Third, a key contributing factor to earnings over the IR term was revenue associated with the optimization of Union's upstream transportation capacity. With the expected elimination of TCPL FT RAM credits in November, 2012, Union's ability to earn revenue from upstream capacity is severely limited (Exhibit C1, Tab 3). Finally, favourable UFG volume variances have contributed significantly to earnings over the IR term. Given the current historic low level of UFG, it is unlikely that UFG will contribute in any significant way to earnings in the future.

FACTORS INFLUENCING UNION'S 2013 REBASING APPLICATION AND NEXT GENERATION INCENTIVE REGULATION

As indicated above, it is Union's view that it is important to identify and describe the significant factors influencing its 2013 rebasing application and its proposals related to the next generation IR. The factors affecting Union's forecast are described under the following headings:

1) Changes in North American Gas Supply Dynamics
    a) Dawn-Parkway Transmission System Impacts
    b) TCPL Maple Constraint

c) TCPL Mainline Toll Application

d) Market-Based Storage Prices

2) Factors Influencing In-franchise Demands and Revenues

a) Energy Prices

b) Demand Side Management

c) Weather

d) Power Generation (Phase-out of Coal-fired Electricity Generation)

e) Other Factors Affecting Commercial & Industrial Demand

3) Other Factors Influencing the 2013 Rebasing Application

a) Productivity Gains Over the IR Term

b) Asset Integrity Programs

c) Compensation

d) Pension, Benefits and Post-Retirement Benefits Cost Pressures

e) Return on Equity and Equity Level

4) 2014 and Beyond (Next Generation IR Mechanism)

1) CHANGES IN NORTH AMERICAN GAS SUPPLY DYNAMICS

Natural gas markets in North America have been substantially transformed in recent years by the decline of traditional supply basins, such as the Western Canadian Sedimentary Basin ("WCSB") and the emergence of unconventional supplies, such as Marcellus shale gas and U.S. Rockies gas. The change in flow patterns has created significant uncertainty for gas flows on Union's Dawn-Parkway transmission system. This uncertainty is expected to continue well beyond the 2013 test year.

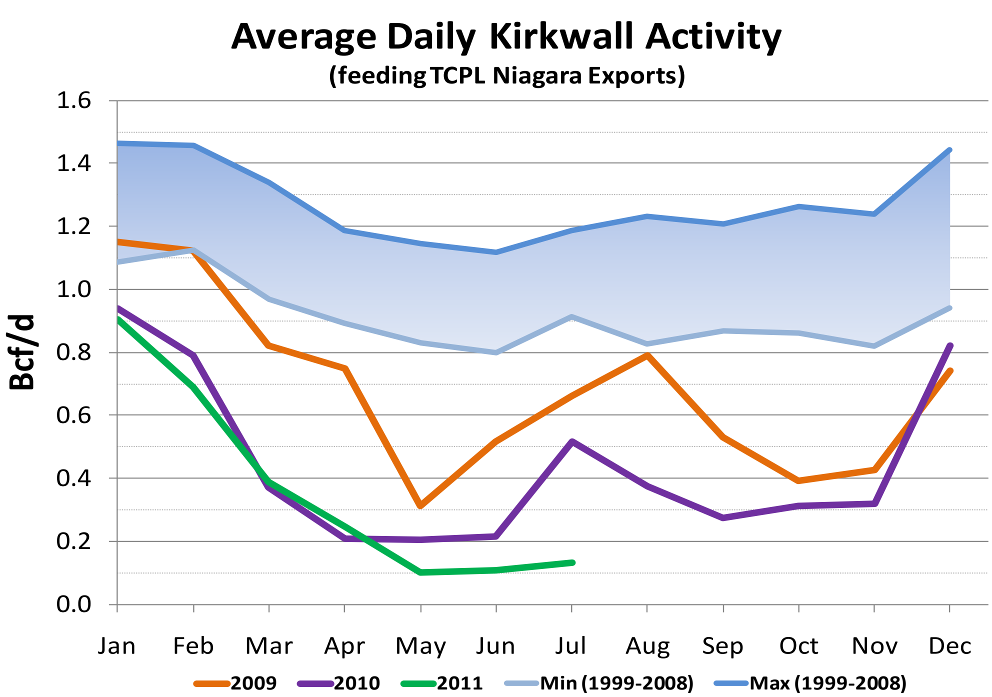
Since 2006, there has been a significant reduction in conventional gas production in the WCSB due to well depletion and the refocusing of production resources on the more economic emerging North American shale gas areas. At the same time that conventional Alberta production has declined, there has been an increase in demand for gas within Alberta by new oil sands development. Although these two factors have been partially offset by emerging shale development in British Columbia, the amount of gas available for export from Alberta on the TCPL mainline has been in steady decline. Natural gas flows on TCPL have declined from approximately 6 Bcf/d to approximately 3 Bcf/d between 2007 and 2011.

The emergence of shale gas production areas such as Marcellus has had a significant impact on North American supply dynamics. Supplies from shale gas plays are displacing WCSB supplies and, as a result, are changing the way gas has been traditionally transported. Further, the overall increase in supply resulting from shale gas development has led to lower and more stable gas prices, significantly impacting storage pricing and demands.

a) Dawn-Parkway Transmission System Impacts

As indicated by Union in the 2010 Natural Gas Market Review ("NGMR") (EB-2010-0199), as a result of the decline in WCSB and the emergence of Marcellus shale supply between 2011 and 2013, revenues from Union's Dawn-Kirkwall transportation service are at risk. As the Marcellus basin continues to develop, the export of natural gas into the U.S. at TCPL's export points (Chippawa and Niagara) has declined. Natural gas that is exported at these two points has traditionally flowed on Union's Dawn-Kirkwall path. As exports decline, the need for parties to hold Dawn-Kirkwall capacity also declines resulting in lost revenue. Figure 1 shows the substantial decline in Dawn-Kirkwall volumes from 1999 to 2011.

Figure 1



Union has already experienced significant turnback of Dawn-Kirkwall capacity by TCPL. At the time of the NGMR, TCPL had already given Union notice (October 31, 2009) for November 1, 2011 non-renewal of 317,000 GJ/d of Dawn-Kirkwall capacity. Union has resold this capacity as Dawn-Parkway service and Dawn-Kirkwall service. On October 31, 2010, TCPL turned back a further 375,000 GJ/d of Dawn-Kirkwall capacity effective November 1, 2012.

On October 31, 2011, TCPL turned back 64,147 GJ/d of Dawn-Parkway capacity and 186,664 GJ/d of Dawn-Kirkwall capacity for November 1, 2013. Two other parties turned back 57,065 GJ/d of Dawn-Parkway capacity. Union's 2013 rebasing forecast includes approximately 350,000 GJ/d of Dawn-Kirkwall and Dawn-Parkway turnback.

The risk of further turnback that exists beyond 2013 is significant. Union estimates the amount of transportation capacity at risk of turnback beyond 2013 to be greater than 800,000 GJ/d.

Table 4 provides the annual turnback starting in 2011 and associated unmitigated revenue impact.

Table 4
Impact of M12 Turnback [1]
Demands as of November 1

Line		Outlook 2011 (a)	Forecast 2012 (b)	Forecast 2013 (c)	At Risk 2014-2018 (d)
	Annual Impacts (GJ/d)				
1	Dawn-Kirkwall	(317,000)	(375,188)	(286,198)	(305,137)
2	Dawn-Parkway	-	-	(67,000)	(509,973)
3	Total	(317,000)	(375,188)	(353,198)	(815,110)
	Cumulative Impact (GJ/d)				
4	Dawn-Kirkwall	(317,000)	(692,188)	(978,386)	(1,283,523)
5	Dawn-Parkway	-	-	(67,000)	(576,973)
6	Total	(317,000)	(692,188)	(1,045,386)	(1,860,496) [2]
	Cumulative Revenue Impact ($000's)				
7	Dawn-Kirkwall	(1,258)	(9,009)	(18,086)	(31,374)
8	Dawn-Parkway	-	-	(324)	(16,741)
9	Total	(1,258)	(9,009)	(18,410)	(48,116) [2]

Note:
(1) All contract changes assumed to commence November 1.
(2) Reflects the cumulative totals from 2011 to 2018 and represents the full year impact in 2018 and beyond.

Union has been able to mitigate the Dawn-Kirkwall turnback for 2011 and 2012 by reselling the 2011 turnback as a Dawn-Parkway service and eliminating winter peaking service requirements in 2012. Union does not have a market for any further turnback in 2013 and beyond. Union is working to repurpose the turnback of Dawn-Kirkwall transmission service as a Dawn-Parkway transmission service. Union's ability to repurpose the turnback of Dawn-Kirkwall transmission service is limited by constraints on the TCPL system at Maple.

b) TCPL Maple Constraint

As discussed in EB-2010-0199, transportation capacity is constrained between TCPL's Maple Compressor Station and Union's Dawn-Parkway system at Parkway. The Maple constraint limits the amount of gas that can be transported from Union's Dawn-Parkway system to Eastern Canadian and US markets via TCPL.

TCPL filed a Mainline Eastern Extension application with the National Energy Board ("NEB"). The intent of this application was to increase capacity between Parkway and Maple and to provide bi-directional capability on TCPL at Niagara. The NEB responded that the application was not complete and requested TCPL to file a complete application when ready.

This constraint is a significant concern with long-term implications to Union. The constraint effectively prevents Union from selling Kirkwall-Parkway capacity and excess Dawn-Parkway capacity to customers wishing to source gas in the Marcellus or at Dawn for markets east of Parkway. Union continues to work with TCPL and others to alleviate the constraint at Maple.

c) TCPL Mainline Toll Application

As indicated above, gas flows on TCPL's mainline have been in steady decline since 2007. As a result, TCPL mainline tolls have doubled since 2007. In response to the significant increase in tolls, TCPL filed an application with the NEB on September 1, 2011 proposing to re-organize their transportation services and change their toll design. TCPL's mainline toll application would set rates for 2012 and 2013.

TCPL's mainline toll application contains a number of toll redesign proposals and financial measures that impact both TCPL long-haul and short-haul tolls. Union's primary concern with TCPL's proposed tolls, as it relates to the Dawn-Parkway transmission system, is with the sustainability of TCPL short-haul tolls. TCPL short-haul tolls must remain competitive in relation to services offered on other transportation paths. Union is concerned that TCPL's rate proposal does not result in a long-term, sustainable solution that maintains the competitiveness of short-haul tolls. If short-haul tolls increase over time, these services may become uncompetitive and cause current short-haul shippers to seek transportation options that bypass Union's Dawn-Parkway transmission system. Only by maintaining competitive short-haul tolls (and the removal of the capacity constraint between Parkway and Maple) will shippers consider contracting for Dawn-Parkway services.

TCPL has also proposed to increase tolls for interruptible ("IT") and short-term firm transportation services ("STFT") and to eliminate the FT RAM. The increase of both the IT and STFT services is intended to extract more revenue from discretionary shippers as well as to attract more shippers to firm service. Eliminating FT RAM is also intended to

8. Conclusion

In this project, PEG-R was asked to assess EGD and Union's IR plans. This was a challenging assignment in light of the myriad issues to be addressed and the limitations of some available data. PEG-R approached the assessment by undertaking a variety of empirical (and at times theoretical) analyses, while attempting to keep in mind the inter-relationships among various aspects of performance and implications for different stakeholders.

This Section provides some brief concluding remarks. We begin by providing a summary assessment of the outcomes of the Companies' IR plans. We then present some concluding comments regarding the IR plan design in Ontario. Next, we provide concluding remarks regarding the IR regulatory process. Finally, we provide an overview of available data sources and data enhancements that would be desirable for developing and assessing future IR plans.

8.1 Assessing the Outcomes of the IR Plans

PEG-R's main focus was assessing how the IR plans performed in practice. We approached this issue by addressing whether the IR plans satisfied the Board's stated criteria for an effective ratemaking framework. In particular, our analysis was centered on answering the following questions:

1. Did the incentive regulation plans encourage cost control and generate productivity and efficiency improvements?
2. Did both customers and shareholders share in the benefits of any efficiency gains that were achieved?
3. Did the Companies provide appropriate service quality to their customers?
4. Was the incentive regulation framework conducive to capital investment?

Our answer to the first question is yes. Our analysis indicates that the IR plans encouraged both EGD and Union to control costs more effectively and generate productivity and efficiency improvements. Union appears to have responded more strongly to these incentives. However, a careful statistical analysis indicates that EGD also responded positively to IR and improved its efficiency, even though its measured TFP growth fell while the IR plan was in place. This decline in EGD's TFP growth was due to the recession in the Company's service territory, and the decline in its output growth, that took place in the 2008-2010 period. Notwithstanding its positive response to the IR incentives, our analysis indicates that EGD still has more potential to expand its TFP growth than Union.

Our answer to the second question is yes. PEG-R attempted to address this question rigorously by quantifying the distribution of TFP gains under IR between customers and shareholders. We believe the methodology we developed is conceptually sound, but its application was limited by the accuracy and availability of data. Nevertheless, the overall thrust of our analysis indicates that the IR plans were effective in generating TFP gains and the welfare of both customers and shareholders improved while the plans were in place. We therefore conclude that customers and shareholders both shared in the benefits of the productivity improvements that were achieved.

On the third question, our answer for Union is yes. Union is satisfying all the service quality requirements the Board has established. However, this is not consistently true for EGD. We are not in a position to assess why this is the case, but EGD's measured service is noticeably lower on service indicators associated with its phone center. Performance on several of the phone center indicators has declined rather than improved over time, although EGD has shown progress on remediating its appointments indicator. On balance, PEG-R is not prepared to say that EGD's overall service quality either is or is not "appropriate," but there are certainly pockets of problems that need to be addressed to satisfy the Board's standards.

On the fourth question, our answer is yes. The Companies are generating healthy, and generally increasing, returns under the IR plan. Their financial performance has also improved on a number of liquidity and leverage measures. The IR plans themselves have also been stable; this is evident in the fact that, when Union's earnings in 2008 prompted a re-opening of its plan, the plan was modified in a way that actually strengthened its incentives and allowed the Company to retain more earnings. The IR regulatory framework therefore adapted effectively to a Company's unexpectedly high earnings, which is an outcome that should reassure investors.

8.2 Plan Design Issues

In light of the positive outcomes generated under the IR plans, it may be instructive to consider what aspects of the IR plans contributed to these beneficial results. Recall that in Chapter Two we noted that there were a number of differences between the Union and EGD IR plans, the net effect of which created theoretically stronger incentives for Union. In considering these differences we wrote:

> The differences in IR plan designs could have implications for PEG-R's analysis. That is, if we find empirical evidence that Union has experienced stronger productivity and efficiency gains under IR than EGD, one of the contributing factors could be that the Union IR plan created stronger performance incentives. Alternatively, if there is no evidence that Union experienced stronger productivity and efficiency gains than EGD (*e.g.* EGD experienced more rapid productivity and efficiency gains), it would suggest that, in spite of the theoretically stronger incentives inherent in the Union IR plan, these plan design differences did not have a material impact on performance gains under IR. Regardless of our ultimate findings, it will not be possible to establish any such linkages unambiguously given the limited available data (only three years under IR) and the wide variety of other factors that can influence productivity and earnings. Nevertheless, even partial and indirect evidence on the impact that different IR plan designs have on productivity gains would be valuable to the Board and have clear policy implications on how the next generation of gas distribution IR plans should be designed.

Our analysis clearly shows that Union did, in fact, "experience stronger productivity and efficiency gains under IR than EGD." Although it cannot be established definitively, one of the factors contributing to Union's performance could be that its IR plan has created stronger incentives than EGD's. The main feature of Union's IR plan that creates stronger incentives, compared with EGD's, is its earnings sharing mechanism. Union's ESM allows shareholders to retain all earnings up to 200 basis points above the approved ROE, while EGD retains all earnings only up to 100 basis points above approved ROE. Shareholders are likely to benefit more from cost reductions under Union's more "progressive" ESM, and this feature should, in turn, create stronger incentives for Union to improve cost performance.

This could have implications for EGD's "next generation" IR plan, particularly in light of our conclusion that EGD appears to have more potential for incremental TFP gains going forward than Union. We believe that if the next generation IR plan for EGD is to be modified, any modifications should move in the direction of strengthening rather than weakening the Company's incentives. Our work provides evidence supporting the view that an IR plan designed more like Union's (*i.e.* a comprehensive IR plan with a more "progressive" ESM) could tend to strengthen performance incentives, to the ultimate benefit of both customers and shareholders.

Another plan design issue that could be relevant to next generation IR concerns the relationship between industry input price trends and the inflation factor. Our research shows that input prices for the Companies have grown more rapidly than inflation in the GDP-IPI, the selected inflation measure. Ideally, the inflation factor in a rate or revenue adjustment would be a good proxy for the industry's input price inflation. While the Companies have been able to generate healthy earnings even while their inflation factor did not apparently fully compensate for input price inflation, the relationship between input prices and alternative inflation factors (including industry-specific inflation measures that are explicitly designed to track industry input price trends) could merit greater attention in the next IR plan.

8.3 Regulatory Process and Reporting Issues

PEG-R wishes to make two concluding comments regarding the regulatory process and reporting for the IR plans. The first concerns the issue of cost deferments. As discussed, it is not possible to evaluate whether a Company is acting on incentives to defer costs to a base year used to rebase rates without examining the Company's base year rate application.

This is a critical issue, however, and a proper consideration of the deferment issue increases the importance of rate rebasing. Setting rebased rates is important not only for establishing appropriate cost-based rates, but also for ensuring that the incentives created by an IR plan are not undermined by what occurs when the plan expires. This would in fact occur if what appeared to be cost "reductions" under an IR plan suddenly re-appear in a base year application and are then reflected in the rates established for that year.

As discussed in Section 6, as part of its review of Companies' rate rebasing proposals, the Board can request information that can help it assess the cost deferment issue. In particular, the Board can evaluate whether large scale cost deferments have taken place by requesting information from the Companies on whether any of the capital expenditures reflected in the proposed rate base for the test year represent either: 1) delayed reactions to a previous request for service; or 2) requests for service that were previously rejected because they failed to satisfy the profitability index but have now been reconsidered and deemed to be sufficiently profitable. Any such capital expenditures reflected in a Company's rate rebasing proposal should be subject to greater scrutiny by the Board.

Some regulatory mechanisms are also potentially useful for addressing the cost deferment issue.[50] It may be too late to consider these options in the short time that is available to establish rebased rates for EGD and Union. However, this issue merits greater consideration during the term of the Companies' next generation IR plan.

The second point concerns the reporting and availability of information on the Companies' IR plans. PEG-R found there is a wealth of information and data on these plans, but it can be better co-ordinated within the OEB. For example, available data and regulatory filings from different but related proceedings are often not coordinated, and sometimes the data available from different sources (or even sometimes within a single regulatory filing) are not internally consistent. The time and costs needed to collate and organize the available information complicates the review of IR regulatory filings by interested parties.

PEG-R cannot offer expert advice on how to improve the organization of this information, but one straightforward modification could be to provide "tags" on files. This would allow all relevant files associated with, say, the gas IR plans to be coded with the same tag (and other relevant tags), so that when that tag is linked, all relevant files will be accessed. This is a fairly common feature on a number of computer sites. In any event, a better organized information gathering and processing system should reduce regulatory costs and facilitate information flow within Ontario's regulatory community.

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[50] These are sometimes referred to as "efficiency carry over mechanisms," and they have been employed in British and Australian variants of incentive regulation. PEG-R briefly discussed these mechanisms in its reports to Board Staff in both second- and third-generation incentive regulation for Ontario's electricity distributors.

8.4 Data Issues

In addition, a number of other data enhancements could be considered that would improve future analyses and IR plan assessments. One improvement would be a requirement that both EGD and Union file information on their gas delivery revenues by rate class and service type. The accuracy of certain parts of PEG-R's analysis was reduced by the lack of this gas delivery revenue data.

It could also be valuable to have standardized reporting of the details of capital and operating expenditures. In this consultation, Union provided us a more detailed and useful breakdown of its operating expenditures, while EGD provided a more detailed and useful breakdown of its capital expenditures.

It could also be useful to have a system in place for tracing through and quantifying all IR-related sources of allowed revenue and price change for EGD and Union's gas delivery customers. This would include the impact of the ESM as well as the net inflation, Y and Z factors. It would also include a clear statement of how the AU factor impacted prices, and separate itemization of the impact of trued-up forecasts on final revenues and prices.

One particularly valuable innovation would be to co-ordinate the reporting of earnings for ESM purposes with other cost and operating information. PEG-R attempted to develop a methodology to quantify the distribution of TFP gains between customers and shareholders. This is a relatively new tool which has not, to the best of our knowledge, been previously applied in the assessment of any previous IR plan. While this methodology provided illustrative results, the accuracy of our findings was limited by having the data available to estimate distributor returns that are identical with the distributors themselves will report. If the Board and Stakeholders believe this methodology has merit, and should potentially be applied in other initiatives, efforts should made to ensure data availability so a more refined and accurate earnings measures could be developed.

A number of other data enhancements could improve TFP estimates. One would be a disaggregation of O&M expenses into labor and non-labor costs by account. Another would be greater details on what sources of capital and operating costs have been outsourced to third parties. A third would be greater detail on capital expenditures by function (*e.g.* growth-related, replacement).

Natural Gas Market Conditions and Impact on Union Gas Limited

Prepared by Bruce B. Henning
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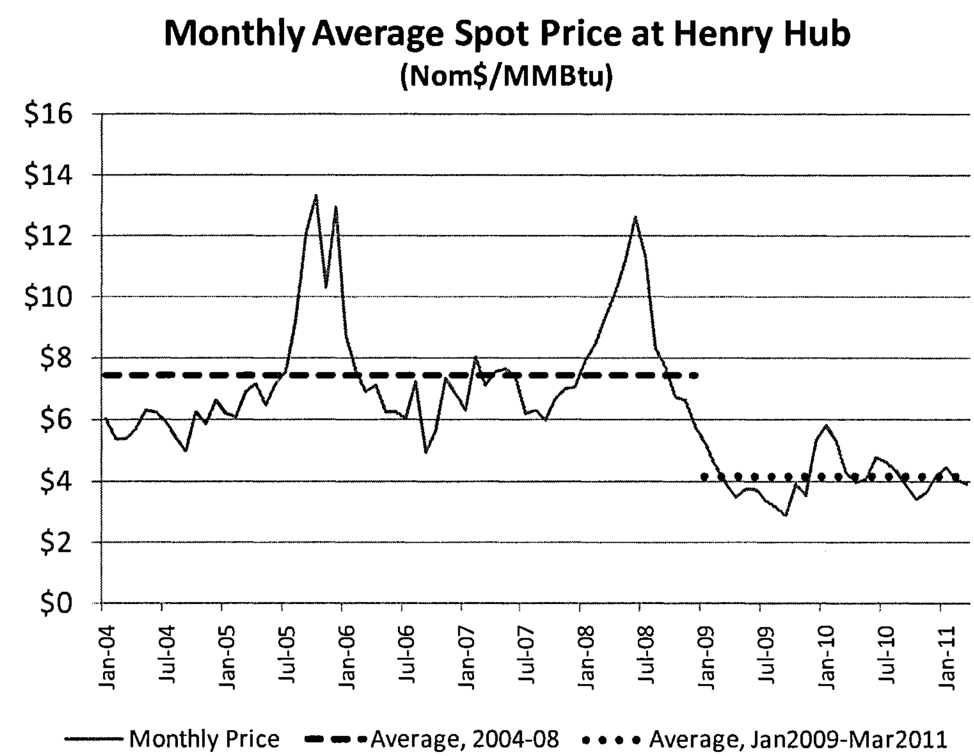
Executive Summary

Natural gas markets in North America have been substantially transformed in recent years by new exploration and development technologies for unconventional gas. In less than five years, the development of gas from shale formations and other unconventional sources have contributed to a significant moderation in natural gas commodity prices. Between 2004 and 2008, natural gas commodity prices averaged more than $7.50 at Henry Hub, Louisiana. Since 2009, natural gas commodity prices have averaged less than $4.50 at Henry Hub, Louisiana. Moreover, the development of new sources of gas supply has led to a more favorable outlook for future commodity prices from the perspectives of gas consumers.

Figure 1



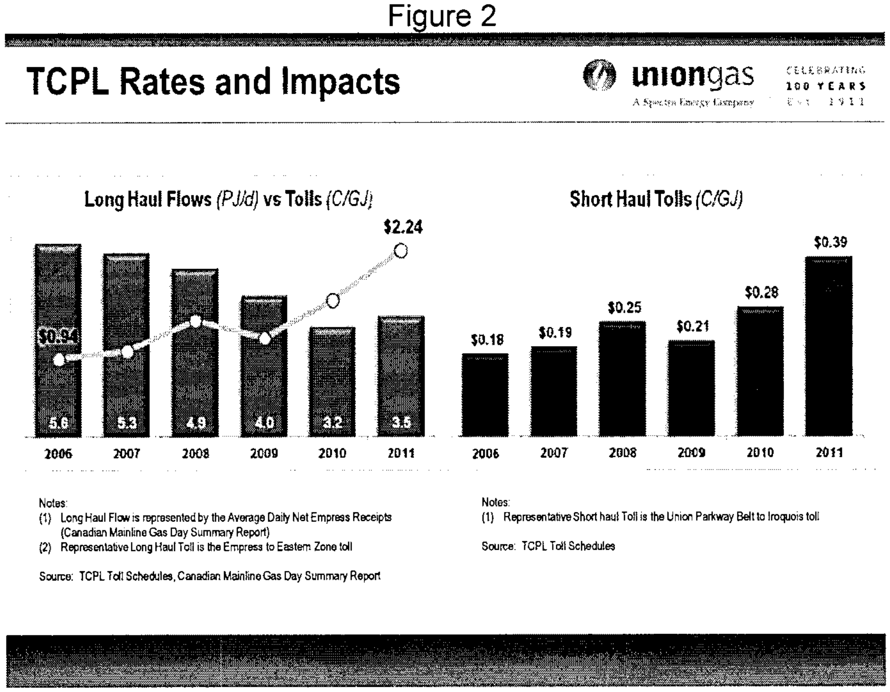
Source: Platts

In August 2010, ICF prepared a report entitled, "2010 Natural Gas Market Review (2010 Report)." That report, commissioned by the Ontario Energy Board, discussed the trends and forces shaping the gas market. During the following year, the trend toward increased shale gas production has accelerated at a faster pace than anticipated, despite the "sluggish" economic recovery and modest gas demand growth.

The trends and forces identified in the 2010 Report and revisited here are quite positive for gas consumers in Ontario, in terms of North American gas commodity prices. However, the rapid nature of market changes and uncertainty regarding the economic recovery and natural gas demand are creating a challenging environment for Union Gas Limited ("Union") and downstream shippers that contract for service on Union Gas facilities. Changing throughput patterns and volumes create significant swings in operating conditions, expected revenues, and regulated transportation rates. As a result, shippers face changing economics for the acquisition of gas supply that will precipitate changes in their portfolio of gas transportation and storage assets under contract.

Compounding uncertainties is the status of the process to determine the tolls on the TransCanada Pipeline System (TCPL). As identified in the 2010 Report, throughput on the TCPL Mainline from the Western Canadian Sedimentary Basin (WCSB) to Ontario and points east have declined markedly just as new options for gas supply have emerged. The decline in throughput has resulted in increases in both the long-haul and short-haul tolls on TCPL. With these increases, TCPL service has become less competitive with other options. Gas shippers able to utilize other options have sought to limit exposure to TCPL rate risk accordingly.

Figure 2



Source: Union Gas

Over approximately the last two years, TCPL and shippers have participated in an intensive effort to develop acceptable tolls that address the competitive threats posed to TCPL service. Despite these efforts, a long-term settlement has yet to emerge. TCPL filed a proposal on September 1, 2011 with Canada's National Energy Board (NEB) to respond to changing North American market conditions and impact on the TCPL Mainline. At this time, it is impossible to fully ascertain the proceeding's conclusions with regard to final toll level, and it is unlikely that a permanent resolution will be reached quickly. Indeed, uncertainty associated with TCPL toll levels through 2018 (even after tolls for 2012 and 2013 are determined) is likely to persist.

With these toll increases, both in-franchise and ex-franchise shippers that secure and/or balance their gas supply at Dawn, are considering alternative routes to secure reliable gas supply in a "best-practice" manner. Supply options include:

- Contracting for gas supply from the Marcellus Shale formation and obtaining transportation back to Ontario. Traditionally, these transactions are considered "back-haul" or exchange transactions, but pipelines are proposing to construct and/or modify facilities to allow for firm transportation service.

- Contracting for gas supplies in Chicago and Michigan, and securing firm transportation to Ontario and onto the Union system along traditional transport routes.

- Contracting for gas supply from the U.S. Rocky Mountains through the Rockies Express Pipeline (REX) and eventually to Dawn through connecting pipelines.

- Contracting for conventional or shale gas supply in Texas, Oklahoma and Arkansas, as well as traditional gas production in the Gulf of Mexico and other onshore production areas.
- Continuing to contract for gas from the WCSB with transportation on TCPL.

With these evolving supply options, ex-franchise shippers that currently contract for service from Dawn are considering their options. Certainly they are exploring the new and increasingly abundant supply in the Marcellus region and how they might directly access this supply. To the extent that these shippers do access Marcellus gas directly, they may de-contract on capacity on other paths including Union facilities from Dawn.

Finally, the soft economy and increasing gas production have had an impact on the economics and market value of natural gas storage. Current forward markets reflect only small values for the spread between winter gas commodity prices and prices for the storage injection season. These "seasonal price spreads" form the primary component of the "intrinsic value" of storage. At the same time, natural gas commodity prices have "decoupled" from volatile oil prices and have not exhibited the volatility that contributes to the extrinsic value of storage. In light of these factors and the development of new storage capacity available, market prices for storage have softened substantially over the last two years, a trend that is likely to continue for several years.

Conclusions

There are a number of factors that create significant uncertainty regarding the throughput and utilization of Union Gas facilities through 2018. The combination of an unclear economic outlook, uncertainty regarding TCPL tolls, a relatively soft market for storage, and considerable uncertainty with regard to re-contracting transportation by Ex Franchise shippers together present challenges to Union and the Board.

As increasing volumes of Marcellus gas and other sources of unconventional gas continue to be made available to the market, shippers are likely to adjust contract portfolios to access these supplies. The changing flow patterns are already apparent. With these changing patterns, it is highly likely that shippers will continue to make adjustments in transportation contract portfolios as current contract obligations expire. For Union Gas transportation services, this pattern of re-contracting may be problematic. Existing contracts for firm service across the Union system held by shippers serving markets in Ontario, Quebec, and the U.S. Northeast are "at risk" upon expiration of current contracts.

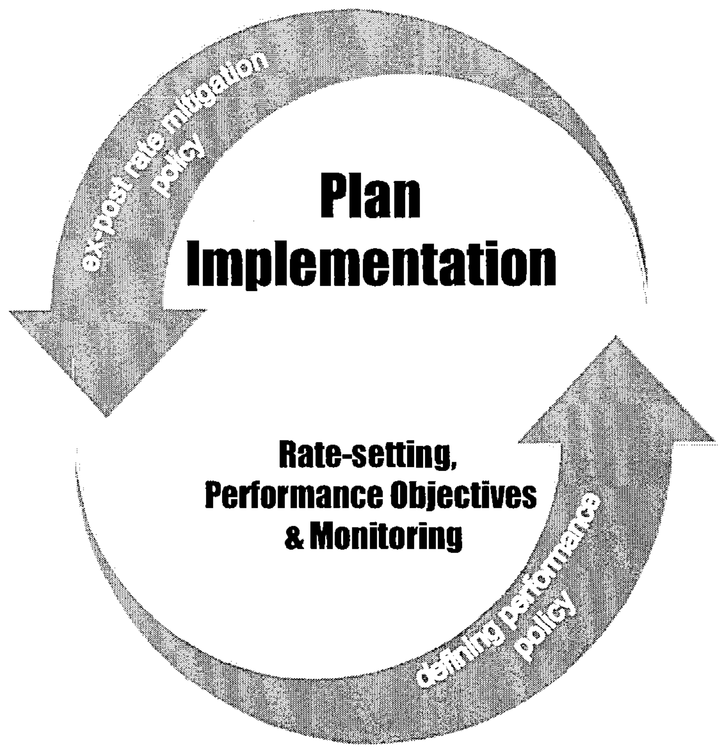
Introduction and Scope of Engagement

On August 20, 2010, ICF[1] delivered a report entitled, "2010 Natural Gas Market Review (2010 Report)," commissioned by the Board to initiate "a stakeholder process that will review and examine changes in the North American natural gas market to better understand the implications for Ontario's market." This White Paper, commissioned by Union Gas Limited (Union Gas):

- Reviews the 2010 Report in the context of the gas market developments and market behavior over 2010.
- Evaluates the degree and pace of market trends identified in the 2010 Report.
- Identifies new developments in the North American gas market.

[1] The report was commissioned by the Ontario Energy Board under a contract with ICF Resources, LLC, a subsidiary of ICF International.

Developing a Renewed Regulatory Framework for Electricity



- Rate Mitigation (EB-2010-0378)

Rate Mitigation: The Board's Existing Mitigation Policy

- The Board's current mitigation policy is described in chapter 13 of the 2006 Electricity Distribution Rate Handbook.
- A mitigation plan is required if total bill increases for any customer class or group exceeds 10% (keeping the commodity component constant).
- Distributors have discretion over the mitigation methodology proposed, which is considered by the Board on a case-by-base basis.
- 10% threshold was initially established to mitigate rate increases from the unbundling of services.

IN-FRANCHISE REVENUE

1/ DEMAND FORECAST OVERVIEW

The demand forecast includes estimates for both the total number of billed customers and the total annual throughput volumes. The demand forecast was prepared during the first half of 2011 as part of Union's annual budget process. The general service market demand forecast is used by Union to prepare both corporate financial and business operating plans.

Three key factors in the general service demand analysis generate an overall flat volume forecast for the years 2011 to 2013. The key demand factors that explain the demand forecast are:

i. The growth in billed customers that increases the volumetric demand, discussed in Section 3.1;
ii. The declining average consumption per customer that offsets the customer related growth, discussed in Section 3.2; and,
iii. Union's Demand Side Management ("DSM") Plan which lowers the total demand.

1.2/ TOTAL THROUGHPUT VOLUMES

Total throughput volumes are generated from the customer and NAC forecasts. Total throughput volumes are expected to be flat over the forecast period 2011 to 2013 (0.2% increase). This compares to a decrease in volumes of 1.5% between 2007 (actual) and 2010. Tables 1 and 2 describe this change in volumetric demand. The change in the total throughput volumes between the 2007 Board-approved and 2013 forecast volumes, both stated according to the 2013 weather normal, is an increase of 0.7%.

Table 1 shows that total throughput volumes between the years 2010 and 2013 are forecast to increase by 8,221 10^3m^3 or 0.2%. Please note that both years in the comparison are normalized according to the 2013 weather normal. The 2013 weather normal is based on the 20-year declining trend weather normal methodology. The 20-year declining trend weather normal is set by actual weather data (*heating degree-days below 18 ℃)* spanning the years 1991 to 2010 and is discussed in Exhibit C1, Tab 5.

Table 1
Change in Total Throughput Volumes: 10^3m^3
2010 to 2013

Line No.	Rate & Service Customer Class	Total W.N. [1] Throughput 2010	Change in volume due to: Customer Growth	DSM Plan	HFO & FX Rate effect	NAC Decline	Total Forecast Throughput 2013	Total Change
1	Residential Rate M1	2,134,240	92,868	(17,666)		(115,055)	2,094,387	(39,853)
2	Residential Rate M2	3,870	(104)	(30)		(133)	3,603	(267)
3	Residential Rate 01	632,954	28,568	(3,405)		(28,258)	629,860	(3,094)
4	Commercial Rate M1	582,100	9,886	(14,766)		136,146	713,366	131,266
5	Commercial Rate M2	722,054	20,001	(12,698)		(123,971)	605,387	(116,668)
6	Tobacco Rate M1	13,834	(334)	-		(3,521)	9,979	(3,855)
7	Tobacco Rate M2	4,381	(1,613)	-		(812)	1,956	(2,425)
8	Commercial Rate 01	223,455	6,727	(3,740)		(706)	225,737	2,282
9	Commercial Rate 10	220,661	(10,424)	(3,987)		21,013	227,264	6,603
10	Industrial Rate M1	52,285	(674)	(970)	1,067	6,971	58,679	6,394
11	Industrial Rate M2	304,737	6,953	(5,810)	9,480	30,346	345,706	40,969
12	Industrial Rate 10	40,753	(4,764)	(268)	1,161	1,993	38,874	(1,879)
13	Industrial L.I.B, Rate 10	61,383	(19,055)	(339)	1,410	6,731	50,130	(11,253)
14	Total	4,996,707	128,036	(63,678)	13,118	(69,255)	5,004,929	8,221
			2.6%	-1.3%	0.3%	-1.4%	0.2%	0.2%
	--- service class summary ---							
15	Residential	2,771,064	121,333	(21,101)	-	(143,446)	2,727,851	(43,214)
16	Commercial	1,766,485	24,244	(35,190)	-	28,151	1,783,689	17,204
17	Industrial	459,158	(17,541)	(7,387)	13,118	46,040	493,389	34,231

[1] The 2010 actual throughput volumes are weather normalized according to the 2013 weather normal which is based upon the 20-year declining trend weather normal methodology.

Several key and offsetting demand drivers explain the relatively flat forecast of total demand between 2010 and 2013. These factors are:

i. Customer growth results in a forecast net increase of 128,036 10^3m^3 attributable to:

a) A forecast increase of 121,333 10^3m^3 as a result of 53,884 additional residential customers at 2010 normalized average consumption levels;

b) A forecast increase of 26,190 10^3m^3 as a result of 1,931 additional commercial customers, or a growth of 1.75% in the commercial market;

c) A forecast decrease of 17,541 10^3m^3 due to a reduction of industrial customers after Q1 2010. Consequently, there are 36 fewer customers in Q1, 2013 than Q1 2010, even though the industrial customer count at year end 2013 is 3 above year end 2010. General service customers consume almost half of their natural gas during the first quarter of the year; and,

d) A forecast decrease of 1,947 10^3m^3 as a result of a forecast decrease of 37 tobacco customers.

ii. An expected decrease of 63,678 10^3m^3 or approximately 1.3% of the 2010 normalized demand as a result of Union's DSM Plan initiatives;

iii. Heavy Fuel Oil ("HFO") price and Foreign Exchange ("FX") changes result in a forecast net increase of 13,118 10^3m^3 attributable to:

a) The appreciating Canada – USA exchange rate which is forecast to lower total throughput volumes by 4,487 10^3m^3; and,

b) Higher fuel oil prices raise total throughput volumes by 17,605 10^3m^3. Natural gas prices are not expected to change materially from current prices (first quarter 2011). As a result, with price inelastic demand (0.1), the estimated impact from natural gas prices is nil. Fuel oil prices, according to the estimates provided by the Energy &

Metals Consensus Forecasts publication, are expected to rise by approximately 15% and this increases industrial gas demand as mentioned above.

iv. NAC Changes result in a net decrease of 69,255 10^3m^3 resulting from:

a) A decrease of 143,446 10^3m^3 as a result of the declines in the normalized average consumption of residential customers of an average of 1.9% over the forecast period;

b) An increase of 32,482 10^3m^3 resulting from changes in the commercial NAC over the forecast period;

c) An increase of 46,041 10^3m^3 resulting from changes in the industrial NAC over the forecast period; and,

d) A decrease of 4,333 10^3m^3 resulting from changes in the NAC of tobacco customers.

Table 2 summarizes the changes in volumetric demand observed over the period 2007 to 2010. The table shows total weather normalized throughput volumes fell by 1.5 % or 77,046 10^3m^3, even though the total number of customers increased by 54,469 or 4.2 % over same period. The weather normalized volumes in this historic comparison are estimated according to the forecast 2013 weather normal; this enables direct comparison with the 2010 – 2013 forecast period throughput volume estimates shown earlier.

Table 2
Change in Total Throughput Volumes: 10^3m^3
2007 to 2010

Line No.	Rate & Service Customer Class	Total W.N. [1] Throughput 2007	Change in volume due to: Customer Growth	DSM Plan	HFO & FX Rate effect	NAC Decline	Total W.N. [1] Throughput 2010	Total Change
1	Residential Rate Old M2	2,139,815	95,003	(16,793)		(79,916)	2,138,110	(1,705)
2	Residential Rate 01	639,272	24,766	(3,515)		(27,568)	632,954	(6,318)
3	Commercial Rate Old M2	1,286,297	29,070	(35,756)		24,543	1,304,154	17,857
4	Tobacco Rate Old M2	15,353	(2,028)	-		4,890	18,214	2,862
5	Commercial Rate 01	205,174	8,925	(3,638)		12,994	223,455	18,282
6	Commercial Rate 10	231,251	(61,587)	(3,270)		54,267	220,661	(10,589)
7	Industrial Rate Old M2	435,649	(3,175)	(8,335)	4,925	(72,042)	357,022	(78,627)
8	Industrial Rate 10 [2]	43,087	(11,367)	(2,406)	487	10,952	40,753	(2,334)
9	Industrial L.I.B. Rate 10 [2]	77,856	(20,693)	(4,347)	880	7,688	61,383	(16,473)
10	Total	5,073,753	58,915	(78,060)	6,292	(64,192)	4,996,707	(77,046)
			1.2%	-1.5%	0.1%	-1.3%	-1.5%	-1.5%
	--- service class summary ---							
11	Residential	2,779,087	119,769	(20,308)	-	(107,484)	2,771,064	(8,023)
12	Commercial	1,738,075	(25,619)	(42,664)	-	96,694	1,766,485	28,411
13	Industrial	556,591	(35,235)	(15,088)	6,292	(53,402)	459,158	(97,433)

[1] The 2007 & 2010 actual throughput volumes are weather normalized according to the 2013 weather normal which is based upon the 20-year declining trend weather normal methodology.

[2] The DSM Plan volume savings for Industrial Rate 10 are allocated according to annual volumes in each market.

A comparison of the forecast period with the changes from 2007 to 2010 in total throughput volumes indicates that:

i. The volumetric impact of the total DSM Plan is similar in percentage terms. The forecast shows a negative 1.3 % while the actual reported a negative 1.5 % of DSM savings;

ii. The volumetric impact due to the NAC decline is also similar in percentage terms. The forecast shows a NAC decline of 1.4% while the actual shows a NAC decline of 1.3%; and,

iii. The volumetric impact from customer growth is larger in the forecast period than in the 2007 to 2010 period for two main reasons:

These customers are primarily small manufacturing establishments that span many industries. These include the food & beverage, automotive, construction materials, machinery, electronic, wood, and chemical industries. Approximately 97% of the customers and approximately 80% of the total throughput volumes occur in Union South. The Contract Industrial Accounts ("CIA") Rate 10 customers refer to a small group of Union North customers with very high NAC that are administered outside of the Banner billing system.

3/ DEMAND FORECAST METHODOLOGY

As in EB-2005-0520, the demand forecasting methodology is based on a multiple regression analysis. The methodology meets generally accepted practices regarding demand forecasting and is consistent with the findings of R.J. Rudden's review, filed in EB-2005-0520, regarding forecast methods. The historic database underlying the statistical analysis contains monthly data from January 1991 to December 2010.

The demand forecast combines four separate estimation steps:

i. Estimate of the total number of billed customers for each rate and service class;
ii. Forecast the NAC for the residential, commercial and tobacco customer service classes. Combining the normalized average usage estimates obtained from the econometric analysis with the billed customer estimates from step 1 yields the total throughput volumes estimates before consideration of the DSM Plan consumption impacts;
iii. Estimate the total throughput volumes for the industrial customers; and,

iv. Remove the future consumption savings of DSM Programming from 2011 to 2013 from the individual econometric estimates obtained from steps 2 and 3.

3.1/ **TOTAL BILLED CUSTOMERS**

The forecast of total number of billed customers is derived from the forecast of total customer attachments. The customer attachment forecast is described in the evidence of Mr. Jeff Okrucky in Exhibit B1, Tab 3.

The forecast of total billed customers is obtained by subtracting the customer shrinkage estimates from the customer attachment forecast. The customer shrinkage, or attrition, is based on past trends and reflects expected demolitions and customer transactional activity. Table 3 in Appendix A details the attachment, shrinkage and billed customer forecast estimates. The historical levels and trends for total customer shrinkage are presented in Table 4 included in Appendix A.

The total number of billed customers at year end 2013 is forecast to be 1.399 million customers. At December 2010 there were 1.343 million customers. This represents an increase of 55,781 or approximately 4.2% over the period. This equates to an annual growth rate of approximately 1.4%.

Table 3
Total Billed Customers at December

Line No.	Service / Rate Class	2010	2013	Change	% Change	Avg. Ann. %
1	Residential Rate M1	945,156	986,142	40,986	4.3%	1.4%
2	Residential Rate M2	35	35	0	0.0%	0.0%
3	Residential Rate 01	281,810	294,708	12,898	4.6%	1.5%
4	Commercial Rate M1	75,773	76,883	1,110	1.5%	0.5%
5	Commercial Rate M2	5,244	5,400	156	3.0%	1.0%
6	Tobacco Rate M1	747	725	(22)	(2.9%)	(1.0%)
7	Tobacco Rate M2	40	25	(15)	(37.5%)	(12.5%)
8	Commercial Rate 01	27,036	27,789	753	2.8%	0.9%
9	Commercial Rate 10	1,976	1,888	(88)	(4.5%)	(1.5%)
10	Industrial Rate M1	4,022	4,007	(15)	(0.4%)	(0.1%)
11	Industrial Rate M2	1,288	1,318	30	2.3%	0.8%
12	Industrial Rate 10	128	122	(6)	(4.7%)	(1.6%)
13	Industrial LIB Rate 10	50	44	(6)	(12.0%)	(4.0%)
14	Total Billed Customers	1,343,305	1,399,086	55,781	4.2%	1.4%

3.2/ NORMALIZED AVERAGE CONSUMPTION FORECAST METHODOLOGIES

Forecast estimates of NAC are prepared for the residential customers by individual rate class. Commercial NAC estimates are first prepared for the total commercial service class, then converted to regional estimates and finally allocated to the individual rate classes on the basis of historic volumetric shares. The industrial market demand is determined by a total volume equation and average consumption estimates are then subsequently derived.

The normalized average consumption forecast for residential and commercial customers incorporates assumptions related to several demand variables: weather normal, energy efficiency, total bill amounts, fall season weather and structural trend variables. Table 4 summarizes the historic and forecast average consumption per customer estimates.

Table 4
NAC Trends: Actual & Forecast
Normalized at 2013 Weather Normal

		Residential		Commercial
Line No.	Time Span	Southern	Northern	All Rates[1]
1	1991-2000 Actual	(0.9)%	(1.0)%	(1.1)%
2	2000-2007 Actual	(1.6)%	(2.0)%	(0.9)%
3	2007-2010 Actual	(1.5)%	(1.6)%	(0.2)%
4	2010-2013 Forecast	(2.0)%	(1.6)%	0.2%

(1) All rate classes consolidated.

3.2.1/ Residential NAC

Residential NAC estimates are prepared for both Union South and Union North customers. The residential econometric forecasting follows the methodology used in EB-2005-0520. The NAC estimates are the product of two regression equations: an average use per customer equation and a total volume equation. The average of the two econometric demand estimates is then adjusted for the forecast DSM program NAC impact.

The key demand drivers in the residential regression analysis are:

a) Weather – normal monthly heating degree days ("HDD") below 18°C
b) A weighted furnace stock energy efficiency index
c) A persons per household measurement

d) The total residential bill monthly amounts

Table 5 highlights the trends present in these key residential demand drivers.

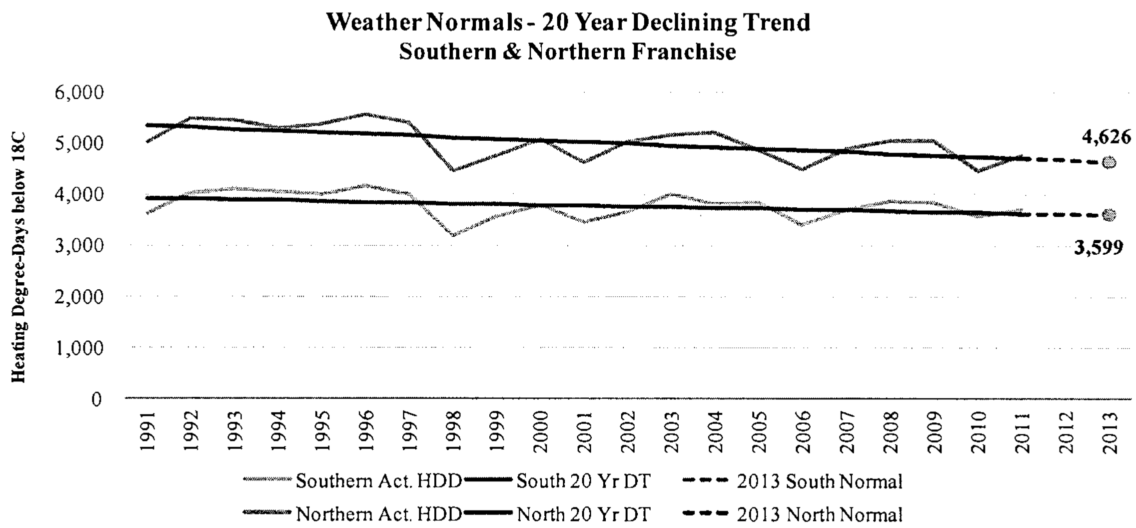
Table 5
Residential Demand Drivers

Line No.		2001	2004	2007	2010	2013
1	Southern Weather Normal (HDD)					3,599
2	Northern Weather Normal (HDD)					4,626
3	Furnace Energy Efficiency Index	0.772	0.780	0.816	0.841	0.865
4	Persons Per Household	3.00	2.70	2.72	2.62	2.53
5	SouthernTotal Bill Amount: $	1,113	1,176	1,112	791	862
6	NorthernTotal Bill Amount: $	1,233	1,315	1,187	855	985

Note: Actual data until 2010. Forecasted data for 2013.

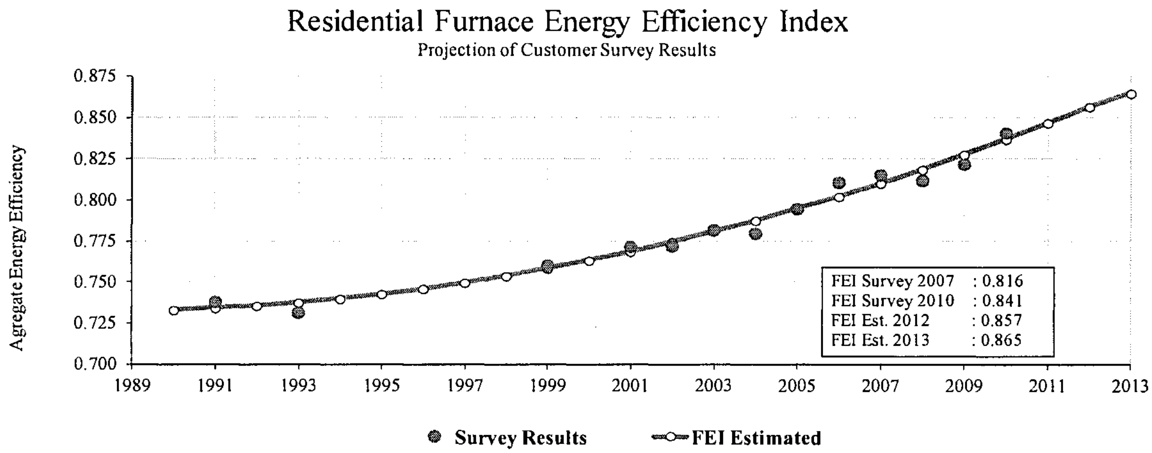
The weather normal provides the total HDD estimates for the year 2013 obtained from the 20-year declining trend methodology that is described in Exhibit C1, Tab 5 and shown in Figure 1. The weather normal coupled with weather demand elasticity obtained from regression analysis enables weather normalization of the actual consumption. The weather normal also estimates the space heating requirement and sets the seasonal pattern present in monthly consumption forecasts.

Figure 1



After weather, the weighted furnace efficiency variable is the second most important in explaining residential natural gas consumption. The historic efficiency measurements are derived from furnace type information obtained from residential customer gas appliance penetration research undertaken by Union. The forecast efficiency index estimate shown in Figure 2 is a projection based on several inputs: customer growth, furnace replacement, changing furnace stock levels for high, mid and conventional efficiency furnaces, and the average fuel efficiency of each furnace type. The furnace energy efficiency variable explains the observed and forecast decline in the average consumption per customer arising from technological improvements.

Figure 2



The same residential customer research provides the historic persons per household estimates and trend analysis of the historic data since the early 1990's generates the projected 2013 level. The trend in the number of persons per household is declining over time. In general, fewer residents translate in lower natural gas consumption. Specifically, in the regression analysis, the person per household demand driver explains the observed declining trend present in summer month natural gas consumption.

The historic total bill amounts are actual revenue figures for system sales customers. The 2013 estimate is determined using the 2011 NAC estimate and the Board-approved delivery and gas supply commodity rate for Rate M1 and Rate 01, effective January 1, 2011. The bill amount is held constant in all forecast years because gas commodity prices are uncertain. The bill amount includes all applicable charges: fixed and variable delivery, transportation, storage, gas commodity and applicable taxes. The total bill amount variable accounts for the inelastic price demand relationship in the demand equation.

3.2.2/ Commercial NAC

The commercial NAC forecast estimates are obtained from regression analysis of commercial consumption data from all general service rate classes. The analysis identified the following demand drivers for the new commercial NAC demand forecast equation:

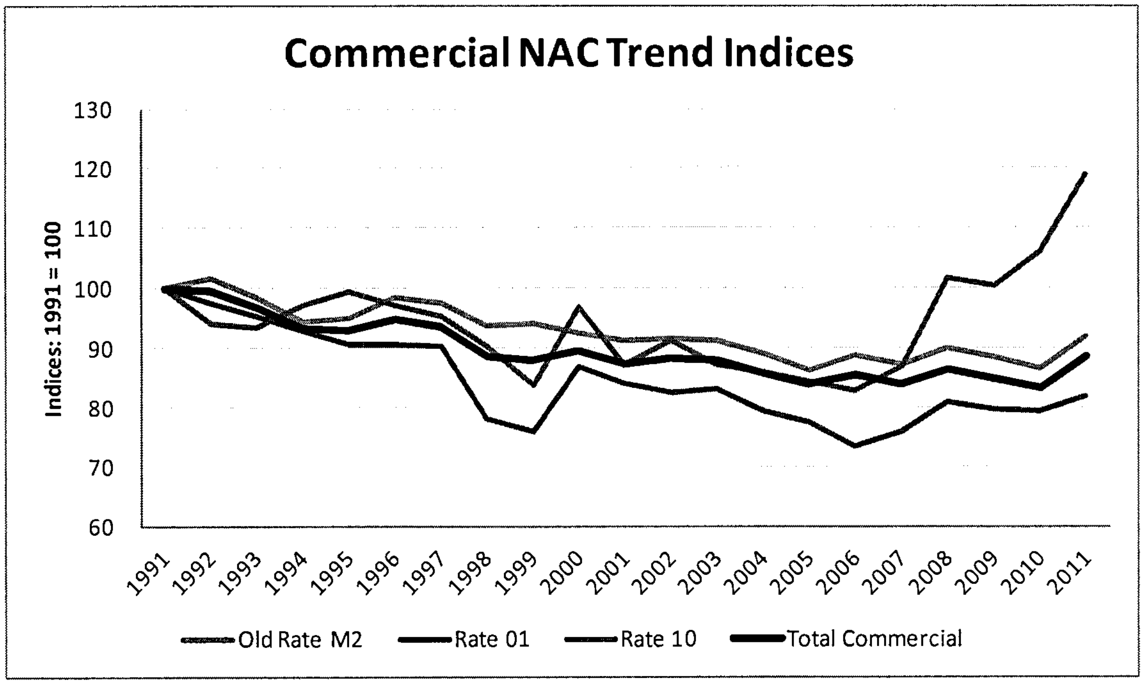
i. Weather – normal monthly HDDs below 18°C
ii. Harvest season weather conditions – September & October HDDs below 18°C
iii. A structural trend variable – starts at a value of 100 in January 1991 and increases until April 2006 to a value of 283 and remains constant thereafter
iv. A structural base variable – equals 1 in all months between January 1991 and December 2001 and equals zero in all months afterwards
v. Binary dummy variables for two monthly data points: March and April 2000

The new demand equation possessed strong statistical results which are detailed in Appendix A, Table 6. The harvest season weather variable is a new and separate demand variable that accounts for weather conditions in the fall. It is a proxy variable for temperature and cloud cover. The structural trend variable accounts for the observed declining trend in NAC from 1991 to 2006. The structural base variable accounts for the change in the low season load before and after 2002. The binary dummy variables address the two outlier observations in March and April 2010.

This new demand equation was identified because several structural shifts and other market changes occurred within the individual rate classes. The structural shifts affected the average consumption trends. These changes necessitated a specification change from the previous 2007 Board-approved forecast demand equations.

Figure 3 indicates the departure from the declining usage trend that was observed in all rate classes over the period 1991 to 2006. Starting in 2007, NAC for Rate 01 and Rate 10 tracked upwards. Notable customer migration from Rate 10 to Rate 01 over the period 2007 to 2011 effectively raised the NAC levels of both of these rate classes. Note that with market consolidation, the total commercial NAC possesses a smoother trend compared to the individual rate classes.

Figure 3



Union also witnessed the following additional changes since 2007 which fostered a consolidated approach:

i. The annual NAC levels changed from the clearly declining trend to a relatively flat trend as shown in the total commercial and southern old M2 NAC index lines in the above chart;

ii. The pattern observed since 2005 is a seasonal consumption pattern that is related to fall weather conditions; and,

iii. Since regression analysis requires sufficiently long time series data, the presence of new rate classes in the Union South in 2008 necessitated the consolidation of the new rates (Rate M1 and Rate M2) according to the former or old Rate M2 classification.

The NAC estimates for the regional franchise area and the individual rate class are subsequently derived from the consolidated estimates by further regional correlation and volumetric share analysis by rate class.

3.2.3/ Tobacco Use per Customer

Trend analysis of both customers and actual usage is applied to the tobacco market; this is similar to the previous 2007 rate case evidence.

3.3/ INDUSTRIAL VOLUMES

The econometric methodology for the industrial total throughput volumes is similar to that filed in EB-2005-0520. Both the demand equation and the explanatory demand variables are the same. The econometric total throughput volume equation is based upon consolidated rate class data.

Table 6 summarizes the 2013 customer and demand estimates by individual rate class. The diversity in terms of the number of customers and the average consumption per customer in the industrial market necessitates a consolidated rate class approach to forecasting this market.

Table 6
2013 Industrial General Service Rate Market

Line No.		Rate M1	Rate M2	Banner Rate 10	CIA Rate 10	Total
1	Customers	4,007	1,318	122	44	5,491
2	% share	73%	24%	2%	1%	100%
3	Volumes: 10^3 m^3	58,679	345,706	38,874	50,130	493,389
4	% share	12%	70%	8%	10%	100%
5	Annual NAC: m^3	14,808	257,901	336,471	1,108,624	90,084

The key demand drivers in the industrial general service rate market are:

i. Weather – normal HDDs below 18°C

ii. Foreign exchange rate: Canada / United States

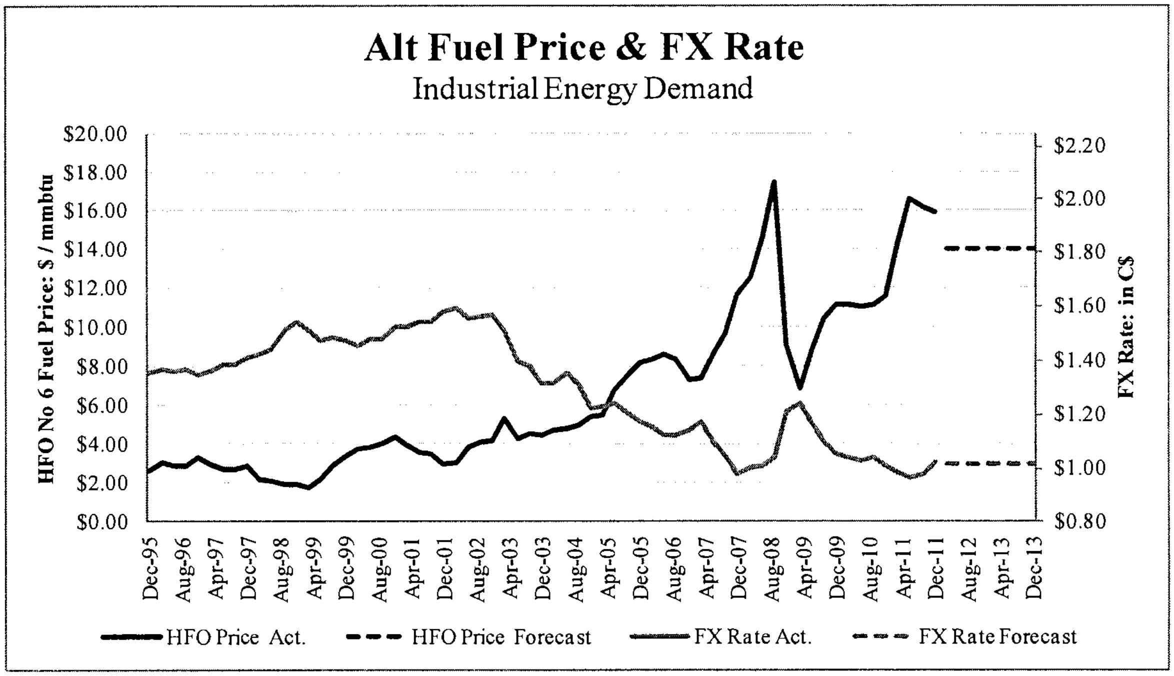
iii. Alternative fuel oil price - Heavy Fuel Oil No. 6

iv. Future estimated DSM Plan NAC impacts

The weather normal demand driver was described earlier, please refer to Section 3.2.1.

Figure 4 presents the Canada / US foreign exchange ("FX") rate and the alternate HFO No. 6 fuel oil price. These two demand drivers have a partial offsetting effect on consumption. The estimated demand cross elasticity (0.25) impact of the exchange rate is approximately 1.5 times larger than the estimated fuel oil price (0.17) cross elasticity impact. As the price of fuel oil rises, gas demand increases; as the U.S. dollar falls, gas demand falls. Over the forecast period, institutional survey estimates for the exchange rate and alternative fuel price as provided by Consensus Economics Inc. (issued during Q1 2011) indicate parallel trajectories.

Figure 4



Historic volume shares are used to allocate the estimated total throughput volumes shown in Figure 8 to each rate class. Once the volumes are estimated, the industrial econometric NAC estimates for each rate class can be subsequently derived. This is generated by dividing the volume estimates by the respective forecast customer estimates. Each industrial rate class NAC is then adjusted for the forecast DSM NAC impacts to yield the NAC forecast estimates.

3.4/ DSM PLAN IMPACT

DSM Programming is expected to lower total consumption over the forecast period by approximately 64,000 10^3m^3. The forecast saved volumes are transformed into DSM NAC impacts which are used to adjust the econometric NAC estimates for individual rate and service classes. These DSM impacts decrease the total market NAC by approximately 0.4% per annum. In the residential market, the forecast DSM volume savings of 21,101 10^3m^3 represents approximately 33% of the total DSM saved volumes. The volume savings are larger in Union South compared to Union North. This explains the difference in the forecast NAC trends between the two delivery areas mentioned earlier. In the commercial market, the forecast volume savings of 35,191 10^3m^3 from DSM Programs represents approximately 55% of the total saved volumes for all customer groups. The DSM Programming offsets load growth that is occurring in the commercial market from other factors. The forecast saved volumes from DSM in the industrial market are 7,387 10^3m^3 and account for approximately 12% of the total volume savings from DSM.

4/ NAC & VOLUME FORECAST RESULTS

Figures 5 to 8 below compare the NAC forecast estimates with past history. The residential and commercial NAC forecast are presented along with the industrial total volume estimates. For numerical volume estimates please refer to Exhibit C1, Summary Schedule 1.

Figures 5 and 6 show a continuation over the forecast period of the declining trend observed in the past in the residential NAC. Figure 7 shows a declining commercial NAC over the forecast period as a result of DSM plan estimates. Figure 8 shows that industrial volumes, after recovering in 2011, remain flat over the next two years. The regional share of the total industrial volumes does not change significantly.

The NAC forecast for residential customers continues to decline over the 2010 to 2013 period; this resembles the trend observed over the past 20 years. The difference in the forecast NAC trends between Union South and Union North residential customers arises from the DSM plan estimates for the forecast period.

Figure 5

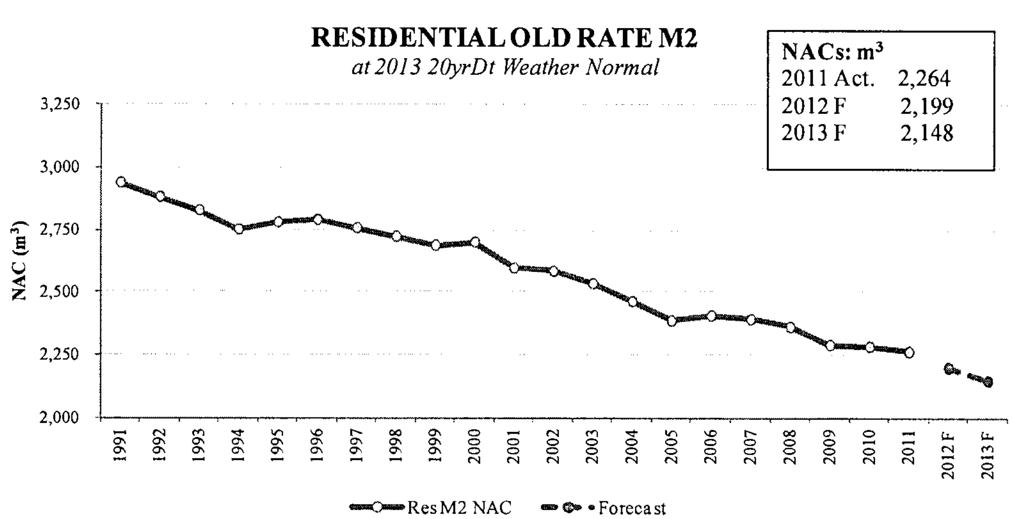
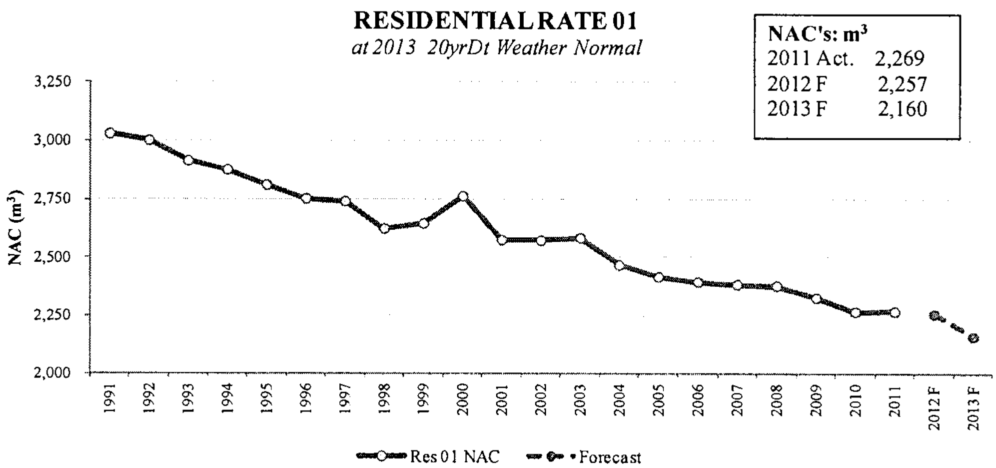
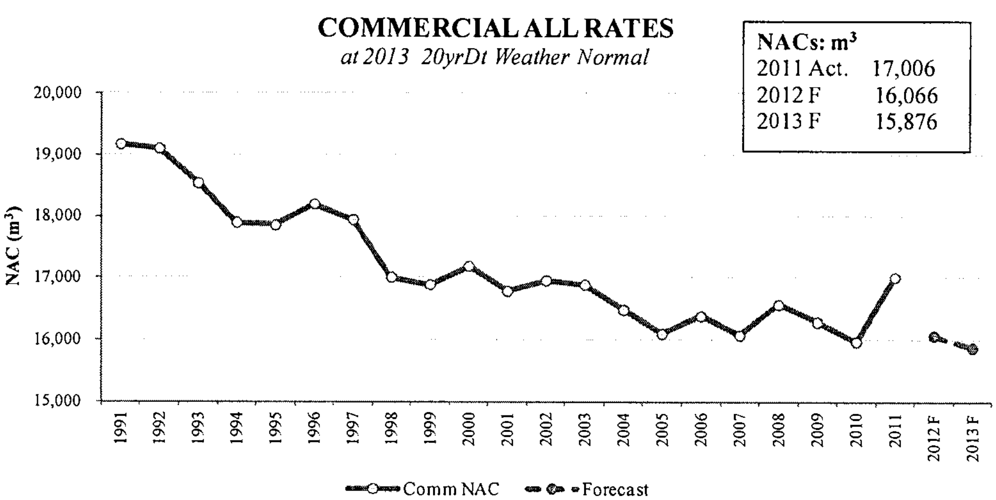


Figure 6



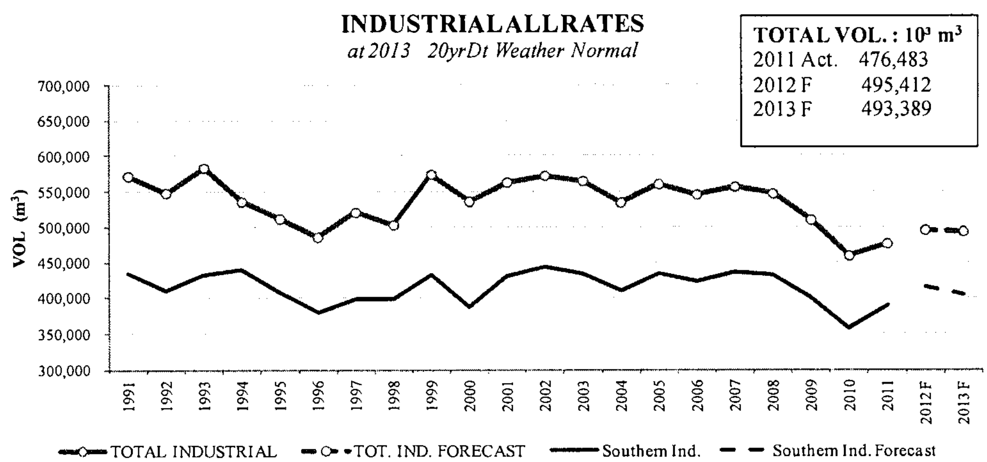
The NAC forecast for commercial customers is essentially flat (+0.2%) and resembles the almost flat (-0.2%) trend from 2007 to 2010. However, the commercial NAC trend in the forecast departs from the declining trend (near -1%) observed over the 1991 to 2006 period.

Figure 7



As noted above, the industrial volume forecast reflects an increase relative to 2010 actual volume consumption. The industrial volume trend in the forecast departs from the declining trend observed between 2007 and 2010.

Figure 8



Union's total in-franchise throughput. These large industrial customers are sophisticated, major consumers of energy that operate in a highly competitive North American and global market.

3/ FORECAST PROCESS

The volume and revenue forecasts for contract customers are developed using two methodologies. An econometric forecast is developed for the majority of the customers and a detailed bottom-up forecast is built for the large T1 and Rate 100 customers.

3.1/ Econometric Forecast Methodology

For the small to mid-size contract markets represented by the LCI and Greenhouse market sectors, Union uses econometric analysis to forecast consumption requirements. Econometric modelling uses mathematical equations to show past relationships between consumption and the variables that influence the consumption. An equation is derived, tested and fine-tuned by regression analysis to ensure that the equation is a reliable representation of the past relationship. Once the equation is established, projected values of the influencing variables are inserted into the equation for forecast purposes.

This forecasting methodology has been in use since 2008. Comprised of approximately 430 accounts from a variety of market sectors, this customer grouping includes 88% of contract customers but accounts for only approximately 40% of Union's contract market revenues.

Union converted to the econometric forecasting methodology for this customer group because the grouping exhibits characteristics that are favourable to formulaic forecasting techniques.

Among the characteristics are:

i. Identifiable key demand drivers
ii. Sufficiently large account populations
iii. Available historic demand data
iv. Clearly identifiable economic indicators that affect these markets

Multiple regression analysis of historic monthly data identifies the key demand drivers in each market segment. The forecasts produced by the econometric modelling are reviewed by account managers to incorporate any known specific customer or market conditions that may affect consumption and to assess the future number of accounts by market sector.

The key demand drivers that affect the demand forecast and associated revenue in these customer groups are:

i. Number of accounts within a market sector
ii. Canada / USA foreign exchange rate
iii. Natural gas price at Dawn, Ontario & Heavy Fuel Oil No. 6 price

3.2/ Detailed Forecast Methodology

The remainder of the contract market is comprised of approximately 60 customers (Steel, Chemical and Refinery, Power and Key market sectors). This group represents 12% of customers and accounts for approximately 60% of volume throughput and revenue in the contract market. Union has historically used detailed, bottom-up forecasts for this group and continues to use this approach given its extensive understanding of these accounts through ongoing interactions between the customer and the account manager. These large industrial and power generation customers are sophisticated, major consumers of energy. Using a combination of historical consumption information and knowledge of specific customer production plans and expectations, the account manager builds the customer forecast. The account manager seeks input from the customer when formulating the forecast and discusses the final forecast with them once completed.

4/ CONTRACT CUSTOMER DEMAND COMPARISONS

Tables 1 and 2 compare consumption volume and revenue between 2007 Board-approved and 2013 forecast by market sector.

Table 1

Volume Comparison by Market Sector
2007 Board-approved through 2013 Forecast
($10^6 m^3$)

Line No.	Market Sector	2007 Board-approved	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
1	Power	1,831	2,078	1,659	1,854	2,349	2,464	2,215	2,189
2	Steel/Chemical/ Refinery	3,374	3,272	3,523	2,971	3,271	3,582	3,866	3,734
3	LCI/Key	2,825	2,806	2,697	2,218	2,163	2,180	2,110	2,117
4	Greenhouse	146	173	203	197	246	287	303	315
5	Wholesale/REM	346	297	305	319	315	324	330	334
6	Totals (1)	8,521	8,625	8,386	7,560	8,344	8,837	8,824	8,689

(1) Excludes MAV volumes.

Table 2

Revenue Comparison by Market Sector
2007 Board-approved through 2013 Forecast
($ Millions)

Line No.	Market Sector	2007 Board-approved	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
1	Power	23.5	26.8	26.3	29.0	32.2	32.7	29.7	29.5
2	Steel/Chemical/Refinery	37.2	38.5	37.7	37.0	36.7	38.4	36.1	35.5
3	LCI/Key	44.8	45.1	43.9	39.5	36.8	36.4	35.2	34.7
4	Greenhouse	4.0	3.9	5.2	4.9	5.8	6.3	6.2	6.5
5	Wholesale/REM	6.2	5.5	5.7	5.8	5.7	5.5	5.4	5.4
6	Totals (1)	115.7	119.8	118.8	116.2	117.2	119.3	112.6	111.6

(1) 2007 (actual) to 2013 revenue is calculated using Q1, 2011 rates.

Table 1 shows volume increases in the Power (358 10^6m^3) and the Greenhouse (169 10^6m^3) sectors from 2007 Board-approved to the 2013 forecast. These volume increases drove an increase in the revenue generated in these sectors during the same period; described in more detail below. Table 1 also shows an increase in volume for the Steel/Chemical/Refinery sector. As described later in this evidence, the volume increase is not matched by a corresponding increase in revenue. The balance of market sectors show either flat or, in the case of the LCI/Key sector, significantly declining consumption levels.

Table 2 depicts the equivalent revenue comparison by market from 2007 Board-approved to the 2013 forecast. Table 2 shows that total contract market revenue is expected to decline by $4.1 million dollars. Table 2 shows that revenue is expected to increase in the Power and Greenhouse sectors by $6.0 million and $2.5 million dollars respectively. Revenue growth in the Power sector primarily arises from the full implementation of several long-term sales cycle projects. Activity in the Power sector is more fully described in the gas fired generation section below. Adding to revenue growth is the expectation that Greenhouse revenues will increase by approximately $2.5 million, from $4.0 million to $6.5 million. This increase in revenue is attributable to the comparatively low and stable gas cost environment over the forecast period. Natural gas continues to meet competition from biomass in the pulp and paper sector, but otherwise, natural gas has displaced most competitive fuels from the Greenhouse market.

Historically, the Greenhouse market has been highly price competitive between oil and natural gas. However in the current gas price environment Union is projecting that, for the forecast period, it has 100% fuel penetration of the Greenhouse market. Union forecasts that the additional revenue will be driven by an increase in the number of greenhouses in this market sector, as well as a number of expansions to the existing infrastructure which will boost production.

Offsetting areas of revenue growth are significant decreases in revenue, primarily in the LCI/Key sector where revenue declines $10.1 million dollars from 2007 Board-approved and the 2013 forecast. Even prior to the recession of late 2008, the LCI/Key sectors, primarily the pulp and paper, mining and automotive part industries were hit hard by the rising value of the Canadian dollar, leading to considerable demand destruction in these industries. With the onset of the 2008 recession, additional demand destruction and reduced production affected the commercial and industrial sectors on an even broader basis, resulting in sizeable reductions in revenue from these contract markets. Union projects demand destruction and further closures will continue in these commercial and industrial markets over the forecast period based on continued economic uncertainty and the high value of the Canadian dollar.

As previously identified in Table 1 the Steel/Chemical/Refinery sector shows a situation of increasing consumption while revenues are declining slightly over the forecast period. This is attributable primarily to contract choices made by the Steel/Chemical/Refinery customers. Some customers have converted from bundled services like Rate M7 or Rate M4 to Rate T1 service.

Rate T1 service, being semi-bundled has lower revenue associated with it. In addition, customers in this sector have in some cases lowered deliverability contract demand parameters and down sized their storage contract parameters resulting in reduced revenue. Finally, incremental throughput has been projected through the more frequent operation of a refinery-based cogen site over the forecast period resulting in increased throughput, although the customers contract demand parameters, and hence the revenue contribution, have not changed.

The Wholesale/REM market shows both declining consumption (12 10^6m^3) and declining revenues ($0.8 million) over the forecast period. This reflects an instance of reduction in distribution contract demand for a Wholesale customer.

Table 3 provides a comparison of the forecast 2013 contract customer volumes by rate class to the 2007 Board-approved volume forecast.

Table 3

Volume Comparison by Rate Class
2007 Board-approved through 2013 Forecast
(10^6 m^3)

Line No.	Rate Class	2007 Board-approved	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
1	100	2,203	2,015	1,964	1,806	1,883	1,892	1,904	1,891
2	20	505	451	481	557	546	645	569	610
3	25	101	424	308	200	220	158	133	129
4	T1	4,232	3,831	3,757	3,446	4,102	4,607	4,814	4,666
5	M7	278	584	554	309	315	258	149	147
6	M4	452	520	519	446	439	442	409	380
7	M5	405	504	498	476	525	511	519	531
8	Other (T3,M9,M10)	346	296	305	319	315	324	330	334
9	Total (1)	8,521	8,625	8,386	7,560	8,345	8,837	8,826	8,688

(1) Excludes MAV volumes.

Overall, when compared to the 2007 Board-approved volumes, the 2013 forecast shows a net volume increase of 167 10^6m^3 from 8,521 10^6m^3 to 8,688 10^6m^3.

Table 4 provides a comparison of the forecast 2013 contract customer delivery revenue by rate class to the 2007 Board-approved revenue forecast.

Table 4

Revenue Comparison by Rate Class
2007 Board-Approved through 2013 Forecast
($ millions)

Line No.	Rate Class	2007 Board-Approved	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
1	100	16.2	15.3	14.5	12.9	12.5	12.6	12.8	12.7
2	20	7.5	7.7	8.1	9.5	10.0	9.5	9.3	9.7
3	25	2.4	8.6	6.1	3.5	3.1	3.5	2.4	2.3
4	T1	55.0	49.5	51.3	56.2	58.8	62.0	58.5	57.8
5	M7	6.7	10.1	9.8	6.7	6.3	5.8	4.0	4.0
6	M4	13.8	14.4	14.7	13.4	12.0	11.9	11.6	10.8
7	M5	8.0	8.2	8.5	8.0	8.8	8.5	8.6	8.9
8	Other (T3,M9, M10, 77)	6.1	6.0	5.8	5.9	5.7	5.5	5.3	5.4
9	Total (1)	115.7	119.8	118.8	116.1	117.2	119.3	112.6	111.6

(1) 2007 to 2013 revenue is calculated using Q1, 2011 rates.

Overall, when compared to the 2007 Board-approved revenue, the 2013 forecast shows a net delivery revenue reduction of $4.1 million from $115.7 million to $111.6 million.

5/ IN-FRANCHISE GAS FIRED POWER GENERATION GROWTH

Growth in gas fired power generation has been driven by the Ontario government's 'off coal' policy. Three gas fired generation facilities have been constructed in Union's franchise area under the Clean Energy Supply ("CES") initiative:

i. St. Clair Generating Station

ii. East Windsor Cogeneration Center

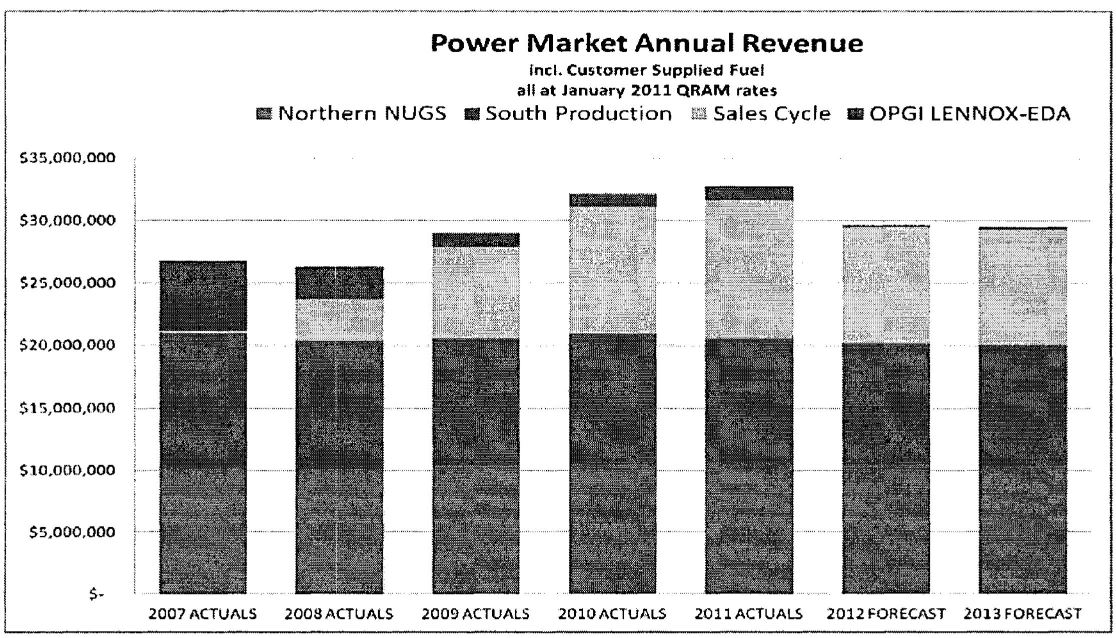
iii. Halton Hills Generating Station

These projects have supported the supply mix change from coal to other generation sources, including gas fired generation. Union has invested approximately $41 million to bring gas infrastructure to these three facilities. In addition, Union is providing high deliverability storage services to these customers, which was developed in response to gas fired generators needs that were identified in EB-2005-0551.

Figure 1 shows the revenue growth in the contract rate gas fired generation segment from 2007 (actual) to the 2013 forecast.

Figure 1

Power Generation Growth 2007 to 2013



The growth in gas fired power generation from the province's CES contracts as well as a coal conversion project at Thunder Bay, as outlined in the provincial government's Long Term Energy Plan, accounts for approximately $9.2 million of revenue growth in Union's power segment. This is offset by a loss of revenue from Lennox of $4 million over the same time frame. Revenue from non-utility generators ("NUGS") located in Union North and production in Union South have remained fairly constant through this period.

Future Growth

Potential future growth in the gas fired power generation is outlined in the provincial government's Long Term Energy Plan mentioned above and the Ontario Power Authority's 'IPSP Planning and Consultation Overview'. These plans identify three potential gas fired generation projects in Union's franchise including the conversion of coal facilities at Nanticoke and Lambton to natural gas as well as a peaking facility in the Waterloo-Cambridge area to provide transmission support.

In response to a request from OPG, Union is proceeding with environmental assessment studies of the coal conversion projects. Neither the coal conversion projects nor the Waterloo-Cambridge peaking facility has received the required approval to proceed.

Filed: 2012-07-17
EB-2011-0210
Exhibit J2.3

UNION GAS LIMITED

Undertaking of Mr. Thompson, added to by Ms. Taylor
To Ms. Van Der Paelt

Undertaking J2.3: For rate 20, to provide model for identified and disaggregated, economic versus ground-up

---

The tables below provide for each contract rate class, by volume and by revenue for the 2013, the forecast methodology used for that particular rate class.

2013 Contract Volumes by Rate Class and Forecast Method
(Volumes in 10^6m^3)

Rate Class	Bottom Up	Econometric Greenhouse	Econometric LCI/Key	Total
100	1,891			**1,891**
20	353	-	257	**610**
25	96	-	34	**129**
T1	4,666			**4,666**
M7	147			**147**
M4		30	351	**380**
M5		243	288	**531**
Other (T3, M9, 77)	334			**334**
Total	**7,486**	**273**	**930**	**8,689**

2013 Contract Revenue by Rate Class and Forecast Method
($ millions)

Rate Class	Bottom Up	Econometric Greenhouse	Econometric LCI/Key	Total
100	12.7			**12.7**
20	5.2	-	4.5	**9.7**
25	1.5	-	0.8	**2.3**
T1	57.8			**57.8**
M7	4.0			**4.0**
M4		0.9	10.0	**10.8**
M5		4.5	4.4	**8.9**
Other (T3, M9, 77)	5.4			**5.4**
Total	**86.6**	**5.4**	**19.6**	**111.6**

(1) Revenue is calculated using Q1, 2011 Rates

PREFILED EVIDENCE OF

PAUL GARDINER, MANAGER, DEMAND FORECASTING AND ANALYSIS

This evidence presents Union's proposed 20-year declining trend weather normalization method used for the 2013 demand forecast. The evidence compares Union's proposed method to the existing 55:45 weather normalization method approved in EB-2005-0520.

The evidence is organized under the following headings:

1/ Overview
2/ Rationale for Change
3/ Statistical Analysis and Criteria
4/ Conclusion

1/ OVERVIEW

Union has forecast the 2013 general service and small volume contract demand incorporating a change in its weather normalization method. The 2013 general service demand is set according to a 20-year declining trend weather normal method. Weather normalization is used to determine Union's demand forecast, storage and transportation allocations, gas supply planning and rate design activities. Weather is defined by heating degree-days ("HDD"), which represent temperatures below 18°C.

The current weather normal method at Union is a blended method that combines the 20- year declining trend method with the 30-year average method. The blend proportions are 55% for the 30 year average and 45% for the 20-year declining trend. The blended normal method has been used since 2004 when the initial blend ratio was set by the Board at 70:30 and then reset in the 2007 rate case decision (EB-2005-0520) at the 55:45 blend ratio.

The primary objective of an acceptable weather normalization method is to set a weather normal level that will best reflect what future weather is typically expected to be. Union and customers will then be kept neutral with respect to weather in the long-term. The 20-year declining trend method meets these requirements.

2/ RATIONALE FOR CHANGE

The main reason for the change in weather normalization method is that the current blended weather normal is biased upwards towards colder weather. Analysis of actual weather over the past 27 years demonstrates this fact.

The historic analysis indicates that the current blended weather normal will not provide a symmetric estimate[1] of weather over the forecast period. This implies that natural gas demand and delivery revenue estimates will most likely be over stated when the actual demand is recorded. The blended 55:45 method for 2013 will most likely overstate the 2013 delivery

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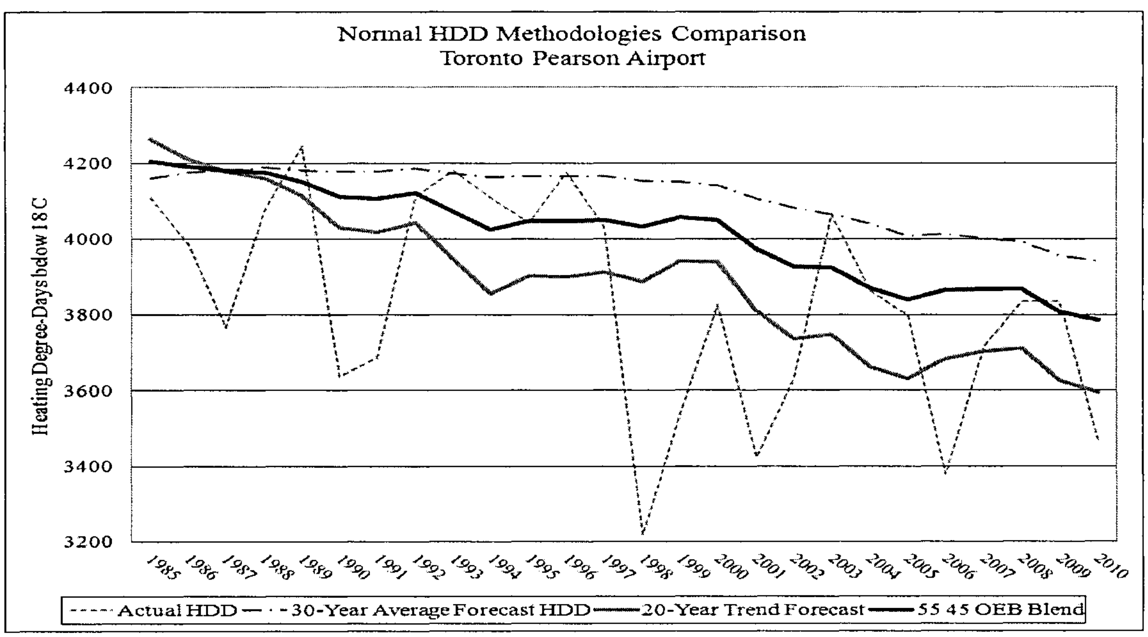
[1] A symmetric estimate of weather is an estimate that results in variances relative to actual weather that are equally positive and negative.

revenue forecast estimates in the general service market by about $7 million when compared to the 20-year declining trend method.

The 20-year declining trend weather normal is a symmetric weather normal and does not possess a colder weather bias. Figure 1 below illustrates the greater symmetry of the 20-year declining trend method (solid red line) against current blended method (solid black line). The 20-year declining trend passes through the middle of the actual heating degree-days observations (dashed line) since 1985. In contrast, the blended method is significantly biased towards the top (colder weather) of the actual weather.

Figure 1

Comparison of Weather Normalization Methods



3/ STATISTICAL ANALYSIS & CRITERIA

Previous weather normal evidence submitted to the Board by both Union and Enbridge demonstrate there are several criteria that describe a good weather normal estimation method.

The five criteria ranked in descending order of importance are:

1) Symmetry – balanced risk about the weather normal estimate (*Figure 1*)
2) Statistical Accuracy – historical metrics *(Table 1)*
    a. Root Mean Square Error ("RMSE")
    b. Average Variance from Actual
    c. Standard Deviation
    d. Mean Percent Error
3) Simplicity – administrative & understanding
4) Sustainability – method is a repeatable process calculation
5) Stability – annual weather normal estimates not volatile over time

The five criteria are discussed in more detail below:

1) Symmetry - The method should result in an unbiased normal temperature condition where there are equal expectations of positive variations and negative variations from actual HDDs. The smaller the mean percent error, the more symmetrical the method. In the case of the Bias Frequency, the closer the ratio is to 1:1, the less biased (more symmetrical) the method.

2) Statistical Accuracy - The method should result in a point estimate that has a minimum variance over time between the normal HDD and the actual HDD value. Accuracy is an error measure that indicates over time the difference between the estimator and actual weather. The most precise accuracy measurement tool is the RMSE. For the RMSE, smaller test results mean greater accuracy.

3) Simplicity - The method and its results should be easily understood and administered. Simplicity addresses the need for internal and external stakeholders to understand and accept the approach that is being taken to calculate the weather normal. The greater the reliance on simple arithmetic methods and limited steps between the input data and the results, the easier it will be to understand the outcome.

4) Sustainability - The new method should stand the test of time and not require significant amendments in the near future. Sustainability is a qualitative assessment of the company being able to understand and maintain the tools underlying the method, over an extended period. The greater the reliance on external participants in the calculation of the methods the lower the assessment of its sustainability.

5) Stability - The new method should result in year over year normalized HDD estimate that does not vary significantly. Stability is a measure of variation; the standard deviation is used to measure variance. Increasing instability means that the fluctuation

from one year's forecast to the next is increasing over time. The increase in variation of the historical weather statistics is a direct contributing factor to increasing instability. For stability, a smaller standard deviation means that the method provides a more stable estimate because the difference between the forecast HDDs in two consecutive years is less significant.

Table 1
Weather Normal Forecast Estimate vs. Actual Weather

Weather normal forecast estimate versus actual annual level
25 Observations: estimates for 1985 to 2010 inclusive

	30 yr Avg.	20 Yr DT	55:45 Blend
Root Mean Square Error: RMSE	375	**269**	306
Average Variance from Actual	276	**56**	177
Std Deviation of Variance	259	269	255
Mean Percent Error	-7.7%	**-1.9%**	-5.1%

The statistical metrics in bold font in the table above show that the 20-year declining trend method ("20 Yr DT") is the superior weather normalization method. This is indicated by three of the four statistical metrics that compare the 20-year declining trend method to the current blended weather normal method and the 30-year average method used by Union before 2004. The RMSE average variance from actual and the mean percent error are accuracy measurements. The standard deviation of the variance is a stability measurement. The 20-year declining trend is a simple and sustainable weather normalization method.

Union notes that Enbridge currently uses a Board-approved 20-year declining trend weather normal method to determining natural gas demand for the Greater Toronto Area.

4/ CONCLUSION

For the reasons set out above, the 20-year declining trend is the appropriate weather normalization method to use in its 2013 demand forecast. The 20-year declining trend method provides a more symmetrical and accurate method relative to the existing weather normalization method.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit C1, Tab 5

a) Has Union investigated whether or not the current definition of a heating degree day (temperatures below 18^{O} C) is still the appropriate balance point for calculating heating degree days? If not, why not? If yes, please provide the results of the investigation.

b) Please provide all the data used to calculate the 20 year trend and 30 year average forecasts shown in Figure 1 in a live Excel spreadsheet. Please also provide all the equations used to forecast the 20 year average forecast figures shown in Figure 1, along with the associated regression statistics.

c) Please provide a similar figure for the Northern Region HDD forecasts as has been provided in Figure 1 for Toronto Pearson Airport. Please also provide all the data used to calculate the 20 year trend and 30 year average forecasts shown in the requested figure in a live Excel spreadsheet. Please also provide all the equations used to forecast the 20 year average forecast figures shown in Figure 1, along with the associated regression statistics.

d) Please provide the equations and regression statistics used by Union to forecast the 2013 South and North HDD forecasts.

e) Please confirm that the figures shown in Figure 1 are based on forecasts determined using data that ends 3 years in advance of the forecast period. For example, the 2010 forecasts are based on actual data up to and including 2007.

f) Is the data shown in Table 1 based on the Toronto Pearson Airport data shown in Figure 1? If yes, please provide a similar table that is based on the data used for the Northern Region.

g) Please provide a table similar to Table 1 that does the comparison of the 2 year ahead forecast, rather than the 3 year ahead forecast based on the Pearson Airport data and the Northern Region data.

h) Please provide the forecasts for the South, North and combined HDD for the 2011, 2012 and 2013 years that result from the methodology used by Union.

i) Please provide a copy of the source of the historical degree day information used to forecast the HDD forecasts for 2013.

j) Please explain and provide an example of how the annual HDD forecast is split into the monthly HDD forecasts used in the various use per customer and volumetric equations.

Response:

a) Union has not recently investigated whether or not the current definition of a heating degree-day (temperature below 18C) is still the appropriate balance point for calculating heating degree-days. The reasons for not investigating are:
   - The current balance point definition of 18 C for the Union normal was defined by the Ontario Energy Board in the previous Union Gas 2004 rate case; and
   - The current definition of 18C or 65F is an industry recognized standard.

b) Table 1 below provides the actual annual weather data for Toronto Pearson Airport. The forecast estimates for each methodology are shown in Table 2. A 3-year lag was recognized when the estimated normals were prepared. The estimates for the 30-year average methodology were obtained by using the simple average function. The estimates for the 20-year trend methodology were obtained by using the trend estimation function in the excel spreadsheet; individual regressions were not prepared. The blended methodology applied the 55% and 45% proportions to the HDD normal estimates obtained from the two other methods: 30-year average and 20-year trend.

Table 1
Toronto Pearson Airport: Annual Heating Degree-Days below 18C

	1940's	1950's	1960's	1970's	1980's	1990's	2000's	2010's
Year 0	4,562	4,163	4,013	4,309	4,382	3,636	3,826	3,465
Year 1	3,923	3,978	3,943	4,166	4,145	3,686	3,423	3,599
Year 2	3,987	3,836	4,105	4,572	4,187	4,112	3,631	
Year 3	4,453	3,622	4,125	3,947	4,066	4,181	4,064	
Year 4	4,113	3,957	4,168	4,236	4,144	4,110	3,862	
Year 5	4,283	3,890	4,359	4,005	4,109	4,042	3,797	
Year 6	3,801	4,181	4,263	4,475	3,987	4,177	3,379	
Year 7	4,153	3,895	4,310	4,181	3,765	4,034	3,719	
Year 8	4,125	4,051	4,309	4,485	4,076	3,219	3,836	
Year 9	3,810	4,025	4,291	4,236	4,246	3,541	3,836	

Note: shaded area indicates data used to estimate the normals

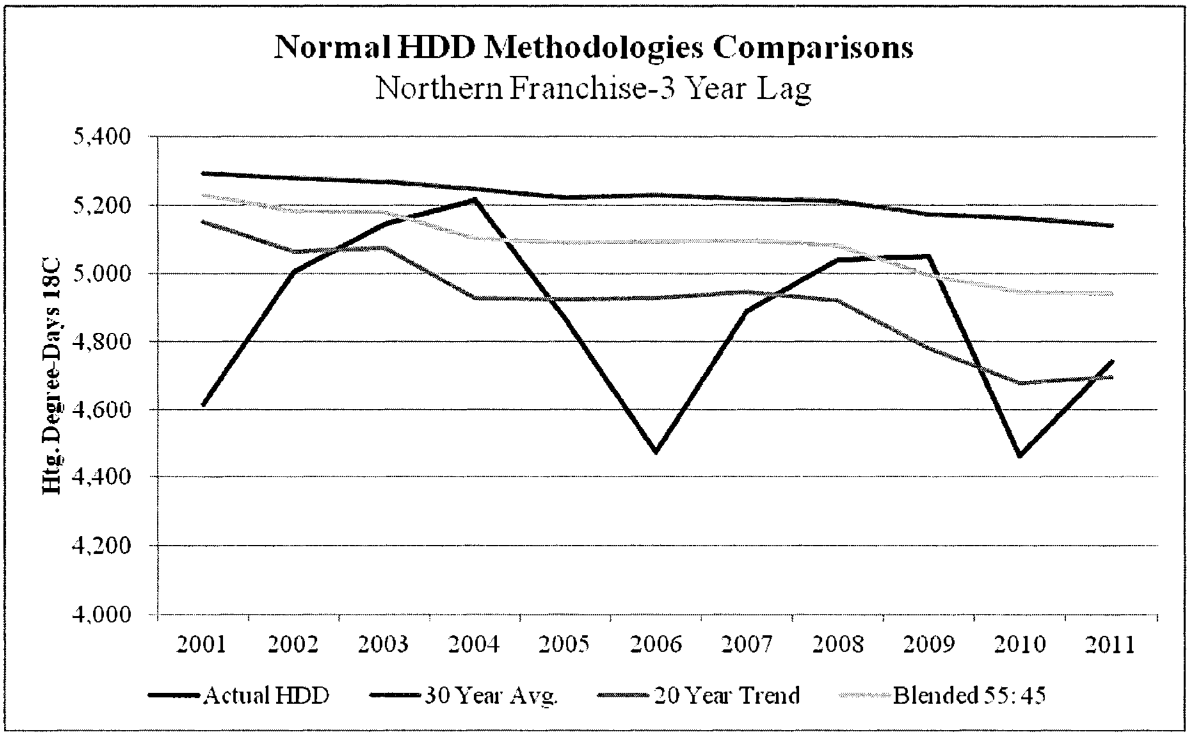
Table 2
Toronto Pearson Airport HDD

YEAR	ACTUAL	30 Yr. Avg.	20 Yr. Trend	55:45 Blend
1985	4,109	4,161	4,266	4,208
1986	3,987	4,176	4,203	4,188
1987	3,765	4,182	4,165	4,174
1988	4,076	4,189	4,147	4,170
1989	4,246	4,183	4,092	4,142
1990	3,636	4,179	3,999	4,098
1991	3,686	4,179	3,987	4,093
1992	4,112	4,187	4,015	4,109
1993	4,181	4,174	3,908	4,054
1994	4,110	4,166	3,803	4,002
1995	4,042	4,166	3,865	4,030
1996	4,177	4,168	3,859	4,029
1997	4,034	4,166	3,874	4,035
1998	3,219	4,155	3,843	4,015
1999	3,541	4,152	3,911	4,044
2000	3,826	4,143	3,909	4,038
2001	3,423	4,107	3,768	3,954
2002	3,631	4,082	3,688	3,905
2003	4,064	4,066	3,708	3,905
2004	3,862	4,041	3,610	3,847
2005	3,797	4,010	3,581	3,817
2006	3,379	4,014	3,642	3,847
2007	3,719	4,001	3,670	3,852
2008	3,836	3,994	3,682	3,854
2009	3,836	3,958	3,586	3,791
2010	3,465	3,942	3,548	3,765
2011	3,599	3,921	3,582	3,768

c) The chart for the northern franchise region presented below compares the actual weather with estimates produced by three normal weather methodologies assuming a 3-year regulatory lag.

Please note that the 20-year declining trend produces weather normal estimates that in most years are the closest to the actual weather. This is especially true in 2011. Both the 30-year average and the blended weather normal methodology well overshoot the actual weather and are biased to cold weather levels.

Please refer to the response provided at part b) above for a description of the weather normal estimation process.


Normal HDD Methodologies Comparisons
Northern Franchise-3 Year Lag
Htg. Degree-Days 18C
5,400
5,200
5,000
4,800
4,600
4,400
4,200
4,000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
Actual HDD
30 Year Avg.
20 Year Trend
Blended 55:45

NORTHERN FRANCHISE Htg. Degree-Days below 18C

Year		Weather Normal Estimates with 3 Year Lag		
	Actual HDD	30-Year Avg.	20-Year Trend	Blended 55: 45
1969	5,121			
1970	5,414			
1971	5,274			
1972	5,742			
1973	4,941			
1974	5,446			
1975	5,134			
1976	5,643			
1977	5,188			
1978	5,640			
1979	5,458			
1980	5,559			
1981	5,092			
1982	5,430			
1983	5,195			
1984	5,175			
1985	5,438			
1986	5,175			
1987	4,722			
1988	5,317			
1989	5,654			
1990	4,994			
1991	5,019			
1992	5,489			
1993	5,460			
1994	5,294			
1995	5,358			
1996	5,550			
1997	5,384			
1998	4,457			
1999	4,754			
2000	5,065			
2001	4,613	5,292	5,151	5,229
2002	5,007	5,280	5,064	5,183
2003	5,147	5,268	5,077	5,182
2004	5,216	5,246	4,926	5,102
2005	4,866	5,222	4,925	5,088
2006	4,473	5,229	4,928	5,093
2007	4,888	5,221	4,946	5,097
2008	5,040	5,212	4,921	5,081
2009	5,049	5,173	4,779	4,995
2010	4,462	5,163	4,677	4,944
2011	4,741	5,143	4,696	4,942

d) The trend line statistics are:

Northern Normal = 5368.61 – (32.30 x YEAR)

R^2 = 30% t-statistics = 38.96 and -2.81

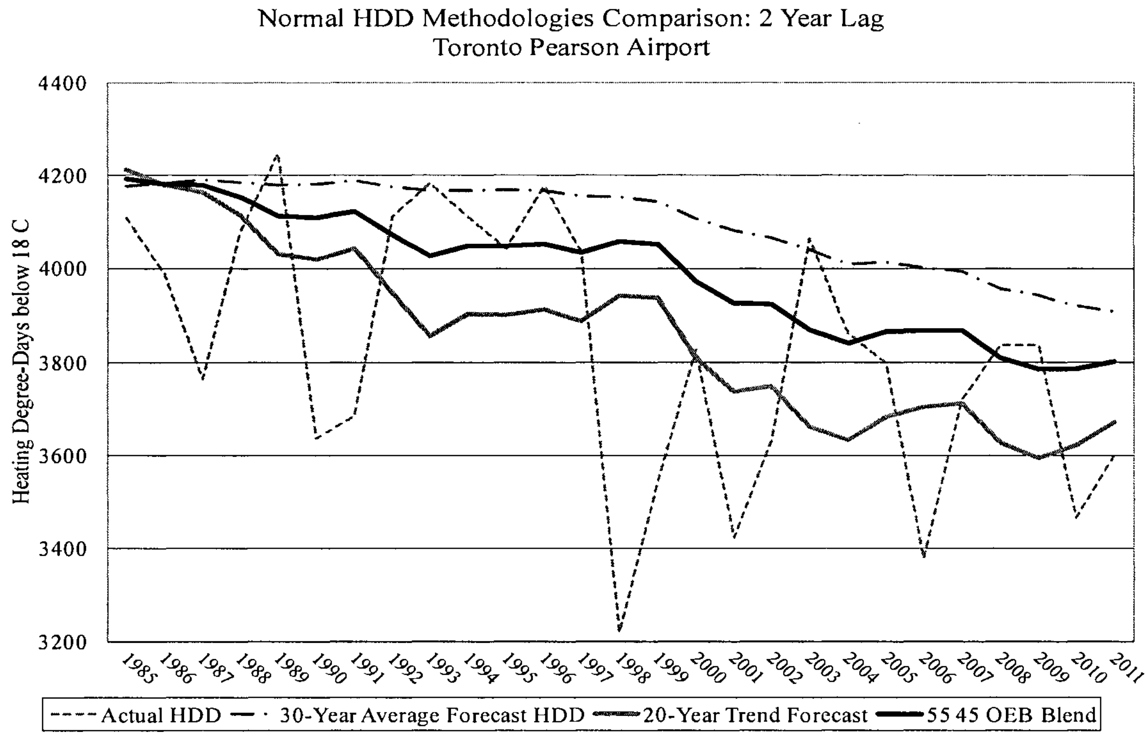
Southern Normal = 3933.18 – (14.53 x YEAR)

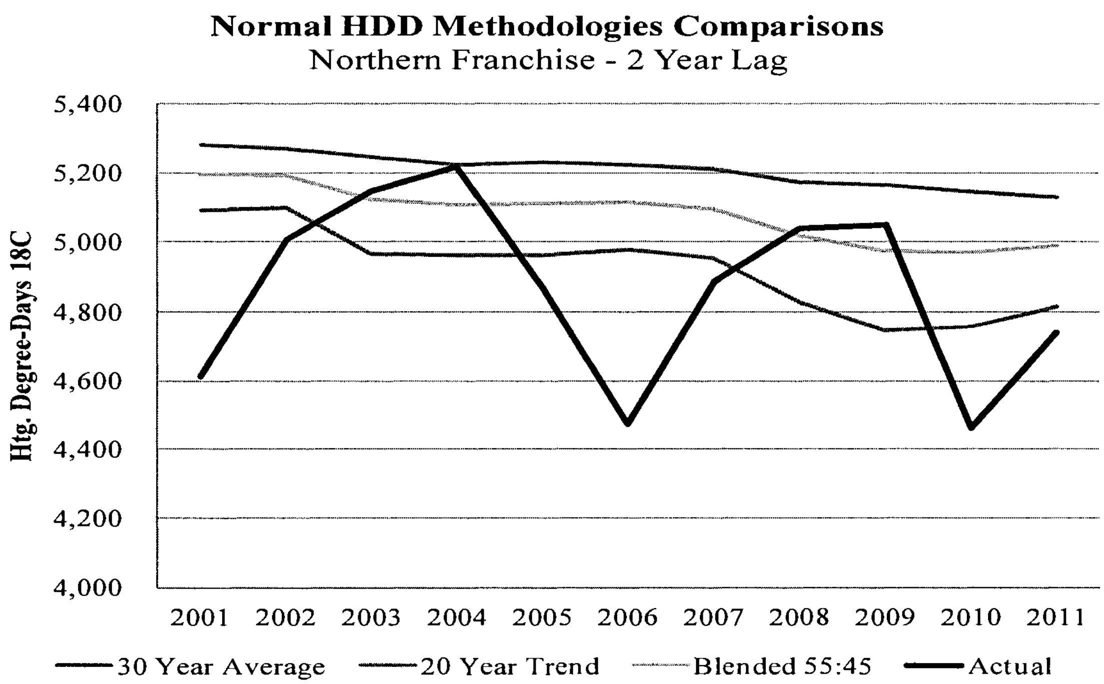
R^2 = 11% t-statistics = 33.73 and -1.5

e) The forecasts in the original evidence incorporate a three year lag. A 3-year lag was used because the test year is 2013 and the actual weather data at the time the demand forecast was prepared spanned until the year 2010.

f) The normalized total volume data shown on table 1 is standardized according to the 2013 Union Gas weather normals for both the southern and northern franchise areas.

g) Please refer to the two charts below for Toronto Pearson Airport and northern franchise weather that incorporate a 2-year regulatory lag instead of a 3-year lag. The 2-year regulatory lag charts demonstrate once again the superiority of the 20-year declining trend weather normal methodology when compared to the current blended weather normal methodology. The estimates obtained by 20-year declining trend weather normal methodology pass though the middle of the actual weather data. The other methods do not provide symmetric results.


Normal HDD Methodologies Comparison: 2 Year Lag
Toronto Pearson Airport
4400
4200
4000
3800
3600
3400
3200
Heating Degree-Days below 18 C
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
Actual HDD
30-Year Average Forecast HDD
20-Year Trend Forecast
55 45 OEB Blend


Normal HDD Methodologies Comparisons
Northern Franchise - 2 Year Lag
5,400
5,200
5,000
4,800
4,600
4,400
4,200
4,000
Htg. Degree-Days 18C
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
30 Year Average
20 Year Trend
Blended 55:45
Actual

h) The table below provides the estimated weather normal heating degree day estimates.

Year	Methodology	South	North	Total Company
2011	Blended 55:45	3775	4978	4075
2012	Blended 55:45	3751	4924	4045
2013	20 Year Trend	3599	4626	3856

i) The actual heating degree statistics for the period spanning the years 1971 to 2011 is contained in the 2013 REGN DATA FILE_Apr 2012 excel file in the Weather Union HDD tab.

j) The weather normal has two components: the 30-year average (55% weight) and the 20-year declining trend (45% weight). The monthly normals are obtained by applying the weights to the monthly estimates for each component as described below.

For the 30-year average component, the monthly HDD averages are calculated directly from the individual month weather statistics. For example for the year 2013, the 30-year average for the month of January is calculated according to reported data for January spanning the years 1981 to 2010. This calculation is performed on both regional franchise areas.

For the 20-year declining trend component, each monthly normal estimate is calculated by multiplying the annual normal estimate derived by the trend line by a seasonal percentage. The seasonal percentage for each month is the average over 20 years of its percent share of the annual heating degree-days. The seasonal percentages are calculated for each franchise area. For example for the year 2013, the 20-year trend HDD estimate for the southern franchise for the month of January is obtained by multiplying the 3,599 HDD estimate by 18.8%. The month of January had a seasonal percent share that averaged 18.8% in the southern franchise over the period 1991 to 2010.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: A2, T1, Schedule 1, Page 21

What requirements are included in the throughout forecasts each year from 2013 to 2018, inclusive, for the Thunder Bay Generating Station? Please provide a copy of the Minister's directive to the OPG for the conversion of the station from coal to gas.

Response:

The Thunder Bay throughput forecast for 2013 is 5000 10^3m^3 and for 2014 32,500 10^3m^3. Union does not have a throughput forecast for 2015 to 2018. Please see the Thunder Bay leave to construct filing EB-2012-0226 for the revenue forecast that underpins the project economics.

Please see Attachment 1.

Ministry of Energy

Office of the Minister

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Fax: 416-327-6754

Ministère de l'Énergie

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Téléc. : 416 327-6754

Filed: 2012-05-04
EB-2011-0210
J.C-1-16-2
Attachment 1

Ontario

AUG 17 2011

MC-2011-2974

Mr. Colin Andersen
Chief Executive Officer
Ontario Power Authority
1600–120 Adelaide Street West
Toronto ON M5H 1T1

Dear Mr. Andersen:

RE: Thunder Bay Generating Station Conversion to Natural Gas

I write to you pursuant to my authority as the Minister of Energy to exercise the statutory power of ministerial direction that I have in respect of the Ontario Power Authority (**"OPA"**) under section 25.32 of the *Electricity Act, 1998.*

Ontario's Long-Term Energy Plan, released in November 2010, proposed converting two coal-fired units at the Ontario Power Generation (**"OPG"**) Thunder Bay Generating Station to natural gas. These converted units are needed not only for local supply to the city of Thunder Bay, but also for system reliability in northwestern Ontario. Given the nature of the conversion, the Ministry of Energy (**"Ministry"**) recognizes OPG's requirement for a long-term energy supply contract in respect of the output from these units (the "**Agreement**"). As such, the Ministry has determined to pursue the initiative (the **"Initiative"**) of negotiating and concluding such an Agreement.

<u>Direction</u>

Therefore, I hereby direct the OPA to assume responsibility for exercising all powers and performing all duties of the Crown regarding the negotiation and conclusion of the Agreement with OPG. It is my expectation that the financial terms of the Agreement should be commercially reasonable for a facility being converted from coal to natural gas of the size and location of the Thunder Bay Generating Station. The Agreement should also provide an incentive to OPG to optimize the operation of the facility to reflect the hour-by-hour value of power to the Ontario electricity system.

The OPA will make reasonable efforts to complete the negotiations and execute the Agreement by December 31, 2011.

This direction is effective and binding as of the date hereof.

Sincerely,

Brad Duguid
Minister

ONTARIO
POWER AUTHORITY

Published on *Ontario Power Authority* (http://www.powerauthority.ca)

Ministry Directive: Thunder Bay Generating Station Conversion to Natural Gas

Wed, 08/17/2011
Downloads:

Ministry Directive: Thunder Bay Generating Station Conversion to Natural Gas [1]

The Minister has directed the OPA [2] to assume responsibility of the Crown for negotiating and entering into a long-term energy supply contract (the "Agreement") with Ontario Power Generation (OPG) for the output from two generating units at OPG's Thunder Bay Generating Station once they are converted from coal to natural gas. The Minister has asked the Ontario Power Authority to endeavor to execute the Agreement by December 31, 2011.

News from OPA

Source URL: http://www.powerauthority.ca/news/ministry-directive-thunder-bay-generating-station-conversion-natural-gas

Links:
[1] http://www.powerauthority.ca/sites/default/files/news/MC-2011-2974.pdf
[2] http://www.powerauthority.ca/sites/default/files/new_files/about_us/pdfs/MC-2011-2974.pdf

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: A2, T1, Schedule 1, Page 21

When (in which year) does Union expect that OPG's Lambton and Nanticoke Gas conversion projects, the proposed Waterloo-Cambridge peaking facility, and the replacement for the "Oakville project", to start using natural gas? How does Union propose to deal with the very large increases in gas consumption, if they occur during the next five IRM years? What expenditures will be necessary on Union's part to serve each of the four planned gas facilities? How much capital and/or O&M is being forecast for each of the four gas plants in 2013?

Response:

The Lambton Generating Station is forecast to be in service by November 1, 2014, however, no Ministerial Directive has been issued to commence that project.

The timing of the Nanticoke Generating Station and the Cambridge Peaking facility are unknown. The capital and O&M associated with the Nanticoke and Cambridge projects are not known at this time.

For 2013, Union has included $1.8 million of capital related to the Lambton Generating Station.

Union is not aware of any proposals to replace the "Oakville project".

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit C1, Tab 1, Updated

a) Please update the general service forecast to reflect the latest forecasts available for the explanatory variables, actual 2011 data, total bill amounts based on the most recent Board-approved delivery and gas supply commodity rates and the DSM plan that results from the EB-2011-0327 proceeding. Please provide the total forecast throughput for 2013 in the same level of detail as shown in Table 1 and the total billed customer forecast for 2013 in the same level of detail as shown in Table 3.

b) Please provide the equations and regression statistics used in (a) above that include actual 2011 data.

c) Please provide all the historical and forecast data used in the updated forecast in an live Excel spreadsheet.

Response:

a) The general service forecast was updated to reflect all available 2011 actual data. The results are tabled below.

The updated demand forecast incorporates the following analyses and revision to assumptions for the demand driver variables:

1. The NAC forecast regression equations for residential , commercial and industrial markets were all updated to include 2011 actual data;
2. The Residential demand variables that were updated included: Weather, FEI variable, PPH variable, Total Bill Amounts, and the DSM Plan NAC Impacts to reflect the 2012 2013 Settlement Agreement;
3. The Commercial demand variables that were updated included: Weather, Harvest Variable and the DSM Plan NAC Impacts to reflect the 2012 2013 Settlement Agreement;
4. The Industrial demand variables updated included: Weather, FX rate, Fuel Oil Price and the DSM Plan NAC Impacts to reflect the 2012 2013 Settlement Agreement;
5. The weather normal was updated and reset to incorporate the 2011 actuals; this eliminates the three year regulatory lag present in the evidence forecast and restores a 2 year regulatory lag; and,

6. The billed customer forecast estimates for the residential, commercial and industrial markets were not changed even though:
    a) The provincial housing start estimates obtained from the March 2012 consensus for 2013 are lower, and customers may be over stated by 1,500 billed customers; and,
    b) The number of billed customers in the industrial market over the past four years have declined by an average of 55 customers per year and the forecast assumes an increase of 12 customers in 2013 over 2010 – a potential gap of about 120 customers.

The table below shows that the impact of the update scenario is an increase in total throughput volumes. Total throughput volumes are 10.8 million cubic metres or 0.2% above the original evidence for the year 2013. This difference is not material.

This comparative forecast scenario did not incorporate two major factors mentioned above related to the 2013 housing start estimates and the strong trend regarding customer losses in the industrial market. The impact of these two factors would lower total throughput in 2013 by about 16.5 million cubic metres. The industrial energy consumption that is lost is the major portion and is estimated at 10.8 million cubic metres. Should these factors occur, the demand forecast shifts back to slightly below the original evidence level for the test year.

TOTAL 2013 THROUGPUT VOLUMES: UPDATED FORECAST SCENARIO FOR 2011 ACTUALS

(in 10^3 m^3)

Rate & Service Customer Class	Total Throughput Original Frcst-2013	Change in volume due to DSM Plan	HFO & FX Rate Effect	Weather Normal	NAC	Total Throughput Updated Frcst-2013	% Diff
Residential Rate M1	2,094,387	5,445		(11,823)	16,623	2,116,456	1.1%
Residential Rate M2	3,603			(20)	42	3,645	1.2%
Residential Rate 01	629,860	378		(3,346)	5,035	635,273	0.9%
Commercial Rate M1	713,366	(71)		(3,596)	(37,554)	675,740	-5.3%
Commercial Rate M2	605,387	(2,543)		(3,213)	42,492	645,336	6.6%
Tobacco Rate M1	9,979			-	594	10,573	6.0%
Tobacco Rate M2	1,956			-	2,767	4,723	141.5%
Commercial Rate 01	225,737	1,106		(1,220)	650	227,493	0.8%
Commercial Rate 10	227,264	841		(1,193)	(6,493)	221,612	-2.5%
Industrial Rate M1	58,679	(651)	(235)	(270)	(1,048)	56,744	-3.3%
Industrial Rate M2	345,706	(3,837)	(1,385)	(1,300)	(7,883)	332,601	-3.8%
Industrial Rate 10	38,874	(432)	(156)	(135)	(951)	37,336	-4.0%
Industrial L.I.B, Rate 10	50,130	(556)	(201)	(178)	(1,171)	48,203	-3.8%
Total Throughput Vol.	5,004,929	(320)	(1,977)	(26,294)	13,103	5,015,735	0.2%
Change						10,806	
By Service Class							
Residential	2,727,851	5,823	-	(15,189)	21,700	2,755,374	1.0%
Commercial	1,783,689	(667)	-	(9,222)	2,455	1,785,478	0.1%
Industrial	493,389	(5,477)	(1,977)	(1,883)	(11,052)	474,884	-3.8%

b) Please refer to the 2013 REGN RESULTS 2011 UPDATE Apr_2012 Excel files for the updated regression results.

c) Please refer to the 2013 REGN DATA FILE_Apr 2012 for the updated forecast variable data.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit C1, Tab 2, Figure 1, Updated

Please explain the reduction in the forecast for power generation in 2012 and 2013 as compared to both the growth experienced between 2007 and 2011 and the level shown for 2011.

Response:

The net growth in power generation revenues from 2007 to 2011 of $6.04 million primarily reflects the development of three Clean Energy Supply ("CES") gas fired generation projects in Union's franchise area offset by a reduction in Lennox and the four South Rate T1 power generators. The 2011 versus 2007 variance by components is as follows:

	Revenue ($ Millions)	Volume (10^6)
North NUGs	0.33	129.4
South Rate T1	(0.66)	(256.4)
Lennox	(4.38)	(161.1)
CES	10.74	660.3
Total	6.04	372.3

The 2012 forecast is less than 2011 actuals by approximately $3.12 million. A contractual change relating to minimum annual volume and decreased customer consumption expectations drove the revenue reduction for the North NUGs. Changes in South revenue were also driven by forecast changes based on customer discussions regarding their consumption expectations. No Rate 25 volumes were forecast for Lennox or authorized overrun for the CES group. The variance for 2012 forecast revenue versus 2011 actuals is as follows:

	Revenue ($ Millions)	Volume (10^6)
North NUGs	(0.11)	(74.1)
South Rate T1	(0.29)	59.2
Lennox	(0.93)	(31.9)
CES	(1.79)	(200.0)
Total	(3.12)	(246.8)

*South Rate T1 excludes the 3 CES Rate T1 customers.

The 2013 forecast is less than 2011 actuals by approximately $3.26 million. The net incremental revenue decrease of approximately $100,000 from the comparison of 2011 actuals to 2012 forecast is driven by relatively small forecast variances in both North and South accounts in addition to one customer who expects to change rate classes in 2013. The variance for 2013 forecast revenue versus 2011 actuals is as follows:

	Revenue ($ Millions)	Volume (10^6)
North NUGs	(0.25)	(105.6)
South Rate T1	(0.35)	59.2
Lennox	(0.93)	(31.9)
CES	(1.73)	(195.0)
Total	(3.26)	(273.3)

*South Rate T1 excludes the 3 CES Rate T1 customers.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Ref: Exhibit A2, Tab 1, Schedule 1, page 6

Please provide all presentations made to the Applicant's executive team or its Board of Directors in 2011 that include a forecast of the 2012 ROE. Please include the full presentations in which the ROE is included. Please provide an explanation of any material changes to the forecast of 2012 ROE during the 2011 year.

Response:

Union has provided the initial executive presentation (July 2011) and the final executive presentation (September 2011) respecting its 2012 forecast. Union has redacted information regarding its unregulated business.

Please see Attachments 1 and 2.

The initial forecast presentation made to Union's executive team in 2011 including a forecast of the 2012 ROE shows a ROE of 6.89%. The presentation of the final 2012 forecast shows a ROE of 9.31%. The main drivers for the increase of 2.42% are:

- Transportation revenue increase from FT RAM credits;
- O&M reductions;
- Unidentified distribution contract market opportunities; and,
- Net fuel cost reductions.

uniongas

Filed: 2012-05-04
EB-2011-0210
J.O-4-15-1
Attachment 1

Union Gas Limited
Earnings Before Interest and Taxes
CDN$Millions

Particulars	2010 Actual	2011 Budget	2012 Forecast	2013 Forecast	2011 6+6 Outlook	2012 Budget	2013 Forecast	2014 Forecast
Operating Revenue								
Distribution Margin	$ 703.7	$ 698.5	$ 676.1	$ 683.8	$ 710.5	$ 698.2	$ 690.4	$ 695.8
S&T	[redacted]				[redacted]			
Other Revenue	28.9	36.9	28.8	28.8	31.5	28.0	27.9	28.0
Earnings Sharing	(4.1)	-	-	-	(6.3)	-	-	-
Stretch / Deficiency	[redacted]				[redacted]			
Total Operating Revenue								
Operating Expenses								
Operating & Maintenance Expense	363.4	371.5	392.3	398.6	374.4	391.9	389.5	398.4
Depreciation and Amortization	198.8	205.7	214.4	222.9	205.6	214.2	205.2	217.1
Taxes Other than Income Taxes	66.8	64.7	66.2	67.7	63.0	64.0	65.0	66.0
Total Operating Expenses	629.0	641.9	672.9	689.2	643.0	670.1	659.7	681.5
HTLP Income / (Loss)	[redacted]				[redacted]			
Other Income / (Loss)								
Earnings Before Interest, Taxes (EBIT CDN GAAP)	[redacted]				[redacted]			
US GAAP Adjustment	[redacted]				[redacted]			
Union Gas EBIT (US GAAP)								
[redacted]								
Gas Distribution EBIT (US GAAP)								
Earnings Sharing								
Rate Base	$ 3,550.5	$ 3,574.3	$ 3,689.7	$ 3,782.5	$ 3,563.2	$ 3,691.6	$ 3,763.7	$ 3,915.7
Utility ROE (before Earnings Sharing)	10.99%	9.84%	9.86%	9.70%	10.81%	6.89%	5.52%	4.22%
Benchmark ROE	8.54%	8.10%	8.10%	8.10%	8.10%	8.10%	9.75%	9.75%
Pre tax earnings gap to 200 bps (50/50 sharing)	$ -	$ 4.6	$ 4.2	$ 7.3	$ -	$ 57.8		
Pre tax earnings gap to 300 bps (90/10 sharing)	$ 10.2	$ 22.5	$ 22.2	$ 25.6	$ 5.3	$ 75.8		

[redacted]

Union Gas Limited
Capital Expenditures
CDN$Millions

Particulars	In Service Date	2010 Actual	2011 Budget	2012 Forecast	2013 Forecast	2011 6+6 Outlook	2012 Budget	2013 Forecast	2014 Forecast
Expansion									
Storage Deliverability Projects	Nov-08	$ 0.2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dawn Trafalgar Phase III (Bright)	Nov-08	-	-	-	-	0.3	-	-	
[redacted]									
Delta Pressure Phase IV	Nov-09	0.1	-	-	-	-	-	-	-
Dawn to Dawn TCPL Export	Dec-10	1.6	-	-	-	1.2	-	-	-
[redacted]									
Tecumseh Sombra Line Extension	Nov-12	(0.2)	-	-	-	0.2	-	-	-
Marcellus-Kirkwall	Nov-12	-	4.6	0.1	-	-	4.7	0.1	-
Oakville Power Generation Station	Nov-12	-	2.0	37.2	0.1	-	-	-	-
[redacted]									
Thunder Bay Power Plant	Nov-13	-	0.2	1.3	25.2	0.6	0.9	28.0	0.2
[redacted]									
Lambton Power Plant	Nov-14	-	0.2	0.6	14.7	0.2	-	1.8	25.2
Parkway West	Nov-14	-	-	-	-	-	21.7	80.0	120.0
[redacted]									
Nanticoke Power Plant	N/A	-	-	-	-	0.1	-	-	-
Red Lake	N/A	0.1	-	-	-	-	-	-	-
Project Pre-spend	N/A	-	2.0	2.0	2.0	1.9	2.0	2.0	2.0
Overheads		0.2	1.7	1.8	1.8	1.7	2.2	2.2	2.2
Total Expansion		[redacted]				[redacted]			
Maintenance									
Distribution New Business		33.2	39.3	40.0	40.7	39.3	51.4	50.5	52.0
Distribution Other		58.0	74.0	77.6	76.3	74.0	72.4	76.3	79.9
Total Distribution		91.2	113.3	117.6	117.0	113.3	123.8	126.8	131.9
Transmission		18.9	44.5	17.9	17.3	44.5	23.5	34.0	24.7
Storage		19.2	37.4	16.1	13.2	37.4	14.3	10.8	7.1
General		12.1	12.5	13.1	12.0	12.5	11.9	9.8	21.1
Overheads		61.6	50.9	51.1	52.1	50.9	52.8	52.7	52.7
Total Maintenance		**203.0**	**258.6**	**215.8**	**211.6**	**258.6**	**226.3**	**234.1**	**237.5**
IT		22.0	25.5	23.9	23.0	23.2	25.6	28.3	26.1
Total Maintenance, IT and OH		**225.0**	**284.1**	**239.7**	**234.6**	**281.8**	**251.9**	**262.4**	**263.6**
Total Union Gas Capex		[redacted]				[redacted]			
[redacted]									
Total Consolidated Union Gas Capex		[redacted]				[redacted]			
[redacted]									
Total Gas Distribution Capex		[redacted]				[redacted]			

unionGas
A Spectra Energy Company

Union Gas Limited
Earnings Before Interest and Taxes
CDN$Millions

Particulars	2011 Actual	2012 Budget	2013 Forecast	2014 Forecast
Operating Revenue				
Distribution Margin	$ 729.5	$ 716.0	$ 702.0	$ 709.1
S&T	[redacted]			
Other Revenue	34.2	26.2	27.9	28.0
Earnings Sharing	(16.3)	-	-	-
Stretch / Deficiency	[redacted]			
Total Operating Revenue				
Operating Expenses				
Operating & Maintenance Expense	378.4	384.9	390.2	397.4
Depreciation and Amortization	204.3	213.0	206.2	218.8
Taxes Other than Income Taxes	62.0	64.3	65.4	66.8
Total Operating Expenses	**644.7**	**662.2**	**661.8**	**683.0**
HTLP Income / (Loss)	[redacted]			
Other Income / (Loss)				
Earnings Before Interest, Taxes (CDN Reporting)	[redacted]			
US Reporting Adjustment	[redacted]			
Union Gas EBIT (US Reporting)				
[redacted]				
Gas Distribution EBIT (US Reporting)				
Earnings Sharing				
Rate Base	$ 3,572.3	$ 3,685.3	$ 3,761.2	$ 3,916.9
Utility ROE (before Earnings Sharing)	11.60%	9.31%	7.13%	6.28%
Benchmark ROE	8.10%	7.67%	9.58%	9.58%
Pre tax earnings gap to 200 bps (50/50 sharing)	**$ -**	**$ 6.4**		
Pre tax earnings gap to 300 bps (90/10 sharing)	**$ -**	**$ 24.4**		

[redacted]

Union Gas Limited
Capital Expenditures
CDN$Millions

Particulars	In Service Date	2011 Actual	2012 Budget	2013 Forecast	2014 Forecast
Expansion					
Dawn Trafalgar Phase III (Bright)	Nov-08	$ 0.1	$ -	$ -	$ -
Dawn to Dawn TCPL Export	Dec-10	0.2	-	-	-
Tecumseh Sombra Line Extension	Nov-12	0.2	-	-	-
Marcellus-Kirkwall	Nov-12	0.1	4.7	0.1	-
[redacted]					
Thunder Bay Power Plant	Nov-13	0.2	0.9	28.0	0.2
[redacted]					
Lambton Power Plant	Nov-14	-	-	1.8	25.2
Parkway West	Nov-14	0.2	21.7	80.0	120.0
[redacted]					
Nanticoke Power Plant	N/A	0.3	-	-	-
St. Clair Power (Invenergy)	N/A	0.1	-	-	-
Project Pre-spend	N/A	-	2.0	2.0	2.0
Overheads		0.1	2.2	2.2	2.2
Total Expansion		[redacted]			
Maintenance					
Distribution New Business		41.9	51.4	50.5	59.7
Distribution Other		71.9	72.4	76.3	74.5
Total Distribution		113.8	123.8	126.8	134.2
Transmission		44.8	23.5	34.0	18.6
Storage		35.0	14.3	10.8	10.8
General		15.4	11.9	9.8	20.8
Overheads		52.7	52.4	52.2	53.9
Total Maintenance		**261.7**	**225.9**	**233.6**	**238.3**
IT		23.0	25.5	28.3	26.1
Total Maintenance, IT and OH		**284.7**	**251.4**	**261.9**	**264.4**
Total Union Gas Capex		[redacted]			
[redacted]					
Total Consolidated Union Gas Capex		[redacted]			
[redacted]					
Total Gas Distribution Capex		[redacted]			

Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2011-0210

VOLUME: 1

DATE: July 10, 2012

BEFORE:

Marika Hare	Presiding Member
Paul Sommerville	Member
Karen Taylor	Member

MR. AIKEN: Then I will ask the question again.

Has Union in this proceeding investigated the other six methodologies that Enbridge has reviewed?

MR. GARDINER: We did not look at the six that Enbridge investigated. We recognized that in 2004 we looked at numerous methodologies. In 2004 we got a blended methodology, which sort of indicated to Union Gas that the concept of the 20-year declining trend was a valid one.

From 2004 to 2007, the Board in its decision allowed Union Gas to increase the percentages to 55/45, and we did so.

In this rate case, we have an extra eight years since 2004. We got to the bottom line: Blend versus 20-year trend, which one is more accurate? The 20-year trend.

MR. AIKEN: So I take it from that response you did not investigate the other two methodologies that the Board approved for Enbridge in 2007?

MR. GARDINER: I did not.

MR. AIKEN: Okay. Now, how did Union land on a trend methodology that used 20 years? In other words, why not ten? Why not 18?

MR. GARDINER: This comes back to the work that was done for the 2004 rate case. Mr. Steven Root, who is one of the external consultants, had advised us to look at a 20-year period. We had examined a 30-year declining trend.

And based on the evidence -- based on the consultation, I should say, from Mr. Root, 20 years was selected.

interpreting it.

MR. WOLNIK: Okay. And do you provide the commodity with that, or without? Is it either way?

MS. VAN DER PAELT: It is either way. Most customers provide their own commodity.

MR. WOLNIK: Thank you. In the south, T1 is the predominant service that generators use; is that right?

MS. VAN DER PAELT: That would be correct.

MR. WOLNIK: Thank you. That is also a demand charge based product?

MS. VAN DER PAELT: That's correct.

MR. WOLNIK: Then there is also a commodity charge associated with all of those services; right?

MS. VAN DER PAELT: That's right.

MR. WOLNIK: Okay. So can you describe how you actually formulate your forecast for power customers?

MS. VAN DER PAELT: So for our power customers, it really depends on which rate class they're in and how long they have been on the system.

For our northern utility generators and most of our southern customers, who have been with us quite a long time, we do look at their three-year historic average. We then take the historical data, as well as what the average would produce to the customer, and ask them if this is equivalent to where they think they will be operating in the year coming up.

So recall that we would have done this in May of 2011 asking them how they were going to operate in 2013 for this point.

Then for the really large power customers who are pure peak shavers, we actually directly go to them with the historicals and ask them for their input. There is not as much data on some of them, so we ask them if they're going -- what services they think they're going to be using, and it really comes around to what is their monthly volume that they will be using.

MR. WOLNIK: So did I understand you said you actually took data from 2007?

MS. VAN DER PAELT: It would be three years. So it would be -- for 2013, we would have looked at '9, '10 and 2011. 2011 would have been a partial year in that.

MR. WOLNIK: So a little bit dated information, then?

MS. VAN DER PAELT: Right. But in terms of making the filing, yes.

MR. WOLNIK: Thank you. Do you ever take into account the IESO forecast for -- take that into account in your forecasts?

MS. VAN DER PAELT: No, we don't.

MR. WOLNIK: Okay. You are aware that the IESO is the provincial company that is responsible for coming up with aggregated forecasts of power demand?

MS. VAN DER PAELT: Yes, I am.

MR. WOLNIK: So why wouldn't you take that into account?

MS. VAN DER PAELT: The IESO forecast looks at the total forecast on an 18-month outlook. It doesn't necessarily go by what fuel source they're going to be dispatching at that point in time, and it doesn't differentiate between sort of what could be base and what could be a peak load. Most of our customers are peak.

MR. WOLNIK: Would you think, if it shows an increasing demand in the province, that that might be a factor you would take into account? Might it be important in your forecast?

MS. VAN DER PAELT: Well, it would depend where we are in terms of our current generation. Currently our base load generation fleet is above what we need as a base load.

So increasing the base may just say that your base generation fleet is going to run more. It may not reflect what the natural gas plants are going to do.

So it really would depend on where the fleet is. We would go to the customers and ask them, because they're the ones dealing with the IESO and how they're going to be dispatched, and ask them what their input is in terms of if this has any impact on their forecast.

MR. WOLNIK: So where they sit in the fleet would be important. If there was declining -- if there was other declining power generation types, that would be a factor you would also take into account?

MS. VAN DER PAELT: What would be important is to how they're dispatched by the IESO, yeah.

MR. WOLNIK: Okay. So your point is an increasing demand in the province is not an important issue to take into account?

MS. VAN DER PAELT: No. My point is an increased demand in the province doesn't reflect an increase in demand in natural gas generation.

MR. WOLNIK: Your point is you have to take into account other generation and where it sits in the stack?

MS. VAN DER PAELT: That's correct, and the other production that is being put into service, such as wind and others.

MR. WOLNIK: So if there was other declining forms of generation, there could be more gas-fired generation, or if there was increasing generation below that, there could be less? Is that fair?

MS. VAN DER PAELT: It could be more or less, yes.

MR. WOLNIK: Okay, thank you.

MS. HARE: Can I just interrupt for a second, because in your response to Mr. Wolnik, you made it clear. You said, for large customers that have been with Union for a long time, you look at the last three years.

What if somebody -- what do you do when somebody hasn't been with you three years?

MS. VAN DER PAELT: So, Madam Chair, it is the mid-size customers who have been with us the longer time.

MS. HARE: Yes. The question really is you said they have been with you for a long time.

MS. VAN DER PAELT: Those who have relatively new, we go to them and talk to them about -- we go to all of our customers, but we don't have any historical numbers to take to them to say, This is what your trend has looked. So we

MS. VAN DER PAELT: That was the reason Thunder Bay was converted, yes.

MR. WOLNIK: My question was a little bit broader. I understand that, but all of the coal plants would be shut down by 2014; is that right?

MS. VAN DER PAELT: Right. But we don't have a ministerial directive suggesting the other two will be converted to gas at this point in time.

MR. WOLNIK: I wasn't necessarily talking about conversion to gas. I am just talking about off coal.

MS. VAN DER PAELT: There is definitely an off-coal strategy in the province, yes.

MR. WOLNIK: So some of the gas plants or all of the gas plants were built in the last few years to replace that coal-generating capability?

MS. VAN DER PAELT: The destruction of demand, I think as evidenced on the IESO website, would also suggest that you didn't even need this capacity to be replaced at this point in time, because demands are much lower than what the peaks were sort of two, three years ago.

MR. WOLNIK: Can you provide more detail on that? What do you mean?

MS. VAN DER PAELT: Well, if you go to the IESO website and look at our peak demands, you know, in 2006 and 2007 and what we had in terms of a fleet that would be used in order to deliver that electricity supply, and then you look at the peak demands now, you could actually take fleets out of service and still meet your daily demands.

MR. WOLNIK: Right. So you could take some of the most inefficient units out, but you still have an aggregate amount of energy that needs to be produced, whether it be from gas or coal?

MS. VAN DER PAELT: Gas or coal or hydro, yes.

MR. WOLNIK: Right, okay. Thanks. Can I take you to your evidence now, C1, tab 2, page 7?

MS. TAYLOR: Sorry, before we leave that particular slide, will you be addressing in your cross the effect on gas demand of intermittent generation?

MR. WOLNIK: Probably, yes. I mean, I'll probably do it from a slightly different angle, but if you have questions on that, feel free to --

MS. TAYLOR: Well, I was somewhat taken by surprise with your answer, given the fact that the fuel mix in the province has changed and we have significant intermittent resources, which also have certain implications for the use of highly responsive generation assets, with the closure of the coal, that that role will then fall to gas.

It doesn't seem to be entering the psyche for potential gas use generally, or specifically to those plants in your service area, which is somewhat curious.

So if you are going to address it in your cross, I will drop this now.

MR. WOLNIK: No, go ahead.

MS. TAYLOR: Otherwise, perhaps you can answer how the answer you just gave stands, in view of the fact the fuel mix has changed and involves other resources.

MS. VAN DER PAELT: So in the time frame that we have here, which is up to 2013, because there's been such a demand destruction, although there has been intermittent -- like, wind has come on and other things, we haven't seen a big impact on the gas fleet. It is really in the period from 2015 to 2019 that is uncertain as to what that will look like.

MS. TAYLOR: Okay.

MS. VAN DER PAELT: So the effect hasn't been realized at this point in time.

MS. TAYLOR: Okay.

MR. WOLNIK: So looking at your evidence, table 1, and just focussing on line 1, which is the power generation volumes, again, we see -- look comparing 2011 throughput volumes to 2013. We're seeing a decline from 2,464 106 m3 to 2,189 106 m3, or about 11 percent.

MS. VAN DER PAELT: Correct.

MR. WOLNIK: And I noticed that this excludes MAV volumes; is that right? There is a footnote here that says that, so...

MS. VAN DER PAELT: That would be correct.

MR. WOLNIK: Can you just tell me, MAV is more of a billing issue, right, that additional charge kicks in if the particular customer doesn't use the MAV volume; is that right?

MS. VAN DER PAELT: Right. If a customer doesn't consume a minimum annual volume in the contract, there is a true-up to the amount that the minimum annual volume would have generated.

MR. WOLNIK: That would be done at the end of the year, would it?

MS. VAN DER PAELT: At the end of the contract cycle.

MR. WOLNIK: If there was an additional charge, it would show up. Even though there may be an increase in sort of deemed volume used, that wouldn't show up as an actual -- as part of the actual consumption? It would just be an additional charge?

MS. VAN DER PAELT: It would just be -- right. The volumes would be what they are on an actual basis, and the charge would be the revenue achieved.

MR. WOLNIK: Do you know if you have had to render those charges through this time frame to any of the power customers?

MS. VAN DER PAELT: I don't know, John. Sorry, Mr. Wolnik.

MR. WOLNIK: Okay. You talked about the Thunder Bay volumes of 5,000, 106 m3. Are they in this forecast?

MS. VAN DER PAELT: The commissioning volumes would be in the forecast, and the revenue associated with November and December.

MR. WOLNIK: So the 2,189 includes that 5,000?

MS. VAN DER PAELT: Yes, it would.

MR. WOLNIK: Okay. Can we go to J.C-3-2-2, the second page, the lower table there? This looks at the 2013 forecast compared to 2011 actuals. You show here by these various categories a reduction in volume.

I just want to focus on the volumes for now, just a reduction in the volumes by category. So I am just trying to understand this reduced forecast in light of -- we have talked about this 2,800 -- sorry, there is one issue we didn't talk about. It is sort of highlighted in this table.

Let's just chat about that first. That is the Lennox plant. You did talk about peakers, and I appreciate that Lennox may be a bit of a unique generating facility where - that would be one of the peakers; right?

MS. VAN DER PAELT: That's correct.

MR. WOLNIK: And that has used a lot of gas in the past, but you are forecasting no consumption there basically for 2012; is that right?

MS. VAN DER PAELT: There is just a minimal base load consumption.

MR. WOLNIK: Okay. And the reason is, presumably, it has one of the highest heat rates, is that right, within the gas fleet?

MS. VAN DER PAELT: That's right.

MR. WOLNIK: The heat rate is really a measure of sort of the inverse -- it is an inverse efficiency index; right? The higher the heat rate, the less efficient it is?

MS. VAN DER PAELT: It is one of the more expensive units to dispatch.

MR. SOMMERVILLE: Some of the newer units, the CES units, for instance, or combined cycle, they would have a much lower heat rate and so they would be dispatched first, most likely?

MS. VAN DER PAELT: There are a lot of things that go into the IESO's determination of dispatch, but if you were just looking at heat rate, they would be first, the newer ones.

MR. WOLNIK: Thanks. So then just kind of looking at that table again, then, so we have talked about the 2,800 megawatts of less coal. Lennox, you are forecasting virtually very little consumption there.

We have talked about the contract demand volumes all staying the same and the MAVs for all plants staying the same.

So can you just sort of describe and explain, by these various categories, why you are seeing a reduction in these -- in the consumption by category?

MS. VAN DER PAELT: Just a question for you, Mr. Wolnik. So we're focussing on 2013; correct?

MR. WOLNIK: Right.

MS. VAN DER PAELT: Okay. So there are several things that are driving the decline in volumes on the power market.

Probably some of the larger ones would be that Lennox is forecasted at a lower number, based on the input provided from Lennox.

We have production at several of the NUGs that were forecasted offset by a few that were increasing. And the NUGs in themselves, along with one of the southern generators, is about a million reduction of the volume.

When you have a decline in volume, there is an associated decline in customer-supplied fuel. That would be about another 1.2 million of the revenue in that number is the decline in customer-supplied fuel.

MR. WOLNIK: When you say customer-supplied fuel, how does that impact this volume forecast?

MS. VAN DER PAELT: Well, your customer-supplied fuel is a function of your volume throughput.

MR. WOLNIK: So you require the customer to deliver a certain percentage of the throughput on a daily basis?

MS. VAN DER PAELT: So customer-supplied fuel, in order to calculate the fuel ratio on Union Gas's system, we have to look at all of the volumes that are moved through the system, both Union-supplied fuel volumes and customer-supplied, so all of the volumes together, in order to establish what is total throughput and what is an appropriate fuel ratio.

To do this, we look at the customers who have contracted to supply their own fuel, and we have to commoditize that, along with the Union-supplied fuel, in order to come out with a fuel ratio and equivalent revenue point.

So it is built in as a revenue line item in the contract market forecast, and there is an offset in the cost of gas.

MR. WOLNIK: So roughly what is your fuel percentage? I don't need precise numbers. Is it one percent, two percent, five, 0.2?

MS. VAN DER PAELT: Roughly half a percent.

MR. WOLNIK: Half a percent? So if I am a customer in the north and I deliver more gas on TransCanada, so I would deliver 100.5 percent of whatever my requirements are, and I would consume 100 percent, that would be -- the difference would go to Union, then.

So how and why do you convert that into a revenue?

MS. VAN DER PAELT: Well, this is the fuel on Union's system, not on TransCanada's system. So this is the fuel used to move gas along Union's pipelines.

And in order to establish a fuel ratio, you have to look at the total throughput, and the only way to do that is to commoditize the fuel that is provided, in order to come up with what is an appropriate ratio.

So this is about sort of the level of my expertise on fuel ratio calculations, but I can assure you that the revenue associated with customer-supplied fuel, the equivalent revenue is embedded in the forecast and the offset is in cost of gas.

MR. WOLNIK: So if I am a northern customer in -- someplace in one of the northern communities, North Bay, and if I have a power plant and I deliver gas off the TransCanada system into your distribution area, you would need the fuel for your franchise system. I understand that. But you don't have compressors on your distribution network; is that right?

MS. VAN DER PAELT: Right. This fuel would be associated with the southern side of our portfolio.

MR. WOLNIK: Okay. So -- but my example was for a northern customer.

MS. VAN DER PAELT: Right. So the question we had in terms of where the variances were -- back to the IR response -- in those total variances, a portion of that, about a million of the 3.26, a million two, is related to customer-supplied fuel, which would be in the south.

MR. WOLNIK: So first focussing on the north, though, the northern NUGs?

MS. VAN DER PAELT: The northern NUGs, the reduction on the NUGs?

MR. WOLNIK: Again, I'm just focussing on volume.

MS. VAN DER PAELT: Yes.

MR. WOLNIK: I think we had a kind of -- the side discussion is really dealing with why you attach some sort of revenue associated with that. I'm --

MS. VAN DER PAELT: No, there is no fuel impact on the northern NUGs. The northern NUG is actually a MAV reduction, for one customer who has changed their forecast, which is reflected due to lower production forecast. So it is a contractual change.

MR. WOLNIK: Let's kind of go back to J.C-3-13-1, then, because we -- I spent a fair bit of time going through that, because you don't show a change in MAVs.

MS. VAN DER PAELT: You are correct. I will have to go back and verify this.

MR. WOLNIK: Okay.

MR. MILLAR: Is that an undertaking?

MR. SMITH: Yes, we will do that.

MR. MILLAR: J1.6. Can we just have a clear recitation of what the undertaking is for?

MR. WOLNIK: I guess to reconcile the -- I guess the change in volume due to MAV reductions, compared to the J.C-3-13-1 that shows no reduction.

UNDERTAKING NO. J1.6: TO RECONCILE CHANGE IN VOLUME DUE TO MAV REDUCTIONS COMPARED TO J.C-3-13-1 THAT SHOWS NO REDUCTION.

MS. VAN DER PAELT: Would it be volume or revenue?

MR. WOLNIK: We're just talking volume here. That's all.

MR. MILLAR: Thank you.

MR. WOLNIK: We will talk about revenue -- I'm sorry, we are talking revenue. Pardon me.

MS. VAN DER PAELT: You -- yeah, I thought it was a revenue question.

MR. WOLNIK: Yes, yes. MAV is revenue, not volume.

Going down the list here, again, so NUGs, the 105.6, 10-6 m3 reduction and the related $0.25 million of revenue, can you explain -- what are the reasons that reduction of 105.6, 10-6?

MS. VAN DER PAELT: So that reduction would be based on the forecast that the customer has provided.

So as I mentioned earlier with the NUGs, we look at a three-year historical average, and we take those to the customers and compare that to what they believe will be occurring in the upcoming forecast year.

So when you look at the three-year average, some customers -- four of them we actually saw a decrease in terms of their average, and three of them we saw an increase, and the offset is that difference of 105.

MR. WOLNIK: So is this their forecast or is this your forecast?

MS. VAN DER PAELT: No, we prepare the forecast and take it to the customer, then get the customer's input on that, and then have them agree or disagree and make changes to it as they see fit.

MR. WOLNIK: How do you think the customers, then, take into account this 2,800 megawatts of reduced coal-fired generation and the fact that you are forecasting Lennox to be zero? Do you think they take that into account?

MS. VAN DER PAELT: I am not sure what they do, John - sorry, Mr. Wolnik.

MR. WOLNIK: So do you modify at all? Do you look at the whole picture after you get them all in and say: You know what? Given that we've got this decision to drop out 2,800 megawatts of coal, given that we now know that OPG is telling us that they're going to consume zero at Lennox, maybe, maybe we should boost up these other forecasts?

MS. VAN DER PAELT: Well, we look at what the customer tells us that they believe is their forecast, because it is really in the customer's self-interest to have an appropriate forecast.

Should they think they're going to consume higher volumes, that would result in an increased contract demand and an increased charge, but they would then not have interruptible or overrun rates.

If they thought they were going to consume less, it would reduce -- reduce their charges.

So the customers have a self-interest in making sure their forecast is an accurate representation of what they believe they will use.

MR. WOLNIK: Again, going back to J.C-3-13-1, I don't see any change to the contract demand level. That's what you have told us.

MS. VAN DER PAELT: But this is -- these volumes may not have affected their contract demands.

MR. WOLNIK: So these are just commodity-based. So these would be whether they dispatched more or less on the basis of their existing CD?

MS. VAN DER PAELT: That is what the customers told us, based on what they thought they would be consuming, yes.

MR. WOLNIK: So I go back to my original question, then. So how do you think the customers take into account the fact there has been a reduction of 2,800 megawatts of less coal, and the feedback you've got from OPG on Lennox not running?

MS. VAN DER PAELT: I am not privy to how the customers establish their volumetric forecasts. We take in their historical; they then provide input as to whether they think it is reasonable or not, but I am not sure what you employed these other three different methods, the 30-year average, the 20-year trend -- which is what you are proposing -- and the 55-45 blend, which is the current method.

So you are getting -- what you are getting there is, as I understand it, what those -- what the forecast of numbers for each of those years, the actuals for which are in column 1, would have been had you used those three forecasting methods; is that right?

MR. GARDINER: That is correct.

MR. BRETT: Okay. Now, what I would like you to do is to focus on columns 3 and 4, which is the 20-year trend, column 3, which Union is proposing and the 55-45 blend, the currently approved method.

If you will -- I would like you to compare, and I am going to compare it for you and give you a chance to react to it, but I want to compare, on the one hand, the 20-year trend number for each year to the actual, and on the other hand, the 55-45 number -- that is to say the forecast derived from using the current plan -- with the actual.

And if I do that, what I find is that the forecasted degree-days -- this is going from the years 1985 to 2011, so I make that to be 26 years. I could be out one, but I think it is 26 years of actual data. And what I get from this is that the -- that using the 55-45 blend and comparing it with the 20-year trend and then comparing each of those to the actuals, the 53-45 blend was closer to the actual number in 14 of the 26 years that are covered by the

20-year trend.

Would you agree with that, subject to check?

MR. GARDINER: Subject to check, yes.

MR. BRETT: Okay. So that the -- so that basically if you compare that with what you have stated below, below you say in section (c), little (c):

> "Please note that the 20-year declining trend produces weather normal estimates that in most years are closest to the actual weather. This is especially true in 2011."

But that isn't the case, really, is it, from what I have just shown you? It isn't the case that in most years the 20, 20 trend is closer to the actual than the 55-45; it is the other way around, subject to check?

MR. GARDINER: Okay. Subject to check.

Mr. Brett, two charts I would like to bring to your attention. One is in the evidence, Exhibit C1, tab 5, page 3 of 7.

MR. BRETT: So this is your --

MR. GARDINER: Weather evidence.

MR. BRETT: Yes, right. Well, I will... Okay, let me just turn that up. I am going to come to that. That is on page what?

MR. GARDINER: Three of 7.

MR. BRETT: Yeah. I have those charts, yeah.

MR. GARDINER: Then the other one is on -- it was a response to Mr. Aiken on J.C-2-2-1, page 7.

MR. BRETT: Right, all right.

MR. GARDINER: And at the top, there is the chart that shows the normal heating degree day comparison that we have been talking about. And the first chart has the comparison, and you can see that the small dashed blue line, those are your actuals.

The red line that goes through the path of those actuals is the 20-year trend, and the black line above that is the 55-45 blend. And the analysis indicates that when we prepared the weather evidence with a three-year lag, which is what is on page 3 of 7, you can see that the 20-year trend goes through the -- more through the middle of the data than does the 55-45. Yes, it does touch 14 points, but those were cold years.

If you go to the response on J.C-2-2-1, there we've gone to a two-year lag, because now -- this was part of the response for updating with the 2011 actuals.

And a similar situation is presented. The 20-year trend does go through the path of the actuals more in the centre than the current blend.

MR. BRETT: Okay. I have studied those charts, but I reiterate -- well, let me go on to a second point.

I was speaking, when I talked about closest -- which years were the 55-45 blend closer to the actual? I take it that that goes to the overall accuracy of the analysis of the 55-45 blend.

You have also raised and your evidence raises the issue of symmetry, what you call symmetry. And in that connection, I want to take you back to my table or Mr.

Aiken's table that he has asked for, J.C-2-2-1.

What I would like to suggest to you, again, subject to check, that if you look at -- and this is the second test I applied. If you look at whether or not -- you looked at the 20-year trend and the 55-45 blend and you looked to see in how many cases they were either over or under the actual, what you found was that, oddly enough, in one case they were exactly even - they each diverged by three HDDs - but in other cases they were split 13/13. No, I'm sorry. Let me correct that. That was my first cut at this. I then had to amend it.

Basically it is not very different, but what it shows is that the 20-year -- the 20-year trend line was over the actual by 16 years and under the forecast -- under the actual by ten years, and the 55-45 was over by 17 years and under by nine years.

So effectively both tended to over-forecast, but the - two things I guess arise from that for me. One is that 55-45 seems to me to be the more accurate of the two, and, as I say, they both seem to be equivalent in terms of their symmetry.

Do you have any comment on that, on that -- on the table?

MR. GARDINER: Well, you mentioned -- you raised the issue of accuracy, and this goes to the statistical analysis in the evidence, the original evidence on page 6 of 7 in C1, tab 5, and the accuracy measure is the root mean square error, and another one is the mean percent error.

And in that table 1, the root mean square error for the 20-year trend is 269 compared to 306. So the 269 is smaller, and this is telling us that over the period, if you do the -- run the estimate for the normal and compare it to the actual when it comes in, that the 20-year trend is more accurate.

If you do it as a mean percent error, it is 1.9 versus 5.1. That was in the original evidence. And in one of the interrogatory responses, this table was updated to include the 2011 actuals and similar results occurred. The root mean square error, the mean percent error -- mean percent error and the average variance from actual for the 20-year trend was smaller.

MR. BRETT: I understand that. I have read those numbers and I will come back to them in a moment, but I would take you back to the table that I quoted you.

The table clearly shows that over that 25-year period, the 55-45 blend was a closer approximation of the actual numbers than the 20-20 was.

I would comment in passing that this -- as I understand it, this is -- this is a short term -- we classify it as a short-term forecast. In other words, you are forecasting -- in any given year, you are forecasting the degree days for the following year and the year after that; right?

MR. GARDINER: In the case of the current evidence, given the lead times, we actually had a three-year lag, because the original evidence was up to 2010 and we were forecasting for 2013.

And when we did the update for 2011, we brought it back to a two-year lag, which is sort of -- was the sort of normal regulatory lag prior to 2004. But I will take your point that we're short term, whether it is two or three.

But the root mean square error is the accuracy measurement, and the mean percent error.

MR. BRETT: Well, I guess what I would --

MS. HARE: Before you continue, Mr. Brett, you are making a lot of statements and comments that probably are best dealt with in your submissions. So just ask your questions, please.

MR. BRETT: All right. Thank you. I was really putting the stuff in the tables to him so he could understand --

MS. HARE: I am reading what you said: I would comment in passing that this -- as I understand it, this is the short term -- we classify it as a short...

There is no question there. So please just focus on the question.

MR. BRETT: All right, thank you. Would you agree with me that from the point of view of -- if you look at page 6 of 7, which is your statistical -- well, let me go back a half a step.

Am I correct in assuming that, in your view, the key criteria for a forecasting methodology are you have five altogether, and the ones that you consider most important are accuracy and symmetry? Is that fair? I don't think you need to repeat your evidence, but if you just could tell me if it is "yes" or "no".

MR. GARDINER: Those are two. Sustainability, yes, and simplicity, also.

MR. BRETT: The three others where you had mentioned - did you mention three others, sustainability, simplicity and stability?

MR. GARDINER: Correct.

MR. BRETT: So you have five altogether?

MR. GARDINER: Yes.

MR. BRETT: And you will agree with me that both methods are simple?

MR. GARDINER: The trend method is more simple than the blend.

MR. BRETT: Why would you say that?

MR. GARDINER: Because I have to have two steps, two calculations. I have to do a 30-year average and then I have to bring in a 20-year trend, and come up with the blend.

MR. BRETT: Is the 30-year average a complicated calculation?

MR. GARDINER: No. But it is another set of numbers that one has to check and bring together.

MR. BRETT: All right. You would agree with me, would you, if you look at -- well, if look at table 1 on page 6, which you were just alluding to, that from a stability point of view, the 55-45 trend is the more stable, since the standard deviation of variance is lower? Would you agree with that?

MR. GARDINER: Yes. And that -- yes, and that is because it has a 30-year average in it. And a 30-year --

MR. BRETT: All right.

MR. GARDINER: And a 30-year average --

Mr. BRETT: From the - sorry, go ahead.

MR. GARDINER: The 30-year average, Mr. Brett, because it's a simple average and because it is 30 years, by construction is more stable.

MR. BRETT: Yes. So that means that another way of saying that, I guess, would be that it is -- it is -- on the stability criteria, it would rank ahead of the 20-year trend; is that fair?

MR. GARDINER: Yes, it does.

MR. BRETT: And the sustainability criteria, I take it -- what does that mean, from your point of view? Does that -- it...

MR. GARDINER: Sustainability means it can be reproduced. There is no issues in databases and collecting the information and --

MR. BRETT: Okay. So they're both equivalent. Would you agree with me that the two methods are both sustainable?

MR. GARDINER: Yes.

MR. BRETT: And then the -- I think we agreed that the two methods were -- were -- you agreed with me that both methods are relatively simple? Although you said, I think, that the trend was a little bit simpler; is that right?

MR. GARDINER: Yes, I will -- yes.

MR. BRETT: So that leaves us, then, with the issue of -- I don't know what the right -- the right word, I guess, is not "fairness" but it's -- symmetry.

Would you agree that the table that I pointed out to you at J.C-2-2-1 shows that the -- demonstrates that the symmetry of the two forecast methods is quite close?

MR. GARDINER: You know, I have difficulty with that, Mr. Brett, because when I go back to the charts, I don't see it.

I see the path of the 20-year trend going through the middle of the data, and that demonstrates the symmetry.

I see the 55-45 sort of clipping the tops of the high, colder years than the actual data.

And that is why to me, when I look at that data in the analysis, is that the 20-year trend is more symmetric and the root mean square and analysis indicates that too.

MR. BRETT: Let me go on, then. Okay. I would like to talk a little bit about the -- well, perhaps one other question on the methodology before moving on to the two types of forecasts. And this, perhaps, is trying to get at, a little bit, the underpinning idea behind the trend.

You -- am I right in that you used the trend that you developed, this trend line, to forecast future degree-days in the years -- the bridge year and the test year?

MR. GARDINER: That is correct, yes.

MR. BRETT: And then at the end of the test year, you

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FILE NO.:	**EB-2011-0210**

VOLUME:	**2**	
DATE:	**July 12, 2012**	
BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

Paul Gardiner, Previously Sworn
Cheryl Newbury, Previously Sworn
Sarah Van Der Paelt, Previously Sworn
CONTINUED CROSS-EXAMINATION BY MR. BRETT:

MR. BRETT: Thank you, Madam Chair.

Good morning, panel. Just a few questions. If you would -- panel, if you would turn up tab C1, tab 2, page 7, and that's -- I have a few questions on this, on the way in which the forecast is done and presented for these large 60 customers that we finished discussing the other day or started discussing the other day.

These are customers that account, as I understand your evidence, for 60 percent of volume throughput and 60 percent of revenue of the contract group of customers; correct?

MS. VAN DER PAELT: That's correct.

MR. BRETT: So it is a very significant chunk of revenue.

Now, my question is, really, you have this -- you discussed this a little bit last day. You have this group of 60 very large customers, and, as I understand it, you do individual forecasts for them, is that...

MS. VAN DER PAELT: That's correct.

MR. BRETT: And you do this by, first of all, making your own forecast, but then you go and discuss that in some detail with each of the -- each of the customers.

When I say "you", I don't mean you personally, but you must have a group of account executives that do this; is that right?

MS. VAN DER PAELT: That's right.

MR. BRETT: And so you get input from your customers, and then each of the account executives finalizes the forecast. Is that how it goes?

MS. VAN DER PAELT: We meet with our customers on an ongoing basis throughout the year to talk about their plans.

MR. BRETT: Right.

MS. VAN DER PAELT: When we present what their historical numbers would indicate would be an appropriate forecast, we then leave it with the customers for them to take it through their own process to determine if that is appropriate.

The account manager or the account executive, as you referred to them, then sits with the customer and confirms that this is the forecast that the customer is willing to back their contract parameters with, and then the contract is set for the next year according to those parameters.

MR. BRETT: Okay. So, in effect, the final decision to make the -- the final decision, if you like, is taken by you, by Union, but after close consultation with the customer. In other words, if there were a disagreement of some sort between you and the customer as to what the forecast should be, in light of the previous actuals and developments that had occurred since, I take it you have the final say in the sense that you are accountable for the forecast; is that right?

MS. VAN DER PAELT: To the extent -- we do have the final say for the forecast. To the extent the discussion with a customer resulted in contractual changes to their parameters, if the customer did not agree with them, they would not sign the contract. So the customer does have to agree with the resulting CD parameters and daily contract quantity parameters should they change as a result of the forecast. Those are set annually.

MR. BRETT: So the contract parameters you are referring to are the contract demand, and, what, a minimum daily volume or an MDV?

MS. VAN DER PAELT: We refer to it as the daily contract quantity. It is the volume of gas that the customer has to deliver to Union every day throughout the 365 days of their contract year.

MR. BRETT: Under his bundled T contract or his unbundled T.

MS. VAN DER PAELT: Or his T1, yes.

MR. BRETT: Right. And the -- now, you haven't presented a forecast of those, as I understand it. Am I correct in saying you haven't presented in your evidence a forecast of the volume that will be taken by those large -- 60 largest customers, as such, a separate forecast? Am I right?

MS. VAN DER PAELT: Their forecast would be embedded in C1, tab 2, page 7.

MR. BRETT: Well, you are referring there to the -- it is embedded in the sense that tab 1, page C1, tab 2, page 7

MR. GARDINER: I have it.

DR. HIGGIN: So as you just stated, this seems to me to be an update to the forecast as requested, and the numbers, for example, for the commercial sector have been updated. I am looking at rates M1, M2, rate 1 -- or 01, and 10.

So also others have been, but I am just focussing right now on the commercial.

So basically, what I would like to understand here is what was the basis of that particular update? How did you come up with those particular forecasts, amendments, that are shown in that schedule A? And B, are they your -- now your forecast?

MR. GARDINER: Mr. Higgin, to prepare the update that you see on J.C-1-2-5, I took the forecast equation that we had in the original. I reran the regressions to include all of the 2011 data.

So I haven't changed my model.

DR. HIGGIN: No, of course.

MR. GARDINER: Or the way I went from the consolidated to the regions to the individual rate classes. So it is the same process.

All I did is, instead of running the regression up to 2010, I ran it to the end of 2011.

From that, new, slightly different regression coefficients came out, and then they were used to prepare the estimates that you see in the table.

DR. HIGGIN: Okay.

MR. GARDINER: So it is the same tool, same process. I am just updating, adding one more year of data to come up with the estimates.

DR. HIGGIN: Okay. So I understand now the methodology.

The second question was: Is this now your forecast?

MR. GARDINER: No, it is not, because when I look at the variation in total, in total we ended up with a result that is 0.2 percent different from the original evidence. That's the total throughput.

And as shown on page 3 of 3 in J.C-1-2-5, you can see the difference in the commercial market, when you add them all up, is 0.1.

Union Gas, when we look at a forecast, an econometric forecast, we recognize that plus or minus two percent is sort of the range of the estimate. So I am well within the forecast range.

So as stated in the -- I believe I stated this in the interrogatory. Here are the numbers. Yes, they're different. There are small differences. They're within forecasting accuracy. So I stand by my forecast.

DR. HIGGIN: Okay. Just one supplementary question.

Did you update the explanatory variables when you did that?

MR. GARDINER: Yes. All of them.

DR. HIGGIN: All of them? Okay.

So you are still -- so Union is still relying on the previous forecast, which would be the updated numbers that

that process 26 times.

We tested the trend 26 times, and then we compared it to the actual. We do that for the blend; same approach. Repeat it 26 times.

MR. SHEPHERD: I understand that.

MR. GARDINER: Okay.

MR. SHEPHERD: But I am actually going in a different direction than this.

You start with the assumption that it is getting warmer, right?

MR. GARDINER: Yes.

MR. SHEPHERD: If you didn't have that to describe, you couldn't use a trend as a predictor, because you wouldn't know, as we saw with the meaningless graphic, you wouldn't know which direction it was going to go. You wouldn't know whether it was cyclical, whether it was a trend in the right direction, whether it was random. You wouldn't know that, right?

MR. GARDINER: We know from the experts that assisted us in 2004 that climate change is occurring.

MR. SHEPHERD: Sorry, are you presenting that as evidence here?

MR. GARDINER: I am going back to the 2004 case and the discussions of Dr. Weaver, and we're not saying -- we're saying there is climate change. Where it is coming from we're not -- we don't know, but it is occurring.

And we are seeing in the weather data the fact that over time it's getting warmer. So how do we represent that in a weather-normal?

MR. SHEPHERD: Okay.

MR. GARDINER: And because we have seen -- if you go back, using the Toronto data and you plot that out, you see it's getting warmer. That is the underpinning of the concept. We're trying to keep it simple. Also, I'm not a climatologist, meteorologist. I am a practising economist doing demand forecasts, and I'm trying to get the best forecast I can.

And I know back when we had the 30-year average, I was always missing the target.

MR. SHEPHERD: So you had a discussion with Mr. Aiken about the fact that in the last 14 years there's actually a trend upwards; right?

MR. GARDINER: Yes.

MR. SHEPHERD: And your answer to that on page 38 of the transcript was, the shorter the period, the more variable the trend; right?

MR. GARDINER: Correct.

MR. SHEPHERD: And so a longer period is better?

MR. GARDINER: Yes.

MR. SHEPHERD: Now, if what you're trying to describe is the warming of climate, then don't you have to know what the period of time is over which it is warming in order to know what the trend is?

MR. GARDINER: We saw that in the 2003 evidence. We had a 30-year declining trend, and the 20-year declining trend performed better. And also Mr. Root, he advised us when looking at this -- because when you look at the annual weather data, the decline in heating degree days becomes really pronounced. It becomes evident in the '80s, although -- our data, anyway, and he suggested that we use -- he advised that we use 20 years.

MR. SHEPHERD: Mr. Root was a climatologist?

MR. GARDINER: No. Mr. Root is a -- I would have to go back to his CV which was provided, which is on the record. I know he is a meteorologist. Whether he is a climatologist like Dr. Weaver, I am not sure, but his CV has been provided.

MR. SHEPHERD: My point is that I didn't see in that evidence, and I don't see in your evidence here before this Panel, any justification for the 20-year period.

Do you have a justification for the 20-year period, other than that's the one that was used last time?

MR. GARDINER: That is the one that was approved in the blend, okay, and we have compared the 20-year trend, which is a component of the blend, to the blend, to see which one is more symmetric and accurate, and we -- making the case that the 20-year trend, which the Board is familiar with and intervenors are familiar with -- and what we're saying is the trend is the true -- is truer than the blend. That's the whole case.

MR. SHEPHERD: No, I understand that, but I am not -- I'm not asking about the blend. I'm asking about the 20 years.

You have said you have to discern the trend in a time series of data. And my question is: Why is the time series 20 years?

MR. GARDINER: Because --

MR. SHEPHERD: Why isn't it 30? Why isn't it ten?

[Witness panel confers]

MR. GARDINER: We focussed on the 20 years because it's a component of the blend, which is Board-approved. It came out of the 2004 analysis, and when we compared the two, the blend against that, symmetry, accuracy -- and all Union Gas is asking for is saying we're not changing the weather-normal. You've got a 20-year trend, only it is blended right now, okay?

And when we do the comparisons, the 20-year trend is more accurate and symmetric. So that is why we're not changing it, 21 or 20. It is a known and it is a performing known.

MR. SHEPHERD: Let me come at this a different way.

You tested the 20-year trend for 26 different periods to get these tests that we saw on the screen a minute ago; right?

MR. GARDINER: Correct.

MR. SHEPHERD: And what the trend is is it's a slope; right?

MR. GARDINER: Correct.

MR. SHEPHERD: You're going to use that slope to predict 2013. That's what you're proposing to do?

MR. GARDINER: Correct.

MR. SHEPHERD: Okay. Those 26 years, the slope was different every single year, wasn't it?

MR. GARDINER: Yes.

MR. SHEPHERD: So doesn't that mean that there was a different trend every year?

MR. GARDINER: Yes.

MR. SHEPHERD: Then why do you think the trend this year is right?

MR. GARDINER: Because it is the most current.

MR. SHEPHERD: But none of them were -- the fact that they were most current in previous years wasn't relevant to whether they were accurate, was it, because you didn't test that?

MR. GARDINER: I disagree, because the test was to repeat those 26 trend lines and the estimate for the test year against the actual for the test year. And when we -- and then the statistics showed that when you look at those 26 tests for the test year, the 20-year trend, compared to the other model, which is also changing because it's a blend -- and even the average will change, because the 30-year average is changing over time -- that the most current is your best estimator of what happens, because the 26 tests indicated that.

MR. SHEPHERD: Well, that's what I'm trying to understand.

You didn't test the most current against an earlier one, for example. So you didn't test the most current slope that you have today against the one from ten years ago to see whether that slope would be more correct, did you? So you don't know whether the most current is, in fact, the most accurate. You haven't tested for that?

MR. GARDINER: No, because the methodology -- the methodology is to use, in the blend, in the original evidence which we prepared in early 2011, the most current 30-year average and the most current 20-year trend.

MR. SHEPHERD: I understand that, but that is tautology.

MR. GARDINER: But the thing is, from regulatory decisions, whenever we prepared demand forecasts, there is a normal methodology and it's the most current one.

So in 2000, we didn't use the average from the '99 rate case. We used an average, 30-year average, up to 2002.

MR. SHEPHERD: Fine.

MR. GARDINER: Similarly, we would do in the original evidence up to 2010.

MR. SHEPHERD: You haven't tested whether a ten-year trend or a 15-year trend or 20 or 30 would be more accurate, have you?

MR. GARDINER: No, we have not.

MR. SHEPHERD: Okay. It is actually not complicated to do that; right? Once of your time series, Excel will do it for you. It will tell you what your next number is, depending on what the time series is you pick; right? It is simple. You can do it in half an hour.

MR. GARDINER: Correct.

MR. SHEPHERD: I am going to ask you to undertake to give us the 2013 degree days based on ten-year up to 30-year trend. Keep 2010 as the last year. All you're changing is the number of years in the trend, so use ten, 11, 12, et cetera, to 30.

Can you do that? It is not a lot of work; right?

MR. SMITH: Yes, we will do that.

MR. MILLAR: J2.5. Is that for each individual -- not each individual year. All of the years from --

MR. SHEPHERD: No, I am only asking for this for 2013. This is not an accuracy test. This is to test whether those various slopes will produce widely varying numbers.

MR. MILLAR: Yes. I'm sorry, I didn't state my question clearly. Do you mean they should run it for ten years, 11 years, 12 years, 13 years?

MR. SHEPHERD: Yes, up to 30.

MR. MILLAR: Thank you.

UNDERTAKING NO. J2.5: TO PROVIDE 2013 DEGREE DAYS BASED ON TEN-YEAR THROUGH TO 30-YEAR TREND, KEEPING 2010 AS THE LAST YEAR.

MR. SHEPHERD: The other area I want to ask you about is -- and this is for you, Ms. Van Der Paelt, I think, and this may be quite brief.

If you could take a look at page 7 and 8 of our materials, this is page 99 and 100 of Tuesday's transcript.

You said, and I'm reading from the bottom of page 99:

"We have always with the large customers used a customer built-up forecast. There's been a lot of focus historically to ensure that the customers' voice was heard in setting their forecast and that it was appropriate. So that's the manner that we have used to set the top 60 contract customers."

You see that?

MS. VAN DER PAELT: Yes.

MR. SHEPHERD: So now you are actually referring to overruns here, but that is how you actually do the full forecast for those 60, right?

MS. VAN DER PAELT: I didn't catch your first word, but yes, that is how I am referring to the bottom, what we call the "bottom-up" for that 60, which, through earlier conversations, is probably a higher number.

MR. SHEPHERD: Okay. And then on pages -- on page 85 you say, at line 7:

"We prepare the forecasts and take it to it the customer, then get the customer's input on that, and then have them agree or disagree and make changes to it as they see fit."

So you start with an assumption as to what you think their 2013 number should be, and then they tell you to change it and you change it?

MS. VAN DER PAELT: So this is a discussion over a period of time. So what we do is we -- it is not just one meeting that you meet with a customer, right? We do meet with these customers on an ongoing basis.

So we take them a starting point, which would be a three-year historical average, as well as their past year's consumption if they wanted to look at it. We would discuss changes in plant operations, changes that they're seeing in terms of how they manufacture the project.

Then we leave those numbers with them to think about.

So when I say we get the customer's input, we don't demand it right at that meeting. We give them time to reflect, right? On those numbers.

Then when they come back with: This is what we think our -- and it is usually related to their production -- this is what we think our production looks like, and therefore our natural gas usage, we then translate that to say: What would this do to your contract parameters? Would it change your contract demand parameter? Would it change your demand contract demand quantities required?

Then we have a discussion around whether that is important, relevant, because ultimately they have to sign off on the contract.

So that's where -- the customer ultimately has to sign a schedule agreeing to the forecast and the parameters that change as a result of that.

So we start with the information, but the customer, if they don't want to sign the contract, that's their right, and -- if they don't agree with the numbers that are there.

MR. SHEPHERD: Well, okay. So there is two parts to that.

First of all, for this rate case, you went to them in 2010 for 2013 demand, right?

MS. VAN DER PAELT: 2011.

MR. SHEPHERD: You went early in 2011?

MS. VAN DER PAELT: Yes. It would have been 2011.

MR. SHEPHERD: Okay. Is that the same conversation in which you talked to them about their contract demand? Or is that something you are actually having this year?

MS. VAN DER PAELT: We would have talked to them about the implications on their contract demand at that point in time, but obviously their 2013 contract wasn't renewing then.

MR. SHEPHERD: Is that --

MS. VAN DER PAELT: Right?

MR. SHEPHERD: So you are having that conversation about their contract demand, the one that matters to them, you're having this year, and is not included in the rate application, right?

MS. VAN DER PAELT: The one that will impact their current contract, yes.

MR. SHEPHERD: Okay. So when you asked them a year ago -- or more than a year ago, I guess -- what's their demand going to be like in 2013, that's something they may not have even forecast yet, right?

MS. VAN DER PAELT: Potentially, yes.

MR. SHEPHERD: So here's what I'm trying to drive at here.

You said -- and if you take a look at the last page of our materials, page 86 of the transcript from Tuesday, at line 17 -- you talk about your forecast and you say:

"That is what the customers told us based on what they thought they would be consuming."

And I took it to mean that your contract demand forecast is essentially what the customers told you.

First of all, is that right?

MS. VAN DER PAELT: It is a reflection of what they have told us, yes.

MR. SHEPHERD: Did you change it in any way?

MS. VAN DER PAELT: Change it without their knowledge?

MR. SHEPHERD: Yes.

MS. VAN DER PAELT: No.

MR. SHEPHERD: Okay. So then they gave you their best guess for basically 24 months into the future, or 20 months into the future. Now a lot of things have happened since then that you know that they don't know.

Have you done anything to fix that forecast to make it more accurate, because you have more information?

MS. VAN DER PAELT: So in terms of 2013 and the contracts, we continue to have the discussions on an ongoing basis with the clients around the impacts on changes that we see and what they're seeing in their production.

We have not --

MR. SHEPHERD: I'm talking about this rate case.

MS. VAN DER PAELT: Right. We have not received -- so 2013 contracts are not set yet. Those discussions -- so we have been talking to them on an ongoing basis about production, but most of those contracts will be coming due in the September, October, November time frame of this year.

So they will not have been finalized at this point.

MR. SHEPHERD: Okay, but I'm not --

MS. VAN DER PAELT: So they therefore cannot be reflected in this forecast.

MR. SHEPHERD: I am not asking you -- you are, again, sort of assuming the methodology. You are assuming that unless they tell you to change it, you have to keep the old number. But I will give you an example.

If you went to them at the beginning of 2008 or the end of 2007 and said: Can you please give us a forecast for 2009? And then the economy went in the tank in 2008, wouldn't you fix it? Wouldn't you make changes, even though they're not telling you anything new because you are not ready to talk to them yet?

MS. VAN DER PAELT: If I adjusted a customer's forecast, I would have to open their contract and adjust their CD and their DCQ. I would need their agreement to do that.

MR. SHEPHERD: I am not asking you to adjust their forecast.

I'm asking you -- you're telling the Board how much revenues you can expect from these particular classes.

This is about your rate application, not about your contracts with them.

MS. VAN DER PAELT: Right. So when look at what's actually materializing in the year -- when we do our forecasting internally, we also have a long lead time. So it is when the actual revenues are materializing in the year that we would then reflect on: Is that year going to be short revenue, or is it going to be over our revenue forecast?

Once we submit our forecast, which is also about six months in advance, four months in advance, we don't change it at that point in time, which would have been based on the customer input.

So the forecast is set. It's the variances to the forecast that we look at on sort of an ongoing, real-time basis.

MR. SHEPHERD: Mr. Wolnik, for example, asked you about the Lennox situation, and the fact that -- or the potential that a change in Lennox output will change the demand for power -- from power producers.

And this is something that is more recent information that they wouldn't have had at the time they talked to you more than a year ago, right?

MS. VAN DER PAELT: That's correct.

MR. SHEPHERD: But you haven't adjusted your forecast for rate purposes to account for that, right?

MS. VAN DER PAELT: That's correct.

MR. SHEPHERD: Doesn't that mean that it is likely to be wrong?

Let's assume it is material. Maybe it isn't, but let's assume it is.

MS. VAN DER PAELT: If you looked at one example, I would say -- and said that you have new information on this which you don't have in your forecast, that one specific could be wrong.

But when you look at the collection of customers within the group, the diversity among the group would suggest some will be up and some will be down over what they have actually told you, and overall your forecast should be quite accurate.

MR. SHEPHERD: Aren't there common causes sometimes?

MS. VAN DER PAELT: Not with the manufacturing, because there's different drivers that impact each manufacturer.

MR. SHEPHERD: I was asking about power producers.

MS. VAN DER PAELT: The power producers, it's not common to all of them, no. That's not what we have seen to date.

It depends on where they are geographically. It depends on why they're being called on. It depends if it is a weather-driven issue as to why they're being called on.

So not all of them have the same -- if you're a northern utility generator, it is based on gas price.

So they each have a different driver, which would change why they may change their forecast.

MR. SHEPHERD: So having an OPG unit in a planned outage for six months next year wouldn't affect, on a common basis, their overall need for gas?

MS. VAN DER PAELT: Not on a common basis, no.

MR. SHEPHERD: Okay. Thank you.

follow-up.

MS. TAYLOR: I wasn't going to ask this, but it has been sort of bothering me throughout the panel. And maybe, Mr. Gardiner, this is for you.

If the regression formula has not been re-specified since 2004, I just have a great discomfort with that, in view of the fact, particularly, that it produced a large and unexplainable error in 2011.

And yes, I understand regression and one year's date is not going to skew the outcome, and so on.

But a regression formula is -- they go stale, I guess is my concern. If you are looking at other in the finance panel and capital markets theory, I mean, we use 60 months beta. It rolls.

I can't recall a time where someone has come in and said to me a regression formula that was specified eight years ago remains relevant today.

And then I also note you shortened up the time frame for analysis on the heating degree-days. You said it is a 20-year trend. If I understand you correctly, you shortened the data from 1991 to 1994, which means it is actually 16 years to 2012, but the data that you would be using ended in 2011.

So I have some difficulty with the overall specification of the regression formula, the time frame that you are including in the data and the fact that it is producing errors that you simply cannot explain.

MR. GARDINER: First, for clarity, are we talking about the demand equations? The consumption equations?

MS. TAYLOR: Yes. Specifically on the errors.

MR. GARDINER: Okay. The regression equations that you have in evidence and in the update are regressions that were prepared early last year, with data up to either 2010 or 2011.

They are not the same regressions that we had in the 2004 rate case.

As we do our budgets, we have our regression formulas, and you saw the demand drivers. So the specification of the model hasn't basically changed.

The results that we get with the model, when at the end of the year -- and we do the variance analysis and we have a NAC variance of less than one percent, because now I've accounted for FEI, accounted for this, you know, the total bill, I have accounted for the DSM plan. So you may see in a given year, yes, I was off by 1.8, but when I account for the other things I am below one percent.

When I get results like that, I say: Don't change the model.

The regression equations in the residential and kin the -- especially the residential, are very robust.

In the commercial market, I had to change them. And that was in the evidence. We used to do it by old residential -- old commercial M2, and then we had one for commercial 01 and commercial 10.

Those models did not work last year, so I changed the model. I consolidated the models to get something to work.

MS. TAYLOR: Okay. Thank you.

MS. HARE: Mr. Smith, do you have redirect for this panel?

MR. SMITH: I do. I wonder if you were planning on taking a break. I may be able to be a bit more efficient if you give me five minutes, 10 minutes to consolidate my notes, or if you were not planning on taking a break --

MS. HARE: No. We were planning to take a break, but then maybe you could have your next panel --

MR. SMITH: Yes, I will have them come up.

MS. HARE: That's great. So let's take a break now until, let's say, 10 to.

Oh, oh, before we break, Mr. Smith, we have on the schedule that we would be starting panel 3 tomorrow.

MR. SMITH: Yes.

MS. HARE: That may be unlikely given that we're taking longer, and so what we were actually wondering is -- particularly since we're going to hear submissions on the issue raised by CME -- is it worth your bringing people from Chatham that might be on the stand for half an hour on a Friday afternoon?

I will leave that for you to think about.

MR. SMITH: I can probably just tell you where we're at. I have brought the people from Chatham, but I appreciate the consideration and I will talk to them. They are here, and so my initial instinct was to say, well, let's just run into panel 3.

I need to make sure that the cost of capital witnesses who are travelling from the United States are available, because if we're running behind, as we are, panel 3 is not going to be done tomorrow. They will be on Monday, which will push cost of capital to Tuesday, and if they're not available Thursday we would have a scheduling problem.

So it may be that we are back to what we had originally thought, and I will be back to you.

MS. HARE: That's fine.

MR. SMITH: Thank you.

MS. HARE: Okay. Thank you. So 10 to, we will be back.

--- Recess taken at 3:37 p.m.

--- On resuming at 3:54 p.m.

MS. HARE: Please be seated. Mr. Smith, your redirect.

RE-EXAMINATION BY MR. SMITH:

MR. SMITH: Thank you, Madam Chair. I do have a few questions.

Mr. Gardiner, I'm sure this is for my benefit perhaps alone and the benefit of the transcript, but can you tell me what the root mean square is?

MR. GARDINER: The root mean square error is a strong statistical measurement of accuracy. It is a recognized method of measuring accuracy, variation between actuals and estimates.

The main benefit of using the root mean square error is it treats the positive variances and negative variances, because if we just did it without -- if we just took an average over 20 years, you get no variances, because the pluses and minuses negate themselves.

And the other thing the root mean square error does is it also treats the fact that you had small variances and large variances, so it is a generally accepted statistical measure of accuracy.

MR. SMITH: Mr. Brett put to you in his cross-examination that it was, to use his words, "an odd conceit" to use a dummy variable.

Is the use of such a variable typical or atypical in regression analysis?

MR. GARDINER: It is typical. It is a way of dealing with -- in energy demand forecasts, if there's a major structural change or, as we discussed yesterday, an outlier, an observation of consumption that is variant by a large amount to standard deviations, then it is there to apply a dummy variable.

It is something that is done in regression analysis for energy demand forecasting and other types of forecasting, because it treats -- the other choice is to take that data out of the regression. You clip it out. You would say it is bad data. But you can do a regression analysis; you put a dummy. It's the same thing.

MR. SMITH: You were asked a question by Member Taylor towards the end about re-specification, and my question for you is: What consideration have you given, if any, to the question of re-specification of your model since 2004?

MR. GARDINER: Well, each year, when we prepare our budget forecast and we go through the exercise, we start with our existing models and we see how well they have forecasted in the past. We look at the regression results, which are provided. They're very strong, and we see if the model works.

And then, for example, we do a forecast for budget. When the budget year comes, we look at it. We do a variance analysis. If it fits within the 2 percent, the model is working.

Well, that is what has happened with the residential model over the past -- since we started doing this 15 years ago. The results indicate that we don't need to change the model.

The same is true with the industrial volume model, which we've been using in this rate case and prior. We look at the results. They're within the reasonable bounds for an industrial class and, therefore, we do not change the model specification.

For the commercial model we did, because the old models that we had, which were by service and rate class, did not work. So every year we go and we look at the results, and we look at the regression results. Do we have in the model demand drivers that you would expect to have, like weather, a price variable and efficiency variable, some kind of economic indicator?

Say, for the industrial market, you would love to get, you know, oil prices and exchange rates in your models, if you can, and -- because you want to have a model that says:

Consumption is a function of, if it's a heat sensitive load, weather, price, efficiency and other sort of you know pertinent demand drivers.

MR. SMITH: And so it is clear on the record, what are the explanatory variables that you use in your model?

MR. GARDINER: In the residential models we have -- there's two, and it's - there's a use equation, which is -- there's weather. There's a furnace efficiency index, which is basically the efficiency driver.

There is total bill. There's persons per household. All of those things explain residential usage.

We also have a residential volume equation where we have the heating degree days, the total bill and -- I have to remember. It's been a long day. Volumes -- oh, customers, because it's a volume equation.

In the commercial, we have weather. We have the fall weather harvest variable. We have two trend variables, one for the heating season - and that was the hockey stick I was talking about yesterday - and we have a trend variable for the summer load to reflect a structural change that has taken place in the summer load.

And then we had two dummies to take account of outliers from March 2000 and April 2000. This is in appendix A, page 11 of 16 of C1, tab 1.

And for the industrial market, we have heating degree days, the price of heavy fuel oil number 6. We have the exchange rate, and then we have some dummy variables to account for some structural changes and the recession effect of 2009 and 2010, early 2010. And those are in the models.

And, again, if you go to the appendix, there's charts and tables that show the models and also have graphs that show how well the models have performed, as well as the regression results, which are very strong.

MR. SMITH: Can I ask you to turn up J.C-1-2-5, please, sir, and ask you to turn to page 3 of 3?

MR. GARDINER: I have it.

MR. SMITH: And I believe I'm in the right spot. And I would draw your attention to the difference that you were taken to by Mr. Millar of 1.1 percent for residential M1. Do you see that? Page 3 --

MR. GARDINER: Yes, correct. I have it.

MR. SMITH: -- in the upper right-hand corner of the table.

MR. GARDINER: Yes, thank you.

MR. SMITH: And you commented on forecast error. But from a statistical perspective, can you tell us what is the difference between the results you obtain at page 3 of 3 and your prefiled evidence in terms of the accuracy of the two?

MR. GARDINER: Well, both are within the forecast accuracy of the demand equations.

MR. SMITH: And what does that mean in simple terms?

MR. GARDINER: That means about -- when you do a forecast, there's going to be -- you're coming up with a point. There's going to be a variance around it, okay?

And the models can have a range of error, and the range of error is 2 percent.

These are well within the 2 percent error. The 2 percent error reflects the unexplained variance that we've seen historically over time.

So when I -- you know, I go back and look at all of my forecasts, and what have you, and I say, How well have I forecasted, after I explain all of the driver assumptions, and what's their ability? And that's how I get this 2 percent range.

So I am well within the range. I'm in the ballpark.

MR. SMITH: Can I ask you, just from a statistical perspective, can you tell the Board which of the two is more statistically accurate?

MR. GARDINER: Well, on page 3 of 3, those are the actual results. That is an actual year, and...

MR. SMITH: Maybe put a different way, sir, at a 95 percent confidence level, what is the difference between the two?

MR. GARDINER: They're both within that.

MR. SMITH: Thank you.

Just moving along, do you have LPMA's compendium?

MR. GARDINER: Yes, I do.

MR. SMITH: And can I ask you to turn to page 3 of 16?

MR. GARDINER: Yes.

MR. SMITH: And at page 3 of 16, this is J.C-1-2-2, and I'm looking at page of 2, sir.

MR. GARDINER: What is the other reference, Mr.

Crawford --

MR. SMITH: J.C-1-2-2, page 2 of 2.

MR. GARDINER: Yes.

MR. SMITH: And if I could draw your attention to, under actual 2011, 3,830, do you have that?

MR. GARDINER: Yes, I do.

MR. SMITH: And forecast 2013, 3,610. Do you see that?

MR. GARDINER: Yes.

MR. SMITH: And you referred to DSM in your discussion with Mr. Aiken, and my question is: What, if any, other factors may be affecting the results from 2011 to 2013?

MR. GARDINER: Okay. I mentioned this earlier.

About 45 percent of the contribution of that decline is coming from the residential market. It's coming from the non-DSM-related energy efficiency. It's coming mainly from the furnace replacement, the 60,000 homes, existing homes that have furnaces that fail and need to be replaced. And because you're going from a conventional furnace to a high-efficiency, you've got a 40 percent gain just per furnace.

That's the major one.

One-third of the -- about one-third of the change that we see there is due to the high-usage, the unexplained high-usage, which is receding in the commercial market.

And then there's the DSM plans, would contribute about 14 percent of that decline.

MR. SMITH: Just picking up on the DSM question, if the suggestion were made that in your calculation of normalized average consumption you were double-counting DSM effects, would you agree with that?

MR. GARDINER: No.

MR. SMITH: Why not?

MR. GARDINER: Because if we look at each of the markets, in the commercial and industrial market in the demand equations, there is no energy efficiency variable.

And 60 percent of the DSM plan is in the commercial industrial in the general service market.

So I need to reflect there is an energy efficiency program, DSM-based, that will affect our forecast. So we apply that.

In the residential market for the forecast period. the DSM programs are mainly thermostat-related, ESK kits, you know, consumer --

MR. SMITH: Perhaps we should break that out. "ESK kits" means?

MR. GARDINER: Oh, these are energy saving kits that you --

MR. SMITH: Thank you.

MR. GARDINER: -- that you get. And also information on the wise use of energy.

The -- so there is no furnace program in our current DSM plans, but we have these programs and they do affect consumption.

The historical data, I do not have -- the historical data is mainly being affected by furnace replacement and new furnaces in new homes and the FEI index, the furnace efficiency index, that is in the model is picking up those changes. And the econometrics gives you a number, and I say: Yes, I have that. And that's similar to the discussion I had with Mr. Aiken on the 2,193, but I know that I have these DSM programs and these targets, and they are achieving the targets.

And over the next -- over the period '11 to '18, you know, at six cubic metres a year, it accumulates -- it is about 18 cubic metres, so that's why I have to reduce the number.

So there is no double-counting.

MR. SMITH: Thank you.

Just moving along, you were asked a series of questions by Mr. Buonaguro relating to heteroskedasticity. Do you recall that?

MR. GARDINER: Yes. Heteroskedasticity, yes.

MR. SMITH: I have a question in relation to heteroskedasticity.

[Laughter]

MR. SMITH: My question in relation to that is whether or not the existing -- well, what, if any, is the difference in the heteroskedasticity in the 20-year -- in what you are proposing and what is in the existing Board methodology?

MR. GARDINER: Both. Because we're talking about the weather data and putting a trend line through the weather data, or the blend, you would see that there is a variance, as we get -- as we go from 20 years ago to today, the variances are bigger. There is a pattern.

That's the heteroskedasticity.

And that's also when we hear about climate change, how the weather is becoming more unpredictable, more variant -- think of last March -- that's the widening, that's the movement of the weather.

So both of them have heteroskedasticity in them.

MR. SMITH: Now, you were asked a series of questions in relation to certain tests done in -- or certain -- certain models with respect to weather that you looked at in 2004. Do you recall that?

MR. GARDINER: Yes, I do.

MR. SMITH: And how did the 20-year trend compare to those other models?

MR. GARDINER: It was the superior model.

MR. SMITH: Which was the superior model?

MR. GARDINER: The 20-year trend.

MR. SMITH: Do you have any reason to believe, sir -- and if so, why -- that situation may have changed between 2004 and today?

MR. GARDINER: I know, in comparison to the 30-year average, the blended method and the 20-year trend, that the 20-year trend is the superior method.

MR. SMITH: Sorry, my question was imprecise.

In relation to -- you tell us the models that you ran -- the models you looked at in 2004 did not perform as well as the 20-year trend.

My question is: Those models that you didn't look at again, do you have any reason to believe that they would perform better today than in 2004?

MR. GARDINER: I have no reason to believe that they would perform better.

MR. SMITH: Going back to -- you were asked in relation to the technical conference transcript at page 88 -- and I would ask my friend to pull that up -- some questions. And you were talking -- you made the observation there, in answer to my friend, that you were looking at the demand equation as opposed to the weather. And I would ask you: Why did you make that distinction?

MR. GARDINER: The distinction is I apply these statistical tests on my demand equations, because as a -- if you want -- economic behaviour effect is a cause, and there's an effect. Weather changes, prices change, consumption changes. And these are models that are used for forecasts and the whole business that we're discussing right now.

So the weather-normal, I don't do those tests because the idea is to come up with a normal.

MR. SMITH: Perhaps you can clarify that, what you mean by that.

MR. GARDINER: Okay. We need an estimate of what standard weather would be, normal weather.

In the past when weather was not varying and the 30-year average worked, if you -- you know, 1940 and 1970, those averages were satisfactory -- with climate change we're seeing weather getting warmer. So we still have to come up with an average, but the average that works best is the trend line, which is an average.

MR. SMITH: Can I ask my friend to turn up JT1.56?

Do we have that? Why don't we come back to it? I will just move along. Ms. Van Der Paelt, you were asked a question by Member Taylor in relation to the forecast, the bottom-up forecast, and you were asked, between 2011 and 2012, you've not revised the forecast to take account of things Union might know. Do you recall that?

MS. VAN DER PAELT: Yes, I do.

MR. SMITH: In aggregate, are there any such things that would cause you to vary your forecast?

MS. VAN DER PAELT: No, there aren't.

MR. SMITH: Now, perhaps to borrow my friend Mr. Thompson's term, I would like to get a bit of context.

Can I ask you to turn up, panel, J.C-1-2-5? I think it is J.C-1-2-5. No, hold on. I might be wrong.

I'm sorry, that is the wrong reference. Can I ask you to turn up your prefiled evidence, tab C1, tab 2, page 5? C1, tab 2, page 5. This is for you, Ms. Van Der Paelt.

MS. VAN DER PAELT: I have that.

MR. SMITH: And if you have that -- and I would ask you to take out Mr. Thompson's compendium at K2.3.

MS. VAN DER PAELT: Yes.

MR. SMITH: And Mr. Thompson asked you about the revenue deficiency/sufficiency components looking at the contract market on page 1 of K2.3. Do you recall that?

MS. VAN DER PAELT: Yes, I do.

MR. SMITH: And, I'm sorry, I may have said page 5. I meant page 7.

I would ask you to look at table 2, Exhibit C1, tab 2, page 7. Do you see that?

MS. VAN DER PAELT: I do.

MR. SMITH: And we have in this -- well, maybe you can tell us. What do we have in this table?

MS. VAN DER PAELT: So in table 2 we have our revenue comparison all stated at Q1 2011 rates. So they're consistent in terms of how they're stated across from 2007 actual to the 2013 forecast.

MR. SMITH: So maybe you can just explain that, when you say actuals. There's a note at line -- at the very bottom. What is being conveyed in that note?

MS. VAN DER PAELT: So in the actual revenue deficiency -- so if I refer back to Mr. Thompson's schedule, page 1, the revenue deficiency and sufficiency components, there would be different weighted average cost of gas factors in the rates and different rates throughout that time period.

MR. SMITH: That's in K2.3?

MS. VAN DER PAELT: That's correct. What this table does is actually show -- so that doesn't really speak to a forecast variance, because there is other noise in the numbers on that page 1.

In the revenue comparison, this truly speaks to your actuals versus your forecast, all stated with the same base assumption around the cost of gas.

MR. SMITH: So if we were interested in knowing how Union had performed relative to its Board-approved figures or even its 2007 actual results, which should we be looking at?

MS. VAN DER PAELT: You should be looking at C1, tab 2, page 7 of 14.

MR. SMITH: Okay.

MS. VAN DER PAELT: Table 2.

MR. SMITH: J.C-1-2-2, please, and page -- I'm sorry. Let me make sure I've got that right. Sorry. We have asked that. J.C-1-2-5, please, page 2 of 3.

My apologies. I should have been -- J.C-1-2-2. I did have the right page, page 2 of 2. And, Mr. Gardiner, you were asked a question by Mr. Millar about NAC. Do you recall that?

MR. GARDINER: Yes, I do.

MR. SMITH: And here again you were asked about the figures for the last five years. Do you recall that?

MR. GARDINER: Yes, I do.

MR. SMITH: And is that an appropriate time period in your view, yes or no, in which to consider NAC?

MR. GARDINER: No, it's not an appropriate period.

MR. SMITH: Why do you say that, sir?

MR. GARDINER: Because the NAC estimate for 2013 is developed by the regression models and the application of DSM, and the assumptions that go into those models.

MR. SMITH: Just a final couple of questions for you, Ms. Van Der Paelt. You were asked very early on by Mr. Wolnik about BCD. Do you recall that?

MS. VAN DER PAELT: Yes, I do.

MR. SMITH: What does that refer to?

MS. VAN DER PAELT: That refers to a new service that came into effect in 2007 called the billing contract demand service.

MR. SMITH: To whom does it apply?

MS. VAN DER PAELT: It applies to new customers or existing customers that have new incremental load in excess of 1,200,000 m^3 a day. They have to be directly connected to the Dawn Trafalgar system, close to Parkway, or they have to have access to a third party pipeline.

MR. SMITH: When you say "they", how many such customers are there?

MS. VAN DER PAELT: One.

MR. SMITH: And who is that?

MS. VAN DER PAELT: That is Halton Hills.

MR. SMITH: Thank you. Thank you. Those are my questions.

MS. HARE: Oh, thank you very much, panel. You are excused. Your testimony has been very helpful.

Mr. Smith, can you introduce your next panel, please?

MR. SMITH: Oh -- no, that's fine. No, it's okay. I was going to go back to JT1.56. I will deal with it with a different panel. Thank you.

MS. HARE: We do have a hard stop at 4:30, but I understand, Mr. Wolnik, you won't be here tomorrow and you

EX-FRANCHISE
REVENUE

PREFILED EVIDENCE OF

PATTI PIETT, DIRECTOR, STORAGE AND TRANSPORTATION SALES

CAROL CAMERON, MANAGER, CAPACITY MANAGEMENT AND UTILIZATION

This evidence provides an overview of Union's storage and transportation ("S&T") revenue forecast for 2012 and 2013. This evidence should be read in conjunction with the ICF report found at Exhibit A2, Tab 1, Schedule 4 which discusses the changing North American natural gas market dynamics. This evidence is organized under the following headings:

1/ The long-term transportation revenue forecast for 2012 and 2013;

2/ The short-term transportation and exchanges revenue forecast for 2012 and 2013; and,

3/ The short-term storage and balancing revenue forecast for 2012 and 2013.

1/ LONG-TERM TRANSPORTATION REVENUE FORECAST

Union's forecast for long-term transportation revenue is $148.5 million in 2012 and $141.9 million in 2013. This forecast is made up of three main components: M12 Long-term Transportation, Other Long-term Transportation, and Other Storage & Transportation ("S&T") Services. Factors which influence this forecast are customer demands, market prices, and long-term expectations regarding supply basins. The forecast for long-term transportation assumes there will be no incremental capacity built downstream of Parkway beyond the proposed TransCanada Pipelines ("TCPL") expansions for 2012 and 2013 which were initially filed with the National Energy Board in July, 2011 (2012 Eastern Mainline Expansion).

M12 Long-term Transportation

The revenue for M12 Long-term Transportation represents long-term firm transportation on Union's Dawn-Parkway transmission system as captured on the M12 transportation rate schedule. It includes M12, M12X, and F24T transportation services which transport gas supplies easterly, westerly, or bi-directionally on this system. Table 1 provides the actual and forecast revenue for M12 Long-term Transportation.

Table 1
M12 Long-term Transportation Revenue

Revenue ($Millions)	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
M12 Transportation	$141.9	$138.3	$134.0	$121.1
M12 Transportation Overrun	0.5	0.0	0.0	0.0
M12X Transportation	0.0	$1.5	5.9	13.5
Total	$142.4	$139.8	$139.9	$134.6

There has been a general decline in M12 transportation revenues since 2010 due to rate changes and a reduction in customer demands. Changes in demand are driven by the changing market dynamics, including shale production causing reduced exports at Niagara/Chippewa, as described in Exhibit A2, Tab 1, Schedule 1 and Schedule 4. Specific variances by year are described below and reconciled in Schedules 1 and 2.

For 2012 and 2013, Union was able to provide Kirkwall-Parkway service of 88,497 GJ/d, commencing November 1, 2012, and an incremental 174,752 GJ/d commencing November 1, 2013.

Other Long-term Transportation

There are three components that comprise the Other Long-term Transportation revenue forecast: C1 Long-term Transportation; M13 (Local Production); and M16 (Storage Transportation Service). Actual and forecast revenues for these services are shown in Table 2.

Table 2

Other Long-term Transportation Revenue

Revenue ($ Millions)	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
C1 Long-term Transportation	$6.3	$7.6	$6.6	$5.2
M13 Transportation	0.4	0.3	0.4	0.4
M16 Transportation	0.6	0.6	0.6	0.6
Total	$7.3	$8.5	$7.6	$6.2

The change in revenue between 2010 Actual and the 2013 Forecast is entirely due to C1 Long-term Transportation demand. The decline in C1 Long-term Transportation revenue since 2011 is due to changes in market dynamics and gas flows affecting the Dawn-Parkway and Ojibway systems. Specific changes are detailed below and provided in Schedules 4 and 5.

i. In 2011, C1 Long-term Transportation revenue is higher than 2010 by $1.3 million. The largest component of this change is a Dawn-Dawn (TCPL) contract for 500,000 GJ/d which commenced November 1, 2010, creating a 10 month (January to October) variance of $1.1 million. There is also a full year impact of nearly $0.5 million related to contract increases of 36,212 GJ/d for Ojibway-Dawn capacity which commenced in October and November, 2010. This is offset by a contract non-renewal for 36,927 GJ/d on the Ojibway-Dawn path, effective April 1, 2011;

ii. In 2011, Parkway-Kirkwall C1 Long-term Transportation demand of 128,316 GJ/d (September 1, 2011 start date) was converted to the new bi-directional M12X transportation service, reducing C1 Long-term Transportation revenue by $0.3 million. In 2012, Parkway-Dawn C1 Long-term Transportation demand of 200,000 GJ/d (November 1, 2012 start date) was also converted, reducing C1 Long-term Transportation revenue by approximately $0.8 million in 2012. Offsetting demands and revenues for the M12X transportation service in both 2011 and 2012 are reflected in M12 Transportation Revenue, described earlier; and,

iii. In 2013, there is a 10 month (January to October) impact of the M12X conversion, reducing revenue by $1.1 million. There is a further reduction in Parkway-Dawn C1 Long-term Transportation demand of 54,357 GJ/d (April 1, 2013 start date), due to contract expiries and reductions, resulting in a decline in revenue of $0.3 million.

Other S&T Revenue

The final component of the Long-term Transportation revenue forecast is Other S&T Revenue. This is comprised of revenue earned from name changes, Ontario Producers and other miscellaneous services. The revenue for these services has been constant at $1.1 million in 2010 and 2011. The forecast for 2012 and 2013 is $1.1 million.

2/ SHORT-TERM TRANSPORTATION AND EXCHANGES REVENUE FORECAST

The short-term transportation and exchanges revenue forecast is $32.2 million for 2012, and $20.2 million for 2013. Factors which influence this forecast are customer demands, market prices, locational basis spreads and weather. The forecast assumes normal weather, and it also assumes there will be no incremental transportation capacity built downstream of Parkway beyond the proposed TCPL expansions for 2012 and 2013.

This forecast is made up of two main components: transportation and exchanges.

Transportation

The transportation component of the transactional forecast is comprised of short-term firm and interruptible transportation on Union's Dawn-Parkway system, the Ojibway system, and St. Clair/Bluewater system. Actual and forecast revenues for these services on the three systems are shown in Table 3.

Table 3

Short-term Transportation Revenue

Revenue - $Million's	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
Dawn-Parkway system	$9.3	$8.0	$8.7	$8.7
Ojibway system	2.6	1.0	0.6	0.6
St. Clair/Bluewater system	0.9	3.5	1.8	1.8
TOTAL	$12.8	$12.5	$11.1	$11.1

The decline in revenues for Dawn-Parkway short-term transportation since 2010 reflects the reduction in Dawn-Parkway values resulting from insufficient take-away capacity on TCPL downstream of Parkway. More detail regarding this can be found at Exhibit A2, Tab 1, Schedule 1 which discusses, among other things, the changes in gas supply dynamics, the impact of the changes on Union's Dawn to Parkway system and the impact of TCPL's capacity constraint between Parkway and TCPL's connection at Maple.

The significant reduction in revenue on the Ojibway path reflects the reduction in market spreads seen in 2011.

Changes in the Transportation Market

Since 2007, there have been significant changes in the North American gas market. These changes are described at Exhibit A2, Tab 1, Schedule 1 and Schedule 4.

There has been a significant reduction in load factors on TCPL long-haul service, resulting in increases in TCPL tolls. In order to mitigate this trend, TCPL introduced the Firm Transportation Risk Alleviation Mechanism ("FT RAM") program. This program gives firm shippers of long-haul capacity (or short-haul capacity linked to long-haul capacity) credits for any capacity left unutilized. These credits can then be spent, in the same month upon which they are earned, on any interruptible service on TCPL's system. The program was designed to encourage shippers to remain contracted on TCPL's system.

On September 1, 2011, TCPL filed evidence with the National Energy Board ("NEB") aimed at redesigning their overall framework. Included in TCPL's proposal was the elimination of the FT RAM program.

The 2012 forecast assumes the TCPL FT RAM program will be eliminated on November 1, 2012. A full year impact of the FT RAM program being discontinued is reflected in 2013.

Exchanges

Exchange revenue is comprised of activity using Union's upstream transportation capacity to provide exchange services to third-parties. It also includes net revenue generated from pipe releases or revenue from TCPL's FT RAM program. Actual and forecast revenue for exchanges are shown in Table 4.

Table 4
Exchange Revenue

Year	$ Millions
2006	2.6
2007	3.4
2008	11.6
2009	20.5
2010	19.7
2011 Actual	31.7
2012 Forecast	21.1
2013 Forecast	9.1

The single biggest factor contributing to growth in exchange revenue was the utilization of the TCPL FT RAM program starting in 2008. Full year impacts of this program are seen in 2009 and 2010. Union's 2011 actual revenue is primarily supported by TCPL's FT RAM program, but also includes activity related to colder-than-normal weather, TCPL outages, and system outages downstream of Parkway. All of these factors resulted in price spikes that are not forecast to reoccur.

It is also expected that during the forecast period, the increase in shale production will continue to put downward pressure on market spreads for exchange paths, thus reducing value of services to points such as Iroquois. This is described at Exhibit A, Tab 2, Schedule 1.

The 2013 forecast of $9.1 million exceeds the actual revenues earned in years prior to the TCPL FT RAM program optimization. As noted earlier, TCPL's FT RAM program is expected to be terminated in 2012.

3/ SHORT-TERM STORAGE & BALANCING

Union's forecast for short-term storage and balancing is $9.1 million in 2012 and $11.5 million in 2013. This forecast is made up of two components: peak short-term storage, and off-peak storage, balancing and loans.

Changes in Short-term Storage Market

Since 2007, there has been a steady decline in short-term storage prices, with the most significant reductions seen since spring, 2010. These storage price reductions reflect a declining spread between summer and winter gas prices. The main drivers for this declining spread are:

i. Increased summer values as a result of higher demands in the power sector;
ii. Lower winter values as a result of higher supplies from increased Marcellus shale production; and,
iii. Lower winter values as a result of lower demands resulting from an overall sluggish economy in the U.S., as well as energy efficiencies.

The decline in storage spreads is exemplified by the reduction in the actual price of short-term peak storage space relative to price included in approved rates. In 2011, 10.1 PJ of short-term peak storage space sold at an average price of $0.66 Cdn/GJ. This compares to a price of $0.85 Cdn/GJ included in current approved rates.

The impact of these market forces has also impacted the volatility of storage prices on a short-term basis. In a market where gas supply is plentiful, price spikes are less likely and the value of gas season over season remains more constant. With reduced volatility in month-to-month and season-to-season gas values, there is less value for short-term storage and balancing services.

The most recent forecast of storage spreads based on NYMEX data is provided in Figure 14 of Exhibit A2, Tab 1, Schedule 4.

Short-term Storage and Balancing Forecast

Short-term peak storage revenue is generated from the sale of short-term storage space based on the difference between the 100 PJ set aside for in-franchise use, and the forecast in-franchise requirement. The in-franchise requirements are described at Exhibit D1, Tab1.

Off-peak storage and balancing represents short-term storage-based services that do not have gas in storage over the October 31 peak time period.

Actual and forecast revenue for these services are shown in Table 5.

Table 5
Short-term Storage and Balancing Revenue

Revenue ($ Millions)	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
Short-term peak storage	$14.9	$9.0	$6.6	$9.0
Off-peak storage, Balancing and Loans	6.0	1.9	2.5	2.5
Total	$20.9	$10.9	$9.1	$11.5

Generally, short-term peak storage is sold with terms which overlap calendar years. For example, for a 12-month contract commencing July 1st, 6 months of revenue would be captured in the first calendar year, and 6 months would carry-over into the following calendar year.

Short-term peak storage revenue in 2011 declined from 2010 by $5.9 million driven by lower storage values. The average price of new contracts in 2011 was $0.66 Cdn/GJ, compared to $1.39 Cdn/GJ for contracts which started in 2010. The short-term space available for sale in 2011 was 10.1 PJ, compared to 10.2 PJ in 2010.

In 2012, short-term peak storage revenue decreases from 2011 by $2.4 million. The main reason for this forecast reduction is the expectation that storage values will continue to decline. In the 2012 forecast, new contracts are expected to be sold for $0.55 Cdn/GJ. The impact of lower prices in 2012 is a reduction in revenue of $3.4 million. This price variance is offset by an increase in the amount of available storage space for sale. In 2012, short-term space available for sale is forecast to increase to 12.6 PJ, resulting in an increase in revenue of $1.0 million.

In 2013, short-term peak storage revenue increases from 2012 by $2.4 million. The main reason for this increase is due to a forecast recovery in storage prices, which increases revenue by $1.7 million. The forecast for 2013 assumes new contracts are sold at $0.85 Cdn/GJ, compared to $0.55 Cdn/GJ in 2012. In addition, the storage space available in 2013 is higher than in 2012, resulting in an increase in revenue of $0.7 million.

The short-term space available for sale and average prices from 2010 actual to the 2013 forecast are summarized in Table 6.

Table 6

Short-term Storage Space and Average Prices

	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
Short-term Peak Storage Space at October 31	10.2 PJ	10.1 PJ	12.6 PJ	13.0 PJ
Average Price (new contracts) - $Cdn/GJ	$1.39	$0.66	$0.55	$0.85

The impact of reduced volatility of gas prices at Dawn can be seen in the reduction in off-peak, balancing and loan revenue between 2010 and 2011. Stable gas prices and reduced volatility significantly reduces the value of these off-peak services because there are limited month-to-month price opportunities to capitalize upon. This trend is expected to continue into 2012, but is forecast to start to recover by 2013.

A summary of Union's Long-term Transportation and S&T Transactional actual and forecast revenues can be found at Exhibit C1, Summary Schedule 5.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: Pages 2 and 3

In what years did TCPL offer an FT RAM credit? Were Union's FT RAM revenue subject to the Earnings Sharing Agreement in each year over the recent IRM period? Please discuss, showing amounts of FT RAM credits in each year. If not, why not? Please discuss fully. Were the FT RAM credits Z-factors for each IRM year during which Union participated in them? Please discuss.

Response:

Please see Attachment 1 for a timeline of what years TCPL offered RAM credits. Please see the response at Exhibit J.C-4-7-1 c).

Please see the response at Exhibit J.C-4-7-9 d) for the amount of RAM credits generated by year. RAM credits do not meet the Z-factor criteria in Union's current IRM.

Filed: 2012-05-04
EB-2011-0210
J.D-1-16-2
Attachment 1

TransCanada

TransCanada PipeLines Limited
450 - 1st Street S.W.
Calgary, Alberta, Canada T2P 5H1

Tel: (403) 920-2046
Fax: (403) 920-2347
Email: murray_sondergard@transcanada.com

January 16, 2009

National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta
T2P 0X8

Filed Electronically

Attention: Ms. Claudine Dutil-Berry, Secretary

Dear Ms. Dutil-Berry:

Re: TransCanada PipeLines Limited ("TransCanada")
Amendments to TransCanada's Canadian Mainline Transportation Tariff

TransCanada hereby files an application with the National Energy Board ("Board") pursuant to Section 60(1)(b) of the *National Energy Board Act* for an order or orders approving certain amendments to TransCanada's Mainline Transportation Tariff's Interruptible Transportation ("IT") Toll Schedule. The proposed amendments were presented to the Tolls Task Force ("TTF") and were unopposed by the TTF in Resolution 04.2009, FT-RAM, STS-RAM and STSL-RAM Permanent Tariff Feature, voted on January 7, 2009.

TTF Resolution 04.2009 describes amendments to the IT Toll Schedule to add the current Risk Alleviation Mechanism ("RAM") for Firm Transportation ("FT") Service, Storage Transportation Service ("STS") and Storage Transportation Linked Service ("STS-L") as permanent features of the Mainline transportation services.

The FT-RAM pilot was originally approved by the Board in a letter dated July 15, 2004 as a feature of FT service for a one year period commencing November 1, 2004 per TTF Resolution 02.2004. The FT-RAM pilot was subsequently extended for a period of one year by the Board in a letter dated September 6, 2005 as per TTF Resolution 20.2005 and again by the Board in a letter dated April 21, 2006 as per TTF Resolution 05.2006. Modifications to apply the FT-RAM pilot to short-haul contracts were made effective April 1, 2006 by Board Order TG-1-2006, and in accordance with the Board's decision in RHW-2-2005.. In a letter dated March 2, 2007, the Board approved an additional two-year extension of the FT-RAM pilot commencing November 1, 2007 as per TTF Resolution 03.2007 and extended the FT-RAM pilot to include Storage Transportation Service (STS-RAM) and Storage Transportation Service Linked (STSL-RAM) for a two-year term commencing November 1, 2007 as per TTF Resolution 02.2007.

During the various RAM pilot periods, the mechanism has been used by a broad spectrum of shippers including producers, producer/marketers, LDCs and end-users TransCanada notes that use of the RAM mechanism does not limit the service entitlements of current FT service.

In support of its application, TransCanada attaches for the Board's information blacklined and clean copies of the IT Toll Schedule and a copy of TTF Resolution 04.2009. TransCanada proposes that these changes become effective November 1, 2009.

Should the Board require additional information, please contact Stella Morin at (403) 920-6844 or stella_morin@transcanada.com.

Yours truly,

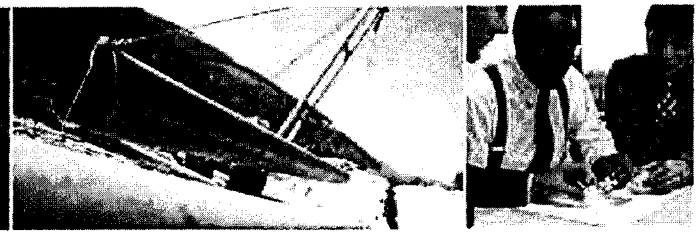
Original Signed by

Murray Sondergard
Director, Regulatory Services

Attachments

cc: Tolls Task Force (on-line notification)
Mainline Customers (on-line notification)

Tolls Task Force



2008 TOLLS TASK FORCE ISSUE	
Date Accepted As Issue: September 4, 2008	**Resolution:** 04.2009
Date Issue Originated: September 4, 2008	**Sheet Number:** 1 of 3
Issue Originated By:	Shell Energy North America (Canada) Inc.
Individual to Contact: Tomasz Lange	**Telephone Number** (403) 216-3580

ISSUE: FT-RAM, STS-RAM and STSL-RAM Permanent Tariff Feature

RESOLUTION:

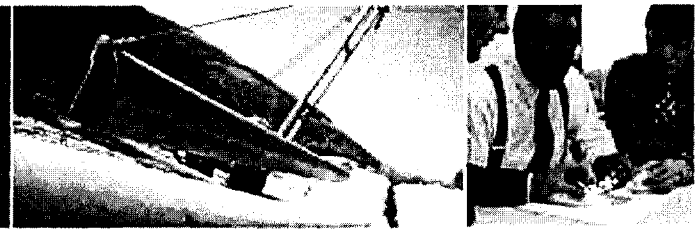
The TTF agrees to the addition of the current FT - Risk Alleviation Mechanism (FT-RAM), STS-RAM and STSL-RAM pilots, to the TransCanada tariff as permanent features of the transport services effective November 1, 2009 as per the attached black lined IT Toll Schedule.

BACKGROUND:

On May 6, 2004 the TTF approved, as an unopposed resolution, the initial FT-RAM pilot (Resolution 02.2004) for a one-year period beginning November 1, 2004. The initial pilot program was adopted as a flexibility feature of long-haul FT contracts only. Long-haul FT contracts are those contracts, which have a primary receipt point originating from Empress or Saskatchewan.

On August 3, 2005 the TTF approved, as an unopposed resolution, an extension of the FT-RAM pilot for an additional one-year term commencing November 1, 2005 and ending October 31, 2006 (Resolution 20.2005).

On February 24, 2006 the NEB approved an application by Coral Energy Canada (now Shell Energy North America (Canada) Inc.) for modifications to the FT-RAM pilot effective April 1, 2006 and ending October 31, 2006, to extend FT-RAM credits to short-haul contracts, which when combined with a long-haul contract create a continuous long-haul contract (Board Order TG-1-2006 in RHW-2-2005 proceeding).



The short-haul and long-haul contracts must be held by the same shipper and must share a common location; i.e. the receipt point of the short-haul contract must be the same as the delivery point of the long-haul contract. For example, a Dawn to EDA short-haul contract when combined with a long-haul contract from Empress or Saskatchewan to SWDA if held by the same shipper, effectively results in a long-haul contract to EDA. In keeping with the intent of the FT-RAM Pilot of encouraging firm long-haul contracts, FT-RAM credits will be granted on the full path or both contracts.

On April 5, 2006 the TTF approved, as an unopposed resolution, an extension of the FT-RAM pilot, as modified by the NEB in the RHW-2-2005 decision, for an additional one-year period commencing November 1, 2006 and ending October 31, 2007 (Resolution 05.2006).

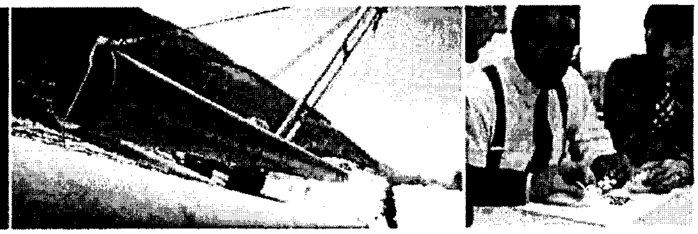
On February 9, 2007 the TTF approved, as an unopposed resolution, an extension of the FT-RAM pilot for an additional two-year term commencing November 1, 2007 and ending October 31, 2009 (Resolution 03.2007)

Also on February 9, 2007 the TTF approved, as an unopposed resolution, a new RAM pilot for Storage Transportation Service and Storage Transportation Service Linked (STS-RAM and STSL-RAM) for a two-year term commencing November 1, 2007 and ending October 31, 2009 (Resolution 02.2007). On July 4, 2007 the TTF approved, as an unopposed resolution, tariff language for the STS-RAM and STSL-RAM pilot (Resolution 08.2007). STS service was originally designed to work in combination with LDC held long-haul FT service on TransCanada and with market storage. It was designed to allow LDCs to meet seasonal and daily fluctuations in market demand while maintaining their long-haul service at a high load factor. STS shipper must hold long-haul FT. The flow of gas and the capacity rights are virtually identical under STS and STSL. The only difference is that under STS, the long-haul contract is held by the LDC, whereas under STSL, the end-users and marketers hold the long-haul contract.

RAM is a tool to mitigate unabsorbed demand charges and provides greater flexibility in order to give shippers increased confidence in contracting for long-haul FT service on the TransCanada Mainline. The motivation behind RAM is to promote the renewal of and incremental contracting for long-haul FT service. During the various pilot periods, the mechanism has been used by a broad spectrum of shippers including producers, producer/marketers, LDCs and end-users. The mechanism will not limit the service entitlements of current FT service.

VOTING RESULTS:

Tolls Task Force



Unopposed resolution at the January 7, 2009 TTF meeting in Calgary.

UNION GAS LIMITED

Undertaking of Ms. Elliott
To Mr. Aiken

Please update chart at J.DV-2-2-1, Attachment 1, to exclude impact of FT RAM.

Please see the Attachment.

Union Gas Limited
Summary of Transportation and Exchange Services
For the Years Ending December 31

Line No.	Particulars ($000's)		Actual 2010 (a)	Actual 2011 (b)	Forecast 2012 (c)	Forecast 2013 (d)
	Transportation and Exchange Services Previously Account #179-69					
1	Net Revenue (Excluding FT-RAM Revenue)	(1)	21,400	22,245	17,986	20,186
2	Less: Costs (Excluding Costs Applicable to FT-RAM Revenue)		11,592	7,792	7,671	6,448
3	Gross Margin		9,808	14,453	10,315	13,738
4	Less: Board Approved Margin in Rates		6,883	6,883	6,883	13,738
5	Hypothetical Deferred Margin	(2)	2,925	7,570	3,432	-

Note:
(1) Revenue less direct costs to provide exchange services.
(2) Margin would have been subject to earnings sharing.

UNION GAS LIMITED

Undertaking of Ms. Elliott
To Mr. Aiken

Please update table from JT1.13 to reflect year-to-date June actual and forecasts, and break out FT RAM credits included in line 4 as a separate line item.

Please see the Attachment.

UNION GAS LIMITED
Summary Revenue from Storage and Transportation of Gas

Line No.	Particulars ($000's)	Actual 2012 (June YTD) (a)	Forecast 2012 (June YTD) (b)	Difference (c)
	Transportation			
1	M12 Transportation	67,669	67,716	(47)
2	M12-X Transportation	2,208	2,215	(7)
3	C1 Long-term Transportation	3,643	3,391	252
4	C1 Short-term Transportation	6,017	6,467	(450)
5	Exchanges - Base	6,628	4,000	2,628
6	Exchanges - Net RAM	19,859	6,997	12,862
7	C1 Rebate Program	-	-	-
8	M13 Transportation	152	182	(30)
9	M16 Transportation	287	312	(25)
10	Other S&T Revenue	513	533	(20)
11	Total Transportation Revenue	106,976	91,813	15,163
	Storage			
12	Short-term Storage Services	5,834	3,125	2,709
13	Off-Peak Storage/Balancing/Loan Services	1,259	1,250	9
14	Total Storage Revenue	7,093	4,375	2,718
15	Total S&T Revenue	114,069	96,188	17,881

UNION GAS LIMITED

Undertaking of Mr. Isherwood
To Mr. Brett

Please provide derivation of net proceeds, how they are generated and reported.

The demand charge outlined in J3.3 represents the TCPL demand charge for the Eastern Zone (EZ). Since ratepayers require this supply, it is purchased at Empress and delivered to Union's market areas, and accordingly, the TCPL demand charge continues to be paid by ratepayers. The net proceeds described in Exhibit J3.3 are the net proceeds generated by optimizing this capacity. The net proceeds are comprised of two components.

1) The value received from third parties for the capacity assignment, net of the cost of the exchange to redeliver Union's supply to its markets (eg. Dawn in the summer; WDA or NDA in the winter). The net value of this transaction is captured in the exchange agreement with the third party. An example of this exchange agreement can be found at J.C-4-7-10 Attachment 3.
2) The incremental cost incurred as a result of moving gas to different market areas, if applicable. For example, as a result of a release of Empress to EDA capacity, Union may incur incremental STS withdrawal charges to serve the EDA market.

Example: November, 2009

In November, 2009, Union assigned 80,000 GJ's of Eastern Zone (EDA & CDA) capacity.

Union continued to buy commodity to fill in the pipe at Empress and to flow this supply to Union's market. Ratepayers were charged the Eastern Zone toll of $33.37571/GJ/month, or approximately $1.10/GJ/day, as if the gas landed in the Eastern Zone, consistent with the gas supply plan. This equates to $2.67 million for the month for the transport. This is the same amount ratepayers would have paid regardless if the capacity assignment was transacted or not. This payment is fixed and is not part of the Net Proceeds calculation found in Exhibit J3.3.

Exchange Revenue Impact:
S&T assigned Eastern Zone capacity to third parties and transacted an exchange with these same parties to redeliver the capacity to the NDA (40,000 GJ/d) and WDA (40,000 GJ/d). For this combined transaction, the third parties paid Union $0.31/GJ for quantities redelivered to the WDA and $0.545 for quantities redelivered to the NDA. Since the net value of the capacity assignment and the exchange were combined into one transaction, Union is unable to determine the exact value of each independent component. However, a comparison can be made between this net value and the difference in the tolls between the Eastern Zone and where the gas was redelivered, as shown in the table below:

Example: November, 2009 $/GJ/d	**NDA Redelivery 40,000 GJ/d**	**WDA Redelivery 40,000 GJ/d**
TCPL Eastern Zone transportation demand charge	$1.10	$1.10
Redelivery area transportation demand charge	$0.84	$0.55
Toll Difference between market areas	$0.26	$0.55
Third Party Assignment/Exchange net value	$0.31	$0.545
Exchange Revenue ($'s)	$372,000 (1)	$654,000
	Total Exchange Revenue:	$1,026,000

In this example, the above table illustrates the exchange revenue of $0.31/GJ (NDA redelivery) and $0.545/GJ (WDA redelivery) is very close to the toll differences between market areas. The market would have considered this toll difference when valuing the transaction.

For the month of November 2009, the total exchange revenue from the NDA and WDA redeliveries is $1,026,000. Deducted from this are incremental costs incurred as a result of the transaction (e.g. STS withdrawal costs) of $277,000 to derive the net proceeds of $749,000. These net proceeds are captured as the Capacity Assignment component of Net Revenue attributable to RAM benefit as reported at Exhibit J.C-4-7-9.

Alternatively, a similar transaction could have been completed had Union retained the capacity. S&T could have left the Empress-Eastern Zone capacity empty, earning RAM credits of $1.10/GJ (2). Using the NDA as an example, S&T could have flowed the supply purchased at Empress to the NDA, using RAM credits of $0.84/GJ (2). The 'excess' RAM credits of $0.26/GJ (2) could then have been used to fund other S&T exchanges. The proceeds from these exchanges (net of any incremental costs) would be captured as the RAM Optimization component of Net Revenue attributable to RAM benefit as reported at Exhibit J.C-4-7-9.

Regardless of which option would have been chosen, the operational result (gas purchased at Empress and delivered to Union's delivery areas) and the ability to earn an economic benefit would be identical. Both options are a direct result of S&T taking action to optimize the gas supply plan due to the existence of the RAM program. The resulting revenues are treated as regulated Transportation and Exchange revenue.

(1) Exchange revenue example calculation: 40,000 GJ/d * 30 days * $0.31/GJ = $372,000
(2) The daily demand charge of $1.10/GJ for Eastern Zone and $.84/GJ for NDA was used as RAM calculation for ease of comparison to capacity release example.

UNION GAS LIMITED

Undertaking of Mr. Isherwood
To Mr. Thompson

Please provide a forecast for the balance of 2012, assuming FT RAM continues for the balance of the year.

As filed in J6.3, year-to-date June exchange revenue related to RAM is $19.9 million. Union estimates RAM-related activity for the balance of 2012 to be an additional $17.9 million, for an annual total of $37.8 million. This includes $3.6 million of the estimated impact of RAM continuing for November and December as filed in J.C-4-7-9 c).

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit C1, Tab 3, Table 4

Please update the status of the TCPL FT-RAM Program.

Response:

The status of the TCPL FT-RAM program will be determined in TCPL's Restructuring and Tolls Proceeding which is now before the National Energy Board (RH-003-2011). Within its application, TCPL has proposed that the FT-RAM program be discontinued effective January, 2013.

Union, as part of the Market Area Shippers group has submitted evidence supporting its continuation.

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit C1, Tab 3, pg 12, lines 5-6 "The single biggest factor contributing to growth in exchange revenue was the utilization of the TCPL FT RAM program starting 2008."
Exhibit C1, Tab 3, pg 11, lines 13-14 "The 2012 forecast assumes the TCPL FT RAM program will be eliminated on November 1, 2012. A full year impact of FT RAM program being discontinued is reflected in 2013."
Exhibit D1, Tab 1, pg 3, line 2

Preamble: TransCanada has applied to the National Energy Board to eliminate the RAM feature of TransCanada's FT service and Union and others have filed evidence in support of retaining RAM. Due to the uncertainty thus surrounding FT RAM, and the impact of potential FT RAM revenues on the Short-Term Transportation and Exchanges Revenue Forecast, TransCanada seeks to better understand the historical and forecast amount of revenue attributable to FT RAM and how the uncertain future of FT RAM will be managed by Union with respect to the 2013 rates.

a) Please provide the following historical information, for November 2007 to March 2012, by month:
   i) Total revenue attributable to FT RAM, in dollars.
   ii) Average revenue attributable to FT RAM, in $/GJ.

b) Please provide the following forecast information, for the months of April 2012 through to December 2012, by month:
   i) Total revenue attributable to FT RAM, in dollars.
   ii) Average revenue attributable to FT RAM, in $/GJ.

c) In the event FT RAM is not discontinued as of November 1, 2012, please describe how Union will alter the Short-Term Transportation and Exchange Revenue forecast for 2012-2013 for the purposes of establishing rates.

d) Please provide the amount of FT RAM credits, in dollars, that Union has generated by month since November 2007.

e) Please provide a monthly breakdown of the Exchange Revenue shown in Exhibit C1, Tab 3 Table 4 into the following categories:

   i) Use of Union's upstream transportation capacity to provide exchange services to third parties.

   ii) Net revenue generated from capacity releases

   iii) Revenue obtained as a result of TCPL's FT RAM program.

   iv) Other

   v) Total exchange revenue.

f) Please explain how the 2013 Exchange Revenue forecast is treated in determining Union's revenue requirement.

g) Please explain how any variance between actual and forecast 2013 Exchange Revenue is allocated between Union shareholders and Union ratepayers.

Response:

a) Please see Attachment 1, lines 1 and 2.

b) Please see Attachment 1, lines 1 and 2.

c) For 2012, Union forecasted revenue of $14.2 million attributable to RAM, assuming the RAM program was eliminated November 1, 2012. If TCPL's RAM program is not eliminated on November 1, 2012, Union's 2012 forecast of exchange revenue attributable to RAM would increase by $3.6 million to $17.8 million. For 2012, exchange revenues, including those associated with RAM, are subject to Union's EB-2007-0606 earnings sharing mechanism.

   If TCPL's RAM program is not eliminated on November 1, 2012, Union's 2013 revenue forecast attributable to RAM would be $11.6 million. The forecast of $11.6 million assumes the structure and parameters of TCPL's RAM program does not change materially, and is based on actual 2011 activity. The 2013 revenue decreases compared to the 2012 forecast are due to expected TCPL toll reductions, price anomaly corrections, and turnback of some of Union's capacity on TCPL.

   For 2013, there are two primary options to manage the possibility of TCPL's RAM program continuing beyond 2012:

1. Increase the S&T forecast to include revenue of $11.6 million and create a deferral account to manage the difference between the forecast revenue and the actual revenue attributable to RAM; or,

2. Maintain the current S&T forecast and create a deferral account to manage the difference between the forecast revenue and the actual revenue attributable to RAM.

d) Please see Attachment 1 Table 1, line 3.

e)

i. Please see Attachment 2 Table 2, line 1.
ii. Please see Attachment 2 Table 2, line 2.
iii. Please see Attachment 2 Table 2, line 3.
iv. Please see Attachment 2 Table 2, line 4.
v. Please see Attachment 2 Table 2, line 6.

f) The exchange revenue forecast of $9.1 million for 2013 is included as a reduction to delivery rates. Please see Union's S&T transactional margin included in the 2013 in-franchise rates at Exhibit H3, Tab 10, Schedule 1, Updated.

g) Union will retain the variance, positive or negative, between the 2013 forecast and actual exchange revenues, subject to the earnings sharing mechanism associated with Union's incentive regulation framework.

Impact of RAM Program *
$ Millions **

Line No.		2007	2008	2009	2010	2011	2012 Forecast
1	Net Revenue Attributable to RAM Benefit ***	$ 0.4	$ 5.0	$ 14.0	$ 11.7	$ 22.0	$ 14.2
2	Net Revenue ($/GJ)****	$ 0.01	$ 0.03	$ 0.09	$ 0.08	$ 0.16	$ 0.11
3	RAM credits generated	$ 1.1	$ 16.7	$ 14.5	$ 31.8	$ 32.2	n/a

* Includes STS and FT RAM
** Unless otherwise noted
*** Union's approximation of exchange revenue related to the RAM program. This is a subset of Net Exchange Revenue.
**** Net Revenue ($/GJ) calculated using Union's contracted quantities eligible for STS and FT RAM.

Components of Net Exchange Revenue
$Millions

Line No.		2007	2008	2009	2010	2011	2012 Forecast	2013 Forecast
1	Base exchanges	$ 3.0	$ 6.6	$ 6.5	$ 8.0	$ 9.7	$ 6.9	$ 9.1
	RAM Revenue:							
2	Capacity Assignments	0.4	3.1	10.2	10.7	14.4	1.4	-
3	RAM Optimization *	-	0.0	2.8	4.7	9.6	13.7	-
4	Other	-	1.9	1.0	(3.7)	(2.0)	(0.9)	-
5	Subtotal **	$ 0.4	$ 5.0	$ 14.0	$ 11.7	$ 22.0	$ 14.2	-
6	Total Net Exchange Revenue	$ 3.40	$ 11.60	$ 20.50	$ 19.70	$ 31.70	$ 21.1	$ 9.1

* Union's approximation of exchange revenue related to the RAM program. Includes
** Net revenue attributable to RAM benefits.

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit C1, Tab 3, pg 12, lines 5-6 "The single biggest factor contributing to growth in exchange revenue was the utilization of the TCPL FT RAM program starting 2008."
Exhibit C1, Tab 3, pg 11, lines 17-19 "Exchange revenue is comprised of activity using Union's upstream transportation capacity to provide exchange services to third-parties. It also includes net revenue generated from pipe releases or revenue from TCPL's FT RAM program."

Preamble: TransCanada requires more information about Union's Exchange Revenues to be able to determine if the 2013 Short Term Transportation and Exchanges Revenue Forecast is appropriate.

a) Please provide a detailed description of how Union obtains revenue as a result of FT RAM.

b) Please provide sample agreements of each type of transaction that results in the FT RAM revenue as described in reference 1 and 2.

c) Please provide, by month since 2008, quantities of FT capacity that Union has assigned to other counterparties that generated Exchange revenue or otherwise reduced Union's transportation costs. For each assignment, please provide the quantity, assignee, toll, and path of the transport assigned.

d) Please explain how Union exchanges gas between points on the Union system and points on the TransCanada system.

e) Please explain what transportation service is used to affect the exchange and how Union determines what to charge for the service.

f) Are exchanges done on a firm basis or an interruptible basis?

Response:

a) Union recognizes the benefit of the RAM Program in three general ways.

First, when balancing supply for its system customers, Union periodically has excess TCPL capacity that Union releases in the market. Union sees higher value for that capacity due to the RAM feature. All proceeds from that released capacity, including those higher proceeds earned as a result of the RAM Program, are returned directly to system customers to offset Unabsorbed Demand Charges (UDC).

Second, prior to November, 2007, Union used the RAM program primarily to fund a base minimal level of Interruptible Transportation (IT) to manage LBA fees in its northern delivery areas. Union expects this base level of IT to continue, regardless of the RAM program.

Third, starting in 2007, Union realized benefits of the RAM Program when optimizing its transportation portfolio. Union began to assign various long-haul firm transportation assets on a monthly, seasonal and annual basis in order to realize some of the value the market placed on TCPL pipe as a result of the RAM program. Since Union continued to purchase supply at Empress, alternative arrangements were required to deliver these supplies to Union's market once the capacity was assigned.

In 2008, Union began to use the RAM program by applying available RAM credits earned on empty FT pipe to transport Empress supplies to various delivery areas to meet market demands for customers. The flexibility to apply RAM credits to any path allowed Union to deliver supply to franchise customers across multiple delivery areas, such as the MDA, WDA, NDA, SSMDA, NCDA, CDA, EDA and SWDA. In addition, these credits could be used alone, or in combination with, other assets to serve exchanges to customers outside Union's franchise area. The credits earned via the RAM program are one of the resources Union employed to serve our customers.

b) Union's standard exchange agreements are included as Attachments 3 and 4 and can be found on Union's website at: http://www.uniongas.com/storagetransportation/resources/pdf/standardcontracts/Confirmation_Exchange.pdf for interruptible agreements and http://www.uniongas.com/storagetransportation/resources/pdf/standardcontracts/EnhancedExchangeAgreement.pdf for firm agreements.

c) Please see Attachment 1 and 2. Attachment 1 reports capacity assignments by month and by zone from November, 2007 which are related to RAM. It does not include any capacity assignments to Union's franchise customers. Attachment 2 shows TCPL tolls also by month and by zone from November 2007.

Union has not identified assignees as that information is commercially sensitive.

d) Union exchanges gas between Dawn and points east or west of Parkway by utilizing TCPL's interruptible transportation services as well other TCPL services such as diversions of firm contracts.

e) Interruptible services provided by TCPL are used to effect the exchange. When negotiating with customers for exchange services, Union includes in its considerations the basis differentials between points of receipt and delivery and the costs of providing the service.

f) Exchanges are done on both a firm and interruptible basis.

Capacity Assignments*

GJ/d

Line No.	Receipt Point	Delivery Area	Winter 07/08					Summer '08						
			Nov '07	Dec '07	Jan '08	Feb '08	Mar '08	Apr '08	May '08	June '08	Jul '08	Aug '08	Sept '08	Oct '08
1	Empress	Eastern Zone	-	35,000	35,000	35,000	35,000	65,753	80,753	60,753	60,753	60,753	65,753	65,753
2	Empress	Northern Zone	-	-	-	-	-	5,000	5,000	5,000	5,000	5,000	5,000	5,000
3	Empress	Western Zone	-	-	-	-	-	-	-	-	12,000	12,000	8,000	5,000

Line No.	Receipt Point	Delivery Area	Winter 08/09					Summer '09						
			Nov '08	Dec '08	Jan '09	Feb '09	Mar '09	Apr '09	May '09	June '09	Jul '09	Aug '09	Sept '09	Oct '09
4	Empress	Eastern Zone	28,000	48,000	48,000	48,000	48,000	77,556	97,556	97,556	108,556	108,556	108,556	97,556
5	Empress	Northern Zone	8,000	8,000	8,000	8,000	8,000	-	-	-	-	40,000	-	30,000
6	Empress	Western Zone	-	-	-	-	-	-	-	-	-	-	-	20,000

Line No.	Receipt Point	Delivery Area	Winter 09/10					Summer '10						
			Nov '09	Dec '09	Jan '10	Feb '10	Mar '10	Apr '10	May '10	June '10	Jul '10	Aug '10	Sept '10	Oct '10
7	Empress	Eastern Zone	80,000	80,000	80,000	80,000	80,000	92,832	92,832	92,832	92,832	92,832	92,832	92,832
8	Empress	Northern Zone	20,062	20,062	-	-	-	-	30,000	40,000	40,000	40,000	40,000	20,000
9	Empress	Western Zone	-	-	-	-	-	-	-	-	-	-	-	-

Line No.	Receipt Point	Delivery Area	Winter 10/11					Summer 11						
			Nov '10	Dec '10	Jan '11	Feb '11	Mar '11	Apr '11	May '11	June '11	July '11	Aug '11	Sept '11	Oct '11
10	Empress	Eastern Zone	60,000	60,000	60,000	60,000	60,000	60,000	96,796	110,000	110,000	110,000	110,000	110,000
11	Empress	Northern Zone	-	-	-	-	-	40,000	40,000	49,000	49,000	49,000	49,000	49,000
12	Empress	Western Zone	-	-	-	-	-	-	-	-	-	-	-	-

Line No.	Receipt Point	Delivery Area	Winter 11/12					Summer 12	
			Nov '11	Dec '11	Jan '12	Feb '12	Mar '12	Apr '12	May '12
13	Empress	Eastern Zone	74,796	60,000	60,000	60,000	80,000	117,796	117,796
14	Empress	Northern Zone	-	-	-	-	-	40,000	48,500
15	Empress	Western Zone	-	-	-	-	-	-	-

* not including capacity assignments to Union's franchise customers

100% Load Factor Posted Tolls

$C/GJ

Line No.	Receipt Point	Delivery Area	Winter 07/08					Summer '08						
			Nov '07	Dec '07	Jan '08	Feb '08	Mar '08	Apr '08	May '08	June '08	Jul '08	Aug '08	Sept '08	Oct '08
1	Empress	Eastern Zone	1.03032	1.03032	1.09000	1.09000	1.09000	1.31000	1.31000	1.39999	1.39999	1.39999	1.39999	1.39999
2	Empress	Northern Zone	0.79389	0.79389	0.83269	0.83269	0.83269	1.02310	1.02310	1.09338	1.09338	1.09338	1.09338	1.09338
3	Empress	Western Zone	0.51804	0.51804	0.55056	0.55056	0.55056	0.67581	0.67581	0.72208	0.72208	0.72208	0.72208	0.72208
			Winter 08/09					Summer '09						
			Nov '08	Dec '08	Jan '09	Feb '09	Mar '09	Apr '09	May '09	June '09	Jul '09	Aug '09	Sept '09	Oct '09
4	Empress	Eastern Zone	1.39999	1.39999	1.19000	1.19000	1.19000	1.19000	1.19000	1.19000	1.19000	1.19000	1.19000	1.19000
5	Empress	Northern Zone	1.09338	1.09338	0.91313	0.91313	0.91313	0.91313	0.91313	0.91313	0.91313	0.91313	0.91313	0.91313
6	Empress	Western Zone	0.72208	0.72208	0.59425	0.59425	0.59425	0.59425	0.59425	0.59425	0.59425	0.59425	0.59425	0.59425
			Winter 09/10					Summer '10						
			Nov '09	Dec '09	Jan '10	Feb '10	Mar '10	Apr '10	May '10	June '10	Jul '10	Aug '10	Sept '10	Oct '10
7	Empress	Eastern Zone	1.19000	1.19000	1.63808	1.63808	1.63808	1.63808	1.63808	1.63808	1.63808	1.63808	1.63808	1.63808
8	Empress	Northern Zone	0.91313	0.91313	1.25894	1.25894	1.25894	1.25894	1.25894	1.25894	1.25894	1.25894	1.25894	1.25894
9	Empress	Western Zone	0.59425	0.59425	0.81513	0.81513	0.81513	0.81513	0.81513	0.81513	0.81513	0.81513	0.81513	0.81513
			Winter 10/11					Summer 11						
			Nov '10	Dec '10	Jan '11	Feb '11	Mar '11	Apr '11	May '11	June '11	July '11	Aug '11	Sept '11	Oct '11
10	Empress	Eastern Zone	1.63808	1.63808	1.63808	1.63808	2.24290	2.24290	2.24290	2.24290	2.24290	2.24290	2.24290	2.24290
11	Empress	Northern Zone	1.25894	1.25894	1.25894	1.25894	1.74219	1.74219	1.74219	1.74219	1.74219	1.74219	1.74219	1.74219
12	Empress	Western Zone	0.81513	0.81513	0.81513	0.81513	1.13287	1.13287	1.13287	1.13287	1.13287	1.13287	1.13287	1.13287
			Winter 11/12					Summer 12						
			Nov '11	Dec '11	Jan '12	Feb '12	Mar '12	Apr '12	May '12					
13	Empress	Eastern Zone	2.24290	2.24290	2.24290	2.24290	2.24290	2.24290	2.24290					
14	Empress	Northern Zone	1.74219	1.74219	1.74219	1.74219	1.74219	1.74219	1.74219					
15	Empress	Western Zone	1.13287	1.13287	1.13287	1.13287	1.13287	1.13287	1.13287					

[Union Gas Logo]

[HUB___B_____]
[SA_____]
[Agreement Date]

Confirmation

Exchange

Attention: [Shipper Rep]

This Exchange Confirmation ("**Confirmation**") incorporates all of the terms and conditions of the Interruptible Service Hub Contract ([HUB___]) between Union Gas Limited ("**Union**") and [Shipper Name] ("**Shipper**") dated [Latest Amendment Date] (the "**Contract**"). All terms and conditions contained in the Contract, and any Schedules referenced by the Contract as amended from time to time, shall apply to this Confirmation, unless specifically set forth herein. In the event of any conflict or inconsistency between the terms and conditions of this Confirmation and those of the Contract, the terms and conditions of this Confirmation shall prevail.

Confirmation terms and conditions:

Service Type: Interruptible	
Term Start: [start date]	**Term End:** [end date]
Receipt Point (to Union): [receipt point]	**Delivery Point (to Shipper):** [delivery point]
Minimum Quantity: [Quantity] GJ/day ([converted] MMBtu/day)	**Maximum Quantity:** [Quantity] GJ/day ([converted] MMBtu/day)
Fuel: [fuel %] – up to [Quantity] GJ/day ([converted]mmbtu/day) at [location]	
Nominations: Must be received [hours] before the [window] nomination window	
Rate: Shipper agrees to pay Union $[Commodity Rate] [Currency]/[UOM] ([Converted Rate] [Currency] /[Converted UOM] which will be invoiced as utilized.	

If on any day Shipper fails to deliver the Authorized Quantity to any of the above noted Receipt Point(s), Shipper agrees to pay $0.1500000/GJ ($0.1582584/MMBtu) multiplied by the difference between the Authorized Quantity and the actual quantity delivered at the Receipt Point ("**Delivery Shortfall**") for every day that the Delivery Shortfall, or any portion thereof, remains, plus any verifiable costs incurred by Union that are directly attributable to Shipper's failure to deliver the Delivery Shortfall. Union retains the right to replace the Delivery Shortfall at any time throughout the period that the Delivery Shortfall, or any portion thereof, remains and Shipper shall use due diligence to deliver the Delivery Shortfall to Union promptly at the Receipt Point or Dawn (Facilities), as decided at Union's discretion. Should Union choose to replace the Delivery Shortfall, Shipper agrees to pay Union's costs to replace such gas at the Receipt Point or Dawn (Facilities), as decided at Union's discretion, plus an additional 25% of such costs.

If on any day, Shipper fails to accept the Authorized Quantity at any of the above noted Delivery Point(s) Shipper agrees to pay $0.1500000/GJ ($0.1582584/MMBtu) multiplied by the difference between the Authorized Quantity and the actual quantity accepted ("**Receipt Shortfall**") for every day that the Receipt Shortfall, or any portion thereof, remains, plus any verifiable costs incurred by Union that are directly attributable to the Shipper's failure to accept the Receipt Shortfall.

Shipper and Union agree that each party shall use reasonable efforts in order to balance as nearly as possible the quantity exchanged on a daily basis and to resolve any imbalances in a timely manner.

[Union Gas Logo]

All quantities will be converted to GJ for billing purposes. Conversion: 1 MMBtu = 1.055056 GJ.

This Confirmation may be signed and sent by facsimile or other electronic communication and this procedure shall be as effective as signing and delivering an original copy.

Please acknowledge your agreement to all of the above terms and conditions by signing and sending this Confirmation to Union Gas Limited at fax: (519) 358-4064 or email to both:
[email address of S&T Account Manager] and Storage.Transportation@uniongas.com.

Failure to provide a signed copy of this Confirmation to Union, or failure to object in writing to any specified terms in this Confirmation, within two business days of receipt of this Confirmation will be deemed acceptance of the terms hereof.

[Electronic Signature] ______________________

[S&T Account Manager] [Shipper Name]
Authorized Signatory

[Union Gas Logo]

[HUB___E___]
[SA_____]
[Month day, year]

(Note: This document shell is for obligated firm Agreements; interruptible and other less firm Agreements are also available; please contact your Account Manager.)

Attention: [Shipper Rep]

Enhanced Exchange Service Agreement

This Enhanced Exchange Service Agreement ("**Agreement**") incorporates all of the terms and conditions of the Interruptible Service Hub Contract ([HUB___]) between Union Gas Limited ("**Union**") and [Shipper Name] ("**Shipper**") dated [Latest Amendment Date] (the "**Contract**"). All terms and conditions contained in the Contract, and any Schedules referenced by the Contract, as amended from time to time, shall apply to this Agreement, unless specifically set forth herein. In the event of any conflict or inconsistency between the terms and conditions of this Agreement and those of the Contract, the terms and conditions of this Agreement shall prevail.

Agreement terms and conditions:

Service Type: [Firm]	
Term Start: [start date]	**Term End:** [end date]
Receipt Point (to Union): [receipt point]	**Delivery Point (to Shipper):** [delivery point]
Firm Exchange Quantity: [Quantity] GJ/day ([converted] MMBtu/day)	
Minimum Quantity: [Quantity] GJ/day ([converted] MMBtu/day)	**Maximum Quantity:** [Quantity] GJ/day ([converted] MMBtu/day)
Fuel: [fuel %] - [Quantity] GJ/day ([converted]mmbtu/day) at [location]	
Nominations: Must be received [hours] before the [window] nomination window.	
Rate: Shipper agrees to pay Union, a demand charge of $[Demand Charge] [Currency] which shall be invoiced in [#] equal monthly instalment(s).	

Shipper is obligated to deliver the Firm Exchange Quantity to the above noted Receipt Point(s), each and every day. If on any day Shipper fails to deliver the Firm Exchange Quantity to any of the above noted Receipt Point(s), Shipper agrees to pay $3.0000000/GJ ($3.1651680/MMBtu) multiplied by the quantity of gas not delivered to Union ("**Delivery Shortfall**"). In addition, should Union choose to replace such Delivery Shortfall, Shipper agrees to pay Union's costs to replace such gas at the Receipt Point or Dawn, as decided at Union's discretion, plus an additional 25% of such costs. If Union chooses not to replace such gas, Shipper agrees to pay $0.1500000/GJ ($0.1582584/MMBtu) for every day that the Delivery Shortfall, or any portion thereof, exists. Union retains the right to replace the Delivery Shortfall at any time throughout the period that the Delivery Shortfall, or any portion thereof, remains and Shipper shall use due diligence to deliver the Delivery Shortfall to Union promptly at Receipt Point or Dawn, as decided at Union's discretion.

Shipper is obligated to accept the Firm Exchange Quantity at the above noted Delivery Point(s) each and every day. If on any day, Shipper fails to accept the Firm Exchange Quantity at any of the above noted Delivery Point(s), Shipper agrees to pay $3.0000000/GJ ($3.1651680/MMBtu) multiplied by the quantity of gas not accepted ("**Receipt Shortfall**"), plus the verifiable costs

[Union Gas Logo]

incurred by Union that are directly attributable to the Shipper's failure to accept the Receipt Shortfall.

Shipper and Union agree that each party shall use reasonable efforts in order to balance as nearly as possible on a daily basis and to resolve any imbalances in a timely manner.

All quantities will be converted to GJ for billing purposes. Conversion: 1 MMBtu = 1.055056 GJ.

This Agreement may be signed and sent by facsimile or other electronic communication and this procedure shall be as effective as signing and delivering an original copy.

Please acknowledge your agreement to all of the above terms and conditions by signing and sending this Agreement to Union Gas Limited at fax: (519) 358-4064 or email Storage.Transportation@uniongas.com with a copy to [email address of S&T Account Manager] or mail to **Union Gas Limited, 50 Keil Drive North, P.O. Box 2001, Chatham, ON, N7M 5M1, Attention: S&T Contracting.**

[Union Representative] (519) 436-____
Account Manager, Union Gas Limited

Acknowledged and Accepted
this ______ day of [Month, year]

[SHIPPER]
Authorized Signatory

____

UNION GAS LIMITED
Authorized Signatory

____

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UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-Housing Providers of Ontario ("FRPO")

Ref: Exhibit C1, Tab 3, page 11

Union states "In order to mitigate this trend, TCPL introduced the Firm Transportation Risk Alleviation Mechanism ("FT RAM") program. This program gives firm shippers of long-haul capacity (or short-haul capacity linked to long-haul capacity) credits for any capacity left unutilized. These credits can then be spent, in the same month upon which they are earned, on any interruptible service on TCPL's system. The program was designed to encourage shippers to remain contracted on TCPL's system."

Since the purpose of FT-RAM is to mitigate the cost of holding long-haul transportation capacity, please provide:

a) Union's explanation of why the net revenues generated from RAM are streamed to Exchange Revenue as opposed to being recognized as a credit to the cost of long-haul TCPL service that is charged to customers.

b) The specific Board approval of a Union Gas request for this treatment of FT-RAM credits.

Response:

a) Net revenues generated from RAM are recorded as Exchange Revenue since this is the service type under which they are contracted and sold.

   Union's use of the RAM program was based on Union's IR mechanism per EB-2007-0606 and was further confirmed in the Board's Decision on Union's 2009 Rates Application per EB-2008-0220. The IR mechanism defined the parameters for earnings sharing, the principles of which were confirmed in practice in the EB-2008-0220 with respect to the DOS-MN service. Union applied these approved parameters to revenues generated through the RAM program.

   Specifically, in EB-2008-0220, the Board agreed that "benefits resulting from transactions to optimize transportation capacity...are recognized as part of Union's regulated S&T transactional activity", and that "the forecast margin for [this] activity included in rates was increased significantly in the 2007 rates settlement agreement". This provided "ratepayers with a <u>fixed level</u> of benefits from S&T transactional activity, and provided Union with a strong incentive to exceed that level of fixed benefit. Union is at risk for achieving the forecast results and is only rewarded if the net benefits exceed the threshold incorporated in rates".

In its decision, the Board stated "ratepayers have been already credited with an amount intended to reflect the transactional services activity of the company. Any additional revenues which may be occasioned by the new TransCanada [DOS-MN] service will not accrue under this heading, but may lead to earnings sharing distribution. In the Board's view this is a fair approach that is consistent with the general architecture of the IRM plan and the Settlement Agreement."

b) In Union's view, the RAM program provides comparable revenue opportunities to the DOS MN program and it is appropriate to account for these revenues in the same way.

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Isherwood

Please provide an actual numeric example of each of the categories to show how net revenue is calculated; to show all the costs associated with the transaction.

Below are the three categories that support Exchange revenue.

Base Exchange:

Example: Union sells Dawn-Niagara exchange for 20,000 GJ/d for one month at $0.35/GJ. Union serves this exchange with TCPL IT transportation.

Revenue from Dawn-Niagara Exchange	$217,000
Cost from Dawn-Niagara Exchange	
IT Cost	180,476
Fuel Cost	6,448
Pressure Charge	12,115
Total Cost	199,039
Net Revenue	$17,961

Capacity Assignment:

Example: Union assigns to a third party 20,000 GJ/d of Empress-Union EDA capacity for one month. The same counterparty also agrees to accept Union's supply at Empress and redelivers the equivalent quantity to Dawn. Customer pays Union $0.04/GJ. In this example, prior to the capacity assignment, the gas is not required in the EDA and would have been transported to Dawn for storage using TCPL STS service.

Revenue from pipe release	$240,000
Costs from pipe release	-
Net Revenue	$240,000

RAM Optimization:

Example: Union sells Dawn-Niagara exchange for 20,000 GJ/d for one month at \$0.35/GJ. Union serves this exchange with TCPL IT transportation funded by RAM credits.

Revenue from Dawn-Niagara exchange	$217,000
IT minimum charge	8,643
Fuel Cost	6,448
Pressure Charge	12,115
Total Costs	27,206
Net Revenue	$189,784

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Isherwood

Please advise whether Union will include a RAM forecast in the S&T forecast; since the future of the FT RAM program is unknown, does Union agree the deferral account for transportation exchange revenue is warranted.

---

a) As indicated at Exhibit J.C-4-7-9, Union would consider including FTRAM revenue in its 2013 S&T revenue forecast with a deferral account to capture any variance between the revenue attributable to FTRAM included in rates and the actual revenues attributable to FTRAM. The deferral account is necessary because of the uncertainty regarding the continuation of TCPL's FTRAM program and Union's ability to optimize the FTRAM program.

b) Union does not support the creation of a deferral account that captures transactional transportation margins in general.

K6.4

EB-2011-0210

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, 2013.

UNION GAS LIMITED

("Union")

DIRECT EXAMINATION COMPENDIUM

EX-FRANCHISE REVENUE

UNION GAS LIMITED

Answer to Interrogatory
from Northern Cross Energy Limited

Reference: Exhibit C1, Tab 3, page 8

Question

a) Please explain the nature and mechanics of an exchange. How is an exchange different from a swap?
b) With respect to the Ashfield storage pool, would Union enter into an exchange agreement for gas received by Union at the Ashfield storage pool connection to the Union system in exchange for gas delivered to Northern Cross Energy at Dawn? If not, why not?
c) What are the rates charged by Union for exchange services?

Answer

a) The reference given refers to an exchange. A reference to swaps is not found in this evidence. Typically an exchange refers to a physical transaction and a swap refers to a financial transaction as described below.

   An exchange is a contractual agreement where party 'A' agrees to give physical gas to Party 'B' at one location and Party B agrees to give physical gas to Party 'A' at another location. Either Party 'A' or Party 'B' may agree to pay the other party for this service. An exchange can only happen between a point on Union's system and a point off of Union's system. The exchange must also happen on the same day at the same time.

   A swap is a financial contract where Party 'A' agrees to 'swap' a floating price obligation for a fixed price obligation with Party 'B'. Party 'A' is swapping price uncertainty (the obligation under a floating priced contract) for price certainty (the obligation to pay a fixed price.) Physically gas does not flow between the two parties.

b) No, see part (a).

c) Exchanges are at negotiated rates.

Witness: David Dent / Steve Poredos
Question: July 24, 2003
Answer: August 7, 2003
Docket: RP-2003-0063

Long Term Peak Storage Premium

Particulars ($000's)	Actual 2002	Forecast 2003	Forecast 2004
Long Term Peak Storage			
Long Term Market Revenue	$18,660	$23,173	$33,531
Long Term Cost Based Revenue	13,491	13,022	15,979
Long Term Market Premium	$ 5,169	$ 9,806	$17,552

3. TRANSACTIONAL SERVICES FORECAST

Union offers a range of short-term transactional services including transportation, short term peak storage, balancing services, exchanges, Hub2Hub^{TM}, exchanges, name changes & redirections, and Ontario Production services.

FORECAST METHODOLOGY

Union forecasts the assets required to meet its in-franchise demands through the gas supply planning process. The Gas Supply Plan for 2004 is discussed at Exhibit D1, Tab 1. Ex-franchise firm requirements are then added to the in-franchise requirements and any remaining assets are used to support the sale of transactional services.

The Gas Supply Plan is based on the corporate forecast of general service and contract customer demand forecasts described at Exhibit C1, Tabs 1 and 2. The Gas Supply Plan allocates the required assets to provide annual and peak day capacity for in-franchise demands. With a balanced gas supply portfolio, which meets the forecast in-franchise and ex-franchise firm demands, there will be few, if any, firm assets available to support transactional services on a future planned basis. Thus, firm assets made available historically on an actual basis are not guaranteed to be available on a future planned basis with a balanced portfolio. Incremental firm assets tend to be available as a result of both weather and market variances. Under these circumstances S&T transactional revenues may be higher or lower than forecast.

Over the last few years, the level of S&T transactional revenue has been impacted by warmer weather and favourable market pricing conditions. In addition, certain TCPL services (e.g. FT make-up, AOS) that were approved and in place for 2002 only provided transactional revenue opportunities in 2002 and are no longer available. For 2003 and 2004, the Gas Supply Plan reflects a balanced or "normal' asset utilization forecast.

The actual assets available for S&T transactional services will change on an ongoing basis dependant upon actual weather and market factors including the amount of direct purchase switching, T-Service switching, in-franchise growth, changes in customer use, market prices, and customer demand for S&T services. Union's forecast for S&T transactional services for 2003 and 2004 reflects normal market and operating conditions.

The S&T transactional services market has declined dramatically over the last few years. The following summarizes some of the key market factors that will reduce the opportunities to generate transactional service revenues at the same levels as have been generated over the last few years:

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- The fallout from the Enron failure has significantly reduced the number of counter parties who contract for these services, and many of the traditional counter parties no longer exist.
- The remaining counter parties have reduced abilities to transact due to more onerous credit requirements being imposed by all market participants. This offsets both the level of the opportunities for transactional services and the cost. As an example, Union has seen a reduction of nearly 60% in title transfer activity at the Dawn hub from the last quarter of 2001 to the first quarter of 2003.
- Reduced summer/winter price differentials for natural gas have reduced year to year peak storage values from the historically high level in 2002 of approximately $1.50/GJ to $0.45/GJ to $0.75/GJ for 2003. Storage values change constantly during the year and are in general based on the summer/winter price differentials on the forward price curve.
- Forecast high commodity values are also expected to reduce natural gas demands in industrial and power generation markets in Canada and the US, thereby reducing ex-franchise transactional opportunities that have been available over the past few years.

Given the above impacts, Union prepared its transactional services forecast by considering logical "blocks" of services. Services have been grouped together in "blocks" where they have similar characteristics, are complementary, and/or are substitutes for one another. The following sections review the forecast for each of these "blocks" of services.

RP-2003-0063
EB-2003-0087
EB-2003-0097

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 for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, storage, and transmission of gas for the period commencing January 1, 2004.

BEFORE: Paul B. Sommerville
Presiding Member

Art Birchenough
Member

DECISION WITH REASONS

March 18, 2004

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Union stated that long term market revenue from the long term peak storage market would increase from the 2002 actual level of $18.7 million to forecast levels of $21.8 million in 2003 and $34.5 million in 2004 respectively. The long term market premium represents $5.2 million of this amount in 2002 and was forecast to represent $8.6 million and $20.6 million, respectively, for 2003 and 2004. Union attributed the increases in revenues and premiums to its expectation "that existing M12 contracts will renew under C1 market based rates as outlined above."

Transactional & Other Services Forecast

There are three components of this forecast. These are transportation and exchange revenues, balancing service block revenues, and other S&T services revenues. Short term services included in the forecast are transportation, peak storage, balancing services, exchanges, Hub2Hub™, name changes and redirections, and Ontario Production services.

Transportation and Exchange Revenues

Union's S&T transportation and exchange revenues for actual 2002 and updated forecast 2003 and 2004 are $12.5 million, $5.8 million and $2.5 million respectively. The corresponding deferred margins are $5.0 million, -$1.2 million and -$0.3 million respectively. The revenue minus costs yields the gross margin, while the gross margin minus the approved forecast yields the deferred margin.

Union stated that with a balanced gas supply portfolio that meets forecast in-franchise and ex-franchise demands, few firm assets are available on a planned basis to support these services. Asset availability is mainly influenced by weather and market variances. The latter variances include the amount of direct purchase switching, T-service switching, in-franchise growth, changes in customer use, market prices, and S&T demand. While actual results depend on actual weather conditions experienced, Union's forecast assumes normal conditions.

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Union cited the following reasons for the decline in the S&T market:

1. a reduction in the number of potential counterparties following the Enron failure;

2. the imposition of more onerous credit requirements on remaining counterparties, reducing the number of transactions;

3. a decrease in peak storage value from $1.50/GJ in 2002, to between $0.45/GJ and $0.75/GJ in 2003, due to reduced summer/winter price differentials for gas; and

4. the expectation that high forecast commodity prices will reduce transactional services demand in the industrial and power generation markets.

Balancing Service Block Revenues

Union's balancing service revenues and deferred margins decreased from $37.1 million in 2002 to a forecasted 2003 and 2004 of $13.4 and $7.5 million respectively. The corresponding deferred margins were $12.3 million in 2002, decreasing to forecast 2003 and 2004 levels of $3.7 million and $1.5 million respectively.

Union attributed the decreased margins on this block for 2003 and 2004 to a number of events in 2002, which are unlikely recur in 2004 including:

1. historically high value of storage in 2002;

2. incremental gas loan revenues due to favourable market conditions in 2002;

3. comparatively lower seasonal loan activity in 2003 due to prior warmer than normal weather; and

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4. incremental balancing activity in 2002 due to weather variations.

Other S&T Service Revenues

Union's other S&T Services revenue for actual 2002 and updated forecast 2003 and 2004 are $3.8 million, -$0.3 million and $0.9 million respectively. The corresponding deferred margins are $0.3 million, -$2.3 million and -$1.0 million respectively.

Union, in explaining the decline in these revenues, noted that it managed jointly with Encana a Hub2Hub™ service, whereby a customer delivers gas at the Alberta Energy Company price point ("AECO") hub and simultaneously receives gas at Dawn, so the service is a substitute for transportation. Union realized $3.1 million of revenue in 2002, and is forecasting $0.6 million in revenue for both 2003 and 2004. In response to an interrogatory, Union indicated that it agreed to wind down the service over 2003 and 2004 at Encana's request.

Position of the Parties

Intervenors expressed concerns about the appropriateness of Union's approach to embedding forecast S&T margins and long-term storage premiums into rates, including variance account treatment.

Numerous intervenors took the position that Union's proposed sharing ratios should be adjusted to provide a higher proportion for the ratepayer and less for the shareholder, including Kitchener, FONOM, LPMA, CAC, IGUA, CME, Schools and VECC.

Union's Position

Union asked the Board to accept its 2004 forecast of incremental S&T revenues of $20.8 million. Union noted that the Board has approved a 75:25 sharing for S&T transactional revenues since EBRO 499 and the same sharing proportion for the total of S&T revenues and the long-term storage premium since RP-1999-0017.

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Union took the position that to embed a greater fraction of the forecast margins into rates would expose Union to an inappropriate level of risk, and not reflect the Board's statements regarding incentive levels. Union submitted that if any percentage of the 2004 deferred margins were put into rates, the S&T and market premium deferral accounts should record positive or negative variations shared 75:25 in favour of the ratepayer.

Union proposed to embed the 1999 forecast of S&T margins in rates with any additional margin shared 75:25. Should the Board decide to embed more of the 2004 forecasted margins in rates, Union requested that 75% of the forecast be put in rates with a symmetric deferral treatment, shared 75:25 in favour of the ratepayer, of any variances.

Board Findings

The Board continues to support the methodology approved in EBRO 499 with respect to embedding forecast S&T margins and the Long-Term storage premium in base rates on a 90:10 basis. However, in this regard and in respect of its finding above, amounts to be embedded apply to forecast 2004 amounts, not to EBRO 499 forecasts that were approved for the 1999 test year.

The Board finds that symmetrical variance account treatment of these revenues is appropriate to hold ratepayers and Union harmless from deviations between actual margins earned and those embedded in rates. The Board further accepts that any such variances be shared 75:25 in favour of the ratepayer.

4.4 OTHER ISSUES

There are two other issues falling into this section. The first of these relates to the concerns expressed, particularly by FONOM et al relating to storage allocations to the Northern and Eastern Operations area, while the second relates to Union's changes in presentation in successive rates cases, with respect to classifications of such items as S&T revenues and customer supplied fuel.

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UNION GAS LIMITED

Accounting Entries for
Transportation and Exchange Services
Deferral Account No. 179-69

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 570 Storage and Transportation Revenue
Credit	-	Account No. 179-69 Other Deferred Charges - Transportation and Exchange Services

To record, as a credit (debit) in Deferral Account No. 179-69, the difference between actual net revenues for Transportation and Exchange Services including C1 Interruptible Transportation, Energy Exchanges, M12 Transportation Overrun, M12 and C1 Non-Loss-of-Critical-Unit Protected Firm Transportation, M12 Limited Firm/Interruptible Transportation and C1 Firm Short Term Transportation, and the net revenues forecast for these services as approved by the Board for rate making purposes.

UNION GAS LIMITED

**Accounting Entries for
Other S&T Services
Deferral Account No. 179-73**

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 570 Storage and Transportation Revenue
Credit	-	Account No. 179-73 Other Deferred Charges - Other S&T Services

To record, as a credit (debit) in Deferral Account No. 179-73, the difference between actual net revenues for Other S&T Services including Hub2Hub™, Offsystem Capacity, Redirection/Name Changes, Ontario Production and other S&T services and the net revenues forecast for these services as approved by the Board for rate making purposes.

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UNION GAS LIMITED

Accounting Entries for
Other Direct Purchase Services
Deferral Account No. 179-74

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 570 Storage and Transportation Revenue
Credit	-	Account No. 179-74 Other Deferred Charges - Other Direct Purchase Services

To record, as a credit (debit) in Deferral Account No. 179-74, the difference between actual net revenues for Supplemental Load Balancing (T1 and R1) and T1 Storage Inventory Demand Charge and the net revenues forecast for these services as approved by the Board for rate making purposes.

UNION GAS LIMITED

Accounting Entries for
Heating Value
Deferral Account No. 179-89

This account is applicable to the Northern and Eastern Operations of Union Gas Limited. Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179-89 Other Deferred Charges - Heating Value
Credit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-89, the difference between the actual heat content of the gas purchased and the forecast heat content included in gas sales rates.

Debit	-	Account No. 179-89 Other Deferred Charges - Heating Value
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-89, simple interest on the balance in Deferral Account No. 179-89. Interest will be computed monthly on the opening balance in said account at the short term debt rate as approved by the Board.

Union Gas Limited
Incentive Regulation Proposal
Prefiled Evidence

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1. As approved by the Board in the EB-2005-0520 Decision with Reasons dated June 29, 2006 Union will be splitting the M2 rate class into two rate classes (M1 and M2) (see Appendix B for the excerpt from Union's evidence and the Board Decision). The effect of this split will be included in the January 1, 2008 rate order.

2. Union requested pre-approval to change rates effective January 1, 2008 to incorporate incremental capital and O&M costs required to implement the Bill-Ready phase of the GDAR. There was complete settlement of this issue in the Settlement Agreement (see Appendix C for the excerpts from Union's evidence and the Settlement Agreement). As such, Union will adjust 2008 base rates accordingly effective January 1, 2008 and include this adjustment in the 2008 rate order. Should there be any changes to the timing of the implementation of the Bill-Ready phase; Union will address the impact on base rates once a decision is made by the Board.

3. In the EB-2005-0520 and EB-2005-0551 proceedings, Union requested that five S&T deferral accounts (179-70, 179-72, 179-69, 179-73 and 174-74) be eliminated. In EB-2005-0520, Exhibit C1, Tab 3, Union stated that it agreed with the Board's direction that, "in a true IR framework, there should be no earnings sharing, and transactional services revenues should not receive special treatment" (page 24). Union further stated that it, "believes that the elimination of S&T transactional service deferral accounts in 2007 is consistent with and supports the Board's direction to reduce deferral accounts and eliminate earnings sharing mechanisms as part of transitioning

to an IR framework." The Board specified on page 112 of the EB-2005-0551 Decision with Reasons that the proposed elimination of the three transmission-related accounts should be considered as part of a comprehensive review that includes all deferral accounts under an incentive regulation mechanism. Therefore, Union is requesting the elimination of the following three deferral accounts (Transportation Exchange Services Account (179-69), Other S&T Services Account (179-73) and Other Direct Purchase Services Account (174-74)) beginning January 1, 2008. Board staff supported the elimination of the three deferral accounts in the Board Staff paper (page 22). The Long-Term Peak Storage Services Account (179-72) is discussed in Section 5.8.3 below.

4. DSM is discussed in Section 5.8.2

Weather Normalization Method

Union proposes that the 20-year declining trend weather forecasting method be fully implemented effective January 1, 2008 as an adjustment to base rates. This would result in an estimated impact to rates of approximately $7 million.

This adjustment would produce greater symmetry in weather risk (i.e. colder weather being as likely to occur as warmer weather.) Using the current 55% 30-year average and 45% 20-year declining trend blended method ("55/45 blend") represents a substantial risk to the company. The use of the 30-year average has a bias toward exceeding the actual number of heating degree days ("HDDs"). Forecasting the HDDs through use of the

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0606

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 for an Order or Orders approving or fixing a multi-year incentive rate mechanism to determine rates for the regulated distribution, transmission and storage of natural gas, effective January 1, 2008;

DECISION

Union Gas Limited ("Union") filed an Application on May 11, 2007 under section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Sched. B, as amended, for an order of the Ontario Energy Board approving or fixing a multi-year incentive rate mechanism to determine rates for the regulated distribution, transmission and storage of natural gas, effective January 1, 2008.

On January 3, 2008 Union filed a Settlement Agreement in this matter which is attached as Schedule "A". On January 8, 2008 the Board heard submissions on the Union Settlement Agreement. The parties who participated in the Settlement Agreement are set out in Schedule "B".

The Settlement Agreement is comprehensive although there are three unresolved matters that will proceed to a hearing. They are: (1) the commodity risk management program (written argument only) (2) the treatment of customer additions under incentive regulation and (3) whether tax changes resulting from changes to federal and/or provincial legislation and/or regulations qualify as a 2007 base rate adjustment and as a Z factor in years 2008 and beyond. The parties to the Settlement Agreement accepted that the Settlement Agreement is not contingent on the outcome of any of these contested matters.

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The parties agree that the deferral accounts listed in Appendix B (including LRAM and SSM) will continue during the IR plan.

The parties further agree to the elimination of the following four deferral accounts:

Transportation Exchange Services Account (179-69)

Other S&T Services Account (179-73)

Other Direct Purchase Services Account (179-74)

Heating Value Account (179-89)

The parties agree that the disposition of Y factor amounts will be in accordance with existing Board approved allocation methods and allocators.

The following parties agree with the settlement of this part of the issue: APPrO, BOMA, CCC, Energy Probe, IGUA, Jason Stacey, Kitchener, LPMA, OAPPA, SEC, Sithe, Timmins, TransAlta, Union, VECC, WGSPG.

The following parties take no position on this part of the issue: Coral, EGD, GEC, PP, PWU, TCPL.

All parties except GEC and PP agree that there should not be a Y factor relating to customer additions during the term of the IR plan.

The following parties agree with the settlement of this part of the issue: APPrO, BOMA, CCC, Energy Probe, IGUA, Jason Stacey, Kitchener, LPMA, OAPPA, SEC, Sithe, Timmins, TransAlta, Union, VECC, WGSPG.

The following parties do not agree with the settlement of this part of the issue: GEC and PP.

The following parties take no position on this part of the issue: Coral, EGD, PWU, TCPL.

Evidence References:
1. B/T1 p.37-39.
2. C1.10, C3.19, C3.22, C4.12, C20.1, C20.2.
3. L/T1/S2, L/T3.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

TransCanada DOS-MN

Question:

On or about November 7, 2008, TransCanada filed an application with the National Energy Board to implement a Dawn Overrun Service - Must Nominate ("DOS-MN") whereby for the balance of the current winter TransCanada will receive gas at Empress and redeliver such volumes at Dawn. The cost for such service is the FT commodity toll, thus shippers avoid the normal demand charge that otherwise would apply. Certain shippers had the right to their pro-rata of this service. Please indicate if Union has taken its pro-rata share of this service and, if so, whether the full benefits of this service will flow through the Y factor transportation costs.

Response:

Yes. Union contracted for its pro rata share of DOS-MN. Union offered a portion of its pro rata share to customers with TCPL assignments. Some of these customers accepted the DOS-MN capacity assignment.

Union is not treating any benefit associated with the use of the DOS-MN as a Y factor. Any benefit from the use of DOS-MN over the term of the incentive regulation framework will be used to contribute to the S&T transactional margins already included in infranchise delivery rates, and will form part of the Union's regulated earnings.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2008- 0220

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 for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas effective January 1, 2009.

BEFORE: Pamela Nowina
Presiding Member and Vice Chair

David Balsillie
Member

Paul Sommerville
Member

DECISION WITH REASONS

INTRODUCTION

Union Gas Distribution Inc. ("Union") filed an Application on September 26, 2008 with the Ontario Energy Board ("Board") under section 36 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, (Sched. B), as amended, for an order of the Board approving or fixing rates for the distribution, transmission and storage of natural gas, effective January 1, 2009.

The Board assigned file number EB-2008-0220 to the Application and issued a Notice of Application dated October 27, 2008.

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should reflect that reduction unless and until a decision in the motion to vary has been rendered displacing or altering it.

The Board will make every effort to ensure that the motion to vary is considered as expeditiously as reasonable. It is our expectation that the motion can be considered and disposed of prior to the approval of the rate order reflecting 2009 rates. In that case the Board would seek to reflect in the rate order any variance arising from Union's motion.

<u>The Filing of 2007 Financial Information</u>

In its submission, IGUA objected to Union's reluctance to file 2007 actual financial information. The Settlement Agreement referenced above provided for the filing of a variety of materials by Union through the course of the IRM plan. The Board considers the informational filing requirement to be a key element of the Settlement Agreement and the IRM framework. The specific dispute highlighted by IGUA concerns the position taken by Union that because the Settlement Agreement requires it to file information arising "during the IR plan", that 2007 financial information does not qualify.

The Board considers Union's position to be inconsistent with the spirit of the Settlement Agreement and contrary to a reasonable application of its terms. Accordingly, the Board directs to Union to file by April 1, 2009, as part of the materials mandated by the Settlement Agreement, 2007 actual financial information.

<u>Upstream Transportation Changes</u>

Union noted that pursuant to the Settlement Agreement ratepayers were credited with a fixed amount reflecting a forecast performance of its transactional services business. Union also noted that the increased capacity that is associated with the Dawn Overrun Service may have benefits for ratepayers pursuant to the earnings sharing mechanism that continues in place. In other words, ratepayers have been already credited with an amount intended to reflect the transactional services activity of the company. Any additional revenues which may be occasioned by the new TransCanada service will not accrue under this heading, but may lead to earnings sharing distribution.

The Board finds Union's explanation with respect to this concern, which was raised by IGUA in its submissions, to be convincing. In the Board's view this is a fair approach

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that is consistent with the general architecture of the IRM plan and the Settlement Agreement.

IMPLEMENTATION

Given current timing, the Board anticipates that the 2009 rates, effective January 1, 2009, will be implemented commencing with the first billing cycle on or after April 1, 2009.

Union is directed to file a draft rate order within 7 calendar days of the issuance of this decision. Intervenors shall have 7 calendar days to respond to Union's draft order. Union shall respond within 7 calendar days to any comments by intervenors.

COSTS

A decision regarding cost awards will be issued at a latter date. Eligible intervenors claiming costs should do so as directed below.

The Board hereby directs:

1. Intervenors eligible for cost awards shall file with the Board and forward to Union their respective cost claims within 25 days from the date of this Decision.

2. Union may file with the Board and forward these intervenors any objections to the claimed costs within 32 days from the date of this Decision.

3. Intervenors, whose cost claims have been objected to, may file with the Board and forward to Union any responses to any objections for cost claims within 39 days of the date of this Decision.

4. Filings are to be in the form of two hardcopies and one electronic copy in searchable PDF format at boardsec@oeb.gov.on.ca and copy Union Gas Limited.

Union shall pay any Board costs of, and incidental to, this proceeding upon receipt of the Board's invoice.

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UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A, page 11

Question:

Union stated that new market opportunities, in part, account for the increase in short-term transportation and exchange revenues.

a) Please describe the nature and characteristics of these new market opportunities.

Response:

Over the last number of years, end use customers have been decontracting firm long haul transportation capacity in favour of recontracting shorter term short haul transportation and commodity purchases at Dawn. This reflects in part a desire by end use customers for shorter term contracts and a lower long term transport contract commitment and related financial exposure.

The increased demand for shorter term short haul services has provided Union with the opportunity to sell increased transportation and exchange services into the market. These services are for terms as short as one day. As described in Exhibit A, Page 7 of 29, lines 10 to 15, to both respond to and support this increased market demand and provide the customer support for these transactions, Union increased its Chatham-based sales staff by two positions in 2008, refocused the contract and customer support staff and initiated process and IT systems changes. The overall objective was to capitalize on these opportunities and optimize and market Union's assets and related services.

Union also focused on further optimizing its upstream supply portfolio. Union was able to extract value from new services introduced by upstream transportation providers in excess of what was achieved historically. An example of these new services includes TCPL's Firm Transport Risk Alleviation Mechanism (FT-RAM), Storage Transportation Service Risk Alleviation Mechanism (STS-RAM), and Dawn Overrun Service – Must Nominate (DOS-MN). These new services provided increased opportunities for transportation and exchange transactions in the market. These opportunities were also influenced by favourable market conditions experienced in 2008.

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Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2011-0210**

VOLUME:	**6**	
DATE:	**July 19, 2012**	
BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

MR. SMITH: Members of the panel, if you have a copy of the direct examination compendium, I just have a few questions in relation to that. And, bearing in mind my earlier discussion, I will be reasonably quick.

Can I ask you to turn to page 1? This appears to be an Interrogatory J20.10 given in the RP-2003-0063 proceeding, which I believe was Union's 2004 rate case.

I would draw your attention to the answer given in relation to question a), and there's a description of an exchange at that answer. And either Mr. Isherwood or Ms. Cameron, can you just take a moment to review that and tell the Board, if you could, how exchanges back in 2003 are different, if at all, from what you undertake now?

MR. ISHERWOOD: Yes. The definition that shows up on this first page actually is a definition that we will have seen through a number of different cases through the years.

An exchange is defined here as really between us and party A. So party A would give us gas at one location, and we would give party A gas in a different location on the same day.

And the only other condition we would put around that is that one of those two spots, either where we give customer A gas or where they give us gas, one of those two spots would be on our system and one would be off our system.

That is a pretty consistent definition going back pretty far into our history, actually. It is no different today than it was back in 2003. We would talk today, and we will be talking today, about exchanges, and some start in our system and some end in our system, but it is always with another party.

MR. SMITH: Just if you can give the Board some sense of it, for how long have you been engaging in exchange activity?

MR. ISHERWOOD: I think the first deferral account actually showed up in 1993, and, as I kind of researched back through some of our history, I found references as far back as '91 as being revenue in that year that was being earned on exchanges, which implies to me it was being done even before that.

So it goes back a number of years.

MR. SMITH: Can I ask you to turn over -- perhaps we can just identify it, but at Exhibit -- at pages 2, 3 and 4, what do we have there? Am I correct that this is an excerpt from your prefiled evidence in that case, in the 00 --

MR. ISHERWOOD: That's correct.

MR. SMITH: And if we can look at page 6 of the compendium, we have an excerpt from the decision. And just dealing with the question of deferral accounts, can I ask you to look over at pages 8 and 9 of the compendium and if you could just describe, Mr. Isherwood, the deferral account treatment that you referred to for exchange activity and how that has been treated by Union and the Board?

MR. ISHERWOOD: It's summarized on page, I guess, 8 and 9 of the compendium, but there are really two different sharing elements. The first is how much of that activity is built into the actual forecast.

So if we forecasted revenue going into the next year, how much of that would be shared between the ratepayer and Union's shareholder? And as described here, that shearing was done on a 90/10 basis. So based on our forecast 90 percent of what we had forecast as being revenue would be built on the actual forecast.

Then the deferral account itself would be set up for any changes in revenue relative to what was in the forecast, and that was shared 75/25, 75 to the benefit of the ratepayer.

And on this decision -- and this deferral account has evolved over time since '93, obviously, but the change that happened in this decision really was -- it is really found under Board findings on page 9 of the compendium, page 67 of the decision, the second paragraph:

> "The Board finds that symmetrical variance account treatment of these revenues is appropriate."

So this was really the first time that we got the symmetry on the account. Prior to that, we would actually have upside but not downside protection.

MR. SMITH: Ms. Elliott, maybe this can be for you, but when we're talking about deferral accounts, which deferral accounts are we talking about here or which deferral account? Oh, I'm sorry, I should have directed you to page 10, my apologies, and thereafter.

MS. ELLIOTT: The accounting orders in this material from page 10 through to page 13 are the accounting orders -- are the orders for those accounts that we have closed.

MR. SMITH: And were these the deferral accounts, these were closed back -- we'll come to it, but were these the deferral accounts that were in existence or were these deferral accounts in existence at the time of the 2004 case?

MS. ELLIOTT: Yes, they were. They were closed in either the 2007 rate case or subsequently in the settlement for the IR framework in 2008.

MR. SMITH: Well, we can, I think, put a bit more precision on that.

Mr. Isherwood, do you have Mr. Thompson's compendium handy?

MR. ISHERWOOD: I do.

MR. SMITH: And if you turn to his page --

MS. HARE: I'm sorry, Mr. Smith, I don't think we have that yet.

MR. SMITH: Oh.

MS. HARE: But since we're going to wait for it, I do want to ask just a question on your compendium, page 9, so that I understand what the mechanism was.

If we assume -- just so I understand this -- if we assume that the forecast was $10 million and so nine would go to ratepayers and one would go to the shareholder -- and you did 11, I understand that. That extra million goes in the deferral account to then be split 75/25, well, what if you only did $9 million? Did the deferral account and the symmetrical treatment apply? Or were you held to the forecast of 10?

MR. SMITH: We should ask Mr. Isherwood, but I believe that is correct.

MS. ELLIOTT: I think the language in the accounting order would suggest that the 75/25 sharing would apply on both sides.

Having never experienced that situation, I'm --

MS. HARE: Oh, you never had a downside?

MS. ELLIOTT: No.

MS. HARE: Okay. Moot point.

MR. SMITH: That's okay.

MS. HARE: Thank you.

MR. SMITH: It's -- well, I can't give evidence. That is not actually 100 percent true. There is a small problem with it, but...

The --

MS. HARE: We have the CME compendium, so we should give that an exhibit number.

MR. MILLAR: Yes. K6.5.

EXHIBIT NO. K6.5: CME COMPENDIUM.

MR. SMITH: Mr. Isherwood, just looking at page 8 of the CME compendium, Mr. Thompson has included here an excerpt from the 0520 case, which was Union's 2007 rate case.

And if I could ask you to turn under item 4.0, "S&T

deferral account proposal," what was Union's proposal at that time?

And you should probably look over at pages 8 and 9.

MR. ISHERWOOD: It actually shows up on the bottom of page 9 and a bit on the top of page 10.

But I will refer to page 24 of 39 of that exhibit, but page 10 of the compendium. Line 4, our proposal really was to eliminate the S&T transactional accounts at that point in time, and it was consistent with a view from the Board in the NGF policy paper in March of '05.

MR. SMITH: And what, then, would have happened to S&T revenues beyond that included in the forecast revenue requirement?

MR. ISHERWOOD: So I think the intent at the time and the purpose at the time was to build in an appropriate amount of revenue into the forecast, and then beyond that, the upside or downside would be at the risk of Union Gas.

MR. SMITH: Now, did those accounts actually get closed at that time?

MR. ISHERWOOD: No, not at that time.

MR. SMITH: If I could ask you, then, to turn over to Mr. Thompson's compendium, over a few pages to page 12, this is an excerpt from the settlement agreement that was entered into by the parties on May 15th, 2006.

And on page 12 of the agreement, page 21 of Mr. Thompson's compendium, can you just advise the Board of what had been agreed to at that time?

MR. ISHERWOOD: So this was really for the cost of service case in 2007. And although Union had proposed to eliminate the deferral accounts, the Board actually sent a letter and asked that that issue be moved to the incentive regulation -- well, a couple of letters, but eventually landed in the incentive regulation hearing.

So at this point in time, those deferral accounts were maintained through 2007 cost of service.

MR. SMITH: And so if I can ask you, then, to turn back to my compendium, at page 15, this is an excerpt from EB-2007-0606, Exhibit B, tab 1, page 11 of 48, paragraph 3, sir.

Can you tell the Board what Union was proposing then in its incentive regulation proceeding?

MR. ISHERWOOD: Still at this point proposing to eliminate the five S&T accounts.

MR. SMITH: And did that ultimately happen?

MR. ISHERWOOD: It did not. Not in the '07 cost of service case.

MR. SMITH: We are now in the --

MR. ISHERWOOD: Sorry, this is the incentive regulation case? Sorry. It did get -- they did get eliminated through the settlement.

MR. SMITH: So if you look over on page 18 -- "the parties further agree..." -- and is that where you are indicating that the parties had agreed to close certain deferral accounts?

MR. ISHERWOOD: That's correct.

MR. SMITH: And it may be useful to draw the Board's attention to this back in Mr. Thompson's compendium, and I apologize for bouncing around.

Can I ask you to turn to page 38 of Mr. Thompson's compendium?

And under item 14.1, we have an agreement, and what is it that Union had agreed to do with respect to S&T revenues in margin?

MR. ISHERWOOD: What Union had agreed to was to actually increase the S&T revenues -- in this case, actually, it is a margin number -- by 4.3 million.

So at that time, our margin forecast was 2.6 million, and by adding the 4.3, it took it to 6.9. And again, that's a margin -- margin, not revenue. And the 6.9 would have been then built into rates to provide rate relief for customers.

MR. SMITH: Can I ask you to turn back to the compendium -- my compendium again or our compendium again, at page 19.

You should have here Exhibit B2.2; do you have that, sir?

MR. ISHERWOOD: I do.

MR. SMITH: And there is a reference there to "DOS MN" and perhaps I should start by asking what "DOS MN" is.

MR. ISHERWOOD: DOSMN stands for Dawn overrun service must nominate; that is what the "DOS MN" stands for.

It was a service enhancement that TCPL added to FT contracts for the winter of 2008 and 2009.

They had previously sold some capacity from Dawn to markets east using the flexibility of their integrated system, and that flexibility really required to have a certain amount of gas flowing from western Canada down through the Great Lakes system and back into Dawn.

And they were actually projecting lower volumes than they needed to make that integrated system work the way they had planned, so they were going to be short gas supply at Dawn. If they didn't have enough gas coming into Dawn, they couldn't provide the services they had contracted for.

So for them it was a way of ensuring that they got the right amount of gas flowing to Dawn to ensure they could meet their firm obligations on their system.

And what they actually needed was 165,000 gJs a day of capacity; they could guarantee, know what's coming, and they actually offered that to the market, the FT shippers, based on how much demand charge you're paying relative to the totals FT on their system. So they kind of offered it on a pro-rata basis.

Depending how much FT you had on TransCanada and the demand charges you were paying, you would be allocated part of what they required.

So they were looking for 165,000 gJs per day for that winter, and Union Gas was allocated about 17,400 gJs per day.

And because we actually assigned some of our FT contracts to our industrials and other direct purchase customers, we offered those customers access to the same program that we had access to, and that actually was --

about 3,000 of the 17,000 gJs went to that part of the market.

So at the end of the day, Union Gas had about 14,400 of that service available to use for that winter.

MR. SMITH: And what financial benefit did that give to Union Gas?

MR. ISHERWOOD: Yes. The benefit to TransCanada was they were guaranteed the gas would flow and they could provide the services they had committed to.

And they offered that service basically, being transportation service from Empress Alberta to Dawn, at basically the firm commodity rate only, which is very low on TransCanada. Most of their tolls earn the demand charge and fuel.

So for a very low toll, we could flow gas from Empress to Dawn.

MR. SMITH: And how did you treat that benefit that you received?

MR. ISHERWOOD: For that year we had, in our gas supply plan, planned to buy gas at Dawn. So instead of buying gas at Dawn at the Dawn price, we actually bought gas at Empress and flowed it on this inexpensive transport to Dawn.

And the gas savings, the savings between what was in the plan versus what we had landed the gas at Dawn, was put through the transportation exchange account as an optimization activity.

MR. SMITH: And you were asked in this interrogatory whether Union had taken its pro rata share and whether the full benefits would, in effect, flow through to ratepayers.

And the answer we have below, which was what?

MR. ISHERWOOD: The answer was it actually flowed through the S&T transactional account, and to the extent that it helped us earn our forecasted amount, it was the first contribution, if you want, towards ratepayers.

And, ultimately, if it contributed towards earnings sharing, it would also contribute towards ratepayer benefit that way.

MR. SMITH: This was obviously the subject of some dispute in the 0220 case. And can I ask you to turn to page 21 of the compendium? What was the Board's decision with respect to that proposed treatment?

MR. ISHERWOOD: So on page 21, the second paragraph from the bottom under the title "Upstream Transportation Changes", it talks -- it gives the Board's decision in terms of agreeing with Union's position that ratepayers were already benefitting from the forecast that was built into rates. As well, it can ultimately contribute to earnings sharing, as well, and that this was normal activity towards the transportation exchange account.

MR. SMITH: A couple of other questions. We have filed at Exhibit J3.1 an answer to an undertaking given to Mr. Quinn, and that was to draw a chart.

If I could just ask that that be pulled up. And perhaps this is for you, Mr. Shorts, but could you just tell me what it is that we're looking at here?

MR. SHORTS: Sure. I will start from the bottom, just to give everybody an idea of what we're showing under this graph.

If we look at the blue area, the blue area represents the daily deliveries into Union's EDA for its in-franchise sales service and bundled customers.

This would exclude our transportation or T-service customers, because they are responsible for bringing their own transportation and supply into the zone each day.

If we go up to the first horizontal line at approximately 60,000, so that yellow line represents the contracted Empress to EDA Union long haul transportation capacity.

I will then move up to the green line, and the green line, which is just below 100, that is the long haul EDA to -- or Empress to EDA long haul capacity, as well as the firm short haul Parkway to EDA capacity that is contracted for.

I'm going to skip right up to the red line at the top, which is just over 160,000 shown, and that represents the contracted Empress to EDA long haul, the short haul firm Parkway to EDA I just mentioned, as well as our firm STS withdrawal rates.

And it is this line that is the firm capacity or the firm portfolio that is used to serve the design day in the plan for the EDA.

Now, a couple of things just to note. You will see that the yellow line or the EDA capacity, that long haul capacity from Empress to the EDA, really serves two purposes.

It not only serves as part of that portfolio of peak day or design day assets, but it also serves to meet those annual delivery needs.

So, for example, if you look at the area in the graph where the blue lines are below the yellow line, that would simply be a time period in which, on a given day, the demands coming into the eastern delivery area were in excess of the daily requirements, and that gas would be STS-injected into Dawn storage to be used later.

And, likewise, when the blue lines are above that, that firm pipe is supplemented by those other assets, so either the firm short haul or the STS withdrawal rates.

One thing to also note is that during this time period, from November of 9 to March 2012, that gas supply was purchased each and every day at Empress. So it was needed there for annual needs, and there was no UDC incurred because of those supplies.

MR. SMITH: Thank you, Mr. Shorts. And just a couple of last questions. We had similarly provided, as we agreed to do, an update to Exhibit B7.7, which was a response to an interrogatory in a different proceeding, the 0087 proceeding.

And, Ms. Cameron, perhaps this is for you, but I would just ask you to focus on the TCPL-Union CDA and just describe what is being captured under the optimization percentage referred to there.

MS. CAMERON: So Mr. Smith brought you to the last line on the graph, the Union CDA Empress to Parkway, and we have indicated we have optimized this 95 percent of the time.

Thinking back to what Mr. Shorts said about the graph, similar to the EDA, in the summertime the CDA would have similar load factors, that we wouldn't need all of the gas at Parkway in the summertime that we currently have demands for.

So we would contract for that by alternate arrangements and have that gas delivered directly to Dawn. And we have characterized that as optimization, because it didn't go to the Parkway delivery point and went straight to Dawn for storage.

In the wintertime, we would have contracted for this gas to go to Parkway, but our actual gas -- our gas plan on a design day dictates that that gas would be delivered to the WDA or the NDA - so think of North Bay, Sudbury area - to serve our design day requirements.

During this particular winter - and I think this was 2011 - we delivered that gas to the WDA and NDA on non-peak days. So just on an average winter day, we would deliver that gas to the WDA or the NDA, Sudbury, Thunder Bay, and we also dictated that as optimization.

It still went where the gas plan dictated it should go, but we did it on a more frequent basis. By doing so, that left some amount of capacity - think of North Bay to Toronto - unutilized and would create RAM credits.

So we would take this transaction -- all of these transactions were due to the RAM credit benefit that Union could receive from that, and we could use those RAM credits to offset exchange costs.

We will do these transactions, while RAM is in place, to earn the credits and offset exchange costs, but we won't do this without the RAM benefit.

MR. SMITH: May I ask you why that is?

MS. CAMERON: Once RAM ends, there will be no -- and financial incentive to transport the -- to leave unutilized pipe, we would only incur incremental costs with no market demand or no need for exchanges.

MR. SMITH: Mr. Isherwood, just picking up on that, just at a high level, assuming the FT RAM program is discontinued by TCPL as they are advocated, what do you foresee the impact on your exchange activity being?

MR. ISHERWOOD: Our 2013 filing has transportation exchange revenue at around $9 million. That's a level not unlike what we saw prior to RAM coming into -- really into being in 2008 in a big way. It existed before that, but in terms of large numbers and revenue, it is 2008 and beyond.

So our revenue from exchanges would go down to kind of a pre-RAM level of around $9 million.

MR. SMITH: Finally, Mr. Isherwood, just one last question.

We have heard some evidence very recently about Marcellus and the impact on Dawn. And how do you characterize that impact?

So my question is this: Why has Union's forecast been so bad? How much of this variance was related to the FT RAM credits, specifically?

MR. ISHERWOOD: The variance is largely attributable to the FT RAM credits and how we optimized those credits and made them into revenue.

MR. AIKEN: Did these FT RAM credits -- sorry, did these FT RAM credits exist at the time of Union's last rebasing application?

MR. ISHERWOOD: FT RAM is a program that started in actually 2004, November 2004, so a very small impact in 2004.

So it was actually in place since 2004, but when you look at the activity in our earnings from 2004 onward, it really started to occur -- the impact started occur in 2008.

MR. AIKEN: So then I guess on this issue of forecasting, if we go to Exhibit K6.4, which was the direct examination compendium filed this morning, and on page 3 of the compendium, this is your prefiled evidence in the RP-2003-0063 case. It is page 6 of Exhibit C1, tab 3 in that evidence.

At the bottom of the page, starting at line 20, it says:

> "The S&T transactional services market has declined dramatically over the last few years. The following summarizes some of the key market factors that will reduce the opportunities to

generate transactional services revenues at the
same levels as has been generated over the last
few years."

Then it goes on to list things like Enron, and counterparty risk, and summer/winter price differentials and so on.

How did your actuals actually stack up against your declining forecast from that case?

MS. CAMERON: To confirm, I believe you are asking what the actuals for 2003 looked like versus the forecast for 2003?

MR. AIKEN: No. I'm asking about the fact that your forecast was that your revenues were going to decline because of the reduced opportunities to generate transactional service revenues at the same levels as had been generated over the last few years.

So that was your forecast in 2003. How did that forecast stack up against what actually happened in 2004 through to the current date?

MR. ISHERWOOD: I think -- I'm not sure we have the information going back to 2003/2004, but I think what I said this morning was it is still valid, in that our forecast for 2013 for this category was a little over $9 million, and we compare that back to our S&T revenue for transportation exchanges in the period prior to the incentive regulation. And the $9 million is in that same range. It is probably the high end of that range.

MR. AIKEN: And what about during IRM? That's when that 9 million would have been substantially lower than what was actually recorded?

MS. CAMERON: When you look at -- actually, if I can take you to IR undertaking J.C-4-7-9 and attachment 2 of that response, and on line 1, you will see what our revenue has been since 2007 for what we would deem base exchanges.

And while everything on this page is an exchange service, we have tried to differentiate the exchanges we could provide without RAM, which is line 1, and the exchanges that we provided that were assisted by the RAM credits.

You will see that our exchange revenue for 2007 was about 3 million, and that escalates to maybe 8 and almost 10 million in 2011.

So that would be, if RAM didn't exist, what we would characterize as our exchange revenue for that period.

MR. AIKEN: So while we're on that attachment 2 of J.C-4-7-9, can you update us as to what your six-month actuals versus forecast for base exchanges are?

MR. ISHERWOOD: That's part of the undertaking, I believe.

MR. SMITH: Let's put it this way: If it's not, I'm happy to make it part of the undertaking.

MR. AIKEN: I'm just wondering which line item on JT1.13 on page 8 of my compendium that base exchanges is included in?

MS. ELLIOTT: It would be included in line 4.

MR. ISHERWOOD: It would be included in line 4.

MR. QUINN: And would that be your first alternative for bringing additional gas into the delivery area if you found yourself short?

MS. CAMERON: The STS service would be continued to be used, yes; it is the alternative. We would continue to use it as planned.

MR. QUINN: Okay. So how do you differentiate that cost, then, to Ms. Elliott's point that it is being streamed off? Does that come through -- does that come through your area, or does it go through capacity utilization?

MR. ISHERWOOD: I am not sure I understand the question.

MR. QUINN: If you choose through the -- let's say the month of February you don't have a STS balance -- you receive significant overrun charges -- who is responsible to take that cost and say: That's being borne elsewhere?

MR. ISHERWOOD: The S&T group would absorb that cost into their overall model or business.

MR. QUINN: And so the capacity utilization people differentiate that cost? Or who does that separation?

MR. ISHERWOOD: Actually, they would be able to identify the fact that we would be in the situation where we're paying the penalty, and they would identify that. It would actually show up on the TCPL invoice for that month's activity.

MR. QUINN: Okay. So I am focussing in this capacity utilization because it goes into my next question.

Clearly - maybe I will start a step back, because I was asked by the second panel to ask this of the ex-franchise panel, Mr. Isherwood, to you, that when you are delivering gas, you've got a contract, and I will use the EDA as example.

My understanding is the gas need not in the summer arrive in the EDA if your flows are low, like is evidenced on this graph.

MR. ISHERWOOD: Right.

MR. QUINN: Who tells the assignee where the gas should go?

MR. ISHERWOOD: Who do you identify as the assignee?

MR. QUINN: A third party. Whoever you have assigned the capacity to, they are to deliver gas, but they need not deliver to the EDA, because its ultimate destination is Dawn.

MR. ISHERWOOD: Right.

MR. QUINN: My first question is: My understanding is it does not need to go the EDA? It can be diverted to Dawn?

MR. ISHERWOOD: So the one option would be we would just leave the contract from Empress to EDA empty, and we would flow from Empress to Dawn on IT and we would do that ourselves. That's one option.

MR. QUINN: Okay. I want to break this down, if I may stop you there.

What you're saying is you now take back the responsibility somehow of landing the gas in Ontario?

MR. ISHERWOOD: The S&T group will optimize the gas supply plan, and, again, a lot of these decisions are made because of FT RAM being a feature of FT.

So if there's economics and if the market requires exchanges, and we try to generate FT RAM credits, one way of doing that would be to leave the Empress to EDA contract empty. That would create FT credits -- or IT credits, sorry, and we would flow that gas from Empress to Dawn on an IT basis.

MR. QUINN: So what you've just described, then, is not an assignment. This is a choice by Union to leave the pipe empty, bank the credit and find a cheaper path to Dawn?

MR. ISHERWOOD: And what happens in that case --

MR. QUINN: Sorry, is that correct?

MR. ISHERWOOD: That's correct. And, Mr. Quinn, just to expand on that, when we do the IT volumes from Empress to Dawn, that path is going to be cheaper than the path from Empress to EDA.

So at the end of the day, we will end up with extra FT credits and we will do other market-based exchanges to derive value out of that. But as the gas supply panel testified to, in all of that case, we're still buying the same gas at Empress and we're still delivering that same gas to Dawn; just on that day we're doing it differently. And I call that option A.

Option B was the option that you had started your question with, which was we assigned the Empress to EDA contract to a third party, and, as part of that deal, they would deliver gas, the same volume of gas we bought at Empress, to Dawn.

So both option A and option B have exactly the same result. They just pay us the differential, if you want, as an S&T benefit.

MR. QUINN: Okay. I want to camp on that second alternative, because that's what I was trying to ask, but I appreciate the understanding on the Union-held S&T, FT RAM scheme that you had.

So the assigning of the Empress to EDA contract, the third party then has the choice to go to Dawn, or do you tell them on any given day where they should land the gas?

MS. CAMERON: We provide the direction where we want the gas to arrive.

MR. QUINN: Each month, or during the winter is it more frequently?

MS. CAMERON: For the term of the transaction. So if the transformer was a one-month transaction, we would tell them for -- the delivery point will be consistent for the term of the transaction.

MR. QUINN: Okay. So on an annual transaction, you will tell them where to deliver the gas each and every month?

MS. CAMERON: For an annual transaction we would say, for the winter months, deliver it at location A, and for the summer months, deliver it at location B.

MR. QUINN: Okay. Now, would location A --

specifically, if the gas is EDA, would location A be, Deliver the gas in the EDA for the winter months?

MS. CAMERON: It could be.

MR. QUINN: You've got a contract. You've got a defined need to go to the EDA, but you're saying would assign away that contract and tell them to transport the gas somewhere else?

MS. CAMERON: I could have them deliver it to a different delivery area, yes.

MR. QUINN: So the northern delivery area, the western delivery area?

MS. CAMERON: Yes.

MR. QUINN: I guess my question would be: Why wouldn't you contract for those delivery areas if that's what your need is? If you know a year in advance, 12 months in advance, of a gas year that your needs are in the northern delivery area not the eastern delivery area or let's use western delivery area -- well, let's use the western delivery area.

If your need is in the western delivery area, why are you contracting for the eastern delivery area?

MS. CAMERON: I'm sorry, I'm not -- could you be more specific with your question?

MR. QUINN: Okay. You have an annual contract -- maybe what we should do is turn up J.C-4-7-10.

If our ready-reference person could keep that other graph handy, we might need to flip back to it.

So attachment 2, I believe it is of that -- sorry, attachment 1, my mistake -- has the amount of assignments, capacity assignments. Now, to differentiate, these are not the in-franchise customer assignments that Mr. Shorts was talking about before. These are ex-franchise customer assignments; is that correct?

MS. CAMERON: Yes.

MR. QUINN: Okay. So if we just start -- because I am going to try to stay consistent with the chart, if we start in November of 2009, you have 80,000 gJs that stems through from November 2009 to October 2010, a minimum of 80,000 gJs.

I think if we're interpreting your graph correctly, that was annualized assignment?

MS. CAMERON: That is not correct.

MR. QUINN: Okay. Help us with that.

MS. CAMERON: If I can take you to the undertakings that were filed I believe last night --

MR. QUINN: J3.6?

MS. CAMERON: Yes.

MR. QUINN: I was going to go there next. Thank you.

MS. CAMERON: And if you look at line 26 -- oops, sorry. I apologize. Line 19, you will see that there is an annual assignment for the eastern zone for 60,000 a day.

And I believe just now, I believe Mr. Smith mentioned that we had also filed the undertakings from day 4, and if you could look to Exhibit J4.2? And, once again, we're looking at the same time period. You will see on line 10 there is an assignment of 20,000 a day, and on line 11 an assignment of 60,000 a day. That will reconcile to the 80,000 that was in the original attachment that was filed as an undertaking.

So when we look at the amount back on J3.6, and I apologize for flipping back and forth, but that an annual assignment of 60,000, no more of that is the 20,000 of EDA.

So the 20,000 in EDA capacity that was demonstrated on the graph is all of the capacity that was assigned on an annual basis. It wasn't 60,000. It wasn't 80,000. On an annual basis, 20,000 of capacity was assigned to the EDA.

MR. QUINN: So you're saying 20 -- I'm sorry, 60,000 -- I'm looking at J3.6, and I think what you have on the screen here is -- this is the challenge with technology, but that is J4. -- oh, it's 3.6, okay.

So you have 60,000 gJs to the eastern zone. Let's just focus on that. That is an annual assignment?

MS. CAMERON: That is an annual assignment made up of 20,000 to the EDA and 40,000 to the CDA. So that 20,000 is the same 20,000 that we would see on the chart that we've looked at several times today.

MR. QUINN: Okay. Well, then just so -- and this is all in the eastern zone? That's why you've got the EDA and CDA?

MS. CAMERON: Yes.

MR. QUINN: So for the annualized -- I am conscious of the clock. I think I would like to ask for the winter, starting November 2009 to March of 2012, can you tell us, of that annual assignment, where you had the gas directed, where you had your assignee direct the gas to for each month during that period?

MR. SMITH: Yes, we will do that.

MR. QUINN: Okay. And what I would like to ask, that if you could also add to that what the demand charge -- multiply out what the demand charge would be to the eastern zone versus where you had the gas directed, and what the difference of cost would be for any of those months.

If there is a difference, if any of the eastern zone gas has been directed to another zone, what the difference in demand charge is between the respective zones, and multiply that by the number of units delivered for that month.

MS. CAMERON: You're interpreting costs -- you mean the TransCanada toll?

MR. QUINN: Demand charge for the TransCanada toll.

MR. SMITH: Yes, we will do that.

MR. QUINN: Okay. I think that is an appropriate time to break, thank you.

MR. MILLAR: J6.5.

UNDERTAKING NO. J6.5: TO ADVISE WHERE UNION DIRECTED ANNUALIZED ASSIGNMENT OF GAS FOR EACH MONTH BETWEEN NOVEMBER 2009 AND MARCH 2012; TO MULTIPLY THE DEMAND CHARGE TO THE EASTERN ZONE VERSUS WHERE THE GAS WAS DIRECTED, AND TO ADVISE THE DIFFERENCE IN COST BETWEEN THOSE PLACES FOR ANY OF THOSE MONTHS; AND IF THERE IS A DIFFERENCE, IF ANY OF THE EASTERN ZONE GAS HAS BEEN DIRECTED TO ANOTHER ZONE, TO PROVIDE THE DIFFERENCE IN

DEMAND CHARGE BETWEEN THE RESPECTIVE ZONES, AND TO MULTIPLY THAT BY THE NUMBER OF UNITS DELIVERED FOR THAT MONTH.

MS. HARE: Thank you.

MR. SOMMERVILLE: That is November to March?

MR. QUINN: Yes, November of 2009 to March of 2012. Thank you.

MS. HARE: Thank you.

We will break until 3:20.

--- Recess taken at 3:03 p.m.

--- On resuming at 3:28 p.m.

MS. HARE: Please be seated. Before we proceed to Mr. Cameron's cross-examination, Mr. Smith, I wanted to ask about the question that Mr. Wolnik on behalf of APPrO left that was then deferred to this panel.

Is this panel prepared to respond?

MR. SMITH: Yes.

MS. HARE: Yes?

MR. SMITH: They can answer the question, and I can just read it in, if that is suitable.

MS. HARE: Please, yes.

MR. SMITH: But before I do that, subject to the Board's guidance, of course, and based on what I understand to be the time estimates remaining, I would not propose to have our panel come from Chatham for the finance panel for tomorrow afternoon. I project, based on current cross-examination estimates, that they would be called after the lunch hour tomorrow.

I am in your hands.

MS. HARE: What do the time estimates take you to, if we start at 9:30?

MR. SMITH: Well, if we start at 9:30, I understand Mr. Cameron has an hour, which would take us through the balance of today.

MS. HARE: Today, yes.

MR. SMITH: I understand that Mr. Quinn has another hour. That would take us to 10:30.

MS. HARE: Yes.

MR. SMITH: If we were to resume at 10:45, I understand that Mr. Buonaguro has somewhere around approximately 15 minutes or so, and that would be 11 o'clock.

And I understand that Mr. Thompson has at least -- has an hour and a half, and Mr. Brett has half an hour to 45 minutes, I believe.

MS. GIRVAN: Sorry, we may have 15, 20 minutes.

MR. SMITH: So I think at the earliest we would be looking, based on those estimates, at the afternoon break.

MS. HARE: I think that is reasonable, particularly since we're not sitting on Monday. There is no point in bringing people from Chatham on a Friday for an hour and a half.

MR. SMITH: I appreciate that. Thank you very much.

MS. HARE: Okay. Mr. Cameron, please.

MR. SMITH: I'm sorry, Madam Chair. I think you wanted me read in Mr. Wolnik's question.

MS. HARE: Yes, I did, sorry. I raised it and I forgot.

MR. SMITH: Not at all. I diverted you, no pun intended.

[Laughter]

MR. SMITH: There's nothing funnier than a glass supply joke.

[Laughter]

MR. SMITH: Cross-examination, this is from page 168 of the transcript on day 2, members of the Panel.

The question is:

> "Do you have a forecast of the earliest reasonable time when those attributes..."

And that's a reference to FT RAM:

> "...could be phased out if the Board approves that within the TransCanada rate case?"

MR. ISHERWOOD: So when we filed our initial evidence, it was all based on a forecast that we did back in the spring of '11, essentially, and at that point we had assumed that FT RAM would end on November 1st, actually, of this year.

The NEB process has taken a bit longer than we had expected back in the spring of 2011. That process should now end -- the end of September is the timeline that people are thinking, with a decision from the NEB to follow.

That question was asked of TCPL. Assuming they get a decision from the NEB end of year, early next year, when would they be able to phase in the new framework? I believe the answer they gave was May of 2012.

MS. HARE: 2012 or 2013?

MR. ISHERWOOD: Sorry, 2013. I'm not sure if some of the easier elements, like eliminating FT RAM, may be sooner, but in terms of total framework, they're saying May of 2013.

MR. SMITH: Thank you.

MS. HARE: Okay. Mr. Cameron, please.

CROSS-EXAMINATION BY MR. CAMERON:

MR. CAMERON: Thank you. Mr. Isherwood, we heard your impressive list of responsibilities at Union and its affiliates. Is it a term of your contract that you not take up hang gliding?

MR. ISHERWOOD: Sorry, I didn't hear the last part.

MR. CAMERON: That you not taking hang gliding.

MR. ISHERWOOD: Yes, absolutely, or sky diving.

MR. CAMERON: I am going to -- I tried to get you out of this, Mr. Isherwood, by punting the questions to Mr. Redford based on a comment made last week -- or, sorry, I guess it was earlier this week, to the effect that Mr. Redford was the one who knew about these St. Clair contracts, but I understand you volunteered to try, at least.

MR. ISHERWOOD: I will do my very best.

MR. CAMERON: All right. So if I could start by taking you to your response to the undertaking that you gave to me that is J3.8? It is the bundle of St. Clair and Bluewater agreements.

ONTARIO ENERGY BOARD

FILE NO.:	EB-2011-0210

VOLUME:	7	
DATE:	July 20, 2012	
BEFORE:	Marika Hare	Presiding Member
	Paul Sommerville	Member
	Karen Taylor	Member

Thank you. It looks like 40,270 of that has been assigned at a snapshot of July.

MS. CAMERON: Yes.

MS. TAYLOR: And how long -- so you're saying that the market has no incentive to take an assignment that would extend beyond the estimated or anticipated termination date or option date, if you will, given the NEB outcome?

And that is kind of mid May'ish 2013. So does that assignment, then, deal with a period prior to?

MS. CAMERON: Subject to check - I don't have the numbers in front of me - I believe at best we've done assignments to the end of October.

The market was tenuous about what to do about November and December, and then into January, February and March, because I think the end date of RAM, and whether it will end, is still subject to much debate at the NEB.

So there wasn't a lot of market interest. A lot of people were waiting to see what the results of that proceeding would be.

MS. TAYLOR: Okay, thank you.

MR. ISHERWOOD: I think the point I was trying to make yesterday was TCPL has given the date of May for the full rollout of their plan.

I think the market is not certain if they can terminate FT RAM sooner. If they could, would they do it sooner? So there is a bit of a question mark on FT RAM post January 1, 2012 -- 2013, sorry.

MS. TAYLOR: My issue with the answer was I had no sense of the timing, so whether this was an annual assignment of the contract or monthly, or it is a snapshot as of July. I had no sense for the length or duration of the assignment of that particular contract.

So what you're telling me is the assignment ends towards the beginning of October --

MS. CAMERON: It would end October 31st, subject to check.

MS. TAYLOR: Okay, thank you.

MS. HARE: Mr. Quinn, I hope our interruption didn't affect your flow of questioning.

MR. QUINN: No, not at all. I am trying to create clarity and, if we haven't done that, I appreciate the additional questions. Thank you.

MR. ISHERWOOD: If I could add to that, I guess the driver behind that, why do we do that exchange, it is really because the gas and the gas supply plan without FT RAM would flow from Empress to the EDA, but because of FT RAM, by leaving that empty, you actually create credits.

The gas ultimately isn't needed in the EDA in the summertime. It is needed back at Dawn. So you would actually move it to Dawn and it is a profitable exercise to do that. It creates RAM benefits. That's why it is such a big number for the summer.

MR. QUINN: So carrying on with that theme, just to ask a follow-up question, to the extent the FT RAM program disappears and you wanted to get that gas back to Dawn, would you be able to, through exchanges, find a way to get that gas back to Dawn and create money through base exchanges?

MS. CAMERON: We would still -- in that scenario, the gas supply provides that the gas would flow -- we would purchase the gas at Empress. So without RAM, we would purchase the gas at Empress in both scenarios.

We would transport the gas to the EDA, and then we would use our STS injection service to transport that gas back to Dawn.

Because those costs are still included for ratepayers, if we transported or purchased a service to transport that gas directly from Empress to Dawn, that would only be an additional cost. There would be no offsetting revenue to offset the cost of transport directly from Empress to Dawn.

MR. QUINN: Using that scenario, Ms. Cameron, you could do what you just talked about in terms of wanting the gas at Dawn, but you could ask if you could -- if you could find a buyer in the east. If the gas is worth 40 cents more in the east, you could ask -- you could go through an exchange whereby you could sell your gas in the east to a counterparty that has value in -- the 40 cents in the east, and they would give you the gas back at Dawn. Is that not correct?

MR. ISHERWOOD: We don't sell gas. We don't arbitrage gas at all. Exchanges are just moving gas from one point to another point. We don't sell and buy. As a utility, we can only sell WACOG. So we don't ever sell gas in the EDA.

MR. QUINN: Thank you for the clarity, Mr. Isherwood, but under that same scenario, could you do an exchange that would create a revenue-generating opportunity by seeking a counterparty who has need in the east?

MR. ISHERWOOD: So our transportation and exchange revenue forecast for 2013 is at $9.1 million. That's to capture any of those one-off type of opportunities.

MR. QUINN: That's what I want to be clear about, then. If there is no FT RAM, you can still do exchanges to create revenue?

MR. ISHERWOOD: We can still use exchanges to create revenues. It is just a much smaller number. That is the 9.1.

MR. QUINN: That's the 9.1. But if you have additional capacity, which you have continued to contract for for the last number of years - and these index of customers demonstrate the ongoing long-term commitments you've made - if the FT RAM program disappears, you have now the potential for more capacity to do exchanges; is that not correct?

MR. ISHERWOOD: I would argue, as Mr. Quigley argued, that his gas supply plan for the EDA is designed to meet the conditions of the EDA, including the design day.

So I would not agree that we have excess capacity.

MR. QUINN: I didn't say excess capacity, but I think you would have to agree with me the empirical results from the last few years would demonstrate there is a cheaper way of getting gas to Dawn when you need it, and, therefore, that creates exchange opportunity. That's accurate, is it not?

MS. CAMERON: The economics of doing a capacity release and purchasing an exchange from Empress to Dawn was 100 percent dependent on RAM credits.

Without the RAM credits, we would not purchase an exchange from Empress to Dawn to transport our gas supplies.

What we would do is, if there was a party who was interested in gas in the EDA - and more particularly, locations likely to be Iroquois, to export that to the US - we would give them our gas supplies at Iroquois and accept gas from them at Dawn. That would be an exchange service, and any benefit from that would go to the S&T exchange account.

MR. QUINN: So if that pipe is not being assigned because the FT RAM program is not there, there would be more opportunity to do those types of base exchanges?

MS. CAMERON: Those opportunities exist today, and that is -- when you look at that undertaking -- I think it is J.C-4-7-9 -- and there is some amount, I think on attachment 2, that demonstrates what our base exchange revenue is, those are the exchanges or the revenue we can earn without RAM credits.

Those will continue on. They're all exchange services, and they will continue on without the RAM program.

When we refer to the $9 million that is included in 2013's forecast, that's exactly the type of transaction we are including there.

MR. ISHERWOOD: I would just add to that that is the transaction types that we have been doing since the beginning of exchanges, back in the early '90s. Nothing different.

MR. QUINN: Okay. We varied from where I was going but I think it was helpful.

I just want to turn back to the index of customer report from TCPL. And, again, I am not going to take you through the detail at this point, but we talked about the fact there is a monthly update of this report.

Who on your staff would monitor those reports, Mr. Isherwood? Would that be your manager of upstream regulation? Or would that be Patti Piett at this time, or in her group?

MR. ISHERWOOD: I guess the question would be: What exactly are you monitoring it for? They're actually reporting our activity, so we know what we're doing.

MR. QUINN: You would also want to know what the market is doing, also, would you not?

MR. ISHERWOOD: It doesn't tell you a whole lot in terms of how much capacity is being assigned away from any of these customers, whether it's Enbridge or GMI or...

MR. QUINN: If you took one report, year over year, November report one year to November report the next year, and you added up the figures to each of the delivery areas, would you not figure out how much was contracted for last year versus this year?

And we provided a number of $11.6 million that was based on 2011 volume, 2011 activity, if you wish.

We also offered, at the top of page 3 of 3, two different options for the Board to consider. The second one was really to keep the current forecast of $9.1 million for exchanges and build that into rates, as per our proposal.

And option number two, which is the simpler of the two, is basically just saying: And have a deferral account in case RAM does continue on.

I would add to this answer that it would be Union's position that, in order to provide incentive, as we've had in the past before incentive regulation and before RAM, to have the deferral account have a revenue sharing of 75-25, which was historically the number we have had there.

And that would provide us incentive to continue to do the good work we're doing in FT RAM, and provide the ratepayer that benefit through that deferral account.

Option number one gets a bit more complicated, but perhaps has different benefits. It is suggesting that you could build in a forecast of the FT RAM, and the number provided here was, again, based on the 2011 activity level of $11.6 million.

And in this case, it's very key that we would have a deferral account for 100 percent protection on the downside, because of the risk that FT RAM would not continue.

But again, we would propose that, on the upside, to provide the proper signals to the utility, we would have sharing on the upside of 75-25.

Just if I could say one more thing, Mr. Quinn, there was another interrogatory that kind of touched on it, as well, just to give a complete record. And it's J.H-1-1-2.

And this provided a slightly different option for the Board to consider, as well. And this interrogatory to Board Staff is really trying to deal with how do we help deal with the impact of the rate increases in the north; the north do have higher rate increases than the south.

One of the suggestions in this IR is you could build the FT RAM benefit into the northern rates to help mitigate some of the impacts there. But once again we would ask for the downside protection at 100 percent, and earnings sharing -- or sharing on the upside, sorry, of the deferral account at 75-25.

MR. QUINN: I guess that was more fulsome answer than I had anticipated. So I want to get back to where I was going with this.

You have demonstrated to us and you say your forecast hasn't changed, that there is some risk on M12 for 2013; is that accurate?

MR. ISHERWOOD: Yes.

MR. QUINN: If that M12 capacity is available, will it sit idle, or will Union tend to find opportunity or look to find opportunity to sell C1 short-term exchanges?

MR. ISHERWOOD: We have -- we were given notice for the 2013 turnback. We always get two years' advance

MR. ISHERWOOD: The very first pilot for FT RAM began November 1st of 2004.

MR. BRETT: Right. Are you the member, by the way, are you -- Mr. Isherwood, are you now and were you over this relevant period the Union Gas rep at the Tolls Task Force?

MR. ISHERWOOD: No, I'm not. People in my group are, but I am not.

MR. BRETT: Okay. Who is, by the way?

MR. ISHERWOOD: Patricia Planting is, currently has that role.

MR. BRETT: All right. Thanks.

Now, this -- so just to summarize again, it started in 2004. It was modified, it looks in this letter, 2006 and again in 2007 for a two-year period; is that fair?

MR. ISHERWOOD: Actually, the history I would like to describe, because I think the history here is important. It was a pilot in November 1, 2004 for a one-year period. It took us to November 1, 2005, extended another year to November 1, 2006. In 2006, they did amend it and added short-term -- sorry, short-haul transportation that is linked to long haul. They added that feature to expand the benefits of FT RAM a little bit.

MR. BRETT: Can I ask you to just pause there? Because I had a question. Could you give us an example of what that amendment did?

MR. ISHERWOOD: Yes, certainly. People think of long haul as typically going from Empress to Dawn or Empress to

Toronto as a good example of long haul.

People have been known to go from Empress to Dawn with one contract, and long-haul contract, and then having a second contract going from Dawn to maybe an export point of Niagara Falls or Chippewa.

That would be a short-haul contract that the customer has that is linked really to a long-haul contract. They typically will stop in Dawn maybe for storage services or some other reason, but it is two contracts, independent contracts, that have a linkage.

MR. BRETT: So as long as they had a receipt, a common point, that kind of contractual arrangement was made eligible for FT RAM at that point?

MR. ISHERWOOD: Right.

MR. BRETT: Okay. Sorry, carry on.

MR. ISHERWOOD: That was still a one-year extension. And in 2007, another enhancement was made where STS contracts were included for RAM, as well. So to the extent it wasn't being used, it creates RAM credits.

It was in 2007 really where it became a two-year extension. So it went from a series of one-year extensions now in 2007 to a two-year extension.

MR. BRETT: Right.

MR. ISHERWOOD: Takes us to 2009, and 2009 is really the context of this letter, asking for it to become a permanent feature.

MR. BRETT: Right.

MR. ISHERWOOD: So I think the history here is important, because you can see it has never really been an established service. It's been pilot for a number of years. It is a two-year term. Then it wasn't really until 2009 where it became permanent, and then by September of 2011 it was being filed by TransCanada to terminate the service.

So it was because of that it is a very temporary -- in our view, a very temporary service. It has lots of evolution to it over its history.

MR. BRETT: Fine. As I understand it, then, the second piece of paper is the -- is really the resolution from the TransCanada Tolls Task Force that underpins that letter. In other words, would you agree with me that the way this works is -- it worked in this case is that this matter or proposal was put before the task force, the TransCanada Tolls Task Force, in September of 2008. I am looking at the little block at the top of the Tolls Task Force letter.

It was originated by Shell Energy North America; correct?

MR. ISHERWOOD: That's correct.

MR. BRETT: And then it was negotiated in the task force and it was -- finally, it resulted in what is called an unopposed resolution at the January 7th, 2009 task force meeting in Calgary.

And is that part of the sort of -- is that the procedure that -- based on that unopposed to resolution, then TransCanada was free to make a recommendation to the

included the elimination of RAM, as well as
the --"

I'm sorry, I want to go down to 17963.

And Smith says to Mr. Pohlod:

"And I guess, Mr. Pohlod, you have 70 percent of your long-haul shippers and your firm shippers saying to you, don't eliminate RAM. The risk alleviation mechanism really has allowed them to defray unabsorbed demand charges in a significant way in the past years."

Do you see that?

MR. ISHERWOOD: I do.

MR. BRETT: Now, in fact, though, most of the benefit, what I think the numbers show in the handout today -- certainly K7.3 -- I put this to you as a proposition. I would like your response. Is that, in fact, the Union -- most of the benefit from the -- most of the revenue derived from the FT RAM has really not come from a defrayal of unabsorbed demand charges.

It has come from -- at least the revenue that has accrued to the ratepayers has not come from the defrayal of unabsorbed demand charges; only a very small part of it has gone to the ratepayers from the defrayal of unabsorbed demand charges.

Is that not the case?

MR. ISHERWOOD: I think you have to look at this in the context of our current incentive regulation framework, Mr. Brett, in terms of, when it got launched in 2008, we had a stretch margin added to our transportation exchange revenue target.

And the stretch target was well above what we were forecasting for 2008 and during that period.

And in return for that, there was no deferral account attached to those regulated revenues. So the signal to us, which I think was what the signal intended, was if you can do better, you should be incented to do better and do as well as you can.

And we have been very active since 2008 in trying to find creative ways to apply the FT RAM program not only to mitigating UDC on the utility's gas supply plan, but also from an S&T optimization perspective, as well.

So to extent that we've done that, that was the intent of the incentive regulation, was to have incentives like that that we could learn and do our business differently by going through the five years.

MR. BRETT: Would you -- let me ask you this, Mr. Isherwood and panel.

What I understand to be the case, and what I think we were told last week, is so long as you had empty pipe, so long as you, Union, had empty pipe, if you released that pipe to the market and you achieved revenues from that - we'll call them RAM-enhanced revenues - that indeed those revenues would flow into the UDC deferral account and pass to the benefit of ratepayers; correct?

MS. ELLIOTT: That's correct.

MR. BRETT: On the other hand, if you had a full pipe, which appears to be the case a lot of the time based on these numbers, if you had a full pipe and you did a transaction with one of the marketing companies or whomever, but it appears from -- if you did a transaction with one of the marketing companies, say a Shell, Coral or a BP, and you earned RAM-enhanced revenues as a result of that transaction, that those revenues did not go to the UDC account; is that correct?

MS. ELLIOTT: That's correct.

MR. BRETT: They went to the S&T -- they effectively were S&T revenue; right?

MS. ELLIOTT: Yes.

MR. BRETT: And at the relevant time - that is to say 2008 through 2012 there - as you pointed out and as we have discussed, there was no S&T deferral account; correct?

MS. ELLIOTT: That's correct.

MR. BRETT: Now, let me put the proposition to you that, in effect, what you have done by the second transaction I have described is created a sort of virtual empty pipe which has permitted the large marketing companies to -- and it is a matter of agreement, of course, that with the assignment goes the FT RAM credits.

So what you have done is created a situation where the large marketing companies can earn, and have earned, enormous revenues from the FT RAM, which they then share with you in some ratio or another, depending on your particular transaction. And you call -- is that fair?

MR. ISHERWOOD: I would not classify their capability as enormous. We have no idea what the capability is.

MR. BRETT: I take your point. They could be big or small, or good or not so good.

MR. ISHERWOOD: But we would -- in the case of where we're assigning them the pipe, we would be sharing in whatever potential upside they're predicting, and we would negotiate that rate.

MR. BRETT: Right. And would you not agree that, in essence, what that transaction is or could very well be viewed as is -- well, what it is, in substance, it is a transaction that would -- that reduces or should reduce, should offset or, in Mr. Smith's words, defray the costs of long-term firm tariff service for ratepayers?

MR. ISHERWOOD: We would disagree with that, that premise.

If you go before the incentive regulation settlement, we had an account -- we had an account, the deferral account, before incentive regulation for transportation exchange and --

MR. BRETT: Yes. That's the one that goes back a long, long way.

MR. ISHERWOOD: A long, long way. We'd do the same activity in that era, the same exchanges, and it would have been shared 75/25.

The distinction here is, starting in 2008 with incentive regulation, by us adopting a higher forecast to be built into margin, which ratepayers benefitted from for the full five years, we were incented -- and, likewise, to eliminate the deferral account entirely -- we were incented to do as well as we could.

MR. BRETT: Let me ask you on that account. I don't doubt that you were given an incentive to reduce your costs, particularly your delivery costs, but we're talking about gas costs here, gas transportation costs, which are part of gas costs.

And insofar as gas costs are concerned, they are, would you not agree, of course, outside the framework of the IRM? They have nothing to do with the IRM?

MR. ISHERWOOD: Gas costs are treated as Y factors.

MR. BRETT: Right. And you do have -- you do have -- well, let me put it this way.

I take it it is clear -- and I don't think there would be any disagreement about this, but I will put it. Would you agree with me you did not ever get approval from this Board to actually characterize the revenues from these assignments when the pipe is full, if I can put it that way, as exchange revenues? You didn't come in and seek approval for that proposition, as opposed to gas cost deferrals, as opposed to reductions in the -- as opposed to reductions in the -- as opposed to revenues that would be effectively treated as reductions to transportation capacity through the QRAM process. You didn't get approval for that?

MR. SMITH: No, I don't agree with that, Mr. Brett.

MR. BRETT: Well, I am asking the witness if he has a view. I am asking him a simple question of fact. I would like him to answer the question. You can in argument characterize it however you like, Mr. Smith.

MS. HARE: Mr. Smith has an objection to the question.

MR. SMITH: I have an objection, because it is not a question of fact. It is a question of what the Board has permitted. These are services sold under a regulated rate schedule. They have been for literally decades, and they were shared.

So I don't think it is a fair question to ask the witness. That is the objection.

MR. BRETT: I think Mr. Smith's problem here is that I'm not -- I'm not accepting the assumption that these were exchange revenues. I am making the proposition that these really are gas cost offsets and, therefore, they never -- they never would have or should have gone into an S&T revenue account. They should have gone into a gas costs account.

So, in that sense -- and I am going to in a moment point to a gas supply deferral account, which I think was the appropriate account for them to go into. But that is the nature of my question. I am challenging the premise of that.

MR. SMITH: Madam Chair, I do have one other concern about this, and this is we're deep in the weeds on this point. So at that point I, you know, throw up my hands and say whatever, at some level.

But on the other hand, the utility of this cross-examination can only be to suggest that there should be proceeding.

MR. THOMPSON: Well, isn't that what I said? Overcharging and not refunding is one in the same.

MS. ELLIOTT: The customers' rates reflected the updated TCPL tolls. The error was in the calculation of the deferral account. We did not credit the deferral account with the amount the customer had actually paid.

MR. THOMPSON: Right. But the point is that it went back some years, two-and-a-half years, I believe, and the remedy that Union proposed and everybody accepted, including the Board, was, We'll just do an entry in the deferral account in the current year to correct for that situation.

That's what happened; is that fair?

MS. ELLIOTT: We were correcting a calculation error in the deferral account, and we did that retroactively to when the error occurred.

MR. THOMPSON: All right. Well, I won't argue with you about what its characterization is.

It won't surprise you that that's what we think should happen here with respect to the $37 million and some odd, because we say that is gas costs.

Now, that then brings me to the next area, which relates to the examination-in-chief that you provided the other day. It is Exhibit K6.4, and you were doing this in a pre-emptive strike on my ex-franchise revenue witness panel package.

Now, I just want to understand what it is you are trying to say in your examination-in-chief. As you know, we characterize these FT RAM demand mitigation amounts as gas supply charge items that should be credited to ratepayers, and I take it that you are characterizing them as something else. And what is the something else that you characterize them as?

MR. ISHERWOOD: We characterize them as regulated revenues.

MR. THOMPSON: Regulated revenues?

MR. ISHERWOOD: Yes.

MR. THOMPSON: Okay. And do you characterize them as --

MR. ISHERWOOD: I should back up. The FT RAM credits by themselves are not regulated revenues, but the S&T transactions stemming from them are the regulated revenues.

MR. THOMPSON: All right. There was a lot of discussion about history in your examination-in-chief, and it started with -- at page 1 of your K6.4, where there was a definition of "exchange".

MR. ISHERWOOD: That's correct.

MR. THOMPSON: And this is an exchange being described as between party A and party B, and Union facilitating that exchange. That is what I take from the description.

MR. ISHERWOOD: This is Union's definition of "exchange"; that's correct.

MR. THOMPSON: All right. But it involves a third party, third party's gas, not Union's gas.

It is not Union seeking an exchange. It is the third party seeking the exchange; fair?

MR. ISHERWOOD: In this definition, Union Gas is giving gas to a party in a location, and we're getting the party B's gas at another location.

So we are actually exchanging the party B's gas from one location to another.

MR. THOMPSON: This evidence dates back to May 2003, I believe. The interrogatory response is August.

Then at pages 2 and following, there is a description in your in-chief binder from that case, describing how transactional services were conducted at that time; is that fair?

MR. ISHERWOOD: Sorry, which page are you on, Mr. Thompson?

MR. THOMPSON: Page 2.

MR. ISHERWOOD: And 3?

MR. THOMPSON: "Union forecasts assets to meet its in-franchise demands."

MR. ISHERWOOD: Yes.

MR. THOMPSON: And it goes on:

> "Any remaining assets are used to support the sale of transactional services."

It talks about the gas supply plan at line 22, and over on page 3, at line 3, it says:

> "There will be few, if any, firm assets to support transactional services on a future plan basis."

Then at lines 5 and 6, it says that:

"Incremental firm assets will tend to be
available as a result of both weather and market
variances."

In other words, it depends on weather and market and other conditions before you could do transactional services in those days. That's the way it was looked at?

MR. ISHERWOOD: I would agree with that. So prior to FT RAM program, that is exactly how transportation exchanges were being accounted for.

And going forward in 2013, if FT RAM does end and terminate, then it would be back to this type of operation.

MR. THOMPSON: But the FT RAM-type transaction, where you actually adopt a different plan from your gas supply plan, that didn't emerge until well after this case; I think you said it was 2008 or later?

MR. ISHERWOOD: That primarily emerged in 2008.

MR. THOMPSON: Okay. And in terms of the dollar amounts that you were forecasting for this type of activity, if you go to page 6 -- in the prefiled evidence, you're making the case this is a declining area, and at page 6, you noted -- sorry, it is noted in the decision under "Transportation and Exchange" that your actual for 2002, 12.5, 2003, 5.8 and 2.5.

So this decline was being painted at that time, right? This is where you thought it was going?

MR. ISHERWOOD: This is back in 2004, that's correct.

MR. THOMPSON: And nobody knew any differently at that time; correct?

MR. ISHERWOOD: Correct.

MR. THOMPSON: And in the 2007 case, your forecast was $2.1 million for this kind of activity.

MR. ISHERWOOD: That was actually a margin number, not a revenue number. That's an important distinction.

MR. THOMPSON: All right. Well, in any event, your margin number was -- forecast was 2.1.

In your evidence-in-chief, you have these deferral account items, 10, 11, 12 and 13, and I took it from the evidence-in-chief that what you are saying is these FT-type RAM transactions are covered by these deferral accounts. And they were closed, and therefore, ratepayers, you're out of luck.

Am I understanding the company's position correctly?

MR. ISHERWOOD: Our position is the activities we're doing since 2008 are very consistent with what was done prior to the incentive regulation.

The only difference is the FT RAM program was added to an FT service as an enhancement to the service.

Otherwise, the transactions are very similar.

MR. THOMPSON: I understand that, but is the company saying that they are covered or they would have been covered by these particular deferral accounts, and since they were closed, ratepayers are out of luck?

MR. ISHERWOOD: I think it is a feature or definition of the incentive regulation settlement that we went through, where our margin forecast for the storage -- sorry, the transmission exchange activity was actually increased from the 2 million to 6.9 million.

And that was a risk that was added to Union Gas, and that was a benefit that was added to the ratepayers.

And our objective during incentive regulation was to do as well as we could in that account, and any success we had would ultimately be shared through the earnings sharing mechanism, and not at the service level or deferral account level.

MR. THOMPSON: No, but the consideration for the four million or 4.3 was the closure of these accounts.

FT RAM was never, in evidence, discussed. I doubt that you even knew about it. Certainly ratepayers didn't, and I don't think the Board knew about it.

But the consideration of four was with respect to the closure of these deferral accounts. So what I am trying to find out: Are you saying these FT RAM credits fall within the ambit of these deferral accounts?

Because if you aren't, then I can move on.

MR. ISHERWOOD: The activity that resulted from FT RAM -- we were able to do transportation exchange activity -- would, prior to the incentive regulation, would have fallen into these accounts.

And it is for that reason we consider them to be traps and exchange revenue, regulated revenue, and shared at the earnings level and not at the service level.

MR. THOMPSON: All right. Well, maybe I can get you to agree with this.

Certainly this activity, the RAM-type activity, does not, I suggest to you, does not fall within the ambit of the deferral accounts at 11, 12 and 13. One is "other S&T services," which is the name changes and that kind of thing. 174 is -- at page 12 is "supplemental load balancing," and 13 is "heating value."

The only account that I think could possibly apply is 179-69. Is that the one you say applies?

MR. ISHERWOOD: In my testimony earlier in the day, we had talked about what happens if FT RAM continues in 2013 and beyond.

And in our evidence, in some interrogatories I had pointed to, we talked about there being a potential for the Board, at their choosing, to pick several different options in terms of reinstating a deferral account around FT RAM.

And I would assume, subject to Ms. Elliott's confirmation, it would be an account similar to this.

MR. THOMPSON: I don't think I have an answer to my question.

Do you say the FT RAM optimization transactions fall inside or outside the ambit of account 179-69?

MS. ELLIOTT: When 179-69 was effective, it captured all of the transportation and exchange revenues or the variances in those revenues between the actual and the Board-approved.

That account was eliminated in 2008.

MR. THOMPSON: So what's the answer to my question?

MS. ELLIOTT: Exchange revenues, prior to 2008, would have been -- variances in exchange revenues would have been captured in this account.

MR. THOMPSON: Actually, what it says is "between actual net revenues for transportation and exchange services."

Can I put in there, parenthetically, "provided by Union"?

MS. ELLIOTT: Yes. It's a Union deferral account. It would be Union's revenues. It would be revenues from services provided by Union.

MR. THOMPSON: To the extent, as we have discussed, the marketers are giving you an exchange, and to the extent you are using IT not for an exchange but to move your own gas to points east, your own western gas, I suggest to you those activities clearly do not fall within the ambit of exchange services, by definition, provided by Union, and secondly, they were unknown at the time.

MR. ISHERWOOD: I think as we described earlier, Mr. Thompson, when we do optimization around the FT RAM program, we have two options.

One is to do a bundled package, if you wish, with a marketer, where we actually get a net revenue coming back.

Or, secondly, we can actually optimize it ourselves and sell in exchange.

And we consider those two things to be equivalent.

MR. THOMPSON: Well, would you agree with me you really had little, if any, idea about the RAM benefits that you could extract at the time that those accounts were eliminated?

MR. ISHERWOOD: I think I go back to the beginning of the incentive regulation, and the intent or the purpose of it was to give the utility some flexibility to create new services to find new ways to earn revenue.

And I would give the Union Gas team some credit in terms of how they have been able to maximize the ability to earn revenue on that program.

And to the extent that RAM continues in 2013 and beyond, subject to having some sort of deferral account around RAM, that would be to the benefit of the ratepayer. That was the whole extent of incentive regulation, find new ways of doing business.

MR. THOMPSON: I don't think you answered my question. I'm suggesting you knew little, if anything, about this back in 2007 and that the light went on later. And if you would turn up page 32 of my brief, again, this is something you say in a response in the TransCanada case, middle of the page:

> "It has taken Union and the other market participants several few years to gain experience with the RAM program and to fully understand to realize its full benefit."

I might put that in other words, but that is what you said in the TransCanada case; fair?

MR. ISHERWOOD: That is my last response, as well. I'm saying the Union Gas team has been very creative in finding ways to move gas and optimize the gas supply plan and earn those revenues. It is consistent with that paragraph.

MR. THOMPSON: Okay. Then in terms of the history, just to do this quickly, because I am trying to keep within my allotted time, you have your compendium that dealt with parts of it.

I just wanted to quickly, if I could, take you through Exhibit K6.5. This all relates to the history. I assume you folks have had a chance to look at this?

MR. ISHERWOOD: Yes.

MR. THOMPSON: Okay. And so at the first page, what we have is the Natural Gas Regulation in Ontario, Natural Gas Forum Report, and I have included there the excerpts from the Board's report dealing with deferral accounts.

And that is one of the things you referenced in subsequent filings; fair?

MR. ISHERWOOD: That's correct.

MR. THOMPSON: And then at page 8, what we have attached is -- and this was in the 2005-0520 case. This was the proposal initially made to close certain S&T accounts, and we find that at the bottom of page 9 and over at the top of page 10 of my brief.

MR. ISHERWOOD: Yes.

MR. THOMPSON: Is that fair?

The settlement agreement in that case you will find starting at page 12, and at page 21 the arrangement was, in that case, that the S&T -- see at the top of the page the S&T deferral accounts will remain in operation until the NGEIR proceeding determines otherwise?

GAS SUPPLY

PREFILED EVIDENCE OF

CHRIS SHORTS, DIRECTOR, GAS SUPPLY

TINA HODGSON, MANAGER, ASSET ACQUISITIONS

MARY EVERS, MANAGER, GAS SUPPLY

DREW QUIGLEY, MANAGER, GAS SUPPLY PLANNING

The purpose of this evidence is to address the gas supply-related matters proposed for 2013. The evidence is organized under the following headings:

1/ Gas Supply Plan

2/ Gas Supply Pricing

3/ Upstream Transportation Portfolio

1/ Gas Supply Plan

The purpose of this evidence is to describe the 2013 Gas Supply Plan. The 2013 (test year), 2012 (bridge year), 2011 (outlook) and the 2010 (historical year) Gas Purchase Expense schedules are found at Exhibit D3, Tab 2, Schedule 1; Exhibit D4, Tab 2 Schedule 1; Exhibit D5, Tab 2, Schedule 1 and Exhibit D6, Tab 2, Schedule 1, respectively. The Gas Purchase Expense schedules are consistent with those presented by Union in previous rates proceedings.

1.1/ Gas Supply Plan Planning Process

In developing the Gas Supply Plan, Union models all upstream transportation capacity and storage assets to provide an integrated service across all delivery areas for bundled customers. Union uses software known as SENDOUT to complete the Gas Supply Plan. Union has used this modeling tool for a number of years and it has been presented in previous rate applications. It was most recently used to support the gas costs approved by the Board in Union's 2007 rates proceeding (EB-2005-0520).

The Gas Supply planning process is guided by a set of principles that are intended to ensure that customers receive secure, diverse gas supply at a prudently incurred cost. These principles are:

i. Ensure secure and reliable gas supply to Union's service territory;
ii. Minimize risk by diversifying contract terms, supply basins and upstream pipelines;
iii. Encourage new sources of supply as well as new infrastructure to Union's service territory;
iv. Meet planned peak-day and seasonal gas delivery requirements; and,
v. Deliver gas to various receipt points on Union's system to maintain system integrity.

Union's five-year Gas Supply Plan, completed during the spring of 2011, includes the following key inputs and assumptions:

i. Union's in-franchise demand forecast based upon customer location (Union North/Union South), supply arrangement (sales service), storage requirement (sales service and direct purchase) and service type (excludes Rate T1, Rate T3, North T-Service and Unbundled service);

ii. A monthly commodity price forecast as described in section 1.6;

iii. Upstream transportation tolls in effect at the time the forecast was prepared;

iv. Heating value of 37.51 $GJ/10^3m^3$ in Union North and 37.75 $GJ/10^3m^3$ in Union South;

v. All upstream transportation contracts held by Union plus existing obligated Ontario deliveries for the bundled direct purchase market;

vi. Sales service and bundled direct purchase storage is cycled completely each year in the plan with storage full on November 1 and empty by March 31;

vii. Sufficient inventory at February 28 to meet the peak day requirements for sales service and bundled direct purchase customers;

viii. No migration between sales service and bundled direct purchase customers for the term of the plan; and,

ix. 9.5 PJ of system integrity space. This storage space is used in a number of ways to maintain the operational integrity of Union's integrated storage, transmission and distribution systems.

1.2/ Gas Supply Plan Results

The Gas Supply Plan model provides a forecast of Union's costs required to serve in-franchise sales service and bundled direct purchase customers. These costs are reflected in the Gas Purchase Expense schedules previously referenced.

Union's 2012 to 2016 in-franchise Gas Supply/Demand Balance forecast for sales service and bundled direct purchase customers in 2013 is provided at Exhibit D3, Tab 2, Schedule 3.

There are no material changes in the proposed 2012 – 2016 Gas Supply Plan from the Gas Supply Plan filed in Union's 2007 rates proceeding (EB-2005-0520).

1.3/ Upstream Transportation Capacity

Union holds a combination of firm upstream transportation contracts, Dawn sourced supply and storage capacity to meet the full forecast annual demand. Firm transportation arrangements provide direct and secure access to a diverse group of supply basins and hubs in North America. A key objective of the Gas Supply Plan is to optimize the use of upstream contracted pipeline capacity. This is accomplished by managing upstream transportation capacity on an integrated basis and shifting the use of this capacity from one area to serve demand in another area when the opportunity and the need exists.

In Union North, Union utilizes TransCanada Pipelines ("TCPL") and Michigan Consolidated Gas Company/Great Lakes Gas Transmission ("MichCon/GLGT") capacity to meet sales service and bundled direct purchase customer demands. The transportation capacity necessary to meet peak day demands on a firm basis exceeds that required to meet the annual demand requirements. The Gas Supply Plan reflects the effective management of TCPL and MichCon/GLGT capacity by:

i. Using 15.4 PJ of TCPL Storage Transportation Service ("STS") injection and TCPL Dawn Diversions. STS injection is a service that allows Union to move excess volumes from Union North to Parkway and ultimately to Dawn storage in the summer; and,

ii. Using 15.0 PJ of TCPL STS withdrawals primarily in the winter months to serve weather-driven demands. Gas is withdrawn from Dawn storage throughout the winter and is transported back to Union North via STS withdrawals without the need for contracting additional TCPL firm transportation ("FT") capacity to that delivery area.

Using contractual STS pooling rights to group all of Union's STS rights serving the various Union North delivery areas provides Union with the flexibility to serve the individual delivery areas in Union North with gas service in excess of that delivery area's specific STS rights. Unutilized TCPL and MichCon/GLGT FT capacity (held in order to serve peak day firm loads for sales service and bundled customers in Union North that cannot be managed via the above mechanisms) is forecast at 10.4 PJ for the 2013 test year. This results in Unabsorbed Demand Charges ("UDC"). If weather is colder than normal, and if it is economical to do so, Union will use this capacity to meet incremental supply requirements in either Union North or Union South, subject to TCPL's authorization of downstream diversions. This unutilized capacity result has increased from the 2007 Board-approved filing. In EB-2005-0520, the Board approved 4.4 PJ of UDC for unutilized TCPL FT capacity serving the Northern bundled customers. The increase in unutilized capacity is the result of decreases in weather-related throughput in the general service market in Union North as discussed in the evidence of Mr. Paul Gardiner at Exhibit C1, Tab 1, and decreases in Union North contract customer throughput as discussed in the evidence of Ms. Sarah Van Der Paelt and Mr. Paul Gardiner at Exhibit C1, Tab 2.

In Union South, Union utilizes capacity on multiple different upstream pipelines to provide service to meet sales service customer demands. The Gas Supply Plan reflects the effective management of these capacities as there is no unutilized transportation capacity forecast for the 2013 test year as the Plan forecasts a 100% load factor on all Union South upstream transportation. In EB-2005-0520, the Board approved 0.2 PJ for Union South.

The Gas Supply Plan includes 15.3 TJ of Dawn Delivered Service as part of the Union South supply portfolio in 2013, which represents approximately 15% of Union's South sales service purchases. Dawn delivered service supports this diversity by providing Union access to a robust and liquid Dawn market hub. With this diversity, Union is less exposed to price volatility.

Dawn sourced supply is acquired on a month-to-month basis following Union's System Gas - Gas Procurement Policy and Procedures (Appendix A). Purchasing on a month-to-month basis provides Union the flexibility to manage to its seasonal inventory targets without incurring additional UDC.

1.4/ Incremental Supply

If Union is required to purchase incremental supply for unplanned balancing purposes, Union considers its various options in terms of cost effectiveness and operational need. Often these transactions take place at Dawn. Since the November, 2004 implementation of the load balancing checkpoints for bundled direct purchase customers, approved by the Board in the RP-2003-0063 Decision, Union's incremental supply purchases are primarily driven by sales service consumption being greater than forecast (primarily due to colder than normal weather). However, even with direct purchase load balancing checkpoints, Union still retains load balancing obligations related to weather variances relative to the February inventory checkpoints and March weather and consumption variances for both sales service and bundled direct purchase customers.

1.5/ Winter Peaking Service

Union is not forecasting a Winter Peaking Service requirement in Union South for the winters of 2012/2013 and 2013/2014. As discussed in the evidence of Mr. Matt Wood at Exhibit B1, Tab 5, there is no Parkway shortfall forecast on the Dawn-Parkway system for the winters of 2012/2013 and 2013/2014.

1.6/ Pricing

The Gas Supply Plan was prepared in the spring of 2011. The transportation tolls and gas prices utilized in the development of the plan are those used to set the January 1, 2011 Quarterly Rate Adjustment Mechanism ("QRAM") commodity price. These prices are reflected in the Gas Purchase Expense schedules and shown at Exhibit D3, Tab 2, Schedule 1; Exhibit D4, Tab 2, Schedule 1; Exhibit D5, Tab 2, Schedule 1 and Exhibit D6, Tab 2, Schedule 1.

1.7/ Direct Purchase

The Gas Supply Plan includes all bundled direct purchase demand and contracted Daily Contract Quantities ("DCQ"), and assumes that the number of direct purchase customers remains constant as of January 1, 2011. Union is unable to predict customer migration between sales service and bundled direct purchase. Therefore, for the term of the Gas Supply Plan, customers are assumed to remain with the service they had received effective January 1, 2011.

On an actual basis, if customers migrate to direct purchase, Union facilitates this movement by displacing planned commodity purchases and allocating upstream transportation capacity, as per the vertical slice allocation methodology approved in the RP-1999-0017 proceeding and as discussed later in Section 3.1.

1.8/ Weather

The Gas Supply Plan is based upon the 2013 weather normalized demand forecast for in-franchise general service customers, as outlined in the evidence of Mr. Paul Gardiner at Exhibit C1, Tab 5.

1.9/ Storage

Union's 2011 to 2015 Peak Storage Availability and Utilization forecast is provided at Exhibit C3, Tab 4, Schedule 3. Storage is provided to in-franchise customers to meet the demand requirements of sales service and bundled direct purchase, Rate T1, Rate T3 and Northern T-service customers.

These storage allocation methodologies were approved by the Board as part of the Natural Gas Storage Allocation Policies Decision (EB-2007-0724/0725).

The storage space available to sales service and bundled direct purchase customers in Union South and Union North is determined using the Board-approved Aggregate Excess methodology. This method is defined as the calculation of the difference between total winter demand (November 1 through March 31) and the average annual demand for a 151 day period. This method determines the allocation of storage space based on the following formula:

Aggregate Excess = Total Winter Consumption – [(151/365)*(Total Annual Consumption)]

Union has provided the storage space allocations available to customers electing U2 (unbundled) service in Union South and electing T-service and unbundled service in Union North at Exhibit D3, Tab 2, Schedules 6 and 7, respectively. These allocations are updated annually based on the methodology approved in the EB-2007-0724/0725 Decision.

Accordingly, customers electing T-service and U5/U7/U9 (unbundled) service in Union South have the option of electing the storage space allocation method which best serves their need. The allocation methods available are the Aggregate Excess methodology and the 15 x DCQ methodology.

New large T1 and U7 (unbundled) service customers in Union South with daily firm transportation demand requirements in excess of 1,200,000 m^3/day have the storage space allocation calculated as follows: Peak hourly consumption x 24 hours x 4 days, unless the customer elects firm deliverability less than the maximum entitlement.

If the customer elects less than the maximum deliverability entitlement, the maximum cost based storage space entitlement is 10 x firm storage deliverability contracted (but not to exceed peak hourly consumption x 24 hours x 4 days).

2/ Gas Supply Pricing

The purpose of this evidence is to review Union's gas supply (commodity and upstream transportation) pricing mechanism.

2.1/ QRAM

Union uses the QRAM to set reference prices for commodity and upstream transportation, including the prospective recovery of gas cost related deferral account balances. The existing QRAM process was reviewed and approved in EB-2008-0106.

The major features of the QRAM include:

i. A quarterly change to the commodity reference prices using a 21 day average of the forward 12 months gas prices as indicated on the New York Mercantile Exchange ("NYMEX"), adjusted for the Alberta basis and foreign exchange rate;

ii. The prospective recovery of applicable deferral account balances;

iii. The prospective true-up of historical deferral account variances, between previously projected and actual deferred costs or credits;

iv. TCPL transportation toll changes as approved by the NEB; and,

v. An efficient, consistent and mechanical filing and approval process.

The Board has consistently approved Union's QRAM applications. The QRAM process is working well and Union is not proposing any changes.

3/ Upstream Transportation

The purpose of this evidence is to provide information on Union's upstream transportation portfolio commitments.

The North American supply/demand dynamics are changing at a rapid rate. The recent introduction of significant sources of shale supply and the declining production in the Western Canadian Sedimentary Basin ("WCSB") are examples of the changing market dynamics that directly impact the supply choices available to Union. A discussion on the impacts of the changing market dynamics can be found at Exhibit A2, Tab 1, Schedule 1 and Schedule 4. Union's transportation portfolio continues to evolve in response to cost effective supplies available to Ontario. Union's current upstream transportation portfolio is diversified with respect to supply basin access, contract term and transportation service provider. Exhibit D3, Tab 2, Schedule 5 presents Union's Summary of Union's Upstream Transportation Contracts.

3.1/ Southern Allocation of Upstream Transportation Capacity (Vertical Slice)

Union allocates its upstream transportation capacity to Union South customers as they migrate from sales service to direct purchase using the vertical slice methodology approved by the Board in its RP-1999-0017 Decision. The components and relative percentages of the vertical slice are based on Union's projected upstream transportation portfolio as of each November 1 and remain in effect for one year. Union communicates the upcoming vertical slice percentages to customers and the Board in August of each year.

Union's sales service vertical slice upstream transportation portfolio for November 1, 2011 is found at Table 1. This portfolio is being allocated to customers switching from sales service to direct purchase during the period November 1, 2011 to October 31, 2012.

Table 1
Union Gas Limited
Union South Sales Service Vertical Slice Transportation Portfolio
(Effective November 1, 2011)

Transportation	Daily Volume (GJ)	% Portfolio
Alliance/Vector	66,436	27.5%
Vector	85,154	35.2%
Trunkline/Panhandle	21,017	8.7%
Panhandle – Ojibway	26,270	10.9%
TransCanada	42,925	17.8%
Total	241,802	100.0%

3.2/ Union South Transportation Portfolio as at November 1, 2011

The following describes the transportation components in Union's South transportation portfolio and vertical slice:

1) Alliance/Vector

Union holds an existing firm transportation contract on Alliance Pipeline and a corresponding contract on Vector Pipeline. These contracts transport gas from the WCSB and deliver it to Union's system at Dawn. The contracts reflect a volume of 84,405 GJ/d of firm transport with a term of December 1, 2000 through November 30, 2015.

Of the total contracted capacity, 66,436 GJ/d serves sales service customers in Union South and is allocated to customers migrating to direct purchase using the vertical slice methodology. The Board previously reviewed these transportation contracts in the RP-2001-0029 proceeding. Since that time, Union was required to give Alliance notice by December 1, 2010 to exercise its right to extend the duration of the contract beyond the original termination date of December 1, 2015. Union elected not to extend the term of the contract for economic reasons.

2) Vector

Union holds a second firm transportation contract on Vector Pipeline, transporting gas from Chicago to Union's system at Dawn. The contract reflects a volume of 81,000 Dth/d (85,460 GJ/d) of firm transport for a term of November 1, 2008 through November 30, 2015.

Of the total contracted capacity, 85,154 GJ/d serves sales service customers in Union South and is allocated to customers migrating to direct purchase using the vertical slice methodology.

The Board previously reviewed this transportation contract in the EB-2009-0052 proceeding.

3) Trunkline/Panhandle

Union holds an existing firm transportation contract on Trunkline Gas Company from the Gulf of Mexico to Bourbon, Illinois, and a corresponding short-haul contract on Panhandle Eastern Pipe Line from Bourbon to Union's system at Ojibway. The volumes are obligated at Parkway by a firm Ojibway to Parkway service. The contracts reflect a volume of 20,000 Dth/d (21,101 GJ/d) of firm transport for a term of November 1, 2007 through October 31, 2012.

Of the total contracted capacity, 21,017 GJ/d serves sales service customers in Union South and is allocated to customers migrating to direct purchase using the vertical slice methodology.

The Board previously reviewed these transportation contracts in the EB-2008-0034 proceeding.

4) Panhandle

Union holds a firm long haul transportation contract with Panhandle Eastern Pipe Line from the Panhandle Field Zone to Union's system at Ojibway. The volumes are obligated at Parkway by a firm Ojibway to Parkway service. This contract reflects a volume of 25,000 Dth/day (26,376 GJ/d) of firm transport for a term of November 1, 2010 through October 31, 2017.

Of the total contracted capacity, 26,270 GJ/d serves sales service customers in Union South and is allocated to customers migrating to direct purchase using the vertical slice methodology. The Board previously reviewed these transportation contracts in the 2010 Deferral Disposition proceeding, EB-2011-0038.

5) TCPL

In total, Union's South portfolio holds 71,327 GJ/d of TCPL capacity transporting gas from Empress, Alberta to the Union CDA.

Of the total contracted capacity, 42,925 GJ/d serves sales service customers in Union South and is allocated to customers migrating to direct purchase using the vertical slice methodology.

3.3/ Union North Transportation Portfolio as at November 1, 2011

The following describes the transportation components in Union's north transportation portfolio.

The vast majority of customers in Union North continue to be served directly from TCPL interconnects. Approximately 95% of Union's long haul TCPL FT contracts and all of Union's TCPL STS contracts have completed their primary term and renew on a 1-year rolling basis. Detailed TCPL contract capacity can be found in Exhibit D3, Tab 2, Schedule 5.

To achieve some supply diversity in Union North, Union contracted for firm transportation from Michigan to the Sault Ste. Marie Delivery Area ("SSMDA") for a volume of up to 6,143 GJ/d beginning November 1, 2011 through October 31, 2014 in order to supply a portion of that delivery area from Michigan. Accordingly, Union holds capacity with MichCon, GLGT and finally on TCPL for service to SSMDA. This path is new for Union beginning in November 1, 2011 and provides some supply diversity to Union North where now 5% of the total Union North system supply is sourced outside of the WCSB.

3.4/ Transportation Committed to Beginning November 1, 2012 – South Portfolio

Niagara – Kirkwall with TCPL

Union holds a firm transportation contract with TCPL for the path Niagara to Kirkwall. The contract quantity is for 21,101 GJ/d (20,000 Dth/d) beginning November 1, 2012 through October 31, 2022 (ten year term).

This contract will become part of Union's upstream transportation portfolio as of November 1, 2012.

K3.1

EB-2011-0210

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, 2013.

Federation of Rental-housing Providers of Ontario

Reference Document for Union Gas Panel #2

Reference:

Application, Section 3.6.1, page 25 and Figure 3-13 (NOL Flow vs. NOL Capacity).

Preamble:

TCPL discusses NOL flows.

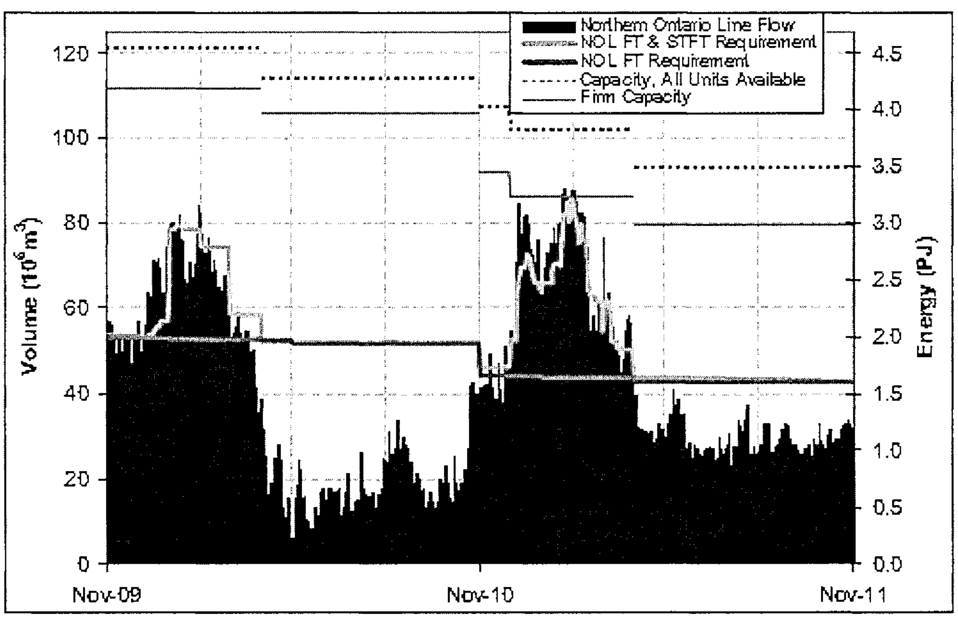
Request:

a. Please redraw the graph in Figure 3-13 to show FT volumes separately from STFT volumes for both the contracted volumes and the nominated volumes.

b. For the period shown in the graph, please indicate by season, the average term for STFT contracts.

Response:

a.

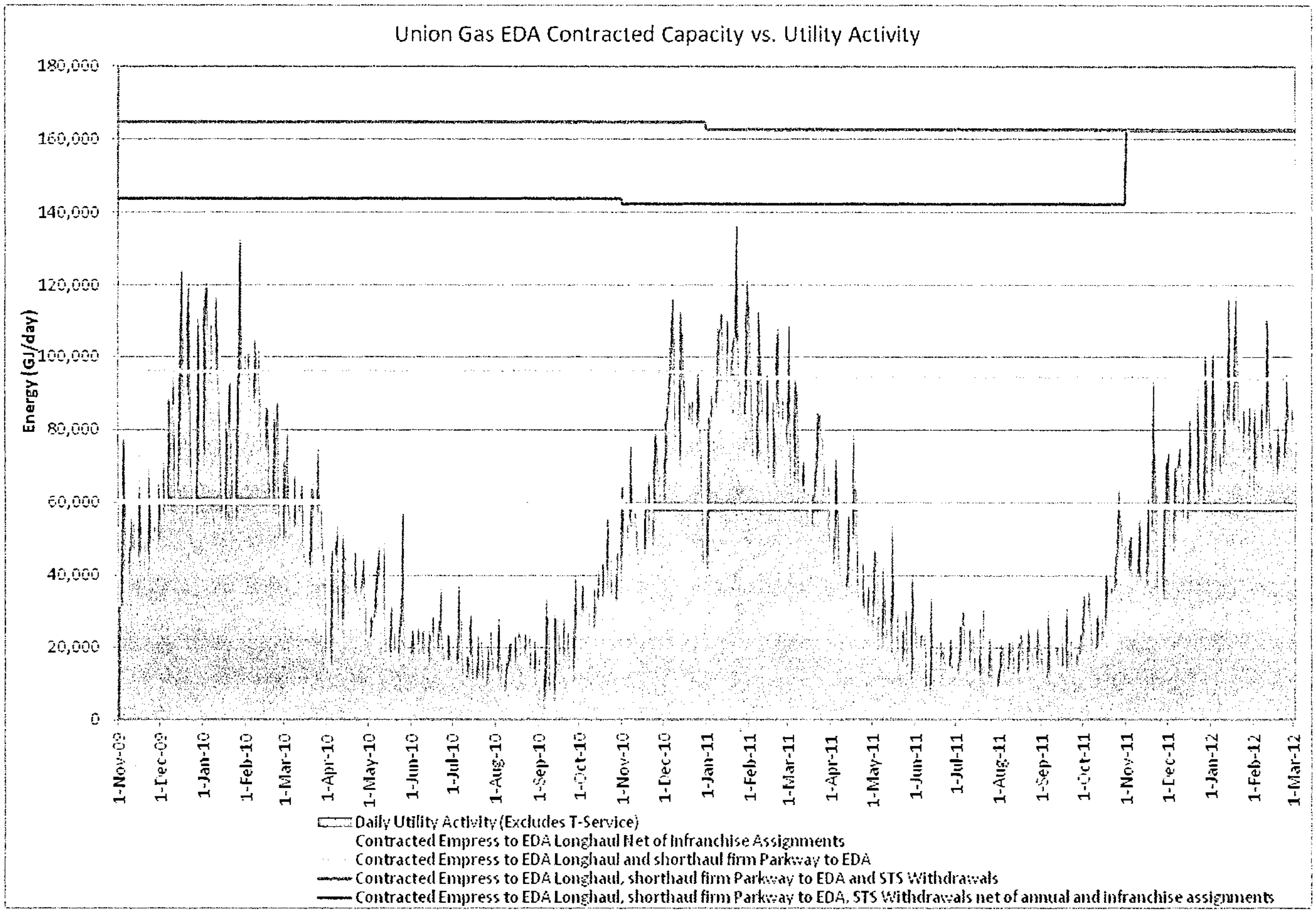


UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Quigley

Please provide contracted FT and contracted STFT to Union's Eastern delivery area, actual deliveries received from TCPL for in-franchise customers, November 1, 2009 to March 31, 2012.

The attached graph reflects Union's contracted capacity and daily utility activity on TCPL in the Eastern Delivery Area.



Note: The Gas supply plan utilizes firm TCPL services (Longhaul, Shorthaul and STS) as shown above to meet design day obligations.

UNION GAS LIMITED

Undertaking of Mr. Brett
To Ms. Hodgson

Please explain FT contract requirement needed to be eligible to purchase an STS contract from TransCanada.

The Storage and Transportation Service ("STS") is a distinct service that TransCanada provides. However, there is the prerequisite of contracting a TransCanada long-haul Firm Transportation contract, amongst other prerequisites, in order to be eligible to purchase the service. Specific references are found both in the Contract Template at:

http://www.transcanada.com/customerexpress/docs/ml_regulatory_tariff/22_STSContract.pdf

The specific reference to the long-haul, firm transportation requirement is found at Sheet No. 1, third paragraph:

> "Whereas TransCanada provides firm transportation service to Shipper from empress, Alberta or a receipt point in the Province of Saskatchewan to ____ the delivery point (the "Market Point") under a FT Contract(s) dated _______ and identified with the TransCanada contract identifier ________ (the "FT Contract"), and..."

The STS Toll Schedule also details this requirement. It is found at:

http://www.transcanada.com/customerexpress/docs/ml_regulatory_tariff/06_STSTollSchedule.pdf

The specific reference to the long-haul, firm transportation requirement is found on Sheet No. 1, at Section 1.1 (a) under the heading of Availability,

- Sub-section 1.1,
    - o "Any Shipper shall be eligible to receive service pursuant to this Storage Transportation Service ("STS") Toll Schedule, provided such Shipper:"
- Paragraph (a),
    - o "has entered into a Firm Transportation Service Contract(s) with TransCanada (the "FT Contract(s)") with a receipt point at Empress, Alberta or in the province of Saskatchewan and such FT Contracts have been identified in Shippers STS Contract;"

STS service, because it is separately contracted for, can still be utilized even if the firm long-haul is assigned on a temporary basis.

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	EB-2011-0210

VOLUME:	3	
DATE:	July 13, 2012	
BEFORE:	Marika Hare	Presiding Member
	Paul Sommerville	Member
	Karen Taylor	Member

MS. HODGSON: Mr. Shorts spoke to our guiding principles a little bit earlier, and the key principle in guiding our firm transportation purchases on TCPL in Union's north is security and reliability at a prudently incurred cost.

So Union Gas has an obligation to serve long-term firm transportation, firm service with long-term firm assets.

In the north, TCPL's firm transportation is also a prerequisite to purchasing the storage and transportation, or STS, service and it carries with it the rights to renew. So contractually we are able to renew the firm transportation if we require it, and it also gives us the right to divert gas.

Supply is then planned to be delivered on this capacity, on a firm, even daily basis, and storage is then used to manage the differences between what is delivered and what is consumed on any given day.

Services other than firm transportation may introduce volume risk, price risk, and even credit risk.

MR. SMITH: Now, you may have captured this -- and I apologize -- but there obviously is discussion in the media and elsewhere about TCPL's utilization or utilization on the TCPL system, which leads me to ask why you don't buy IT services from TCPL to serve Union's north.

MS. HODGSON: Interruptible transportation is not a reliable transportation, in that it is subject to curtailment. So although it doesn't happen often, there have been times when Union Gas has had both interruptible transport and firm transportation scheduled, nominated and scheduled on our system, and the interruptible transportation has been curtailed when the firm transportation has not.

MR. SMITH: What about what is called STFT? I understand that is short-term firm transportation.

MS. HODGSON: It is firm. Short-term firm transportation is firm service, and although it is available, it is not guaranteed to be available.

So the way the process works at a very high level on TCPL is they'll come out throughout the year for firm transportation that is available, first yearly and then shorter terms as the year progresses.

Not all paths are offered on short-term firm transportation open seasons. So for example, there currently is one open out in the market right now, and not all long-haul delivery areas are available.

MR. SMITH: Okay. What about third-party market services? Are there any of those available?

MS. HODGSON: They can be. It is very much they are - you can purchase it between any two points. However, we wouldn't know how that service is underpinned. We wouldn't know -- there would -- typically not carry renewal rights, or if there were, they would be typically at a very high premium. And there would be no STS rates, diversion rates that would accompany that service.

MR. SMITH: Thank you. Those are my questions in examination-in-chief.

resources you'll need to meet the coldest day of the winter from an integrated storage and transportation planning perspective?

MR. QUIGLEY: Correct.

MR. QUINN: Okay. So I want to separate that from the seasonal planning, and the seasonal planning relates more to making sure there is enough gas in your franchise, predominantly in storage, to ensure that the amount of deliverability from storage is met.

So would you agree with me that seasonal planning is about ensuring there's adequate monthly supply to meet storage targets that support late season delivery for either a March 1st peak day or, as you alluded to earlier, a March 31st target?

MR. QUIGLEY: I would say that the seasonal plan is to ensure there's enough supply delivered to meet monthly seasonal demands.

The gas plan is -- we're trying to manage the demands within the south and north -- the south delivery area and the north delivery area to ensure we have enough supply landing to meet our seasonal demand requirements.

MR. QUINN: Okay. So said another way, is it correct to say that for the March 1st peak design day, the amount of deliverability from storage is set, and then you have to determine the amount of transportation needed to ensure that that amount of gas is available for that March 1st peak day?

MR. QUIGLEY: I would suggest it's the other way around. We plan our seasonal plan, and then that determines how much gas for in-franchise customers will be in the ground on February 28th, March 1st.

Then that -- then we look to see: Is that sufficient to meet design day in the south?

MR. QUINN: Okay, I think this is an important point of clarification, so I will ask it a different way. On March 1st, you're assuming a certain level of deliverability from storage to be able to meet the design day conditions; is that correct?

MR. QUIGLEY: Correct.

MR. QUINN: And so when you come up with your design day plan, you know the amount of deliverability needed, and, therefore, you know the minimum amount that you need to have in storage, and you hold yourselves and other direct purchase customers to targets that are based on a March 1st design?

MR. QUIGLEY: Well, the gas plan itself is not a design day plan. It's a monthly -- it's an average day plan. Then the storage -- another group looks at what the design deliverability requirements out of storage are, and they base that -- they look to our plan to how much gas would be in the ground for in-franchise customers on February 28th, March 1st.

MR. QUINN: Okay. Said very simply, that design group gives you a target to have in storage -- and I am going to deal just with the system gas and bundled services. They have given you a target to hit as of February 28th that quite broad. I guess -- I'm sorry, I was thinking of eastern delivery zone. So you say eastern delivery area.

You have multiple contracts to the eastern delivery area, though, do you not?

MR. QUIGLEY: Correct.

MR. QUINN: Okay. From those multiple contracts, is one of those contracts labelled as: This is the contract that would go unfilled on a planned basis for March deliveries?

MR. QUIGLEY: We would not model the specific contract. We would lump the contracts together as being available to serve the eastern delivery area, and the UDC would just be calculated in total.

MR. QUINN: Okay, thank you. So we started touching on it before about the alternatives that would be considered. I am going to deal first with UDC, because we're on that.

So on a planned basis, you say in the eastern delivery area you've got 1.2 pJs that would not be filled in the month of March. You also indicated that you would use firm service. Your choices would be looking at firm service to meet needs.

Have you considered or does your model allow you to consider, as opposed to using a firm annual contract, the opportunity to use a monthly contract for the months of the winter that it is expected to be needed?

MR. QUIGLEY: Well, as we've outlined by Mr. Shorts in the gas supply planning principles, we look to use long-term firm assets to serve our long-term end user obligations in the delivery area.

The issue would be, to eliminate that UDC, we would have to turn back 365-day capacity on that pipe, which is flowing at 100 percent load factor in 11 of the 12 months of the year, which means that we would need to replace that capacity 11 of the 12 months of the year with a short-term service that is not guaranteed to be renewable, in any one year, to serve average annual demands in the delivery area.

MR. QUINN: Okay. So if I summarize that, because it is a firm service need, your belief is that long-term contracts are the best way to serve that economically?

MR. QUIGLEY: Correct. Because UDC is all occurring in one month, but the only way to eliminate that UDC is to turn back 365-day firm pipe, which now means we don't have enough firm capacity to serve our average annual demands in the delivery area.

So then we would have to go out in the marketplace and try and find services for 11 of those 12 months.

MR. QUINN: Now, we just touched on -- and I think it was Ms. Evers that talked about -- one of the panel members was talking about short-term firm.

So you are aware that you can buy short-term firm service for the entire winter, November to March?

MS. HODGSON: Yes, we are.

MR. QUINN: And you could buy that for each individual month of the winter season?

MS. HODGSON: If it's available. If it's been offered every month, and I guess I'm trying to understand why you would keep the long-haul transport.

So can you help me with why, what reasons you would have to keep the long-haul transport?

You did cover some in your opening remarks, but I want to make sure we have clarity on it.

MS. HODGSON: Your reference to "chart," I was just curious which chart. Are you talking about that chart originally that we were looking at? You said something about "in a chart."

MR. QUINN: What I referred to, sorry, I looked at the screen because Mr. Buonaguro still has J.C-4-7-10, attachment 1 up on the screen.

MS. HODGSON: Thank you.

MR. QUINN: So that's the chart I was referring to. Thank you for the clarity.

MS. HODGSON: Sorry, and your question?

MR. QUINN: Union has maintained -- well, I will ask the question.

During that period of time, the period of time we have been discussing, November 2009 and moving forward, you have long-term, long-haul contracts.

Can you help us understand, again, why you would keep a long-term annual contract, as opposed to contracting shorter-term?

MS. HODGSON: Yes, I can do that.

The short-term firm transportation options that are available have some significant downsides from underpinning long-term firm assets.

The big one is that it is not renewable. So in terms of having firm long-term assets, the only way that we have to ensure that we can continue to get those long-term firm assets is through the contractual right to renew.

So short-term firm transportation doesn't carry the right to renew. It actually -- the term that you can get it for is one day less than a year. So you can't renew it. That is a significant downside.

Another significant downside is we rely very much on a service called "storage and transportation service" or "STS service" is what it is often referred to. And that allows us tremendous flexibility in managing our -- in managing storage for the -- I'm not saying that quite the right way -- in managing our flexibility of moving our molecules for storage for the north. There is no other way that our storage customers in the north -- sorry, there is no other ways that our north customers can access storage without that service.

And long-term -- long-haul on TCPL is the only prerequisite to getting that service. So that's a significant benefit.

The other issue is cost. We are -- although there is total uncertainty on TCPL, we know that that -- what that contracted cost is. It is not a biddable service, if you will. You can't bid it up higher.

Short-term firm transportation is a biddable service. So when you go into the marketplace or go to bid for it on

TCPL, people can compete with a different price.

So those are the big -- those are probably the big things, why we would stay with our long-term firm transportation.

MR. QUINN: Thank you.

MS. HODGSON: And, again, back to our principles -- sorry, just one more point. Back to our principles, it would be imprudent to use other services than firm transportation.

MR. QUINN: I am going to leave that last point, I guess, for argument. So I will cover them in reverse order, then.

You said contracted STFT, you would have to compete for the service. Does Union monitor the open seasons of TransCanada to determine the amount of transport that is actually taken up relative to the amount that was available?

MS. HODGSON: We monitor what is offered and what is available.

MR. QUINN: And how much was actually contracted for? Do you follow that when the bids are closed and TCPL puts its index of customers out?

MS. HODGSON: Union might. This group does not -- I do not.

MR. QUINN: You're the gas supply group, though, and -

MS. HODGSON: Yes.

MR. QUINN: -- you're trying to find the most economical way of getting the gas. You have said one of the reasons you would not want STFT is because you might get into some form of bidding war that would raise the price.

MS. HODGSON: We look for economical, but security and reliability are our primary focus at a prudently incurred price. So short-term firm transportation, again, is not renewable.

MR. QUINN: So it's not renewable. But you don't have any knowledge that you would have to bid -- bid above the firm toll price?

MS. HODGSON: I know that it's a biddable service.

MR. QUINN: But I guess as a gas supply panel and you're looking for economic alternatives, wouldn't it be --

MS. HODGSON: I can only bid up. I can't bid down.

MR. QUINN: Right. So would the amount that was available versus the amount that was actually contracted for not be market information you would want to have?

MS. HODGSON: I guess I'm not sure why it would be relevant.

MR. QUINN: Because it would tell you that you're probably not going to be in a bidding war. If a million units were available and 500,000 were contracted for, would that not give you an indication that the firm toll price was not bid up?

MS. HODGSON: The principles that Mr. Shorts spoke to are independent of current market conditions. So today there might be excess capacity on TCPL, but tomorrow there might not be, and I am not willing to go into the market to say it may or may not be available.

The only way that I can ensure that Union Gas has long-term firm transportation is through contractual rights, and STFT does not have that.

MR. QUINN: Does not have what contractual rights?

MS. HODGSON: Renewable right, the right to renew.

MR. QUINN: And to the extent that you turned back a contract and the next year said, You know what? We had to pay a little bit more for that service, would you not have the opportunity to enter into another long-term agreement?

MS. HODGSON: Yes.

MR. QUINN: So you could get that transportation back if you determined that --

MS. HODGSON: If it's available, yes.

MR. QUINN: And, again, going back, do you monitor how much capacity is available in the TransCanada system to see if that is one of the alternatives you would consider?

MS. HODGSON: I thought your question was around STFT. My apologies. Long-term, yes, we're aware of what's available.

MR. QUINN: And so if you decided that your need was more winter related and you wanted to bid for the winter, you're telling us your risk would be -- if you turn back the associated contract that was delivering the gas to the east, at that point you would have the opportunity to deliver in the winter.

To the extent that that in some way created a higher cost, you would have the opportunity to recontract with

TransCanada for a long-term contract; is that not right?

MS. HODGSON: I think it goes back to what Mr. Quigley was speaking to earlier around what we need in the EDA.

MR. SHORTS: As well, Mr. Quinn, just to add to that, as Ms. Hodgson mentioned, it is not just the cost. Cost is obviously a factor, but, you know, those other characteristics, for example, the STS and the extra non-windows that come with the STS and the flexibility it provides, those are really key attributes as to why we have to continue with the way -- the service that we've contracted for so far.

MR. QUINN: Okay. Well, I was going to move to that, so maybe -- because I'm not sure we're getting clarity on the STFT opportunity. You've talked about the value of the STS service.

My specific question is: If you have -- like as shown in the chart in J.C-4-7-10, if you have assigned that right to somebody else and the pipe stayed empty so that the counterparty has used the FT RAM credits, do you get STS credits?

MS. HODGSON: STS doesn't work like that.

MR. QUINN: That's what I mean. And I guess my question -- okay, then maybe it is helpful to the panel.

The STS system is storage transportation service from TransCanada Pipelines.

MS. HODGSON: Yes.

MR. QUINN: To the extent that gas arrives in the market area and it is incremental to the needs of, in this

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ONTARIO ENERGY BOARD

FILE NO.:	EB-2011-0210	
VOLUME:	4	
DATE:	July 16, 2012	
BEFORE:	Marika Hare	Presiding Member
	Paul Sommerville	Member
	Karen Taylor	Member

is, UDC can be assigned and the assignee can use the RAM credits to transport anywhere on the TransCanada system, there is a RAM credit overlay to this increased UDC forecast; would you agree?

MR. QUIGLEY: The UDC -- if the capacity is left empty, it does generate a RAM credit, yes.

MR. THOMPSON: Well, you are forecasting that it will be empty?

MR. QUIGLEY: Correct.

MR. THOMPSON: Okay. And so right then and there, there's a RAM credit opportunity?

MR. QUIGLEY: Correct.

MR. THOMPSON: And so is that one of the drivers for the forecast?

MR. QUIGLEY: No. The UDC is a result, as I think I mentioned, of -- we need to hold sufficient firm capacity to meet our design day demands in each of the northern delivery areas. Those design day demands are in excess of the average day demands, which drive the gas plan.

So the UDC is -- as -- the increase in UDC from 2007 to now is a result of the decline in average throughput through the north in the general service and contract rate markets, but the design day demands have not -- or have not changed, or have changed by a small amount.

So we still have the obligation on a design day to serve those customers, and we need that firm capacity in order to serve those customers on a design day. That gas is flowing at 100 percent load factor on a design day.

All that capacity we hold is full to 100 percent capacity on a design day.

MR. THOMPSON: Okay. Well, this, then, comes back to something Mr. Quinn was talking to you about, and that's the opportunity to use ST FT to manage the peak and have a lower level of FT than what you are planning.

And that discussion, you've had that with him, but I understood you to be saying that one of the reasons you feel compelled to contract long-haul is you need the STS rights that go with it.

Did I understand that correctly?

MR. QUIGLEY: As to acquire a STS contract, a prerequisite of that is to hold long-haul TCPL transportation.

There's not STS rights attached to a TCPL long-haul transportation contract. Holding the long-haul transportation contract is a prerequisite to contracting for TCPL's STS service.

MR. THOMPSON: I misspoke, and thank you for clarifying that.

But did you not say that one of your reasons for sticking with long-haul as opposed to going to this combination of long-haul ST FT that the market seems to be favouring, was you wanted to have -- to keep the rights to acquire STS. That was the rationale for long-haul, exclusive long haul?

MS. HODGSON: Yes, that's right. That's one of the reasons that we hold long-haul.

pipe.

So if you don't assign 100 percent of your pipe, then you can use it.

MR. THOMPSON: All of it? Or just some of it?

MS. HODGSON: On any one day, you may or may not be able to use all of it, and you may or may not need all of it.

MR. THOMPSON: Well, it sounds to me that your rationale for justifying long-haul, exclusive long-haul instead of long-haul and some ST FT combination, of sustaining STS, is rather diluted when you assign -- you make the assignments that you've made. It undermines your rationale for refusing to even consider this ST FT approach; is that fair?

MR. SHORTS: Mr. Thompson, it's not just long-haul capacity that's serving the design day requirements. It's a combination of long-haul. It's a combination of the STS withdrawal rights, et cetera, that are actually embedded within the plan to provide that proper level of management of the peak day or design day requirements for each individual zone.

It's not just long-haul that is contracted for and used on any given day.

MR. THOMPSON: All right. Well, I'll move on to a few closing points here.

Now, with respect to the identity of the assignees who have responsibility of bringing a lot of your gas to Ontario, are you prepared to disclose the identity of these

MR. QUIGLEY: No.

MR. MILLAR: Maybe you could help me with that. I heard you say you plan for design day.

MR. QUIGLEY: We have to hold enough capacity, have enough supply in order to meet a design day within a given winter. So it could be a one-day event, it could be a multiple-day event, but it's not an everyday event, a design day.

That's -- like in the north, you're talking about one-in-50-year type event as a design day event.

MR. MILLAR: So you don't plan for every day being a design day?

MR. QUIGLEY: No.

MR. MILLAR: Thank you for that. Could I ask you to turn to your guiding principles, as you presented them in your prefiled evidence? I think it is at D1, tab 1, page 2. You also discussed them yesterday -- or, pardon me, on Friday in your examination-in-chief from Mr. Smith.

Again, that's Exhibit D1, tab 1, and page 2 of that.

MR. SHORTS: We have that.

MR. MILLAR: I'll just let it get pulled up on the screen in case people are watching along.

Why don't I just begin if we have it in front of us?

You will see starting at line 9, you state:

> "The gas supply planning process is guided by a set of principles that are intended to ensure the customers receive secure, diverse gas supply at a prudently incurred cost. These principles

are..."

Then you go on and list five of them there.

But when I was looking through this, it seemed to me that none of those principles include cost.

Can you help me out with that?

MR. SHORTS: If you read the overall guiding statement, the overall guiding statement basically says "at a prudently incurred cost," so that's what all of this is intended to provide us.

MR. MILLAR: Well, it says "secure, diverse" and then "cost" would be the three words I take from the statement before you get into the actual --

MR. SHORTS: Correct.

MR. MILLAR: And I see that security and diversity are handled by 1 through 5.

I don't see any specific reference to cost there.

MR. SHORTS: Well, again, cost is trying to find that reasonable balance between what the security and reliability will provide us, and the flexibility.

But we don't have cost specifically noted there. It is one of the overriding principles.

MR. MILLAR: Do you have any normal type of cost-benefit -- when you -- I'm talk transportation right now, transmission, but I suppose it would be the same for commodity supply, but let's just look at transportation.

You would have a couple of options in many cases to get gas from A to B; is that fair enough?

MS. HODGSON: Yes, we do.

MR. MILLAR: And you would assess the two options, in my theoretical by looking at these five criteria; is that correct?

MS. HODGSON: Yes.

MR. MILLAR: And how does cost feed into that?

MS. HODGSON: There's an analysis that we file when we take on a new path, or extend -- renew -- let me start over again.

When we take on a new path, or we extend the term of an existing path, we file an analysis -- a "landed cost analysis" is what it's referred to -- and that came out of -- I'm trying to think of the rate case. It was either 2003 or 2005.

Was it 2005? Thank you.

Where that was agreed upon. And that landed cost takes into account the supply, the cost of the supply, the path itself included demand -- including the demand cost and the commodity cost, as well as fuel implications for that path.

MR. MILLAR: So is that a type of cost-benefit analysis?

MS. HODGSON: It's referred to as a landed cost analysis, and it takes all the paths that were considered in comparison and looks at those. So you can see each path, what the landed costs would have been to bring that supply to Union's system.

MR. MILLAR: Okay. That's something you prepare internally?

was --

MS. TAYLOR: Only incremental, and it does not appear that you are doing any sort of analysis when you terminate a path, which I think we established in the last discussion.

So that's really what I am trying to get at. Your own contracting activities affect the value of the portfolio overall, on a cost basis, but you don't seem to be internalizing that exercise; is that correct?

MS. HODGSON: When we look at the incremental analysis, that can be over -- that can be a five-year decision, that can be a one-year decision, that could be -- so if we contract -- so, for example, right now we have -- some of our contracted path goes out to 2017, and that is filed in the deferral disposition that we file every time we take on a new path.

And so that is when we do our landed cost analysis and we look at the eligible transportation paths that would then be included in our portfolio. So those are the types of things that the plan would then take as givens, when you're looking at it.

So we -- so we do look out at the market. When we have our transportation contracts in the US, for example, those are often a fixed toll, and they stay the same over a period of time.

So I think what gets flat-lined are the ones where the toll is perhaps uncertain in the future or is eligible to change. We use what is approved or existing.

Ontario

ONTARIO ENERGY BOARD

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	Paul Sommerville	Member
	Karen Taylor	Member

whether Union had taken its pro rata share and whether the full benefits would, in effect, flow through to ratepayers.

And the answer we have below, which was what?

MR. ISHERWOOD: The answer was it actually flowed through the S&T transactional account, and to the extent that it helped us earn our forecasted amount, it was the first contribution, if you want, towards ratepayers.

And, ultimately, if it contributed towards earnings sharing, it would also contribute towards ratepayer benefit that way.

MR. SMITH: This was obviously the subject of some dispute in the 0220 case. And can I ask you to turn to page 21 of the compendium? What was the Board's decision with respect to that proposed treatment?

MR. ISHERWOOD: So on page 21, the second paragraph from the bottom under the title "Upstream Transportation Changes", it talks -- it gives the Board's decision in terms of agreeing with Union's position that ratepayers were already benefitting from the forecast that was built into rates. As well, it can ultimately contribute to earnings sharing, as well, and that this was normal activity towards the transportation exchange account.

MR. SMITH: A couple of other questions. We have filed at Exhibit J3.1 an answer to an undertaking given to Mr. Quinn, and that was to draw a chart.

If I could just ask that that be pulled up. And perhaps this is for you, Mr. Shorts, but could you just tell me what it is that we're looking at here?

MR. SHORTS: Sure. I will start from the bottom, just to give everybody an idea of what we're showing under this graph.

If we look at the blue area, the blue area represents the daily deliveries into Union's EDA for its in-franchise sales service and bundled customers.

This would exclude our transportation or T-service customers, because they are responsible for bringing their own transportation and supply into the zone each day.

If we go up to the first horizontal line at approximately 60,000, so that yellow line represents the contracted Empress to EDA Union long haul transportation capacity.

I will then move up to the green line, and the green line, which is just below 100, that is the long haul EDA to -- or Empress to EDA long haul capacity, as well as the firm short haul Parkway to EDA capacity that is contracted for.

I'm going to skip right up to the red line at the top, which is just over 160,000 shown, and that represents the contracted Empress to EDA long haul, the short haul firm Parkway to EDA I just mentioned, as well as our firm STS withdrawal rates.

And it is this line that is the firm capacity or the firm portfolio that is used to serve the design day in the plan for the EDA.

Now, a couple of things just to note. You will see that the yellow line or the EDA capacity, that long haul capacity from Empress to the EDA, really serves two purposes.

It not only serves as part of that portfolio of peak day or design day assets, but it also serves to meet those annual delivery needs.

So, for example, if you look at the area in the graph where the blue lines are below the yellow line, that would simply be a time period in which, on a given day, the demands coming into the eastern delivery area were in excess of the daily requirements, and that gas would be STS-injected into Dawn storage to be used later.

And, likewise, when the blue lines are above that, that firm pipe is supplemented by those other assets, so either the firm short haul or the STS withdrawal rates.

One thing to also note is that during this time period, from November of 9 to March 2012, that gas supply was purchased each and every day at Empress. So it was needed there for annual needs, and there was no UDC incurred because of those supplies.

MR. SMITH: Thank you, Mr. Shorts. And just a couple of last questions. We had similarly provided, as we agreed to do, an update to Exhibit B7.7, which was a response to an interrogatory in a different proceeding, the 0087 proceeding.

And, Ms. Cameron, perhaps this is for you, but I would just ask you to focus on the TCPL-Union CDA and just describe what is being captured under the optimization percentage referred to there.

or did I miss some differentiating feature?

MR. SHORTS: You can also -- like a bank account, if you have overdraft protection, you could withdraw more than what was in that bank account.

MR. QUINN: Okay. Well, we will get to that in a moment, then.

MR. ISHERWOOD: I think the one differentiation Mr. Shorts was making was you can't buy gas at Dawn and put it into the STS account. It has to come off the TCPL system from the EDA or WDA, for example. Then it is counted as an injection into the account.

MR. QUINN: It has to come from the EDA system, as an example. Let's use EDA to make it simple, Mr. Isherwood, and that has to be coming long haul transport to the EDA?

MR. ISHERWOOD: That is coming long haul transport into Ontario.

MR. QUINN: The long haul transport to your service area, in this case, the eastern delivery area, creates a deposit like it would into a bank account?

MR. ISHERWOOD: Yes, the gas that is required in the EDA that day. You can go back to the graph Mr. Shorts talked about this morning. You say the kind of sine waves, the peaks and the valleys. That whole valley period, you would be expecting injections into the STS account.

MR. QUINN: We will get back to those graphs, but I just want to take this one step at a time, because unfortunately I didn't get clarity.

So like a bank account, you make your deposits in good

[Mr. Millar passes out the exhibit]

MS. HARE: So we are on page 5 of this compendium; is that correct?

MS. CAMERON: Yes. If you go to page 5 of the compendium, in the seventh grouping of customer information, you will see "Union Gas" is in the middle of that, and the first "Union Gas" line, it starts with 11, 4-2.

The contract start date is listed there as April of 1992, and that refers to the STS service. I can't be certain that it didn't exist before then, but I think this does support that it has existed for quite some time.

MR. QUINN: So historically this service was used for some time to be able to meet peak winter demands. When did Union ––

MR. ISHERWOOD: Actually the purpose of the service is to make sure the FT contracts can flow on a hundred percent load factor, or as close to that as possible.

So it not only helps you serve the winter peak, but also helps you serve the summer valley and provide a spot for that to go back to Dawn. So it really is a very unique tool. It is a great service TCPL offers that allows us to balance our system, summer and winter.

It is just as important in the summer as it is in the winter. Otherwise gas would be very expensive in Ontario.

MR. QUINN: Okay. Well, I am trying to work backwards from the graph into where Ms. Cameron led us, but I think I will just do it this way.

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Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2011-0210**	
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DATE:	**July 26, 2012**	
BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

MR. SMITH: And that is distance-based?

MR. STRINGER: Yes.

MR. SMITH: And other than the elimination of FT RAM, which you have proposed in your current Mainline application, are there any changes to this service being proposed in that application?

I don't believe so.

[Witness panel confers]

MR. STRINGER: No changes to the service features.

MR. SMITH: If I can ask you to turn to page 15, and this is the description of STFT from the website; is that correct?

MR. STRINGER: Yes.

MR. SMITH: And if we look over at page 17, have I got the toll schedule correct there?

MR. STRINGER: Yes, you do.

MR. SMITH: And am I right that in order to access this service, the shippers must bid through an open season by submitting a completed Exhibit A form to the toll schedule, indicating the quantity and transportation path and the price of their bid?

MR. STRINGER: Yes. And that is based on the available capacity, again, on the system. So it's not a service we construct for.

So we hold -- we'll hold an open season -- in fact, we're just closing one today, I think -- but we'll hold an open season for the winter season, commencing in July.

MR. SMITH: And we --

MR. STRINGER: In the latter half of July, and then we offer up the individual winter months, and then as we move closer to the winter months we offer up a weekly service.

MR. SMITH: And we see that at item 2.2 on page 19: "Facilities construction policy."

You indicate it utilizes existing capacity and it is understood that you are not going to construct additional facilities for the purpose of providing this; correct?

MR. STRINGER: That's correct.

MR. SMITH: And am I correct that there are no renewal rights for this service?

MR. STRINGER: That's correct.

MR. SMITH: And am I correct that the minimum bid price for this service is 100 percent of the firm transportation toll?

MR. STRINGER: As it stands now, that's right. The current minimum bid floor is 100 percent.

MR. SMITH: Yes, we will come to that.

And the maximum bid? There is no maximum bid?

MR. STRINGER: That's correct.

MR. SMITH: And can you confirm that the minimum bids that you are proposing in relation to this service in your Mainline application are 140 percent for services offered for a full winter or summer, or longer?

MR. STRINGER: So the proposal would be that a full season would be priced -- or would have a minimum bid floor of 140 percent. The monthly bids would be priced -- or have a minimum bid floor, rather, of 150 percent, and bids with the term of seven days, which is our minimum bid term, would have a bid floor of 160 percent, but we're also asking for the discretion to offer that price below the or at the 100 percent FT toll.

MR. SMITH: And that's a discretion that would be reserved to TransCanada?

MR. STRINGER: That's correct.

MR. SMITH: And am I right that the reason why you are proposing an increase in your floor price is to encourage shippers to contract FT long-haul?

MR. STRINGER: The purpose is to increase the value of FT service, relative to shorter-term services.

MR. SMITH: And can I ask you to turn to page --

MR. STRINGER: I would also add it's also to optimize revenue to the system, overall to the benefit of all shippers by -- with the objective of lowering tolls.

MR. SMITH: Can I ask you to turn to page 47?

Am I correct that this is the interruptible firm transportation description from your website?

MR. STRINGER: Yes.

MR. SMITH: And page 49, we have the toll schedule; is that correct, sir?

MR. STRINGER: Yes.

MR. SMITH: And is it fair to describe this service as a daily blanket interruptible transportation service?

MR. STRINGER: It could be bid for a daily service, correct.

MR. SMITH: And in order to access this service, you have to sign a master IT contract with TransCanada?

MR. STRINGER: That's correct.

MR. SMITH: And the way you do -- the way you bid is by placing a nomination on the TransCanada electronic bulletin board on a daily basis, indicating quantity, path and the price?

MR. STRINGER: Yes, that's correct.

MR. SMITH: And the way you award IT service is based on price?

MR. STRINGER: Based on the -- on the bid price; that's correct.

MR. SMITH: And am I correct that the current minimum toll for IT service is 110 percent of the FT toll?

MR. STRINGER: Yes, that's correct.

MR. SMITH: And there is no maximum?

MR. STRINGER: That's correct.

MR. SMITH: And am I correct that in your Mainline application, your proposed minimum bid price is 160 percent of the FT toll?

MR. STRINGER: Yes. And as with the short-term firm services, we are seeking the discretion to lower that floor to 100 percent.

MR. SMITH: And again, that is a discretion reserved for TransCanada?

MR. SMITH: Correct.

MR. SMITH: Am I correct that under your Mainline redesign, equally there would be no maximum IT bid price?

MR. STRINGER: Correct.

MR. SMITH: Now, page 61, have I got the STS service -- sorry, page 59, I think, is the STS service description from your website; is that correct?

MR. STRINGER: Yes.

MR. SMITH: And page 61 is where we find the toll schedule?

MR. STRINGER: Correct.

MR. SMITH: And am I right that STS is a service allowing for injections and withdrawals at storage locations?

MR. STRINGER: Yes.

MR. SMITH: And I am equally correct, sir, that an STS contract holder must also hold a long-haul FT contract to their market point?

MR. STRINGER: That's right.

MR. SMITH: And am I right that one of the key features and benefits identified by TCPL of holding an STS agreement is that it offers additional nomination windows?

MR. STRINGER: Yes, four additional nomination windows on top of the four standard NAESB nomination windows.

MR. SMITH: Right. So you have under STS eight nomination windows, as opposed to four?

MR. STRINGER: That's correct.

MR. SMITH: And I take it that the reason for that is to better balance daily gas supply and consumption?

MR. STRINGER: Yes. To better allow the holders of that service to balance -- it's held by our Canadian LDC customers. And that's correct, it is used to help them balance the gas consumption in that franchise.

MR. SMITH: You anticipated my question. I'm right, just picking up on your last point, that all or substantially all of your STS is used by utilities; correct?

MR. STRINGER: Yes. Union Gas, Enbridge Gas Distribution and Gaz Métro would hold the service.

MR. SMITH: And can you confirm for me that injections and withdrawals are firm?

Maybe I can be a bit more precise: Dependent on the season and location?

MR. STRINGER: That's correct.

MR. SMITH: So for example, winter injections to the WDA would be interruptible, given that you're using peak day capacity, but withdrawals in winter would be firm and in the expected direction; is that right?

MR. STRINGER: That's correct.

MR. SMITH: Can you confirm that one of the other attributes of STS is that there is a renewal term of one year, with six months' prior notice?

MR. STRINGER: Yes, as with FT service.

MR. SMITH: And that in order for TransCanada to expand its facilities, you need a long-term STS commitment of 10 years?

MR. STRINGER: Yes. Again, whenever we expand our facilities, we record our long-term contractual commitment with a minimum term of ten years.

MR. SMITH: And, equally, this is a service that is billed on a monthly demand charge basis?

MR. STRINGER: That's correct.

MR. SMITH: And am I right that there are no proposed changes to this service in your Mainline application, aside from the elimination of RAM?

[Witness panel confers]

MR. STRINGER: Yes. There are no proposed changes to the service features.

MR. SMITH: Thank you, members of the panel. Those are my questions.

QUESTIONS BY THE BOARD:

MS. HARE: Mr. Emond, K10.3, you had wanted to provide some context to this presentation. I am not sure whether or not you think you had the opportunity to do that in answering the questions.

If there is more that you would like to share with the Board about this presentation, we would be pleased to hear from you.

MR. EMOND: As I recollect, what I wanted to mention is that Enbridge had -- had informed us that they had some concerns about the reliance of so much of their peak day demand on one source, being the Union delivery at Parkway.

And there were other concerns at the time in terms of direct sellers and the firmness of upstream supply, but that was one thing that Enbridge had mentioned to us.

So when we, in our presentations, went back and were pointing out that reliance and alternatives to get gas to Enbridge via a separate path to increase their security of

COST OF CAPITAL

UNION GAS LIMITED

Undertaking of Mr. Thompson
To Mr. Broeders

Please confirm if Union accepts that its financial and business risk have either remained unchanged or have declined since last analyzed by Dr. Carpenter of the Brattle Group.

Union has not analyzed it business and financial risks, but accepts that its overall risk profile has not materially changed 2004. Dr. Carpenter's evidence was part of the evidence filed by the Brattle Group in EB-2005-0520. Written evidence was also prepared by Dr. Kolbe and Dr. Vilbert.

The Brattle Group's evidence is attached as Attachments 1, 2 and 3. It was the Brattle Group's opinion that the appropriate deemed equity level for Union ranged between 40% and 56% depending upon the allowed return on equity.

PREFILED EVIDENCE OF

MICHAEL BROEDERS, MANAGER FINANCIAL PLANNING AND FORECASTING

This evidence addresses Union's cost of capital, capital structure, and financing plans. The cost of capital and capital structure approved by the Board for 2007 is as per the EB-2005-0520 Settlement Agreement, Appendix E, Schedule 3 (adjusted to reflect regulated services only and the 2007 Return on Equity ("ROE") as determined at the time using the October 2006 Consensus Forecast). The 2010 and 2011 actual results are shown at Exhibit E6 and Exhibit E5 respectively. The forecast for 2012 bridge and 2013 test years are shown at Exhibit E4, and Exhibit E3, respectively. Table 1 summarizes the cost of capital shown in these exhibits.

Table 1
Cost of Capital Summary

Line No.	$millions	Board Approved 2007 (a)	Actual 2010 (b)	Actual 2011 (c)	Forecast 2012 (d)	Forecast 2013 (e)
1	Long-term debt	154.4	147.3	142.5	143.7	146.9
2	Short-term debt	(0.5)	1.1	1.3	1.6	(1.5)
3	Preferred equity	5.0	2.7	3.1	2.9	3.1
4	Common equity	100.6	109.7	104.5	107.4	143.4
5	Total	259.5	260.8	251.4	255.6	291.9

The $32.4 million increase in the 2013 cost of capital compared to the 2007 Board-approved cost is due to an increase in total rate base ($37.3 million), a proposed change in capital structure ($12.4

million[1]), and a proposed change to the ROE ($14.0 million[2]) which are offset by a lower average cost of debt ($31.3 million). These changes are discussed in more detail below.

OVERVIEW OF CAPITAL STRUCTURE AND FORMULA RETURN ON EQUITY RECOMMENDATION

Union's investment in rate base is financed by a combination of short-term and long-term debt, preferred shares and common equity. The current Board-approved capital structure is based on a 36% common equity component. The remaining 64% is financed by short-term and long-term debt and preferred shares.

Union is proposing an increase to its common equity component to 40%. Increasing Union's current 36% common equity to 40% will provide a capital structure that is comparable to the capital structures of other regulated utilities with whom Union competes in the capital markets. This will allow Union to finance capital expenditures at favourable debt rates.

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1 The pre-tax impact of the proposed capital structure change is $17.3 million. It is calculated using the 2013 rate base multiplied by the 4% change in equity multiplied by the difference between the pre-tax equity rate and the short-term interest rate of 1.31% ($3,741,542,000 x 4% x (9.58%/(1-0.255) – 1.31%)

2 The pre-tax impact of the proposed ROE change is $19.0 million. It is calculated using the 2013 rate base multiplied by the 2007 equity percentage and the change in ROE and grossed up by the 2013 tax rate ($3,741,542,000 x 36% x 1.04% / (1 - 25.5%)

FINANCING PLANS

This evidence summarizes Union's financing plans with respect to short-term debt, long-term debt, and preferred shares. Further details regarding Union's current cost of capital can be found in its 2011 Annual Report filed at Exhibit A3, Tab 2.

Short Term Debt

Union has a $500 million credit facility which will expire in July 2012. It is anticipated that it will be replaced with a $400 million credit facility. Short term borrowing levels fluctuate significantly during the year due to Union's need to fund construction activities; the timing of long-term debt issues and maturities; and, the seasonality of the Company's business. Peak borrowings are forecast to reach $353.9 million in 2013. The additional short-term borrowing capacity over the peak borrowing forecast is necessary to compensate for fluctuations in gas commodity prices.

The average amount of the short-term debt in the utility capital structure for 2013 is the difference between the average utility rate base and the total of the common equity component, the preferred share component, and the long-term debt component. The difference between the short-term debt included in the utility capital structure and the Company's average short-term borrowings for the period is related to the financing of items that are not included in utility rate base, primarily construction work in process ("CWIP").

The cost of short-term debt used in the cost of capital calculation reflects the projected Canadian Dealer Offered Rate ("CDOR") which represents the 1-month bankers' acceptances minus a spread of 0.10% (based on historical experience), plus issue costs of 0.10%.

In the past the fixed portion of short-term debt representing arrangement, facility and agency fees have been small and have been included within the short-term debt rate. The treatment in the past can cause variations in the debt rate depending on the magnitude of costs as well as the associated short-term debt level. These costs have grown and are now a larger proportion of the cost of short-term debt. Beginning in 2013, Union is proposing to move the fixed program costs to "Other financing" as shown on line 8 in Exhibit F3, Tab 2, Schedule 1. This change will result in the short-term debt rate being more reflective of market conditions and will eliminate the impact the level of short-term debt has on the short-term debt rate.

Exhibits E3 to E6, Tab 1, Schedule 4 show the cost of short-term debt for the years 2013, 2012, 2011 and 2010 respectively.

Long Term Debt

Union has a Medium Term Note ("MTN") program under a shelf prospectus that allows it to issue up to $500.0 million of debentures with terms ranging from 1 to 31 years. The MTN program allows Union to issue debt on a frequent basis to meet its financing needs. Debt can be issued with varying terms to manage the maturity profile, such that significant refinancing risk in any one period can be avoided while still prudently securing long-term financing for the long-lived assets of the Company.

The MTN program also provides the flexibility to stagger maturities such that frequent refinancing of Union's long-term debt results in an embedded cost which reflects the average of market interest rates across economic cycles. The current shelf prospectus will expire in October 2012 and Union expects to file a new shelf prospectus, with similar terms, prior to expiration.

In June 2011, Union issued $300.0 million of MTNs with a 30-year term and a coupon rate of 4.88% (4.93% effective cost rate). Therefore, Union could issue an additional $200.0 million under the current shelf prospectus. The forecast reflects an additional issuance of $125 million in the last quarter of 2012 at a coupon rate of 3.85% (3.90% effective cost rate). There are no scheduled redemptions of long-term debt between the date of filing and December 31, 2013. The next maturity date of existing debt is February 24, 2014 for $150 million. A listing of Union's outstanding long term debt can be found at Exhibit E3, Tab 1, Schedule 2.

Union's embedded cost of long term debt is expected to decrease from 7.66% in 2007 to 6.50% in 2013.

Preferred Shares

The average embedded cost of preferred share capital for the 2013 test year is 3.05%. This is a decrease from the 2007 Board-approved level of 4.74%.

Union has four preference share issues which are all redeemable at the option of the Company. The dividend rate of the Class B, Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2013.

Formula Based Return on Equity

As noted above, Union is requesting the use of the Board's current ROE formula to establish an appropriate allowed ROE. In applying the formula, Union's 2013 cost of service forecast has been prepared using an ROE of 9.58%, which aligns with the ROE provided by the Board for electricity distributors with a May 1, 2011 effective date for rate changes. The ROE embedded in Union's rates effective January 1, 2013 will be in accordance with the current ROE formula reflecting the September 2012 actual and forecast bond yields. A 50 bps change in the ROE changes the revenue deficiency by approximately $10.0 million. Please refer to the schedules at Exhibit F3, Tab 1 which summarize Union's ROE and revenue deficiency for 2013.

DEBT RATINGS

Union considers it prudent to plan for an "A" debt rating. This rating provides a safety net in the event of a rating downgrade and helps Union achieve the lowest risk adjusted cost of debt. The debt ratings of Union's capital instruments by Standard & Poor's and DBRS are shown below. Copies of these reports can be found at Exhibit A3, Tab 6. The Standard & Poor's debenture ratings are a Global Scale Rating while the commercial paper and preference share ratings are National Scale Ratings.

	Standard & Poor's	Dominion Bond Rating Service
Commercial paper	A – 1 (low)	R – 1 (Low)
Debentures	BBB+	A
Preference shares	P – 2 (low)	Pfd – 2

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The S&P debenture rating reflects the consolidated credit profile of Spectra Energy.

Financial Risk Indicative Ratios (Corporates)

	FFO/Debt (%)	Debt/EBITDA (x)	Debt/Capital (%)
Minimal	greater than 60	less than 1.5	less than 25
Modest	45-60	1.5-2	25-35
Intermediate	30-45	2-3	35-45
Significant	20-30	3-4	45-50
Aggressive	12-20	4-5	50-60
Highly Leveraged	less than 12	greater than 5	greater than 60

Q. HOW DO YOU VIEW UNION GAS WITHIN THE CONTEXT OF THE S&P MATRIX?

A. It is clear that Union Gas' equity thickness should be enhanced. As I discuss below, my consideration of recent equity thickness determinations by Canadian regulators leads me to set a floor of 40% for Union Gas' authorized equity level going forward, with expansion of that level to a range of 40 to 42% upon consideration of common equity levels recently authorized by US regulators and the utility financial guidelines publicly disseminated by S&P.

Q. HOW DO YOU COME TO THAT RECOMMENDATION?

A. Equity levels for regulated utilities within the United States are rarely set below the 40% level. In Concentric Energy Advisors' research report[12] prepared for the OEB in 2007 – *I note, prior to the global financial crisis* – they found that the average authorized equity level for U.S. natural gas utilities was 48%, with a level of 46.44% for companies comparable to Union Gas. I have supplemented that data with a review of recent US regulatory decisions from January 1, 2010 through September 30, 2011 (See Appendix B) which shows 48 natural gas utility decisions with authorized equity levels averaging 49.46% with a median level of 50%. In addition, a review of Canadian rate decisions since the time of the Concentric Report also shows positive movement in authorized equity thickness. For example, the OEB set a 40% equity thickness for Natural Resource Gas in 2010, stating that "NRG has presented no evidence that its risk profile is significantly different from other utilities in Ontario."[13] Also, on April 13, 2011, the Alberta Utilities Commission ("AUC") issued a decision for ATCO Electric's electric distribution activities with an equity level of 39%. Other recent AUC decisions during 2009 and 2010 also show consistency with the 40 to 42% equity thickness range I recommend here: AltaGas at 43%; Fortis Alberta, Enmax disco, and Epcor disco, all at 41%; and ATCO Gas at 39%. Finally, the Manitoba Public Utilities Board found that Centra Gas Manitoba, a gas distribution utility, was entitled to a 30% equity level if a provincial guarantee was applicable, but a 40% equity thickness if no such guarantee existed. These equity determinations lead me to conclude that an authorized equity thickness for Union Gas in this

[14] S&P Research: "Union Gas Ltd.," May 4, 2011.
[14] S&P Research: "Union Gas Ltd.," May 4, 2011.

proceeding should be no lower than 40%, and could appropriately be set anywhere within my recommended range of 40 to 42%.

Q. WHAT UNDERLIES YOUR RECOMMENDATION THAT UNION GAS' EQUITY THICKNESS BE AUTHORIZED WITHIN A RANGE OF 40 TO 42%?

A. Having served as a utility commissioner for six years, I appreciate that there does not exist within the ratemaking process such precision that there can only be one right result. Ratemaking is more an art than a science. Regulators in carrying out their ratemaking responsibilities are called upon to make difficult fairness judgments concerning current and future economic conditions. They have to strike a reasonable balance between the rates that ratepayers must pay, and the rate levels necessary to attract ongoing funding from investors. With increasing global competition for investment capital, I feel strongly that analysis beyond Canadian regulatory decisions is appropriate, especially with the recent financial crisis not discriminating by sovereign boundaries. If one were to look at S&P's ratings matrix and the equity levels authorized for U.S. regulated utilities, one would think that an equity level in the range of 48 to 52% might be appropriate. My 40 to 42% recommended range attempts to strike a fair balance that factors in recent Canadian and US regulatory decisions, along with a recognition of S&P's point of view with regard to current norms for utility financial measures. Taken together, that evidence supports enhancement of the Company's equity thickness, thereby improving Union Gas' financial strength. That positive factor, considered along with the current constructive regulatory climate in Ontario, will have a major influence upon investors when they decide where to invest their capital.

Q. HAS S&P POINTED TO THE COMPANY'S CURRENT EQUITY THICKNESS AS A NEGATIVE FACTOR?

A. Yes. In its May 2011 report on Union Gas, S&P stated:

> Influencing our view of Union Gas' significant financial risk profile are higher balance-sheet leverage and generally weaker financial metrics. The amount of equity on which the regulators allow Union Gas to earn an equity rate of return drives the capital structure.[14]

While S&P goes on to say that the Company's "stable cash flow generation allows it to withstand greater-than-normal financial leverage for its financial profile," such a low equity component certainly influences the rating agencies and debt and equity investors.

IV. CONCLUSION

Q. DO YOU HAVE CONCLUDING THOUGHTS?

A. Yes. The concept of utility regulation is to provide a surrogate for the competitive market that is not present when a utility possesses monopoly or near-monopoly status with regard to an essential good, such as utility service. With all the turmoil that has occurred within the utility sector during the past decade, utilities and their regulators should strive to maintain strong financial profiles, so as to be able to withstand virtually all of the setbacks that have financially harmed certain

[14] S&P Research: "Union Gas Ltd.," May 4, 2011.

companies within the utility sector during the recent past. On the other side of the coin here, absence of regulatory support can cause very severe problems for a utility with a weaker financial profile. Accordingly, my recommendation in this testimony is that both Union Gas and the Board should take the steps necessary to enhance the Company's financial strength, with a key first step being authorization of an equity thickness level within the range of 40 to 42%, consistent with current regulatory and economic circumstances.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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Exhibit F2

ONTARIO ENERGY BOARD

EB-2011-0210

JAMES H. VANDER WEIDE, PH.D.

FOR

UNION GAS INC.

2011

because Canadian utilities are generally regulated through formula ROEs, and formula ROEs may be more likely to differ from the market cost of equity than ROEs based on market evidence in each rate proceeding.

Q 27 What is the difference between business and financial risk?

A 27 Business risk is the variability in return on investment that equity investors experience from a company's business operations when the company is entirely financed with equity. Financial risk is the additional variability in return on investment that equity investors experience due to the company's use of debt financing or leverage.

Q 28 How does the financial risk of Canadian utilities compare to the financial risk of U.S. utilities?

A 28 Canadian utilities generally have greater financial risk than U.S. utilities because, as shown below, they rely more heavily on debt financing than U.S. utilities.

Q 29 What are the average bond ratings of your groups of natural gas and electric utilities?

A 29 The average bond rating of my groups of natural gas and electric utilities is BBB+, the same bond rating as Union.

Q 30 What conclusions do you draw from your investigation of alternative groups of comparable utilities?

A 30 I conclude that my groups of Canadian and U.S. utilities are reasonable proxies for the purpose of estimating Union's cost of equity.

Q 31 Has the Board determined that cost of equity evidence for U.S. utilities is useful in estimating the cost of equity for Ontario utilities?

A 31 Yes. In the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084, December 11, 2009, ("2009 Cost of Capital Report") the Board states:

> Second, there was a general presumption held by participants representing ratepayer groups in the consultation that Canadian and U.S. utilities are not comparators, due to differences in the "time value of money, the risk value of money and the tax value of money." In other words, because of these differences, Canadian and U.S. utilities cannot be comparators. The Board disagrees and is of the view that they are indeed comparable,

> and that only an analytical framework in which to apply judgment and a system of weighting are needed. ...
>
> The Board is of the view that the U.S. is a relevant source for comparable data. The Board often looks to the regulatory policies of State and Federal agencies in the United States for guidance on regulatory issues in the province of Ontario. For example, in recent consultations, the Board has been informed by U.S. regulatory policies relating to low income customer concerns, transmission cost connection responsibility for renewable generation, and productivity factors for 3rd generation incentive ratemaking. [2009 Cost of Capital Report at 21 – 23]

Q 32 Has the National Energy Board ("NEB") determined that cost of equity evidence for U.S. utilities is useful in determining the cost of equity for Trans Québec & Maritimes Pipeline Inc. ("TQM")?

A 32 Yes. In Decision RH-1-2008 the Board finds:

> In light of the Board's views expressed above on the integration of U.S. and Canadian financial markets, the problems with comparisons to either Canadian negotiated or litigated returns, and the Board's view that risk differences between Canada and the U.S. can be understood and accounted for, the Board is of the view that U.S. comparisons are very informative for determining a fair return for TQM for 2007 and 2008. [RH-1-2008 at 71.]

III. Estimates of Comparable Utilities' Cost of Equity

Q 33 How do you estimate your comparable utilities' cost of equity?

A 33 I estimate my comparable utilities' cost of equity by applying standard cost of equity methods to groups of comparable risk companies.

Q 34 What methods do you use to estimate your comparable utilities' cost of equity?

A 34 I use three generally accepted methods: the discounted cash flow ("DCF"), the risk premium, and the CAPM. The DCF method assumes that the current market price of a firm's stock is equal to the discounted value of all expected future cash flows. The risk premium method assumes that the investor's required rate of return on an equity investment is equal to the interest rate on a long-term bond plus an additional equity risk premium to compensate the investor for the risks of investing in equities compared to bonds. The CAPM assumes that the

A 78 I conclude that my comparable utilities' cost of equity is in the range 10.3 percent to 11.2 percent, with an average of 10.7 percent.

TABLE 2
SUMMARY OF COST OF EQUITY RESULTS

METHOD	MODEL RESULT
Discounted Cash Flow	10.3
Ex Post Risk Premium	11.2
Ex Ante Risk Premium	11.1
CAPM	10.3
Average	10.7

IV. Allowed ROEs and Equity Ratios for Comparable Risk Utilities

Q 79 Do you have evidence on recent allowed rates of return on equity for U.S. utilities?

A 79 Yes. I have evidence on recent allowed rates of return on equity for U.S. natural gas and electric utilities from January 2009 through May 2011. Since January 2009, the average allowed ROE for natural gas utilities has been in the range 10.1 percent to 10.3 percent, and for electric utilities, 10.3 percent to 10.5 percent (see Exhibit 8 and Exhibit 9).

Q 80 Why do you examine data on allowed rates of return on equity for U.S. utilities rather than Canadian utilities?

A 80 I examine data on allowed rates of return on equity for U.S. utilities rather than Canadian utilities because allowed rates of return on equity for U.S. utilities are based on cost of equity studies for utilities at the time of each case rather than on an ROE formula. Thus, recent allowed rates of return on equity for U.S. utilities are an independent test of the reasonableness of Union's requested ROE in this proceeding.

Q 81 Are allowed rates of return on equity the best measure of the cost of equity at each point in time?

A 81 No. Since the cost of equity is determined by investors in the marketplace, not by regulators, the cost of equity is best measured using market models such as the equity risk premium and the discounted cash flow model. However, as noted above, because allowed rates of return in non-formula jurisdictions are based on regulators' judgments regarding the cost of equity and fair rate of return, they provide additional information on the reasonableness of Union's recommended ROE.

Q 82 You note that Union is recommending a common equity ratio equal to 40 percent. How do the approved equity ratios for U.S. utilities compare to Union's requested equity ratio?

A 82 The average approved equity ratio for U.S. natural gas utilities during the period January 2009 through May 2011 is in the range 48 percent to 52 percent, and for U.S. electric utilities, 48 percent (see Exhibit 8 and Exhibit 9). Thus, the average approved equity ratio for U.S. utilities is significantly higher than Union's requested 40 percent equity ratio in this proceeding.

Q 83 How does Union's requested equity ratio compare to the approved equity ratios for other Canadian gas and electric distribution utilities?

A 83 Union's requested equity ratio is approximately equal to the average approved equity ratio of Canadian gas and electric distribution utilities (see following table).

TABLE 3

COMPANY	DEEMED EQUITY RATIO
Terasen (Fortis B.C.)	40%
Pacific Northern Gas	40% - 45%
ATCO Electric Disco	39%
Enmax Disco	41%
Epcor Disco	41%
ATCO Gas	39%
Fortis Alberta	41%
Alta Gas	43%
Gaz Metro	38.5%
Gazifére	40%
Nova Scotia Power	40%
Heritage Gas Ltd.	45%
Enbridge Gas	36%
Union	36%

Q 84 How does Union's requested equity ratio compare to the market value equity ratios for your comparable groups of U.S. utilities at March 2011?

A 84 The composite market value equity ratio for my group of natural gas utilities at March 2011 is 63 percent, and for my group of electric utilities, 60 percent (see Exhibit 10).

Q 85 Why do you present evidence on market value equity ratios for U.S. utilities as well as evidence on book value equity ratios?

A 85 I present evidence on market value equity ratios as well as book value equity ratios because financial risk depends on the market value percentages of debt and equity in a company's capital structure rather than on the book value percentages of debt and equity in the company's capital structure.

Q 86 What conclusions do you draw from your evidence that allowed ROEs and equity ratios for comparable U.S. utilities are significantly higher than the Board's formula-derived ROE and Union's requested equity ratio?

A 86 My evidence on allowed ROEs and equity ratios for U.S. utilities provides further support for the conclusion that Union's recommended ROE and equity ratio is reasonable.

V. Summary and Recommendations

Q 87 Please summarize your written evidence in this proceeding.

A 87 My written evidence may be summarized as follows:

1. I assess the reasonableness of Union's request to earn the Board's formula ROE on a 40 percent equity ratio by examining evidence on the required rate of return on equity (cost of equity) and capital structure for several groups of comparable risk utilities.
2. The cost of equity for my comparable risk utilities falls in the range 10.3 percent to 11.2 percent, based on my application of the DCF, Ex Post Risk Premium, Ex Ante Risk Premium, and CAPM cost of equity methods.
3. Recent average allowed rates of return on equity for U.S. utilities are in the range 10.1 percent to 10.5 percent, whereas the Board's formula currently produces an ROE equal to 9.58 percent.
4. Recent average allowed equity ratios for U.S. utilities are in the range 48 percent to 52 percent, whereas Union is requesting an equity ratio equal to 40 percent.
5. The average allowed equity ratio for Canadian natural gas and electric distribution companies is approximately 40 percent.

6. Union's business risk is approximately equal to the average business risk of my U.S. utility groups.

Q 88 What conclusion do you reach from this evidence?

A 88 I conclude that Union's request to earn the Board's formula ROE on an equity ratio equal to 40 percent is reasonable, if not conservative.

Q 89 Does this conclude your written evidence?

A 89 Yes, it does.

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Ontario

ONTARIO ENERGY BOARD

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	Paul Sommerville	**Member**
	Karen Taylor	**Member**

MR. FETTER: Yes. I have participated in approximately 85 proceedings during the ten-and-a-half years.

MR. SMITH: And how many of those would be rate cases?

MR. FETTER: I'd say probably about two-thirds of these would be pretty much traditional rate cases.

MR. SMITH: And would those include cases in which you were providing evidence in relation to capital structure?

MR. FETTER: Yes. That would be cases where I would comment on the capital structure under consideration.

MR. SMITH: Have you ever failed to be qualified, sir?

MR. FETTER: No, sir.

MR. SMITH: I would ask that Dr. -- sorry, that Mr. Fetter be accepted by this Board for the purposes of providing expert opinion evidence on the appropriate capital structure for Union Gas in this matter.

MS. HARE: Do any of the parties have an issue with accepting Mr. Fetter as an expert?

Thank you.

MR. SMITH: Maybe we can just do this in a bit of reverse order, and I will be brief.

But Mr. Fetter, what is your opinion as to the appropriate capital structure for Union Gas?

MR. FETTER: As a result of my analysis, I recommend within my evidence that a reasonable range for equity thickness for Union Gas in this proceeding would be 40 to 42 percent.

MR. SMITH: And how is it, sir, at a high level, because -- how is it, sir, that you arrive at your conclusion?

MR. FETTER: I considered the authorized levels, not only within this jurisdiction but across Canada, to look for comparability, since I view Union Gas as in the mainstream of regulated utilities within the country.

And then I also considered United States levels of authorized equity, which are actually quite higher.

I felt a fair accommodation of those two analyses would be to set a reasonable range between 40 and 42 percent.

MR. SMITH: And Dr. Vander Weide, what is your opinion, sir?

DR VANDER WEIDE: My opinion is that the -- an equity ratio 40 percent is reasonable, if not conservative.

MR. SMITH: And can I ask you to turn to your -- if you still have it there -- your opinion at F2?

And just briefly, I am going to ask you about how you arrived at your conclusion.

If I could ask you to turn to page 7, sir?

DR VANDER WEIDE: Yes.

MR. SMITH: Under the heading "Comparable risk, utilities," I would ask you: How, if at all, is your discussion of comparability relevant to the issue of capital structure?

DR VANDER WEIDE: Well, my discussion is very relevant to the issue of capital structure, because normally, comparable risk utilities would have similar capital structures.

They would be similar in regard to both business risk and financial risk, or at least a combination of those two.

And so the -- by assessing the risk of those comparable risk utilities and looking at their capital structures, both their allowed capital structures and their actual market capital structures, I am also assessing the reasonableness of a 40 percent equity ratio for Union Gas.

MR. SMITH: Can I ask you to turn over the page, beginning at page 9? Can I ask you -- when you mean "risk" what aspects of risk are you looking at?

DR VANDER WEIDE: I'm looking at both business and financial risk, and --

MR. SMITH: And -- I'm sorry, go ahead.

DR VANDER WEIDE: And I define "business risk" as the variability and return that a company would face, even if it did not have any debt or leverage in its capital structure.

And financial risk is the additional risk that a company incurs when it has debt in its capital structure.

MR. SMITH: Now, in your report, you refer to both Canadian and US utilities. How do you assess the risk of Canadian utilities relative to US utilities?

DR VANDER WEIDE: I examined both the Canadian and US utilities, and in my opinion, the risks are similar to each other. The Canadian and US utilities face similar risks.

MR. SMITH: And why do you say that, sir?

DR VANDER WEIDE: Well, one, I've testified in both

Canadian and US jurisdictions and feel I understand the risks faced by utilities in both Canadian and US jurisdictions.

I also read analyst reports and credit rating reports on a frequent basis. I have examined -- I understand and examine the various costs adjustment mechanisms that US and -- utilities have on average.

And I understand their capital structures, which are an element in their financial risk, and have evidence -- presented evidence on their capital structures.

So I believe that the average risk of my comparable companies is equal to -- is similar to the risk of Union Gas.

MR. SMITH: Have you had an opportunity to review Dr. Booth's evidence, sir?

DR VANDER WEIDE: Yes, I have.

MR. SMITH: And do you agree with his comments with respect to the comparability of US utilities?

DR VANDER WEIDE: No. Dr. Booth has the opinion that US utilities are very much riskier than Canadian utilities and should not be used for comparison purposes.

I believe that Dr. Booth's evidence is out of date.

US utilities in the 1990s were involved more in deregulated and competitive markets, but there's been a tremendous change in the composition of the markets that US utilities are involved in, in the 2000s, and in their capital structures and bond ratings and with regard to their various other risk measures.

US utilities on average now have between 85 and 95 percent of their assets devoted to regulated services. They are viewed as having comparable business risks, either excellent or strong business risk positions. And their equity ratios have increased very significantly over the last 10 or 15 years, and they have also succeeded in obtaining much stronger cost adjustment mechanisms and revenue adjustment mechanisms that reduce the variability of their operating incomes.

MR. SMITH: If I can just ask you -- you were asked in an interrogatory at J.E-3-12-5 -- and you needn't bring it up, but you were asked whether you had assessed the relative business risk of the companies that you considered.

And you indicated you had not. And I ask: What did you mean by that, sir?

DR VANDER WEIDE: That I didn't examine -- well, I meant that I didn't examine the risks, the relative risks of the companies in the group. That is, I didn't rank-order the companies, but I, instead, sought to ascertain that Union Gas was similar in risk to the average utility in the group, and hence that the utilities in the group would be -- would provide useful information for assessing Union's capital structure.

MR. SMITH: In your view, was it necessary to provide a rank-ordering of those in order to arrive at an opinion?

DR VANDER WEIDE: No, it was not.

MR. SMITH: Thank you, members of the panel. Those business risk have either remain unchanged or have declined -- I think it should say "have not declined" -- since last analyzed by Dr. Carpenter of the Brattle Group.

The response was Union has not analyzed its business and financial risks. Is that correct?

MR. BROEDERS: Sorry, just give me a minute.

The answer to the undertaking is saying that we have not analyzed our business and financial risk, but we accept that its overall risk profile has not materially changed since 2004.

MR. THOMPSON: All right. So whatever you have asked the experts to do, you did not ask them to analyze whether Union's -- there have been any significant changes in the company's business and/or financial risks since 2007. They were not asked to do that?

MR. BROEDERS: That's correct.

MR. THOMPSON: And Union accepts that its overall risk profile is not materially changed since -- from 2004. You don't take it to 2007 only. You go back to 2004.

You accept that your overall risk profile has not materially changed; is that correct?

MR. BROEDERS: That's correct. We have submitted evidence based on the comparables and we believe that the risk, as we submitted in 2004, which has not materially changed to this day, is not commensurate with the equity percentage that we have.

MR. THOMPSON: All right. So I suggest to you it is the end of the story. You cannot discharge the

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	Karen Taylor	**Member**

when looking at this. Seventeen million is the number we put out there.

To go to 14, I think it's probably only about 14.8 million, assuming long-term debt of about $200 million at 4 percent.

MR. WARREN: Well, what's a fair number for us to use for purposes of today's discussion, recognizing that there are a number of variables that may affect it? Is it a $15 million number or a $17 million number? You tell me what you think is a fair number for us to proceed on today.

MR. BROEDERS: If you're going down to 36, the 14.8 million I believe is most appropriate number.

MR. WARREN: Okay. Dr. Vander Weide, I wonder if I could begin with you. In your exchange with Mr. Janigan - and you don't need to turn it up, I don't think, but it appears at transcript page 120 - your observation apropos Dr. Booth's evidence was that on the topic of the comparison of Canadian and US utilities, you said you thought Dr. Booth's evidence was out of date. Do you remember that?

DR. VANDER WEIDE: Yes, I do.

MR. WARREN: Okay. And as I understand it from the transcript, Dr. Vander Weide, that was principally because US utilities now have a higher percentage of their activities that are regulated than was the case, you believed, when Dr. Booth's evidence -- or you believe was Dr. Booth's reference; is that correct?

DR. VANDER WEIDE: That would be one of the reasons.

The other is that the US utilities have increased the percentage of equities -- equity in their capital structures and have focussed primarily on the regulated utility businesses.

MR. WARREN: Now, in that context, I wonder, Dr. Vander Weide, if you would turn up pages 70 and 71 of Dr. Booth's testimony, and it appears conveniently at pages 36 and 37 of the brief that Mr. Janigan prepared for you.

DR. VANDER WEIDE: Pages 36 and 37 of Dr. Booth's testimony?

MR. WARREN: No. It is page 70 of his testimony, but pages 36 and 37 of the brief that Mr. Janigan filed with you.

DR. VANDER WEIDE: Oh, okay. Yes, I'm there.

MR. WARREN: Now, beginning on -- I'm going to use the pagination in the Janigan brief. Beginning on page 36, Dr. Booth refers to a Moody's report in 2005 in which - and this is my paraphrase, my gloss, with which of course you are free to disagree - Moody's analysis was less on the fact of regulation than on the substance of regulation; that is, the differences between the substance of regulation in the United States and the substance of regulation in Canada.

And as I read, first of all, beginning at line 7 on page 36, what Dr. Booth draws from the Moody's 2005 report is that substantively regulation is more protective in Canada than it is in the United States, and then he goes on. At the bottom of page 36, he says:

"Moody's reviewed this report and issued a new one in August 2009. The new Moody's report refines their assessment into four major areas where in the following table the % indicates the weights applied by Moody's."

And if I could turn you over to the next page, that is page 37 of the brief, beginning at line 4. And I quote:

"Moody's states very clearly 'for a regulated utility the predictability and supportiveness of the regulatory framework in which it operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors.'"

Then going down to the next paragraph, beginning at line 9 --

DR. VANDER WEIDE: I'm sorry, which page is that on?

MR. WARREN: Page 37 of the Janigan brief, beginning at line 9. He is quoting Moody's. He says:

"Further in discussing the US and Canada Moody's states:

"'Moody's views the regulatory risk of US utilities as being higher in most cases than that of utilities located in some other developed countries, including Japan, Australia and Canada. The difference in risk reflects our view that individual state regulation is less predictable than national regulation; a highly fragmented market in the US results in stronger competition in wholesale power markets; US fuel and power markets are more volatile; there is a low likelihood of extraordinary political action to support a failing company in the US; holding company structures limit regulatory oversight; and overlapping and unclear regulatory jurisdictions characterize the US market. As a result no US utilities, except for transmission companies subject to federal regulation, score higher than a single A in this factor.'"

Now, that is a 2009 report of Moody's. And can you and I agree as a starting point, Dr. Vander Weide, that that is not, quote, "out of date"? Is it?

DR. VANDER WEIDE: No, I don't think we can agree on that. There is -- since 2009, there has been quite a noted increase in the number of cost adjustment clauses and revenue stabilization clauses, as I discuss in my testimony, and the US utilities now have a much greater use of cost adjustment and revenue stabilization mechanisms than they did several years ago.

In addition, I would note that Moody's view, as expressed there, as expressed by Dr. Booth, is inconsistent with Standard & Poor's. Standard & Poor's has published a document at the end of 2011, I believe it was, in which they discussed the business risk of Canadian utilities, and they state clearly that they include regulatory risk in their assessment of business risk.

And they provide essentially the same business risk ratings for US utilities as they do for Canadian utilities. Indeed, it is possible to interpret that it is slightly higher for US utilities.

And this is -- these are more recent than the Moody's assessment.

MR. WARREN: So am I to take it from your testimony that you regard the 2009 Moody's report, some two-and-a-half years old, as now on every respect, every point they make in that paragraph, as being out of date? That is your position?

DR. VANDER WEIDE: No. I think you're mischaracterizing my testimony.

My testimony was that many of the things in Booth's testimony are out of date. I didn't say that every single one of them was out of date.

For instance, his references to Enron and bankruptcies that occurred many years ago are certainly out of date. And certainly, his reference to the 2005 Moody's is out of date. And even the 2009, although perhaps more recent, is not up to date on the cost adjustment mechanisms and the revenue stabilization mechanisms that are now used more frequently at US utilities.

MR. WARREN: So am I to understand your evidence, then - I want to deal with what Moody's says, not what Dr. Booth says, what Moody's says in the paragraph I have quoted - on all of the points in there, is it your position that Moody's is out of date?

DR. VANDER WEIDE: I don't think that Moody's -- I wouldn't use the word -- I don't know what the word "out of date" means entirely, although I have used that word.

I would say that Moody's does not reflect the latest information on the cost adjustment mechanisms and the revenue stabilization mechanisms for US utilities.

MR. WARREN: Could I ask you to turn up, please, Exhibit J.E-2-12-15, which appears conveniently at pages 42 and 43 of the Janigan brief?

Now, this is an interrogatory from Mr. Thompson's client, the CME, directed to Mr. Fetter.

And on page 43, in answer to a question, Mr. Fetter says -- and I quote, and this is in subparagraph e):

> "Mr. Fetter believes that this is an accurate statement (See attached S&P report ranking Canadian Utilities Strongest to Weakest). Mr. Fetter believes that, on a general basis, regulatory support for Canadian utilities has a greater positive influence on how their credit ratings are assigned as compared to U.S. utility credit ratings."

Now, that was filed on the -- depending on whether you are using US or Canadian dating mechanisms, either the 5th of May -- sorry, the 5th of April or the 4th of May.

Was Mr. Fetter out of date when he made that statement?

DR. VANDER WEIDE: I believe it reflects Mr. Fetter's current view, as at the time that he responded. I have reflected what my view is.

MR. WARREN: Do you disagree with what Mr. Fetter says?

DR. VANDER WEIDE: I think -- well, my view is the view that I have expressed here this morning.

MR. WARREN: Mr. Fetter, could I, then, turn to you, please? Again, I am going to begin with a couple of transcript references, and I don't think you need to turn them up, but for reference, one is at page 147 of yesterday's transcript, in which you say - and I am paraphrasing - that an enhanced equity thickness would benefit customers through the company's enhanced ability to attract capital from investors when needed, and upon reasonable terms.

Then at page 149, you said that sustaining credit quality is helpful to the operation of the utility and ultimately its customers, and compared to a weakening credit profile.

Now, when it was put to you -- and this is at page 150 of the transcript, in response to Union's acknowledgement that enhancing the equity portion of their capital structure is unlikely to result in a rating upgrade or a significant impact on the cost of debt -- your response to that was that you pointed to the need to create a credit profile which can respond to unforeseen events such as the 2008/2009 worldwide financial crisis.

Do you remember generally that response?

MR. FETTER: Yes. And I have the document in front of me, if that helps.

MR. WARREN: Now, I would ask you to turn up, please, Exhibit J.E-2-12-8, which appears conveniently at page 34 of Mr. Janigan's brief.

Now, this is the DBRS and S&P ratings for Union for the period from 1990 to 2011. Do you see that on page 2 of 2? That is actually page 34 of the document; 34.

MR. FETTER: You are talking about the response under a) of that IR?

MR. WARREN: Yes. It is on page 2 of 2.

MR. FETTER: I see it.

MR. WARREN: Now, you can help me with this, Mr. Fetter, because you are more familiar with these ratings than I am, but my reading of the DBRS rating is that Union maintained an A rating in the years 2007, 2008, 2009, 2010, 2011; in other words, they maintained an A rating through a financial crisis which everybody from the most sophisticated financial advisors in the world down to the guy who runs the Rabba store on my corner said was the most serious financial crisis we have had since the Great Depression.

Do you agree with me they were able to maintain that A rating through that, sir, with their current --

MR. FETTER: According --

MR. WARREN: -- equity structure?

MR. FETTER: I'm sorry, sir. According to this chart, they maintained an A rating.

MR. WARREN: Now, would you agree with me that the S&P rating, it's my understanding that the S&P rating, which declined from an A and A minus and A in 2001, 2002 to a BBB-plus or BBB in the succeeding clears, is a function of S&P rating Union on the basis of its relationship with Duke Energy? Is that fair? Is that your understanding?

MR. FETTER: There has been some discussion of that relationship, although they -- in more recent times, S&P's noted that there is some protection for the regulated entity versus the parent.

MR. WARREN: But in fairness to you, Mr. Fetter -- because these exchanges have an unhappy way of turning up in final argument -- your proposition yesterday was that they needed a change in the equity structure in order to deal with unforeseen events.

And am I wrong in my conclusion that they were able, through that financial crisis, to withstand unforeseen, severe financial crises with their existing equity structure?

MR. FETTER: Let me note that they did sustain it through that economic crisis, but that regulators across Canada have increased equity thicknesses for utilities -- I think in large part in response to that economic crisis -- to ensure the ability to access funding at reasonable levels going forward, if there is another financial crisis that were to occur.

MR. WARREN: Could I ask you, Mr. Fetter, to turn up J.E-2-14-1, and this is not, unhappily, in the Janigan brief. I apologize for that. So it will take a moment for you to turn it up. J.E-2-14-1.

balancing the interests in ratepayers by asking your experts to assess your financial and business risks?

Did you not think that was an obligation on you in order to satisfy that Court of Appeal obligation, or the obligation expressed by the Court of Appeal?

MR. BROEDERS: As I stated yesterday, Union Gas does not believe that its risk has materially changed.

However, our risk is not -- or, sorry, the equity structure is not commensurate with the risk that we have. Also, when we take a look at our interest coverage ratios, based on the regulated side of the company, the regulated entity could not issue debt, because we would be under the 2.0 requirement.

The only reason that we can issue debt is because the unregulated entity is subsidizing the company.

DR. VANDER WEIDE: I would note, as well, that when one compares the benefits to the ratepayers -- to the company and the cost to the ratepayers, just by comparing the interest rate on the debt to the cost of equity, that this misstates what the benefit is.

If one just compares the interest rate on the debt to the cost of equity, one could easily conclude that it would benefit the ratepayers, if a company had 100 percent debt and no equity. And everybody would agree that is ridiculous.

What that comparison of the cost of debt to the cost of equity misses is the risk to the company on a going-forward basis and being able to deal with financial crises and being able to reduce the uncertainty in the business and financial environment.

And it is undoubtedly clear that since the financial crisis, there has been a tremendous shift in attitudes toward debt and the use of leverage across both Canada and the US.

US companies, US -- and Canadian individual investors have reduced the amount of debt in their capital structures and in their financing.

We learned that debt can have deleterious consequences during that difficult period, and across the board the attitude is that investors, individuals, corporations and governments ought to reduce their reliance on debt. That is pretty much a universal change in the views of leverage -- of the use of leverage for individual and corporate and government entities.

MR. WARREN: If I could return to you, Mr. Broeders, for an answer to my question, which was: Did you not feel it incumbent on you, in balancing the interests of your ratepayers and your shareholder, to provide the Board with evidence that your financial and business risk was fundamentally different than it was in 2004? Did you not feel that was an obligation on you?

MR. BROEDERS: We submitted evidence on the change before. However, as we look at doing our filing for 2013, we felt the risks have not materially changed. So it was -- our position is based on comparability to other entities.

credit profile to weaken, it makes the job more difficult, and, potentially, if the crisis was bad enough, no matter how good the people on this panel would be, they might not be able to finance at a reasonable level when needed.

MR. SHEPHERD: Now, the last question I wanted to ask about, and Mr. MacIntosh asked you a question about this and I got the first part of it. And he may have got the last part, because I missed about three minutes as I was coming up the elevator.

This is page 13 of our materials. This is the comparables, Canadian comparables.

MR. FETTER: If it is for me, I don't have page 13.

I now have page 13.

MR. SHEPHERD: Yes. I don't think it is for you. I actually think it's for anybody on the panel, but probably Mr. Broeders. But it could be anybody on the panel.

I'm trying to find a pattern in which the equity ratio, higher equity ratios, mean a better credit rating. And what I see, in fact, is the pattern tends to be the opposite, that it is the lower equity ratios that tend to have the higher credit ratings. Now, not always. There is actually probably no pattern there.

But I am not seeing a pattern that is consistent with the evidence that I am hearing from Union. Do you see a pattern there?

MR. FETTER: I think you would have to look at each entity individually, because the weaker its credit profile, the more important it is for regulators to increase their equity thickness, and that is what I believe has been happening over the last few years since the economic crisis.

Most of these higher equity thicknesses have occurred in the last few years, and credit rating agencies do not turn on a dime and immediately raise someone's credit rating.

So I view this as an evolutionary process where there is a reaction to what the global financial crisis wrought across all industries, including this one.

MR. SHEPHERD: So you're saying --

DR. VANDER WEIDE: I have a comment on that, as well.

If the external business risk has increased as a result of the global credit crisis, and you raise your equity ratio to more appropriately reduce your leverage, then those two things will offset each other.

So just raising your equity ratio when the business risk in an economic climate doesn't change might, with some lag, increase your credit rating.

But if at the same time you had much greater awareness of the deleterious effects of having a lot of debt, which almost everybody does since the credit crisis, then that is just going to offset -- the increase in the equity ratio will just offset the greater awareness of the business risk involved, and your rating will stay the same.

MR. SHEPHERD: So what you're saying is the ones with the higher equity ratios here had an increase in their business risk, so their regulators responded by saying, We'll give you more -- a higher level of equity?

DR. VANDER WEIDE: No. I think the important information from this exhibit is that the majority of companies have equity ratios of about 40 percent; and not only that, if you couple that with information in the rest of the filing, that these equity ratios have all been increasing.

And, hence, that that's evidence that the financial community and the utilities and the regulators understand that debt adds additional risk, and so you ought -- and when the environment changes - and you have evidence that debt has gotten a lot of people into a lot of trouble - then maybe you ought to reduce your debt and increase your equity.

MR. SHEPHERD: That's always been true, right, that debt increases risk?

DR. VANDER WEIDE: It's always been true, except that prior to 2008 people had kind of become complacent about it.

And so we had individual borrowers borrowing to buy, speculate on homes, and we had banks that were making more risky decisions by borrowing money.

Once you have an episode where you become very aware of the very high costs of high leverage, now you're going to change your view on what the appropriate level of equity is.

MR. SHEPHERD: So you're saying the same thing as Mr. Fetter, that this is all really about the financial crisis, and, after the financial crisis, Union's got to have more equity? That is the simple message; right? That is the elevated --

DR. VANDER WEIDE: I wouldn't use the word "all". I would say it is about risk and the perception of risk, and that perception has changed in recent years.

MR. SHEPHERD: Thank you, Madam Chair. Those are our questions.

MS. HARE: Thank you.

QUESTIONS BY THE BOARD:

MS TAYLOR: Sorry, I would like to come back to page 2 of Mr. Shepherd's compendium.

The answer that you gave, and we will compare that I guess to page 4, and Mr. Shepherd discussed -- sorry, page 5, rather, of his compendium.

Your answer, about the long-term debt appears to be greater than 60 percent, was that there are other factors that are outside of rate base that need to be financed, and that's why they're showing up not only on page 2, but on page 5; is that correct?

MR. BROEDERS: That's correct.

MS. TAYLOR: So given that we're dealing with a rate-regulated entity and these are matters that will flow through rate base, why is it appropriate to show amounts of debt that actually are not included in rate base in these schedules?

MR. BROEDERS: There are utility operations that are not included in rate base. For instance, when we're coverage ratios, based on the regulated side of the company, the regulated entity could not issue debt because we would be under the 2.0 requirement."

And then you continue:

"The only reason that we can issue debt is because the unregulated entity is subsidizing the company."

Do you recall that discussion?

MR. BROEDERS: Yes, I do.

MR. MILLAR: You mentioned a coverage ratio or interest coverage ratio of less than 2.0 for the regulated side of the business; is that number on the record anywhere?

MR. BROEDERS: No, it's not.

MR. MILLAR: So is this the first we have heard of this?

MR. BROEDERS: I believe so.

MR. MILLAR: So is this a calculation you can provide? Because I believe the coverage ratios are in the high twos, for the -- pardon me, for Union Gas Limited.

MR. BROEDERS: On an actual basis. For the 2013 projected, the calculation is about -- on a proposed basis it's about, it's a little over two. Without the equity proposal, it would be below two.

MR. MILLAR: So would you be able to show us how you got to the coverage ratio of less than two for the regulated side? Is that an undertaking you could take?

MR. SMITH: Yes.

MR. MILLAR: That's J5.5.

UNDERTAKING NO. J5.5: TO SHOW HOW THE INTEREST COVERAGE RATIO OF LESS THAN TWO FOR THE REGULATED SIDE WAS REACHED.

MR. MILLAR: Then you stated that the only reason that you can issue debt is because the unregulated entity is subsidizing the company.

So absent the unregulated side of the business, you couldn't issue debt? Union Gas couldn't issue debt? Is that true?

MR. BROEDERS: Based on our capital structure, no, we could not.

MR. MILLAR: So if the unregulated side got hived off somehow, sold off, the regulated business wouldn't be able to issue debt?

MR. BROEDERS: That's correct.

MR. MILLAR: Okay. Thank you for that clarification.

You had a discussion with Mr. Shepherd involving the preference shares or preference equity, and there was a bit of a discussion as to whether or not that is treated as debt or equity, and I think you agreed with him that it was treated as equity.

But can you confirm how your auditor treats those, that equity? Is it debt or equity for your auditors?

MR. BROEDERS: I believe there -- there's multiple components within the pref shares. I think this is four separate issues.

Two of them are treated as debt, and the other two are treated as equity.

MR. MILLAR: And the total amount, is it about 4 percent?

That could be wrong. There was a schedule, I think, that --

MR. BROEDERS: I believe it was 2.75 percent, per Mr. Shepherd's schedule that I just saw.

MR. MILLAR: Do you happen to know what portion of that is debt versus equity, at least according to your auditors? Is it about 50-50?

MR. BROEDERS: I don't know the numbers specifically, but the majority would be equity.

MR. MILLAR: The majority would be equity?

In calculating your coverage ratios, did you treat it as debt or equity, the same way your auditors did? Maybe you could confirm that, or --

MR. BROEDERS: I will confirm it. I know I treated it the way it was supposed to be, consistent with the interest coverage calculation.

MR. MILLAR: Could we include that as 5.5? When you produce the calculation, you can --

MR. BROEDERS: It will be part of the calculation. It will be shown there, how it is treated.

MR. MILLAR: If this isn't already part of that, can you include which portion of the preference equity is equity versus debt, just to be clear, by your auditors?

We can do it as a separate undertaking.

as to the marketability of an underwriting?

MR. FICHTNER: We rely heavily on information from our bankers in terms of indicative pricing, demand for our securities, and so forth. And, yes, they advise us through the process in terms of what we can expect from the investor side.

MR. SMITH: Dr. Vander Weide, I believe this is a question for you. You were taken by Mr. Warren to Mr. Janigan's compendium and a reference to a Moody's report. Do you recall that, sir?

DR. VANDER WEIDE: Yes.

MR. SMITH: You made an observation about S&P's subsequent report. I would like you to assume, for the purpose of my question, that S&P hadn't released its subsequent report, because we have your evidence as to that.

But does -- just on the Moody's report alone, does that change your view as to the applicability of US information?

DR. VANDER WEIDE: No, not whatsoever.

MR. SMITH: Just pausing there, why do you say that?

DR. VANDER WEIDE: Because, as I discussed in my testimony, the business risks of the US and Canadian utilities are very similar. They both use the same technologies. The economics of electric and gas distribution is the same in the US as it is in Canada.

They each have similar cost adjustment mechanisms and rate stabilization mechanisms. And, also, it has been generally aware for the last several years, that the rate stabilization and cost adjustment mechanisms have increased considerably for US utilities to make them very comparable to those for Canadian utilities.

MR. SMITH: Mr. Broeders or perhaps Mr. Canniff, can you just tell us why you treat preferred shares as debt for the purposes of your capital structure?

MR. BROEDERS: When I made that reference, it was more that our proposal is based on 40 percent equity. When we say that, we mean our common equity component. So when I'm saying preferred shares we view more as debt, it was in relation to that.

MR. SMITH: That's fine. Thank you. Those are my questions.

MS. HARE: Thank you.

We will adjourn for the day, then, and resume on Thursday with Dr. Booth at 9:30, and then the schedule shows that it would be 90 minutes. So we would then have panel 4, revenue ex-franchise. Is that your understanding, Mr. Smith?

MR. SMITH: Yes, it is.

MS. HARE: Just for planning purposes, on Thursday we will break at 12:20 for lunch until 1:50.

MR. SMITH: Thank you.

MS. HARE: Thank you.

--- Whereupon the hearing adjourned at 12:10 p.m.

UNION GAS LIMITED

Undertaking of Ms. Taylor
To Mr. Broeders

Please restate the tables to show situation at 36 percent and 40 percent.

The attached schedule shows Union's capital structure proposed to finance the 2013 utility rate base at 40 percent common equity and what the capital structure would look like at 36 percent common equity.

The capital structure is established to finance utility ratebase to arrive at the cost of capital included in the test year revenue requirement. Utility ratebase for 2013 as per the settlement agreement is $3,713,887,000. The proposed capital structure is:

- 40 % common equity;
- the utility portion of preferred shares; and
- the utility portion of the long term debt
- the balance is short-term debt.

In the proposed case the long-term debt reflects Union's actual long-term debt as at December 31, 2011 plus a new issue of $100 million in October 2012.

Adjusting to the 36% common equity scenario decreases the common equity component and increases the short-term debt component to balance. In this case the resulting short-term debt maximizes the short-term borrowings requiring a long-term debt issue of $ 200 million in September 2013 to rebalance. The resulting capital structure has a smaller negative short-term component than the proposed structure.

The difference between Union's actual short-term borrowings and the amount included in the utility capital structure relates to the financing of items not included in rate base, these include construction work in process (CWIP), pension contributions in excess of amounts expensed.

EB-2011-0210
Settlement Agreement
Appendix B
Schedule 3

UNION GAS LIMITED
Summary of Cost of Capital
Calendar Year Ending December 31, 2013

Line No.	Particulars	Utility Capital Structure ($000's)	Utility Capital Structure (%)	Cost Rate %	Requested Return ($000's)
		(a)	(b)	(c)	(d)
	Per Settlement Agreement at proposed Common equity component of 40%				
1	Long-term debt	2,234,597	60.17	6.53%	145,957
2	Unfunded short-term debt	(108,513)	(2.92)	1.31%	(1,422)
3	Total debt	2,126,084	57.25		144,535
4	Preference shares	102,248	2.75	3.05%	3,117
5	Common equity	1,485,555	40.00	9.58%	142,316
6	Total rate base	3,713,887	100.00		289,969
	Per Settlement Agreement at assumed Common equity component of 36%				
7	Long-term debt	2,289,139	61.64	6.47%	148,138
8	Unfunded short-term debt	(14,499)	(0.39)	1.31%	(190)
9	Total debt	2,274,639	61.25		147,948
10	Preference shares	102,248	2.75	3.05%	3,117
11	Common equity	1,336,999	36.00	9.58%	128,085
12	Total rate base	3,713,887	100.00		279,150

		Long-term debt	Short-term debt	Preference shares	Common equity
13	Balance at 40% (Lines 1,2,4,5)	2,234,597	(108,513)	102,248	1,485,555
14	Common equity reduction to 36% (Line 6, col (a) x 4%)		148,556		(148,556)
15	Sept 2013 - $200 million long-term debt issue	54,542	(54,542)		
16		2,289,139	(14,499)	102,248	1,336,999

UNION GAS LIMITED

Undertaking of Mr. Millar
To Mr. Broeders

Please show how the interest coverage ratio of less than two for the regulated side was reached.

The interest coverage ratio is calculated by dividing available earnings by the interest requirement. Available earnings are defined as net income before long-term interest and income taxes. The interest requirement is a pro-forma value of the long-term interest expense giving effect to new debt issues and any retirements. i.e. it recognizes the annualized interest of debt in existence at the date of the calculation.

Attachment 1 shows the interest coverage ratios calculated as follows:

- 2010 & 2011 excluding the sufficiency and for actual results
- 2012 & 2013 excluding the sufficiency/deficiency and for estimated results
- 2013 assuming a 36% common equity component and 9.58% ROE
- 2013 assuming a 37.25% common equity component and 9.58% ROE as proposed by SEC per K5.1 page 2
- 2013 assuming a 36% common equity component and updated for the June ROE formula of 9.10%

Based on the capital structure and related return the only instance where the Utility company would be in a position to issue debt on its own merit is when the common equity component is 40% since the interest coverage ratio is above the required 2.0. Only by including the unregulated operations to supplement the utility business would Union be able to exceed the requirement.

On an actual basis the regulated business was above the required 2.0 due to earning above the allowed ROE.

Line No	Particulars ($000s)	2010 Actual E6 T1 S1 (a)	2011 Actual E5 T1 S1 (b)	2012 Estimate E4 T1 S1 (c)	2013 J5.4 - 40% Common Equity (d)	2013 J5.4 - 36% Common Equity (e)	2013 K5.1 pg 2 - 37.25% Common Equity (f)	2013 36% Equity 9.10% ROE (g)
1	Long-term debt	147,329	142,509	143,680	145,957	148,138	135,809	148,138
2	Unfunded short-term debt	1,074	1,312	1,679	-1,422	-190	1,946	-190
3		148,403	143,821	145,359	144,535	147,948	137,755	147,948
4	Preference shares	2,670	3,075	2,892	3,117	3,117	3,115	3,117
5	Common equity	109,765	104,488	107,391	142,316	128,085	132,532	121,667
6		112,435	107,563	110,283	145,433	131,202	135,647	124,784
7	Return	260,838	251,384	255,642	289,969	279,150	273,402	272,732
8	Add (deduct) unfunded short-term debt (Line 2)	-1,074	-1,312	-1,679	1,422	190	-1,946	190
9	Increase return by income tax expense(1)	30,214	33,119	18,560	9,989	9,989	9,989	9,989
10	Adjust actual taxes for deficiency(sufficiency)(2)	-13,707	-16,694	-1,527	14,232	9,361 (4)	10,883 (5)	7,164 (6)
11	Available Earnings based on approved/proposed capital structure (sum of Lines 7 to 10)	276,271	266,497	270,996	315,611	298,690	292,328	290,075
12	Regulated interest requirement(3)	143,152	141,135	144,596	144,134	151,520	151,520	151,520
13	Utility interest coverage ratio based on interest requirement (Line 11 / Line 12)	1.93	1.89	1.87	2.19	1.97	1.93	1.91
14	(Deficiency)/Sufficiency	44,069	62,449	11,963	-56,580			
15	Actual Utility Available Earnings (Line 11 + Line 14)	320,340	328,946	282,959	259,031			
16	Actual/Projected Utility Interest Coverage Ratio (Line 15 / Line 12)	2.24	2.33	1.96	1.80			

Notes

1 Exhibit D1, Summary Schedule 1, line 7, columns (b), (c), (d) respectively
2013 - Settlement Agreement, Appendix B, Schedule 2, Line 13

2 Exhibits F6, F5, F4, Tab 1 Schedule 1, Line 6, column (a)
2013 - Settlement Agreement, Appendix B, Schedule 1, Line 6

3 The interest requirement gives effect to maturities and new issues to annualize the interest expense for debt issues that exist at the end of the period. See Attachment 2

4 Adjusted for reduction in equity from 40% to 36% in line 5, 14,232 + (128,085 - 142,316) / (1 - 25.5%) * 25.5% = 9,361

5 Adjustment for reduction in equity from 40% to 37.25% in line 5, 14,232 + (132,532 - 142,316) / (1 - 25.5%) * 25.5% = 10,883

6 Adjustment for reduction in ROE from 9.58% to 9.10% in line 5, 14,232 + (121,667 - 142,316) / (1 - 25.5%) * 25.5% = 7,164

Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2011-0210

VOLUME: 6

DATE: July 19, 2012

BEFORE:

Marika Hare	Presiding Member
Paul Sommerville	Member
Karen Taylor	Member

tiered corporate structure. I don't want to testify, but it is not a small utility. ATCO Gas is the gas distribution assets for the City of Edmonton and City of Calgary. They are not --

DR. BOOTH: Oh, it's a very big utility.

MS. TAYLOR: You said it was very small, and I think we need to correct the transcript. They are fairly large gas distribution entities.

DR. BOOTH: That's right. ATCO Gas is, if I recollect, a little bit smaller than Terasen Gas, but it is one of the premier gas distribution utilities in Canada.

And it, along with ATCO Pipelines, is part of Canadian Utilities which, in turn, is owned by ATCO, which is traded on the Toronto Stock Exchange. So the phrase "ATCO", sometimes we use it, but we're not referring either to the pipeline or the gas -- or the holding company.

MS. HARE: I think what Ms. Taylor was asking you to correct, though, is you called it a "small department".

DR. BOOTH: Oh, okay. Yes, it is -- the gas company is not a separate traded utility that issues debt under ATCO Gas. It is not limited or incorporated. It is just a division, and ATCO Pipelines is another division within the same company, within Canadian Utilities.

So that.... it is a small department, but it is a big company.

MS. HARE: Yes, thank you.

MR. MACINTOSH: Dr. Booth, overall, can you provide your opinion on whether Union's business and financial risk

DR. BOOTH: Yes.

MR. SMITH: So I take it it is fair to conclude that the report was prepared by you?

DR. BOOTH: That's correct. I suspect Mr. Janigan should have asked me that question.

MR. SMITH: Perhaps.

If we look at your CV, sir, and if you look particularly at my compendium at page 12, do you have that? Under the heading "Testimony" on the left-hand side --

DR. BOOTH: That's correct.

MR. SMITH: -- you list a number of appearances.

And I am correct, am I not, that you have testified in Canada, but not in the United States?

DR. BOOTH: That's correct.

MR. SMITH: And you have, therefore, never been qualified as an expert in the United States?

DR. BOOTH: That's correct. I have never been asked to testify in the United States.

MR. SMITH: I am also correct sir, am I not, that you testified in the Board's consultation process on the cost of capital review?

DR. BOOTH: I don't know whether the phrase "testify" is correct. The Board Chairman at the time made great pains in saying that it was a technical conference. It was not testifying under oath and it was a lot more informal, but I provided an opinion at the time of that technical conference.

MR. SMITH: I have always wondered about that distinction, sir, when we talk about people not testifying under oath.

You are a professional; correct?

DR. BOOTH: Correct.

MR. SMITH: I assume that you knew, when you were providing answers to questions, that people might rely on those answers?

DR. BOOTH: Oh, true, and everything I said in that technical conference was absolutely correct. I was just surprised at the intervention by the Board Chairman at the time when he prevented lawyers from asking questions and saying, Well, this is not cross-examination.

MR. SMITH: I take it you don't quibble with the fact, as you just said, though, that to the extent you gave answers, and you did, that you gave them honestly and to the best of your ability?

DR. BOOTH: Absolutely. And everything I say in this hearing I say to my students, as well.

MR. SMITH: Now, if you turn over at page 17 of the compendium, and at line 10, you were asked a question by Mr. Cass:

> "So when you do make your comments about US regulation of utilities, you are not doing so as an expert in the area, right?

And you answer:

> "That's right."

DR. BOOTH: That's correct.

MR. SMITH: And that continues to be true?

DR. BOOTH: That continues to be true. What's happened over the last 10 years is we're getting more and more US witnesses coming into Canada, bringing in evidence from US utilities.

So gradually people have had to become more aware of what is happening in the United States. If I am ever asked to testify in the United States, then I would be qualified at that point in time.

MR. SMITH: But, sir, as the answer says, you are not offering any evidence with respect to the regulation of US utilities, as an expert; correct?

DR. BOOTH: At the current point in time, correct.

MR. SMITH: Okay.

DR. BOOTH: I haven't been qualified, as I said, to offer an expert opinion in the United States.

MR. SMITH: If you turn over to page 18, at the bottom you were asked again:

> "It was, in particular, the third of the three areas that I was referring to that you're not an expert in. It is the impact of regulation in the United States; correct?"

DR. BOOTH: That's correct.

MR. SMITH: And that continues to be true to this day?

DR. BOOTH: That's correct. And that's why I rely upon the opinions of Moody's and S&P.

MR. SMITH: We will come to that in a minute, sir, but continuing over in the compendium, page 20 in the bottom, and if I could ask you to look at line 4, you were asked

MR. SMITH: Now, if I could ask you to turn to page 38 of the compendium, this is a bit, perhaps, of a walk down memory lane for you. Have you got that?

DR. BOOTH: I do.

MR. SMITH: And this is your testimony in the Alberta Utilities generic cost of capital proceeding back in 2000 -- I believe your report is 2003, and the proceeding itself was 2004; correct?

DR. BOOTH: Yes. The decision was certainly 2004.

MR. SMITH: I take it as a general matter, sir, that you agree that utilities with the same risk profile should be treated the same from a cost of capital perspective?

DR. BOOTH: As long as they have the same business risk, then the only thing that would cause them a difference in the capital structure is market access. You can have two utilities with the same business risk, but it doesn't mean to say that they have equal access to the capital markets and financing opportunities.

So as a result, you will have differences in capital structure.

MR. SMITH: I take it --

DR. BOOTH: Business risk is the first leg in analyzing capital structure. The second is financial integrity, financial market access.

MR. SMITH: I take it that you similarly agree that it is possible to compare utilities to one another?

DR. BOOTH: Broadly, yes.

MR. SMITH: And that is true both across sectors, gas and electricity; correct?

DR. BOOTH: That's correct.

MR. SMITH: And that is true across jurisdictions; correct?

DR. BOOTH: That's correct.

MR. SMITH: And, in fact, you've done that on a number of occasions?

DR. BOOTH: That's correct.

MR. SMITH: So if we look, again, at the compendium, and we have in your pre-filed evidence -- and turning over to page 40, can I ask you to look at what you have entitled "Business Risk Rankings"?

DR. BOOTH: Yes.

MR. SMITH: And am I correct, sir, that beginning at page 40 of the compendium, paragraph 11 - and just so we have it, this was appendix A to your evidence in that proceeding - that you set out a ranking of the various business risks of the utilities by sector; correct?

DR. BOOTH: That's correct.

MR. SMITH: So if we look, beginning at page 40, you set out some of the short-term risks that utilities face, and you referred to some of these earlier in answer to some questions. Do you recall that?

DR. BOOTH: I do, yes.

MR. SMITH: And then over at page 41 you identify some -- what you describe as medium and longer term risks. Do you see that?

DR. BOOTH: That's correct.

distribution companies, including both gas and electric."

Do you see that?

DR. BOOTH: Yes.

MR. SMITH: And there you are saying, sir, that gas and electric local distribution companies face the same business risk; correct?

DR. BOOTH: That's correct. And that judgment was actually the judgment of the AUC, as well.

MR. SMITH: I agree. No doubt about that.

So if you would turn over the page to page 44, what you will see is you say there that the conventional yardstick for LDCs is Enbridge and Union Gas.

DR. BOOTH: That's correct.

MR. SMITH: And then you go on to talk about Terasen at 33, and then you make a recommendation of 35 percent common equity ratio for ATCO Gas and for all the Alberta LDCs. And that was your recommendation at that time?

DR. BOOTH: That was correct.

MR. SMITH: And if we look at the bottom, sir, page 44, you rank your risk and you set out your recommended equity ratios, and they follow what we've just gone over from pages 41 through to 44; correct?

DR. BOOTH: That is correct.

MR. SMITH: Now, three years later, you filed evidence in EB-2005-0520, which was Union's 2007 rate case. Do you recall that?

DR. BOOTH: I do.

MR. SMITH: And if you would turn over the page a couple of pages to page 46; do you have that?

DR. BOOTH: I do.

MR. SMITH: And this is your evidence, which was in that proceeding Exhibit K2.

So if we turn over the page to page 47, sir, you have a discussion under the heading "What Comparators Would" -- I assume, "Would I Use For Union Gas".

Do you have that? There should be a big heading,

"What Comparators Would Use For Union Gas?"

DR. BOOTH: Sorry, I missed the big heading. Yes, I see that.

MR. SMITH: And what you will see, beginning at line 13, is you set out what you discuss are your major short-term risks. Do you have that?

DR. BOOTH: That's correct.

MR. SMITH: And I didn't do a black line, but I take it you would agree with me this is the very same discussion set out in your AUC evidence?

DR. BOOTH: Absolutely. It is the same discussion, the same factors that I've looked at for --

MR. SMITH: For many years.

DR. BOOTH: For many years, yes. They are the factors that determine the variability and short-run ability to earn the allowed rate of return and the risk.

MR. SMITH: So let's just go through this, then, quickly, if we can.

So here, again, you say on page 48, line 27:

"Electricity transmission assets have been the lowest risk."

And that was certainly your opinion at the time.

DR. BOOTH: Yes. And I think that still is my opinion.

MR. SMITH: And if you look over the page at page 49, top of the page, page 2, you then, again, ranked gas transmission pipelines as the second lowest risk group. Do you see that?

DR. BOOTH: That's correct.

MR. SMITH: Then on line 13, we jump to your third ranking for local LDCs, and then again you rank both gas and electric together?

DR. BOOTH: That's correct.

MR. SMITH: And then you say at line 18, the sentence that begins, "Within this group" --

DR. BOOTH: Yes.

MR. SMITH: Do you have that?

DR. BOOTH: Yes.

MR. SMITH: Then you again refer to both Enbridge and Union Gas having 35 percent common equity. And then you make your recommendation of 35 percent common equity for a typical local distribution company.

Again, that would be both gas and electric?

DR. BOOTH: That's correct.

MR. SMITH: And then if you turn over the page, you say on page 50:

"In the two years since the Alberta --"

This is at line 6, sir.

"In the two years since the Alberta generic hearing, I have testified in business risk hearings..."

Then you list a number of proceedings in which you testify, and your views remain unchanged.

And that was true?

DR. BOOTH: That's correct. As I mentioned there, the only situation that was changing was the emerging supply problems in western Canada that were hitting the main line.

MR. SMITH: Then you say at line 16:

"The only other significant change is that the BCUC has recently increased the allowed common equity ratio of Terasen from 33 to 35, to bring it in line with Union and Enbridge."

Do you see that?

DR. BOOTH: I do.

MR. SMITH: And the clear implication of that is that the BCUC thought that Terasen and Union and Enbridge should have a comparable equity ratio; correct?

DR. BOOTH: I think that was the implication, yes. The --

MR. SMITH: Certainly the implication from your sentence?

DR. BOOTH: That's right. I am just trying to remember what was in my mind when I wrote that six years ago.

So there may have been other things in my mind at that comparison, are paid out of net income?

DR. BOOTH: As are preferred share dividends.

I mean, actually there is no legal distinction in Canada between preferred shares and common shares; they're just different classes of shareholder capital.

MR. SMITH: And if I could ask you to turn to the compendium back at page 84, do you have that?

DR. BOOTH: I do.

MR. SMITH: You will see schedule 6, and your, I take it -- if you look down at line 4, you will see a reference to "preference shares"?

Do you see that?

DR. BOOTH: I do.

MR. SMITH: I take it you are aware that Union has had preference shares in its capital structure for some time?

DR. BOOTH: For some time, yes. I think it has about $100 million worth of floating rate preferred shares, which -- then it has a little bit of its leftover more conventional preferred shares.

MR. SMITH: Thank you, sir. Those are my questions.

MS. HARE: Thank you.

We will take our morning break now, before we turn to you, Mr. Janigan, for redirect.

So we will be back at, let's say, 11:15.

MR. SMITH: Madam Chair, I take it it would make some sense for me to have the ex-franchise panel come up at that time?

MS. HARE: Yes, please.

But there is a reason why the regulators give different capital structures for different utilities.

And you miss that, just by just by adding them all up and saying: Well, the average is 41 percent.

MS. HARE: That's really why I asked you which do you think with comparable. I heard you say Fortis BC, ATCO Gas, Gaz Met and Enbridge might be comparable.

So my next question is: In your opinion, how important is it for a regulator to look at what comparable utilities have as a deemed equity ratio? Should we attach any weights to the fact that Terasen is at 40 percent, ATCO Gas is 39 percent, Gaz Met is 39 percent?

DR. BOOTH: Yes, you should. The Régis regards Gaz Met as above-average risk utility. Traditionally, Gaz Met has had a lot of industrial load, and it's had to use a lot of regulatory protection to protect Gaz Métropolitan.

And the capital structure decisions was set at a time, particularly Gaz Mét, when natural gas wasn't that competitive in Québec, where electricity, because of Hydro-Québec, was incredibly competitive.

The same thing for -- I keep saying BC Gas, but -- I prefer to call it BC Gas, but -- I mean, the same with BC Gas. The problem there is you've got -- BC Hydro has incredibly competitive electricity rates. And when they heard the case in 2009, natural gas was actually more expensive or at least on the cusp in terms of competitiveness with electricity.

And the big problem was that the lower mainland is getting so much high density housing that they're basically choosing electricity as the fuel of choice.

So it's a comparator in terms of the overall access to capital markets and what is involved in the utility, but none of these utilities are identical. You have to take into account the qualitative factors, which is what goes on in the rating reports.

So there are benchmarks. I prefer to look at them as benchmarks, that the reasonable range is, say, on this basis, 36 to 40 percent for the big gas distributors, and within that range there are ones that are a little bit more risky, like Gaz Métro, and I continue to place Enbridge and Union as amongst the lowest risk.

MS. HARE: Okay. Thank you, Dr. Booth. I think maybe Ms. Taylor has a follow-up.

MS. TAYLOR: It comes back to your conversation with Mr. Sommerville earlier regarding the presence or absence of undertakings between the corporate owner and the operating utility that is subject to regulation.

So undertakings or other covenants, do they exist in the regulatory relationship or corporate structure in any of the other utilities in Canada that you are aware of?

DR. BOOTH: I think the BCUC had a hearing -- well, in fact, I know the BCUC had a hearing when Kinder Morgan purchased what was then Terasen Gas. And, as far as I remember, there were some undertakings to the BCUC surrounding what was then Terasen Gas.

I'm not so sure that there's any undertakings, for

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UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit E2, Page 16 &
Exhibit F2, Page 28, Table 3

a) Please provide all available *Canadian* Comparables (at a minimum Enbridge Gas Distribution) showing Equity Thickness DBRS and S&P Ratings and Financial Risk indicators.

b) Where possible include financial ratios, especially Interest Coverage.

Response:

a) Please see Attachment 1.

b) Union is not able to provide the Financial ratios and interest coverages for the comparables as the work required to research this data is onerous.

Line No	Company	Deemed Equity Ratio	S&P	DBRS
		(a)	(b)	(c)
1	Terasen (Fortis BC)	40%	A-	A (low)
2	Pacific Northern Gas	40% - 45%		
3	ATCO Electric Disco	39%	A	A (low)
4	Enmax Disco	41%	BBB+	A (low)
5	Epcor Disco	41%	BBB+	A (low)
6	ATCO Gas	39%	A	A (low)
7	Fortis Alberta	41%	A-	A (low)
8	Alta Gas	43%	BBB	BBB
9	Gaz Metro	39%	A-	A
10	Gazifere	40%		
11	Nova Scotia Power	40%	BBB+	A (low)
12	Heritage Gas Ltd.	45%		
13	Enbridge Gas Distribution	36%	A-	A
14	Union Gas	36%	BBB+	A

Ratings were not found for Pacific Northern Gas, Gazifere, and Hertiage Gas Ltd.

PREFILED EVIDENCE OF

JIM REDFORD, DIRECTOR, BUSINESS DEVELOPMENT

The purpose of this evidence is to provide details on Union's Parkway West construction project scheduled for completion in 2014. Further details regarding this investment can be found in Exhibit B1, Summary Schedule 2.

This evidence is organized under the following headings:

1/ Changes in Parkway Exports
2/ Loss of Critical Unit Protection
3/ Gas Supply to the Greater Toronto Area
4/ Parkway West Project Facilities Description
5/ Parkway West Project Timing and Development

The Parkway compressor station ("Parkway") is located at the eastern end of the Dawn to Parkway system. On the suction side of Parkway, Union currently is contracted on a firm basis to deliver 1.6 PJ/d to Enbridge Gas Distribution ("EGD") through the Parkway (Consumers) and Lisgar connections. On the discharge side of Parkway, Union currently is contracted on a firm basis to deliver 2.0 PJ/d to TransCanada Pipelines Limited ("TCPL") through the Parkway (TCPL) connection, including 0.4 PJ/d to supply Union's northern and eastern franchise areas as well as a portion of Union's franchise area in Oakville and Burlington. Schedule 1 provides a schematic of the Dawn to Parkway system.

1/ CHANGES IN PARKWAY COMPRESSION EXPORTS

Flow through the Parkway compression has dramatically increased in the past 6 years from less than 0.5 PJ/d in 2005 to a maximum volume of approximately 2.0 PJ/d in 2011.

Union expects that firm demand on the discharge at Parkway will continue to increase as a result of:

i) Growth in the Greater Toronto Area ("GTA") and in key eastern Canadian and U.S. Northeast markets;
ii) Union's desire to partially supply the northern and eastern franchise areas through short-haul service;
iii) The emergence of new U.S. gas supply seeking Ontario, eastern Canadian and U.S. Northeast markets; and,
iv) A market shift from long-haul transportation to short-haul transportation.

Union estimates that design day demand for exports through Parkway compression could exceed 3.0 PJ/d by 2015/2016.

In addition to an increase in demand, Union has also seen a change in net flows through Parkway. Historically, there have been a number of days during the summer months where gas is imported at Parkway from the TCPL system to fill storage at Dawn or to be exported at Kirkwall. Over the past two years, imports at Parkway from the TCPL system have diminished resulting in a fundamental shift to year-round exports through the Parkway compression as shown in Schedule 2. Year-round exports through the Parkway compression have impacted the ability to schedule maintenance activities for the Parkway A Unit and Parkway B Unit as well as the associated facilities.

2/ LOSS OF CRITICAL UNIT PROTECTION

Compression on the Dawn to Parkway system is located at Dawn, Lobo, Bright and Parkway. Currently, Union has Loss of Critical Unit ("LCU") protection for Dawn, Lobo and Bright compression which will protect gas flow along the Dawn to Parkway system (including gas to Kirkwall and gas to the Parkway (Consumers) and Lisgar feeds) in the event of a compressor outage at one of those compressor stations. The discharge at Parkway is the only location on the Dawn to Parkway system without 100% LCU coverage. The increase in design day and peak day send out through Parkway compression (today and forecast) and the shift to year-round exports through the Parkway compression makes LCU protection at Parkway critical.

Under current system design however, loss of the Parkway A Unit (24,000 HP) results in a loss of delivery capability to Parkway (TCPL) of 1.0 PJ/d. Loss of the Parkway B Unit (47,000 HP) results in a loss of delivery capability to Parkway (TCPL) of 1.8 PJ/d. An outage of either the Parkway A Unit or the Parkway B Unit could result in the loss of key markets east of Parkway in Ontario, eastern Canada and the U.S. Northeast, particularly during periods of peak demand. In addition to the direct impact of the outage, loss of the Parkway A Unit or Parkway B Unit during a peak period of demand would impact the market's confidence in Union's ability to provide reliable service and could lead to decontracting of the Dawn to Parkway path.

With increasing throughput at Parkway and with year-round Parkway exports, the reliability of the Parkway compressors becomes critical to supplying the major markets mentioned above. To ensure security of supply to these markets and to provide operational flexibility to complete maintenance activities, Union proposes to build LCU coverage for the Parkway (TCPL) discharge.

3/ Gas Supply to the Greater Toronto Area

In addition to the volumes exported through the Parkway (TCPL) interconnection, Union delivers 1.6 PJ/d to EGD through the Parkway (Consumers) and Lisgar interconnections. EGD supplies the western and central portion of their franchise area within the GTA through Parkway (Consumers) and Lisgar, which is located off of the suction side of Parkway. An outage of the Dawn to Parkway system interconnection at Parkway (including the valve site) would result in no gas being delivered to Parkway (Consumers) and Lisgar. During periods of peak demand, such an outage would have a significant impact on EGD's ability to supply a large number of Ontario customers.

Parkway (Consumers) and Lisgar are critical facilities in servicing the western and central portion of the GTA. To ensure security of supply to these Ontario customers, Union proposes to install a second metering and a header system connected to the Dawn to Parkway system that would allow continued supply to EGD in the event of an outage of the existing Dawn to Parkway system interconnection at Parkway (including the valve site).

4/ PARKWAY WEST PROJECT FACILITIES DESCRIPTION

The Parkway West Project facilities are comprised of three components that are proposed to be constructed over a three year period. These facilities will allow Union to meet export demand on a design day to Parkway (TCPL) and Parkway (Consumers) under an outage of the major components of the existing Parkway compression station.

1. Parkway West Land Purchase – 2012: $15.0 million
2. Parkway West Metering and Headers – 2013: $80.0 million
3. Parkway West Loss of Critical Unit Protection – 2014: $120.0 million

5/ PARKWAY WEST TIMING AND DEVELOPMENT

5.1/ Parkway West Land Purchase

The existing Parkway site is confined by the Ninth Line and housing developments to the east, a proposed development to the south, Highway 407 to the west and Derry Road to the north. Union plans to purchase land in 2012 for the Parkway West site across Highway 407 to the west of the existing Parkway site.

5.2/ Parkway West Metering and Headers

To increase reliability for deliveries to the GTA and to markets east, Union proposes to install i) headers and custody transfer metering to connect the Dawn to Parkway system to the EGD system at the proposed Parkway West station, which will provide EGD with a secure feed in the event of an outage of the existing Parkway (Consumers) feed; and ii) headers to connect the LCU compression to the Dawn to Parkway system and the TCPL system at the proposed Parkway

West station, which will provide TCPL with a secure feed in the event of an outage of an existing Parkway compressor or associated piping. These facilities are proposed to be completed for November 1, 2013 at a cost of $80.0 million.

5.3/ Loss of Critical Unit Protection

To increase reliability for deliveries into the TCPL system and to provide operational and maintenance flexibility, Union proposes to install approximately 40,000 HP of compression that connects to suction and discharge headers and custody transfer metering. This compression will provide 100% LCU protection for an outage of either of the Parkway A or Parkway B units. The new interconnection will provide a secure feed to the TCPL system at the proposed Parkway West station. The new compression will give Union the flexibility to operate the Parkway and Parkway West compressor stations as efficiently as possible, will offer lower NO_x emissions, lower fuel utilization and will be more efficient at lower suction pressures. No capacity created by the LCU protection at Parkway will be sold as firm transportation capacity. The facilities are proposed to be completed for November 1, 2014 at a cost of $120 million.

UNION GAS LIMITED

Undertaking of Mr. Redford
To Mr. Thompson

Please provide relevant Board filing guideline.

Union filed the evidence related to the Parkway West project in accordance with Exhibit 2.1 on page 7 of the Board's Minimum Filing Requirements for Natural Gas Distribution Cost of Service Applications dated November 30, 2005.

VT INCEPIT FIDELIS SIC PERMANET

Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2011-0210

VOLUME: 8

DATE: July 24, 2012

BEFORE:

	Marika Hare	Presiding Member
	Paul Sommerville	Member
	Karen Taylor	Member

So the LCU, we started looking at LCU, loss of critical unit coverage, as early as 2010. And, really, it is a result of increased flows through Parkway.

In 2005, Parkway discharged about a half a pJ a day into the TCPL system. Today it is about four times that, and we predict that to grow to about 3 pJs per day. And that's -- really, it's the only spot in our system and, as near as we can tell, in the transmission system in Ontario that is without loss of critical unit protection.

The second feed into Enbridge, we started discussing with Enbridge some reliability concerns that they had about feeding their system, and it was an item that Enbridge had brought up in discussions. As part of those discussions, Enbridge had looked at a third feed into the Toronto area, into the GTA.

We talked about Parkway West and a second feed for that Parkway (Cons) and Lisgar as a means of satisfying the reliability for the Parkway (Cons) and Lisgar volumes.

MR. SMITH: Can you just tell me the approvals being sought by Union in this proceeding in relation to the project?

MR. REDFORD: We are seeking no approvals.

MR. SMITH: Okay. That being the case, when do you anticipate seeing approvals?

MR. REDFORD: We would file a leave to construct application in September or October of this year for the components of the project which would be typically covered under leave to construct. We would look for approval for pipeline headers between the Dawn-Trafalgar system and the station itself -- and the Parkway West station itself.

As part of that application, we would include a full description of the project, full economics, which would include the compression and the metering facilities, and also rate impacts.

Rate -- or cost recovery would be sought at the time that the 2014 rates are set in whatever process or proceeding is used to determine that.

MR. SMITH: Now, in its evidence, TCPL proposes certain alternatives to the project.

Have you had a chance to look at those, sir?

MR. REDFORD: I have.

MR. SMITH: And can you tell me Union's response to those alternatives?

MR. REDFORD: Yes, I can. There were four alternatives proposed. The first alternative was Empress to Union CDA, either STFT, a contracted service, to replace loss of critical unit.

The second alternative was a new compressor in the vicinity of Parkway. The third alternative was use of the domestic line, an upgrade to their domestic line, plus two compressors located, again, in the vicinity of Parkway.

The fourth alternative was an option using Great Lakes Gas Transmission, and flowing across the northern Ontario line.

I will start with the second alternative, which is a new compressor at Parkway. The second alternative is similar, but not the same, as Union's. It is a physical reliability solution. It is a loss of critical unit to replace Plant B, seemingly, and appears to be at this point less developed than the Parkway West project that we're proposing.

While the details aren't fully available, that project, in order to work, would need to be located directly in the vicinity of Parkway.

MR. SMITH: Okay. So that's alternative 2. Let's maybe go back to alternative 1.

MR. REDFORD: Alternative 1 is the short-term firm transportation. The short-term firm transportation, it is a biddable service on TransCanada's system. It is not renewable. And, in our view, there is no guarantee of availability, and that really is not a substitute for a loss of critical unit protection or loss of critical unit coverage.

TransCanada had suggested that Union could purchase STFT in the event of an outage. Our belief is that that is not -- that's not prudent. That capacity may not be available when you need it. And when you need it most is going to be the coldest time of the year, and that is the time that people are looking for capacity.

If Union were to look at something like that option, we would have to take capacity over a longer period of time, which could be hundreds of millions of dollars on an annual basis.

Another component of that, of that option or that alternative, was for Union to buy gas at Empress, and then sell gas at Dawn or wherever we were receiving the gas.

While we buy and sell gas for our customers, for our in-franchise customers, it is really not in Union's business to be buying gas and selling gas on the day at two different spots like that, specifically when they're not necessarily in-franchise customers that we're covering.

So for those number of reasons, STFT really does not work for us.

MR. SMITH: What about option 3?

MR. REDFORD: Option 3 is the use of the domestic line. It was two compressors and an upgrade to the domestic line. It seemingly is a bit of a hybrid between physical and contractual solution.

I think for Union we would have to contract 1.1 pJs a day of coverage on the domestic line to make sure that we have loss of critical unit coverage, and I think there isn't a rate at this point for that. But even in the evidence, TCPL had identified that the annual cost of that service would be more than what the annual cost of the Parkway West facilities are for the LCU.

MR. SMITH: And does that cover option 3?

MR. REDFORD: That covers option 3.

MR. SMITH: Option 4?

MR. REDFORD: Option 4, really, I would look at it in the same light as option 1, that if we were to take capacity to backstop the loss of critical unit at Parkway, we would have to take it over a longer period of time than on an event, and our view is that that cost is multiple millions of dollars, much more than the annual cost of the LCU at Parkway, a physical solution.

It also -- it isn't detailed as to how that service would be provided, so we would have concerns about capacity. We're not sure whether Great Lakes would even have the ability to serve 1.1 pJs a day of backhaul.

MR. SMITH: Thank you very much. Those are my questions and I tender you for cross-examination.

MS. HARE: Thank you. I understand, Mr. Cass, that you are first up?

CROSS-EXAMINATION BY MR. CASS:

MR. CASS: Yes, I do have a few questions, Madam Chair. Thank you. Because I wasn't here when the Board took appearances and also perhaps for the benefit of the witnesses, I should maybe identify myself.

I am Fred Cass and I am here on behalf of Enbridge Gas Distribution, and I do have only a very few questions. In fact, the examination-in-chief did cover some of the ground that I was going to cover with my questions. Perhaps I could just start by ensuring that I have it correctly.

Union is not asking for any approval in this case by way of the Board granting approval for the Parkway West project. That approval, to the extent that leave to construct is required for any particular facilities, will be in a later leave to construct application; is that correct?

MR. REDFORD: That is correct.

MR. CASS: What is the purpose of Union raising the issue in this case? What is Union looking for here?

MR. REDFORD: We included the Parkway West information and costs into the rates filing. Under the filing guidelines the Board requests that any projects where spends are greater than half-a-million dollars be identified, and that's why Parkway West was included.

MR. CASS: Okay, thank you. So I did want a little more information, if you don't mind, about the forthcoming leave to construct application. In that context, you referred specifically to something you called "headers". Could you just describe a little more, please, what you are referring to when you talk about these headers?

MR. REDFORD: I can. Ideally we would love to purchase an option on property directly across the 407 from Parkway. There is not enough room on the Parkway site, the existing Parkway site, to locate another compressor and have enough buffer around the site. So we needed to move off the site to do so.

The property right across the 407 was not available, and we attempted a number of times to try and secure that land, but to no avail.

So we took the nearest property we could get, which was about a kilometre north, almost directly north of that property. So we will have to build a pipeline or pipelines from the Trafalgar lines to this property in the north, and those are the "headers" that we talk about.

MR. CASS: And you would be seeking leave to construct from the Board for those pipelines?

MR. REDFORD: For those headers, yes. For those pipelines, yes.

MR. CASS: Now, in the context of seeking the Board's leave to construct those pipelines, would Union then consider that to be the Board's approval, if granted, of the proposal for loss of critical unit protection?

MR. REDFORD: We would still have to seek cost recovery in our 2014 rate proceeding, whatever that takes form.

MR. CASS: Yes. But to the extent that the Board grants any sort of project approval, the context in which Union would be looking for approval of the proposed headers is the context in which the Board would consider this overall loss of critical unit protection?

MR. REDFORD: Correct. We would expect that to be part of the -- we would expect the loss of critical unit to be part of the discussions in that leave-to-construct application.

MR. CASS: Okay. So would it follow, then, that I would I be right in thinking that options and alternatives can be dealt with in that leave-to-construct proceeding?

MR. REDFORD: I would expect them to.

MR. CASS: Okay. Would that include, for example, options and alternatives that TransCanada Pipelines Limited might want to bring forward?

MR. REDFORD: Yes. I would agree.

MR. CASS: And so -- sorry?

MR. REDFORD: That's fair. I think that's where they would come up.

MR. CASS: All right. So would I be right in thinking that all interested parties -- so this would include TransCanada, and it would also include Enbridge, which I represent -- will be able to participate in that leave-to-construct proceeding, and there have a full examination of options an alternatives?

MR. REDFORD: I would agree with that.

MR. CASS: Would I also be right in thinking, then, at least in Union's view, that in light of what we just discussed, and bearing in mind also that Enbridge has not been an active participant in this proceeding, that Union's 2013 rate case is not the best proceeding for the Board to try to reach decisions about options and alternatives to the Parkway West project?

MR. REDFORD: I would agree with that, yes.

MR. CASS: Okay. Thank you, Madam Chair. Those are my questions.

MS. HARE: Thank you.

Mr. Cameron, I believe you are next to cross-examine?

MR. CAMERON: I will just be one second. Thank you.

MS. HARE: Sure.

CROSS-EXAMINATION BY MR. CAMERON:

MR. CAMERON: Mr. Redford, let me begin on the point you were discussing just now with Mr. Cass, and that's the land issue.

I understand that you, Union, secured an option to

Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2011-0210

VOLUME: 9

DATE: July 25, 2012

BEFORE: Marika Hare — Presiding Member

Paul Sommerville — Member

Karen Taylor — Member

MR. CAMERON: Thank you, Madam Chair.

With that done, I would ask that the witnesses come forward to be sworn.

TRANSCANADA PIPELINES LIMITED - PANEL 1

Lawrence Jensen, Sworn

Steven Alexander Emond, Sworn

Donald Bell, Sworn

Tim Stringer, Sworn

EXAMINATION-IN-CHIEF BY MR. CAMERON:

MR. CAMERON: Thank you, Madam Chair.

Now, before I introduce the witnesses to the Panel and parties, I just wanted to make a comment that might help people in their -- and the Board in its potential cross-examination of this panel, which is to make the point that TransCanada believes that it fully understands the role of the Board in this proceeding, in reviewing Union's capital budget.

And we thought we made it clear in our submissions on the contested motion that we understood that it was not in this proceeding that the Board would approve or disapprove the Parkway West project, or approve or disapprove some alternative proposed by TransCanada. We get that.

Our objective, as noted in our evidence and interrogatory responses, was to apprise the Board and parties of options for consideration. Not approval or disapproval, but consideration that we believe Union should consult with TransCanada and perhaps also Enbridge about these options.

And we're doing this in case the Board wishes to comment on or provide guidance to Union or to other parties with respect to this project in Union's capital budget.

That is why my cross-examination of TransCanada was very brief. I wasn't trying to say that their proposal was a bad one, or that TransCanada's were good ones. We just put these forward with a view to encourage consultation among the parties on what is effectively a reliability -- a system reliability issue where we believe parties connecting pipelines should be cooperating.

So that also makes me wonder why Union has allocated so much time for the cross-examination of this party on an issue that they say is irrelevant, or even if they were to concede my point, merely a matter of review.

But I believe we understand why we're here. I hope that we can provide some assistance to the Board, and with that in mind, I welcome the cross-examination of this panel on the point that is relevant before you today.

MS. HARE: Okay. Thank you, Mr. Cameron.

Just one point of correction. You said your cross-examination of TransCanada was very brief; I think you meant Union Gas?

MR. CAMERON: Sorry, yes, I did.

MS. HARE: Just to correct that.

MR. CAMERON: Just wait until you hear my cross-examination of TransCanada.

MS. HARE: Of this panel?

MR. CAMERON: Yes.

COST ALLOCATION/
RATE DESIGN

PREFILED EVIDENCE OF

GREG TETREAULT, MANAGER, RATES AND PRICING

HAROLD PANKRAC, TEAM LEADER, RATES AND PRICING

This evidence will address the following rate related matters:

1/ Revenue Deficiency Restatement

2/ Recovery of the 2013 Revenue Deficiency

3/ S&T Transactional Services Revenue

4/ Rate Design Considerations

5/ In-Franchise Rate Design Proposals

- a) Rate Review Guidelines
- b) General Service Rates
- c) Union South Bundled Contract Rate Eligibility
- d) Rate M4 Interruptible Service Offering
- e) Rate T1 Redesign
- f) Customer Charges in Contract Rates
- g) Elimination of Wholesale Transportation Service Rate 77
- h) Elimination of Contract Rate Unbundled Service Offerings

6/ Ex-Franchise Rates

a) Response to the M12-X and C1 Kirkwall to Dawn and M12 and C1 Kirkwall to Parkway Directives

b) C1 Dawn to Dawn-Vector Fuel Ratios

7/ Other Rate Schedule Changes

a) In-Franchise Rate Schedules

b) Ex-Franchise Rate Schedules

1/ REVENUE DEFICIENCY RESTATEMENT

Union has restated its revenue deficiency to reflect revenue and cost revisions not captured in Union's Phase I Settlement Agreement filed on June 28, 2012. As shown at Settlement Agreement, Appendix B, Schedule 1, line 10, Union's revenue deficiency was \$56.580 million. Union's restated revenue deficiency is \$54.524 million, a decrease of \$2.056 million. Table 1 summarizes the Phase II revenue deficiency restatements.

Table 1

Restatement of Union's 2013 Revenue Deficiency/(Sufficiency)

Line No.	Particulars	($ millions)
	Phase I Revenue Deficiency	
1	Total Deficiency	55.810
2	Shareholder Portion of Storage Margin	0.770
3	Adjusted Deficiency	56.580
	Phase II Revenue Deficiency	
4	Deficiency Per Phase I	56.580
5	Compressor Fuel Budget Adjustment	0.300
6	Update to Non-Utility Cross Charge	(0.196)
7	C1 Union Supplied Fuel Revenue Adjustment	(0.103)
8	Heritage Pool M16 Transmission Charge	(0.057)
9	C1 St. Clair to Dawn Revenue Adjustment	(2.000)
10	Updated Deficiency	54.524

The adjustments to the Phase I revenue deficiency are described below.

Compressor Fuel Budget

Union has updated its compressor fuel budget to account for M12 transportation activity that was not included in the compressor fuel budget. As a result of this increase in compressor fuel costs, Union's revenue deficiency has increased by $0.300 million.

C1 St. Clair to Dawn Revenue

The C1 transportation revenue forecast for St. Clair to Dawn transportation provided at Exhibit H3, Tab 1, Schedule 2, page 11, line 3, column b) has been updated to include an additional $2.000 million. The increase in C1 transportation revenue results in a decrease of $2.000 million to Union's revenue deficiency.

2/ RECOVERY OF THE 2013 REVENUE DEFICIENCY

Union's proposed recovery of the 2013 revenue deficiency is provided at Exhibit H3, Tab 1, Schedule 1. Union proposes to increase in-franchise delivery and gas supply transportation rates to recover a deficiency of $58.491 million, and increase ex-franchise transportation rates to recover a deficiency of $1.467 million. Union also proposes to decrease the Gas Supply Administration Charge by $3.990 million, resulting in a net deficiency of $55.968 million for recovery.

In addition, there is a Gas Supply Commodity sufficiency of $1.765 million, which Union is not proposing to recover as part of this proceeding. Union will continue to process Gas Supply Commodity-related rate adjustments through the Board-approved QRAM process.

Finally, there is a non-utility system integrity cost deficiency of $0.321 million, which Union is not proposing to recover from ratepayers. The non-utility system integrity costs are recovered from the non-utility business, not ratepayers.

The rate adjustments in total recover the restated revenue deficiency of $54.524 million. Table 4 provides the proposed recovery of the 2013 revenue deficiency.

Table 4

Recovery of Union's 2013 Revenue Deficiency/(Sufficiency)

Line No.	Particulars	($ millions)
1	In-franchise Delivery and Gas Supply Transportation-related Revenue Deficiency	58.491
2	Ex-franchise Transportation-related Revenue Deficiency	1.467
3	Gas Supply Administration Charge-related Sufficiency	(3.990)
4	Total Deficiency for Recovery	55.968
5	Gas Supply Commodity-related Sufficiency	(1.765)
6	Non-utility System Integrity Costs Deficiency	0.321
7	Restated Phase II Revenue Deficiency	54.524

Union proposes to increase delivery and gas supply transportation rates in Union North to recover $33.335 million of the total in-franchise delivery and gas supply transportation related deficiency of $58.491 million. The in-franchise delivery and gas supply transportation deficiency in Union North is primarily driven by cost increases related to return, depreciation expense and O&M expenses, offset by increases to delivery revenue. For a residential customer consuming 2,200 m^3 per year this represents an annual increase of approximately $65.

Union proposes to increase in-franchise delivery rates in Union South to recover $25.155 million of the total in-franchise delivery and gas supply transportation related revenue deficiency of $58.491 million. The in-franchise delivery deficiency in Union South is primarily driven by cost increases related to return, depreciation expense and O&M expenses, offset by increases to delivery revenue. For a residential customer consuming 2,200 m^3 per year this represents an annual increase of approximately $13.

As indicated above, the proposed recoveries of the 2013 revenue requirement by rate class are provided at Exhibit H3, Tab 1, Schedule 1. Exhibit H3, Tab 1, Schedule 1 also provides the 2007 Board-approved and 2013 revenue to cost ratios. Exhibit H3, Tab 1, Schedule 2 provides detailed in-franchise and ex-franchise rates. The percentage change in average unit prices is provided at Exhibit H3, Tab 1, Schedule 3.

3/ S&T TRANSACTIONAL SERVICES REVENUE

Union has included the ratepayer portion of forecast S&T transactional service revenue in the revenue stream for ratemaking purposes in 2013. To reflect the results of the 2013 cost allocation study, Union proposes to include S&T transactional services revenue of $23.903 million in in-franchise rates. The S&T transactional services revenue restated to reflect 2013 costs is provided at Exhibit H3, Tab 10, Schedule 1.

4/ RATE DESIGN CONSIDERATIONS

When designing 2013 proposed rates for Union North and Union South, the following factors (in no particular order) have been taken into consideration:

a) The revenue deficiency for the company as a whole;
b) The relative rate changes of other rate classes;
c) The allocated cost of service;
d) The level of current rates and the magnitude of the proposed change;
e) The potential impact on customers;
f) The level of contribution to fixed cost recovery;
g) Customer expectations with respect to rate stability and predictability; and
h) Equivalency of comparable service options.

The revenue to cost ratios resulting from Union's 2013 rate design proposals have been filed at Exhibit H3, Tab 1, Schedule 1. For purposes of comparison, Union has also provided the EB-2005-0520 revenue to cost ratios approved by the Board for 2007 in column (j) of Exhibit H3, Tab 1, Schedule 1. The revenue to cost ratios reflect Union's application of accepted rate design principles and as noted above, are underpinned by the cost allocation study filed at Exhibit G3, Tab 1 through Tab 5. The 2013 proposed revenue to cost ratios are within an acceptable range and are generally consistent with those approved by the Board in EB-2005-0520.

5/ IN-FRANCHISE RATE DESIGN PROPOSALS

a) RATE REVIEW GUIDELINES

In reviewing in-franchise rates and service offerings, Union has defined a number of key guidelines to determine appropriate rate class boundaries and rate structures:

i. Common profiles within rate classes – Rate class groupings should exhibit sufficiently similar profiles with regards to average and peak use, seasonal usage and annual volume.

ii. Sufficient rate class size – Each rate class should be sufficiently large enough to produce meaningful average costing/pricing to ensure ongoing rate stability within the rate class (i.e. rates and costs that are stable and predictable).

iii. Sufficient differentiation among rate groupings – Proposed rate groupings must be examined to determine if they are materially different from other groupings with regards to the criteria developed in item (i). Sufficient differentiation is necessary to avoid an unnecessary number of rate classes, minimize undue rate class switching and to reduce the number of customers with similar operating profiles in different rate classes.

iv. Sufficient interest and reasonable prospect of use – Union continues to assess the appropriateness of its rates and service offerings based on customer interest and use (or lack thereof) in order to avoid hypothetical rate designs in the absence of a proven market. The design of rates should be driven by a demonstrated need and provide customers some assurance that workable services will be offered on a sustained basis.

v. Rate harmonization – Where appropriate, Union will consider common rate structures, but not necessarily common rate levels, in accordance with the Board's EBO 195 Report (Application to Amalgamate Union Gas and Centra, Section 2.5 Rates).

b) GENERAL SERVICE RATES

Union is proposing two rate design changes in its General Service market. The first proposed change is to lower the annual volume breakpoint between the Rate 01 and Rate 10 rate classes in Union North and the Rate M1 and Rate M2 rate classes in Union South from 50,000 m^3 to 5,000 m^3. The second proposed change is to harmonize the rate block structures in the small volume General Service rate classes (Rate 01 and Rate M1) and in the large volume General Service rate classes (Rate 10 and Rate M2).

Union proposes to implement the annual volume breakpoint and rate block structure harmonization to General Service rate classes on a revenue neutral basis effective January 1, 2014. Each of the proposed changes is described below.

Lowering the Annual Volume Breakpoint

The current annual volume breakpoint between small volume General Service rate classes (Rate 01 and Rate M1) and large volume General Service rate classes (Rate 10 and Rate M2) is 50,000 m^3.

The annual volume breakpoint of 50,000 m^3 was first approved for small volume General Service Rate 01 by the Board in E.B.R.O 411-III/E.B.R.O. 430-II Decision with Reasons, dated May 20, 1988. Based on the Customer Reclassification Study for ICG Utilities (Ontario) Ltd, the Board approved the current Rate 01 rate class, which previously applied strictly to residential customers, to include residential, small commercial, and small industrial customers in Union North.

In EB-2005-0520 (Union's 2007 rate case), the Board approved the use of the annual volume breakpoint of 50,000 m^3 to split the General Service Rate M2 rate class into small volume Rate M1 and large volume Rate M2 in Union South. Using an annual volume breakpoint of 50,000 m^3 to split the rate class recognized that a small volume residential customer does not incur the same level of customer-related costs as a large volume industrial customer.

Union is proposing to lower the annual volume breakpoint between small volume General Service rate classes (Rate 01 and Rate M1) and large volume General Service rate classes (Rate 10 and Rate M2) to 5,000 m^3 from 50,000 m^3 to improve the rate class composition of Rate 01 and M1 and achieve more homogeneous rate classes. Union's proposal will also improve the rate class size in Rate 10 and Rate M2, which will ensure viable large volume General Service rate classes and improve rate stability.

Rate Class Homogeneity

The small volume General Service rate classes (Rate 01 and Rate M1) display a lack of homogeneity at the current annual volume breakpoint of 50,000 m^3. Union proposes to improve the homogeneity of these rate classes by lowering the annual volume breakpoint to 5,000 m^3.

As shown at Table 5, line 16, at the current annual volume breakpoint of 50,000 m^3 for Rate M1, the class average use per customer is 2,700 m^3. However, within the residential, commercial and industrial markets there are significant differences in average use per customer.

The residential market average use per customer at the 50,000 m^3 breakpoint is 2,258 m^3, which is similar to the class average of 2,700 m^3. The commercial and industrial market average use per customer are 7,650 m^3 and 12,966 m^3 respectively, which differ significantly from the class average use.

Table 5

Union South - General Service Rate Class Profiles
Annual Volume Breakpoint Analysis using 2010 Actuals

		Rate M1			Rate M2		
Line No.	Annual Volume Breakpoint	Annual Volume (m^3)	Number of Meters	Average Use per Customer (m^3)	Annual Volume (m^3)	Number of Meters	Average Use per Customer (m^3)
		(a)	(b)	(c) = (a/b)	(d)	(e)	(f) = (d/e)
	2,500 m^3						
1	Residential	1,073,442,283	619,856	1,732	997,338,294	295,369	3,377
2	Commercial	30,624,470	25,579	1,197	1,237,704,163	52,917	23,390
3	Industrial	930,477	752	1,237	310,881,622	4,339	71,648
4	Total	1,104,997,230	646,187	1,710	2,545,924,079	352,625	7,220
	5,000 m^3						
5	Residential	1,949,672,659	898,064	2,171	121,107,917	17,161	7,057
6	Commercial	90,773,709	42,241	2,149	1,177,554,925	36,255	32,480
7	Industrial	3,437,553	1,432	2,401	308,374,546	3,659	84,278
8	Total	2,043,883,921	941,737	2,170	1,607,037,388	57,075	28,157
	20,000 m^3						
9	Residential	2,061,185,940	915,011	2,253	9,594,636	214	44,835
10	Commercial	324,435,758	65,832	4,928	943,892,876	12,664	74,534
11	Industrial	20,838,044	3,021	6,898	290,974,055	2,070	140,567
12	Total	2,406,459,741	983,864	2,446	1,244,461,567	14,948	83,253
	50,000 m^3						
13	Residential	2,066,157,260	915,184	2,258	4,623,316	41	112,764
14	Commercial	561,651,565	73,418	7,650	706,677,068	5,078	139,164
15	Industrial	51,749,801	3,982	12,996	260,062,298	1,109	234,502
16	Total	2,679,558,627	992,584	2,700	971,362,682	6,228	155,967
	80,000 m^3						
17	Residential	2,067,536,745	915,206	2,259	3,243,831	19	170,728
18	Commercial	698,927,422	75,604	9,245	569,401,212	2,892	196,888
19	Industrial	71,464,633	4,296	16,635	240,347,466	795	302,324
20	Total	2,837,928,799	995,106	2,852	812,992,509	3,706	219,372

As shown at Table 5, line 8, at the proposed annual volume breakpoint of 5,000 m^3 for Rate M1, the class average use per customer is 2,170 m^3. The residential, commercial and industrial markets all exhibit average uses per customer that are similar in magnitude to the Rate M1 class average use shown at Table 5, line 8. This demonstrates that the annual volume breakpoint of 5,000 m^3 best achieves a homogeneous grouping of customers in Rate M1.

A similar improvement in rate class homogeneity in Rate 01 is also achieved. As shown at Table 6, line 16, at the current annual volume breakpoint of 50,000 m^3 for Rate 01, the class average use per customer is 2,797 m^3. However, within the Rate 01 residential, commercial and industrial markets there are significant differences in average use per customer.

The residential market average use per customer is 2,250 m^3, is similar in magnitude to the rate class average of 2,797 m^3. The commercial and industrial market average use per customer, however, are 8,413 m^3 and 27,318 m^3 respectively, which differs significantly from the rate class average use.

Table 6

Union North - General Service Rate Class Profiles
Annual Volume Breakpoint Analysis using 2010 Actuals

		Rate 01			Rate 10		
Line No.	Annual Volume Breakpoint	Annual Volume (m³)	Number of Meters	Average Use per Customer (m³)	Annual Volume (m³)	Number of Meters	Average Use per Customer (m³)
		(a)	(b)	(c) = (a/b)	(d)	(e)	(f) = (d/e)
	2,500 m³						
1	Residential	321,514,442	186,202	1,727	292,983,236	86,765	3,377
2	Commercial	9,594,021	7,662	1,252	415,381,609	20,370	20,392
3	Industrial	1,425	5	285	42,876,633	140	306,262
4	Total	331,109,888	193,869	1,708	751,241,478	107,275	7,003
	5,000 m³						
5	Residential	578,531,026	267,742	2,161	35,966,652	5,225	6,884
6	Commercial	30,835,838	13,498	2,284	394,139,792	14,534	27,118
7	Industrial	4,456	6	743	42,873,602	139	308,443
8	Total	609,371,320	281,246	2,167	472,980,046	19,898	23,770
	20,000 m³						
9	Residential	612,892,618	272,913	2,246	1,605,060	54	29,723
10	Commercial	130,045,789	23,394	5,559	294,929,842	4,638	63,590
11	Industrial	61,526	10	6,153	42,816,533	135	317,160
12	Total	742,999,932	296,317	2,507	339,351,434	4,827	70,303
	50,000 m³						
13	Residential	614,276,579	272,963	2,250	221,100	4	55,275
14	Commercial	222,217,874	26,413	8,413	202,757,756	1,619	125,236
15	Industrial	901,507	33	27,318	41,976,551	112	374,791
16	Total	837,395,960	299,409	2,797	244,955,407	1,735	141,185
	80,000 m³						
17	Residential	614,497,678	272,967	2,251	0	0	0
18	Commercial	270,391,583	27,188	9,945	154,584,047	844	183,156
19	Industrial	2,415,034	56	43,126	40,463,025	89	454,641
20	Total	887,304,295	300,211	2,956	195,047,071	933	209,054

As shown at Table 6, line 8, at the proposed annual volume breakpoint of 5,000 m^3 for Rate 01, the class average use per customer is 2,167 m^3. The residential and commercial markets exhibit average uses per customer that are similar to the Rate 01 class average use shown at Table 6, line 8.

Union notes that the industrial customers' average use per customer is only 743 m^3. In Union's view, the level of the average use for industrial customers has no material impact on the improved homogeneity of the new Rate 01 rate class as there are only six customers identified as industrial.

Rate Class Size

By lowering the annual volume breakpoint from 50,000 m^3 to 5,000 m^3, Union is also able to improve the rate class size and composition of large volume General Service rate classes (Rate M2 and Rate 10).

As shown at Table 5, line 16, at an annual volume breakpoint of 50,000 m^3, the current Rate M2 rate class is comprised of 6,228 customers. Of the 6,228 customers in the current Rate M2, 81% (or 5,078) are commercial customers. The remaining customers in the current Rate M2 are predominantly industrial customers.

Lowering the annual volume breakpoint to 5,000 m^3 results in an increase in customers in the Rate M2 rate class to 57,075 customers. Of the 57,075 customers in proposed Rate M2, 64% (or 36,255) are commercial customers. Residential customers in proposed Rate M2 represent 30% (or 17,161) and industrial customers represent the remaining 6%.

A similar improvement in rate class size and composition is also achieved in Rate 10.

As shown at Table 6, Line 16, at an annual volume breakpoint of 50,000 m^3, the current Rate 10 rate class is comprised of 1,735 customers. Of the 1,735 customers in current Rate 10, 93% (or 1,619) are commercial customers. The remaining customers in current Rate 10 are predominantly industrial customers.

Lowering the annual volume breakpoint to 5,000 m^3 results in an increase in customers in the Rate 10 rate class to 19,898 customers. Of the 19,898 customers in proposed Rate 10, 73% (or 14,534) are commercial customers. Residential customers in proposed Rate 10 represent 26% (or 5,225) with industrial customers representing the remaining 1%.

The increase in rate class size in the Rate 10 and Rate M2 is consistent with Union's rate review guidelines and will ensure viable large volume General Service rate classes with improved rate class composition. The increase in rate class size will allow for more meaningful average pricing and rate stability in these rate classes.

Harmonization of Rate Block Structures

As indicated above, Union is proposing to harmonize the rate block structures in the small volume General Service rate classes (Rate 01 and M1) and in the large volume General Service rate classes (Rate 10 and Rate M2). Union proposes to utilize the current Board-approved rate block structures for Rate M1 and Rate M2 in Union South for Rate 01 and Rate 10 in Union North respectively. Union proposes to implement the volume breakpoint and rate block structure harmonization to General Service rate classes on a revenue neutral basis effective

January 1, 2014.

The current approved rate block structure of Rate M1 is provided at Table 7.

Table 7

Rate M1
Current Appoved Rate Block Structure

Particulars	Annual Volume Breakpoint of 50,000 m^3
Rate M1	First 100 m^3
	Next 150 m^3
	All Over 250 m^3

The first delivery block volume of 100 m^3 is intended to capture base load consumption. The second block, the next 150 m^3, accommodates the consumption of the average customer. The final block, all over 250 m^3, accommodates customers with higher volume and is priced to ensure a smooth transition between small volume and large volume General Service rates.

The current approved rate block structure for Rate M2 is provided at Table 8.

Table 8

Rate M2
Current Appoved Rate Block Structure

Particulars	Annual Volume Breakpoint of 50,000 m^3
Rate M2	First 1,000 m^3
	Next 6,000 m^3
	Next 13,000 m^3
	All Over 20,000 m^3

The first block volume of 1,000 m^3 is intended to capture base load consumption. The second block and third block, the next 6,000 m^3 and 13,000 m^3, accommodates the consumption of most commercial/industrial customers. The final block, all over 20,000 m^3, accommodates customers with higher volume and is priced to ensure the smooth transition between large volume General Service and contract rates.

Proposed General Service Pricing and Bill Impacts

Union's proposed 2013 and 2014 pricing and rate blocking structures for small volume General Service rate classes Rate 01 and Rate M1 and large volume General Service rate classes Rate 10 and Rate M2 are provided at Tables 9 and 10.

Table 9

Small Volume General Service
Rate Structure Harmonization and Proposed Pricing

Particulars	2013 Rate Structure - Annual Volume Breakpoint of 50,000 m^3	2013 Proposed Rates (cents/m^3)	2014 Proposed Rate Structure - Annual Volume Breakpoint of 5,000 m^3	2014 Proposed Rates (cents/m^3)
Rate 01	Monthly Charge	$ 21.00	Monthly Charge	$ 21.00
	First 100 m^3	9.7156	First 100 m^3	9.6122
	Next 200 m^3	9.1911	Next 150 m^3	9.2420
	Next 200 m^3	8.8184	All Over 250 m^3	8.7256
	Next 500 m^3	8.4764		
	Over 1,000 m^3	8.1939		
Rate M1	Monthly Charge	$ 21.00	Monthly Charge	$ 21.00
	First 100 m^3	4.0938	First 100 m^3	4.2635
	Next 150 m^3	3.8873	Next 150 m^3	3.9188
	All Over 250 m^3	3.3988	All Over 250 m^3	3.4122

Table 10

Large Volume General Service
Rate Structure Harmonization and Proposed Pricing

Particulars	2013 Rate Structure - Annual Volume Breakpoint of 50,000 m^3	2013 Proposed Rates (cents/m^3)	2014 Proposed Rate Structure - Annual Volume Breakpoint of 5,000 m^3	2014 Proposed Rates (cents/m^3)
Rate 10				
	Monthly Charge	$ 70.00	Monthly Charge	$ 35.00
	First 1,000 m^3	7.5628	First 1,000 m^3	6.7117
	Next 9,000 m^3	6.1492	Next 6,000 m^3	6.6340
	Next 20,000 m^3	5.3430	Next 13,000 m^3	5.9873
	Next 70,000 m^3	4.8269	All Over 20,000 m^3	4.9660
	Over 100,000 m^3	2.8717		
Rate M2				
	Monthly Charge	$ 70.00	Monthly Charge	$ 35.00
	First 1,000 m^3	4.1184	First 1,000 m^3	3.3112
	Next 6,000 m^3	4.0421	Next 6,000 m^3	3.2234
	Next 13,000 m^3	3.8147	Next 13,000 m^3	3.1256
	All Over 20,000 m^3	3.5418	All Over 20,000 m^3	3.0517

In Rate 01 and Rate M1, Union proposes to maintain the current approved monthly customer charge of $21 per month. The remaining customer-related costs and all demand and commodity-related costs will continue to be recovered in volumetric delivery rates.

In Rate 10 and Rate M2, Union proposes to decrease the monthly customer charge to $35 per month from the current approved monthly customer charge of $70 per month. Union is proposing to decrease the monthly customer charge to recognize that the redesigned Rate 10 and Rate M2 rate classes will have significantly more customers than the current Rate 10 and Rate M2 rate classes. A monthly customer charge of $70, when applied to the increased number of customers, results in a significant over-recovery of allocated customer-related costs.

The proposed monthly customer charge of $35 is more reflective of the composition of the new Rate 10 and Rate M2 rate classes, which have lower average use per customer than at the 50,000 m^3 annual volume breakpoint. The lower monthly customer charge also helps mitigate rate impacts for smaller customers migrating to the new Rate 10 and Rate M2 rate classes. The remaining customer-related costs and all demand and commodity-related costs will continue to be recovered in volumetric delivery rates.

The bill impacts associated with Union's proposal to lower the annual volume breakpoint and harmonize the rate block structures between small and large volume General Service rate classes are provided at Table 11 for Union North and Table 12 for Union South.

Table 11

Union North
Annual General Service Delivery Bll Impacts of
2014 Rate Proposals

Line No.	Annual Volume (m^3/year)	2013 Proposed - Annual Volume Breakpoint of 50,000 m^3 Rate 01 ($)	2013 Proposed - Annual Volume Breakpoint of 50,000 m^3 Rate 10 ($)	2014 Proposed - Annual Volume Breakpoint of 5,000 m^3 Rate 01 ($)	2014 Proposed - Annual Volume Breakpoint of 5,000 m^3 Rate 10 ($)	Annual Bill Impacts ($)	Annual Bill Impacts (%)
1	1,800	422.31		421.12		(1.19)	-0.3%
2	2,200	458.73		457.04		(1.69)	-0.4%
3	2,600	494.80		492.79		(2.01)	-0.4%
4	3,000	530.67		528.39		(2.28)	-0.4%
5	5,000	705.54		705.23		(0.31)	0.0%
6	7,000	876.55			889.80	13.25	1.5%
7	10,000	1,128.39			1,090.00	(38.39)	-3.4%
8	20,000	1,957.51			1,755.24	(202.27)	-10.3%
9	30,000	2,780.82			2,419.31	(361.50)	-13.0%
10	50,000	4,422.82			3,743.64	(679.18)	-15.4%
11	80,000		5,899.52		5,626.55	(272.97)	-4.6%
12	100,000		7,037.89		6,863.64	(174.24)	-2.5%
13	200,000		12,571.60		12,626.80	55.19	0.4%
14	300,000		17,752.05		17,917.17	165.12	0.9%
15	500,000		27,715.09		28,150.63	435.54	1.6%

Table 12

Union South
Annual General Service Delivery Bll Impacts of
2014 Rate Proposals

		2013 Proposed - Annual Volume Breakpoint of 50,000 m^3		2014 Proposed - Annual Volume Breakpoint of 5,000 m^3		Annual Bill Impacts	
Line No.	Annual Volume (m^3/year)	Rate M1 ($)	Rate M2 ($)	Rate M1 ($)	Rate M2 ($)	($)	(%)
1	1,800	323.12		324.97		1.85	0.6%
2	2,200	337.57		339.58		2.01	0.6%
3	2,600	351.94		354.09		2.14	0.6%
4	3,000	366.20		368.47		2.27	0.6%
5	5,000	436.44		439.21		2.77	0.6%
6	7,000	505.38			651.36	145.98	28.9%
7	10,000	608.53			749.11	140.58	23.1%
8	20,000	948.89			1,073.28	124.39	13.1%
9	30,000	1,288.78			1,396.41	107.64	8.4%
10	50,000	1,968.54			2,038.38	69.85	3.5%
11	80,000		4,031.07		2,987.00	(1,044.07)	-25.9%
12	100,000		4,804.38		3,616.58	(1,187.80)	-24.7%
13	200,000		8,521.82		6,720.25	(1,801.58)	-21.1%
14	300,000		12,148.30		9,797.39	(2,350.91)	-19.4%
15	500,000		19,308.57		15,922.58	(3,385.98)	-17.5%

c) Union South Bundled Contract Rate Eligibility

Union is proposing to lower the eligibility criteria for the mid-market bundled contract rate class (Rate M4 or Rate M5A) and the large market bundled contract rate class (Rate M7) in Union South. Union proposes to implement the bundled contract rate class eligibility changes effective January 1, 2014.

d) Rate M4 Interruptible Service Offering

Union is proposing to enhance the current Rate M4 firm service by adding an interruptible service offering to the Rate M4 rate schedule. Union's proposal to introduce an interruptible service offering to firm Rate M4 mirrors the optional, firm base service currently available to interruptible customers taking service under Rate M5A. The introduction of this interruptible service offering to Rate M4 ensures all contract rate customers in Union South for which Union provides the burner-tip service (Rates M4, M5A, M7 and T1) have both firm and interruptible service offerings.

The eligibility criteria for the proposed Rate M4 interruptible service will be an interruptible daily contracted demand of at least 2,400 m^3 and a minimum annual interruptible volume of 350,000 m^3. The structure and pricing of the proposed Rate M4 interruptible service matches the Rate M5A interruptible service.

e) Rate T1 Redesign

Union is proposing to split current Rate T1 into two rate classes with distinct rate structures; a new Rate T1 mid-market service and a new Rate T2 large market service. If approved by the Board, Union proposes to implement the new rate classes, eligibility changes and rate structures, on a revenue neutral basis, effective January 1, 2013.

Current Rate Design

The Rate T1 rate schedule is applicable to customers with combined firm and interruptible annual consumption of 5,000,000 m^3 or more. Customers can contract for 100% firm, 100% interruptible or combined firm and interruptible transportation service. Interruptible transportation rates are customer specific and are negotiated within a Board-approved range. Union is not proposing any rate design changes to the rates it charges for interruptible services.

The current rate design for firm transportation service was approved by the Board in RP-2003-0063. In RP-2003-0063, the Board approved Union's proposal to introduce a two demand, two commodity block rate structure for Rate T1 firm transportation service. This rate design was proposed by Union to better align cost incurrence with cost recovery and to reduce intra-class cross subsidization of small customers by large customers.

Proposed 2013 rates designed using the current approved rate structure for firm Rate T1 transportation service are provided at Table 13.

Table 13

2013 Proposed Rate T1 with no Redesign

	2013 Proposed Rate T1 Firm Transportation Rate with no Redesign	
Monthly Customer Charge	Charge per Re-delivery point	$6,600.83
Monthly Demand Charge (cents/m^3)	First 140,870 m^3 All Over 140,870 m^3	17.8705 12.2113
Monthly Commodity Charge (cents/m^3)	First 2,360,653 m^3 All Over 2,360,653 m^3	0.0232 0.0116
Fuel Ratio	Transportation	0.237%

Union is not proposing any changes to the rate design for storage service provided under the Rate T1 rate schedule. Storage service is an optional service available at cost-based rates for space up to the amount determined by applying the aggregate excess methodology or 15 times the customer's daily contract quantity ("DCQ"). Rate T1 customers may also contract for cost-based deliverability at the greater of DCQ or CD minus DCQ. The current method for allocating cost-based storage to T1 customers was approved in EB-2007-0725.

Rationale for Splitting the Current T1 Rate Class

Union is proposing to split current Rate T1 into two rate classes to better align cost incurrence and cost recovery by recognizing the differences in distribution demand and distribution customer-related costs between small Rate T1 and large Rate T1 customers. The proposed split also addresses the significant diversity in daily contracted demand and firm annual consumption that exists between small and large customers within the current Rate T1 rate class.

Customers Served Directly Off Transmission Main

Under the current cost allocation method used to allocate distribution demand-related costs, rate classes with customers served directly off transmission main are allocated less distribution demand-related costs than rate classes with fewer customers served directly off transmission main. The proportion of customers in a rate class served off transmission main has an impact on the overall level of distribution demand-related costs allocated to a rate class.

As customers served directly off transmission main are generally larger in terms of daily contracted demand and annual consumption than those customers served off distribution main, an intra-class subsidy of small customers (CD's less than 140,870 m^3/day) by large customers exists. The current two block demand rate design for Rate T1 firm transportation service only partially recognizes the costing differences within the Rate T1 class. In the current Rate T1 rate class, 20 of 59 customers (or 34%) are served directly off transmission main, while the remaining 39 customers (66%) are served off distribution main.

Mains and Services Replacement Costs

Mains and services classified to distribution customer are allocated to rate classes using service replacement costs. The allocation of service replacement costs to Rate T1 is determined by estimating the cost of replacing the service based on service length, size and type of pipe. When preparing the 2013 cost allocation study, Union updated the service replacement cost information used to determine its service replacement cost allocator. The allocation of service replacement costs to the current Rate T1 rate class has increased, primarily as a result of the service replacement costs associated with large Rate T1 customers. This is the case because, generally, the service replacement costs for large Rate T1 customers are greater than the service replacement costs for small Rate T1 customers due to the services being of greater size and length.

By proposing to split the current Rate T1 rate class, Union is able to address the intra-class subsidy of large Rate T1 customers by small Rate T1 customers by setting monthly customer charges that are more reflective of the level of customer-related costs for each of the new semi-unbundled rate classes.

Non-homogeneous Rate Class Characteristics

As shown at Table 14, the current Rate T1 rate class is comprised of a diverse group of customers with significantly different load profiles.

Table 14

Load Profile - Current Rate T1 Customers

Particulars		2013 Rate T1 Customers
Number of Customers		59
Firm Contracted Demand (m^3/day)	MIN	9,300
	MAX	2,755,000
	AVG	343,191
	MED	67,800
Annual Firm Volume (m^3)	MIN	4,640,210
	MAX	836,320,120
	AVG	78,383,593
	MED	13,628,490
Customers served directly off transmission (Percent of class)		20 (34%)

Of the 59 customers forecasted in current Rate T1 for 2013, there is significant diversity in firm daily contracted demands. The smallest Rate T1 customer has a firm daily contracted demand of 9,300 m^3, while the largest Rate T1 customer has a firm daily contracted demand of 2,755,000 m^3 (296 times the size of the smallest Rate T1 customer). The average firm daily contracted demand is approximately 343,000 m^3.

This diversity within Rate T1 is also exhibited when examining firm annual consumption for small and large Rate T1 customers. The smallest Rate T1 customer has firm annual consumption of approximately 4,600,000 m^3, while the largest Rate T1 customer has firm annual consumption of 836,000,000 m^3 (181 times the consumption of the smallest Rate T1 customer). The average firm annual consumption is approximately 78,000,000 m^3.

Union's proposal to split current Rate T1 will result in a more homogeneous group of customers in both the new Rate T1 and Rate T2 rate classes.

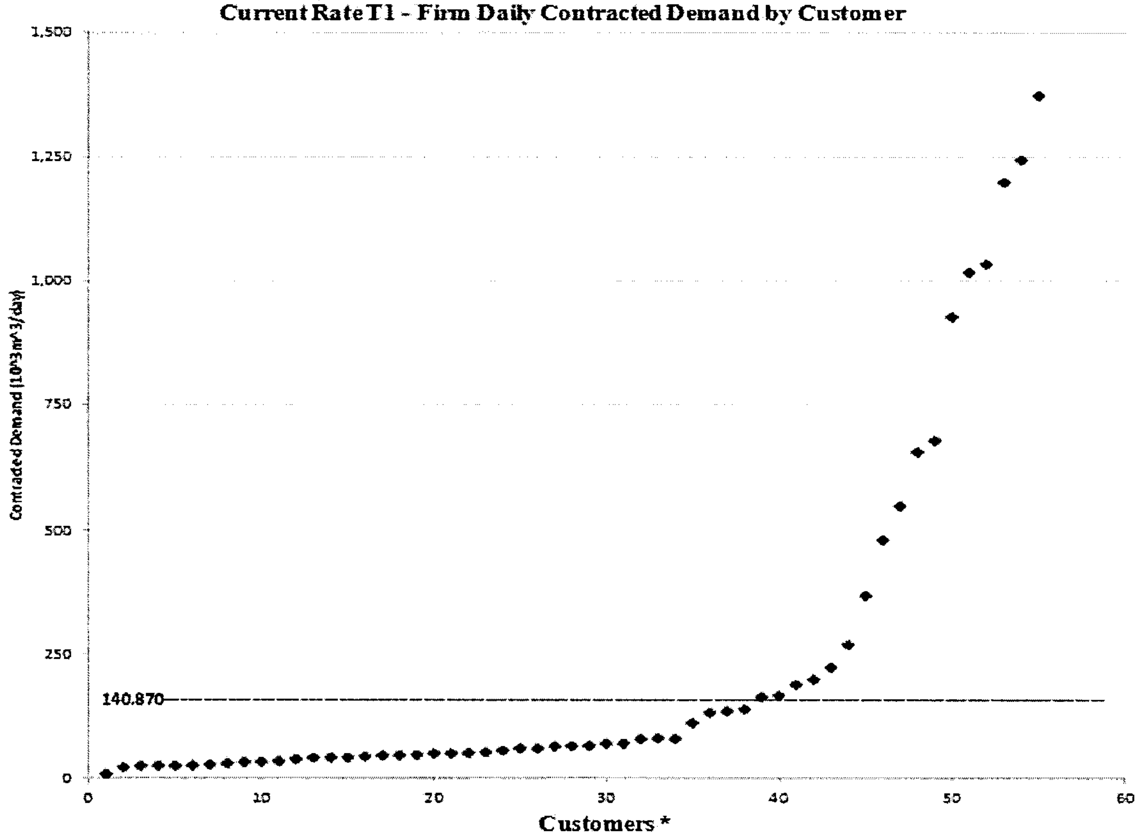
Proposed Rate T1/Rate T2 Eligibility

As indicated above, to qualify for the current Rate T1 service, a customer must have combined firm and interruptible annual consumption of 5,000,000 m^3 or more. For the new Rate T1 mid-market service, Union is proposing a minimum annual volume of 2,500,000 m^3. Further, Union is proposing that the daily firm contracted demand for the new Rate T1 not exceed 140,870 m^3.

The new Rate T2 large market service will be available to customers with a minimum firm daily contracted demand of 140,870 m^3. Union is not proposing any minimum annual volume requirement as a condition for qualifying for new Rate T2.

The proposed firm contracted demand breakpoint between mid-market Rate T1 and large market Rate T2 is derived using the scatter diagram plotting firm daily contracted demands provided at Figure 1.

Figure 1
Current Rate T1 - Firm Daily Contracted Demand by Customer



Union's proposal to split the current Rate T1 into two rate classes will result in improved rate class composition in both Rate T1 and Rate T2. Specifically, both proposed Rate T1 and Rate T2 will be comprised of more homogeneous customers in terms of firm contracted demands and firm annual consumption. The proposed split of current Rate T1 will also recognize cost differences within the current Rate T1 rate class associated with the allocation of distribution demand-related and distribution customer-related costs. Table 15 shows the load characteristics after the proposed split of the current Rate T1. For comparison purposes, Table 15 also includes the load characteristics of the current Rate T1 provided at Table 14.

Table 15

Load Profile - Current Rate T1 Customers
with Rate T1 Redesign

Particulars		2013 Rate T1 without Redesign	Rate T1 Redesign	
			Proposed Rate T1	Proposed Rate T2
Number of Customers		59	39	20
Firm Contracted Demand (m^3/day)	MIN	9,300	9,300	165,000
	MAX	2,755,000	140,000	2,755,000
	AVG	343,191	55,812	889,212
	MED	67,800	48,750	669,000
Annual Firm Volume (m^3)	MIN	4,640,210	4,640,210	22,590,890
	MAX	836,320,120	42,600,000	836,320,120
	AVG	78,383,593	12,795,770	199,721,065
	MED	13,628,490	10,726,120	146,616,000
Customers served directly off transmission (Percent of class)		20 (34%)	6 (15%)	14 (70%)

The rate structures and proposed pricing for the new Rate T1 and new Rate T2 rate classes are described below.

Rate T1 Rate Design and Pricing

Union is proposing that the rate structure of the new Rate T1 consist of a monthly customer charge, a two block monthly demand charge and a single block commodity charge. Table 16 provides a comparison of Rate T1 before rate redesign and proposed new Rate T1 rate structures and proposed rates.

Table 16

Comparison of 2013 Proposed Rate T1 with no Redesign and 2013 Proposed Rate T1 with Redesign

	2013 Proposed Rate T1 Firm Transportation Rate with no Redesign		2013 Proposed Rate T1 Firm Transportation Rate With Rate Design Changes	
Monthly Customer Charge	Charge per Re-delivery point	$6,600.83	Charge per Re-delivery point	$2,001.29
Monthly Demand Charge (cents/m^3)	First 140,870 m^3 All Over 140,870 m^3	17.8705 12.2113	First 28,150 m^3 Next 112,720 m^3	31.5395 23.2744
Monthly Commodity Charge (cents/m^3)	First 2,360,653 m^3 All Over 2,360,653 m^3	0.0232 0.0116	All Volumes	0.0715
Fuel Ratio	Transportation	0.237%	Transportation	0.256%

The proposed monthly customer charge of $2,001.29 is cost-based and fully recovers all of the customer-related costs applicable to the new Rate T1. The two block demand charge recovers approximately 82% of new Rate T1 demand-related transportation costs. The remainder of new Rate T1 demand-related transportation costs are recovered through the Rate T1 storage-related sufficiency. The single commodity charge recovers all the variable transportation costs.

The two block demand and single block commodity rate structure for firm service in new Rate T1 is based on the comparable Rate M4 firm service, which also has a daily contracted demand breakpoint of 28,150 m^3. This approach results in consistency between mid-market bundled and mid-market semi-unbundled service offerings.

As indicated above, Union is not proposing any changes to the storage services currently available under the current Rate T1 rate schedule. However, given that Union is proposing a maximum firm daily contracted demand of 140,870 m^3 in the new Rate T1, the new Rate T1 rate schedule will exclude the storage space, storage injection/withdrawal rights and transportation service provisions that are only applicable to new and existing customers with incremental daily firm demand requirements in excess of 1,200,000 m^3/day.

The derivation of the Rate T1 monthly customer charge, demand charges and commodity charge are provided at Exhibit H3, Tab 11, Schedule 1.

Delivery bill impacts for typical proposed Rate T1 customers are provided at Table 17.

Table 17

Calculation of 2013 Estimated Bill Impacts with and without Rate T1 Redesign

Particulars ($'s)		Transportation Bill at 2013 Rates No Redesign (a)	Transportation Bill at 2013 Rates With Redesign (b)	Estimated Bill Impacts (c) = ((b-a)/a)
Small Customer - Rate T1				
Contracted Demand (m^3/day)	25,750			
Load Factor	80%			
Annual Volume (m^3)	7,537,000			
Demand Bill		55,220	97,457	
Commodity Bill		1,750	5,392	
Customer Charge		79,210	24,015	
Total Annual Bill		136,180	126,864	-6.8%
Average Customer - Rate T1				
Contracted Demand (m^3/day)	48,750			
Load Factor	65%			
Annual Volume (m^3)	11,565,938			
Demand Bill		104,542	164,075	
Commodity Bill		2,686	8,274	
Customer Charge		79,210	24,015	
Total Annual Bill		186,438	196,364	5.3%
Large Customer - Rate T1				
Contracted Demand (m^3/day)	133,000			
Load Factor	53%			
Annual Volume (m^3)	25,624,080			
Demand Bill		285,213	399,379	
Commodity Bill		5,759	18,330	
Customer Charge		79,210	24,015	
Total Annual Bill		370,182	441,725	19.3%

New Rate T2 Rate Design and Pricing

Union is proposing that the rate structure of the new Rate T2 consist of a monthly customer charge, two block monthly demand charge and a single block commodity charge. Table 18 provides a comparison of Rate T1 before rate redesign and proposed new Rate T2 rate structures and proposed rates.

Table 18

Comparison of 2013 Proposed Rate T1 with no Redesign and 2013 Proposed Rate T2 with Redesign

	2013 Proposed Rate T1 Firm Transportation Rate with no Redesign		2013 Proposed Rate T2 Firm Transportation Rate With Rate Design Changes	
Monthly Customer Charge	Charge per Re-delivery point	$6,600.83	Charge per Re-delivery point	$6,000.00
Monthly Demand Charge (cents/m^3)	First 140,870 m^3 All Over 140,870 m^3	17.8705 12.2113	First 140,870 m^3 All Over 140,870 m^3	21.7032 11.3232
Monthly Commodity Charge (cents/m^3)	First 2,360,653 m^3 All Over 2,360,653 m^3	0.0232 0.0116	All Volumes	0.0081
Fuel Ratio	Transportation	0.237%	Transportation	0.234%

The proposed monthly customer charge for the new Rate T2 rate class has been set at $6,000. At this level, the proposed monthly customer charge recovers approximately 50% of the customer-related costs attributable to the new Rate T2. Union is proposing to set the monthly customer charge at $6,000 to ensure a smooth rate continuum between Rate T1 and Rate T2 at the daily contracted demand breakpoint of 140,870 m^3. The balance of the customer-related costs not recovered in the Rate T2 monthly customer charge are recovered in the first block demand charge, which is common to all Rate T2 customers. The revenue to cost ratio for new Rate T2 is consistent with the revenue to cost ratio for Rate T1 before rate redesign.

The two block demand rate structure for the new Rate T2 is based on a daily contracted demand breakpoint of 140,870 m^3. This is the same daily contracted demand as the current Rate T1 structure. The two block demand charge also recovers all the demand-related transportation costs. The single commodity charge recovers all the variable transportation costs.

As indicated above. Union is not proposing any changes to the storage services currently available under the current Rate T1 rate schedule. The proposed 2013 Rate T2 rate schedule, which is provided at Exhibit H3, Tab 3, Schedule 2, will include all the current Board-approved storage space and storage injection/withdrawal rights per the current approved Rate T1 rate schedule. Also, the transportation service provisions that are applicable to new and existing customers with incremental daily firm demand requirements in excess of 1,200,000 m^3/day are included in the proposed T2 rate schedule.

The derivation of the Rate T2 monthly customer charge, demand charges and commodity charge are provided at Exhibit H3, Tab 11, Schedule 1.

Delivery bill impacts for typical proposed Rate T2 customers are provided at Table 19.

Table 19

Calculation of 2013 Estimated Bill Impacts with and without Rate T1 Redesign

Particulars ($'s)		Transportation Bill at 2013 Rates No Redesign (a)	Transportation Bill at 2013 Rates With Redesign (b)	Estimated Bill Impacts (c) = ((b-a)/a)
Small Customer - Rate T2				
Contracted Demand (m^3/day)	190,000			
Load Factor	85%			
Annual Volume (m^3)	59,256,000			
Demand Bill		374,082	433,637	
Commodity Bill		10,152	4,808	
Customer Charge		79,210	72,000	
Total Annual Bill		463,445	510,445	10.1%
Average Customer - Rate T2				
Contracted Demand (m^3/day)	669,000			
Load Factor	81%			
Annual Volume (m^3)	197,789,850			
Demand Bill		1,075,988	1,084,495	
Commodity Bill		26,160	16,049	
Customer Charge		79,210	72,000	
Total Annual Bill		1,181,358	1,172,543	-0.7%
Large Customer - Rate T2				
Contracted Demand (m^3/day)	1,200,000			
Load Factor	84%			
Annual Volume (m^3)	370,089,000			
Demand Bill		1,854,092	1,806,009	
Commodity Bill		46,069	30,029	
Customer Charge		79,210	72,000	
Total Annual Bill		1,979,371	1,908,039	-3.6%

Appendix A

Summary of In-Franchise Rate Proposals

Rate Design Proposals	Current Approved	Proposed
Contract Service **Effective January 1, 2013**		
1. Rate 77	N/A	Eliminate Rate Schedule effective January 1, 2013
2. Rate 20 and Rate 100 Unbundled Services	N/A	Eliminate Contract Unbundled Service offerings effective January 1, 2013
3. Rate U5, Rate U7 and Rate U9	N/A	Eliminate Contract Rate Schedules effective January 1, 2013
Contract Service - Semi-Unbundled **Rate T1 Redesign** **Effective January 1, 2013**		
4. Proposed Rate T1	• Qualifying Annual Volume of 5,000,000 m^3 • Two Firm Contract Demand blocks: First 140,870 m^3/day All Over 140,870 m^3/day • Two Firm Commodity blocks: First 2,360,653 m^3 All Over 2,360,653 m^3	• Qualifying Annual Volume of 2,500,000 m^3; • Firm daily Contract Demand up to 140,870 m^3/day • Two Firm Contract Demand blocks: First 28,150 m^3/day, Next 112,720 m^3/day • Single block Firm Commodity rate
5. Proposed Rate T2	• Qualifying Annual Volume of 5,000,000 m^3 • Two Firm Contract Demand blocks: First 140,870 m^3/day All Over 140,870 m^3/day • Two Firm Commodity blocks: First 2,360,653 m^3 All Over 2,360,653 m^3	• Firm daily Contract Demand greater than 140,870 m^3/day • Two Firm Contract Demand blocks: First 140,870 m^3/day, All Over 140,870 m^3/day • Single block Firm Commodity rate
General Service **Effective January 1, 2014**		
1. (a) Annual volume breakpoint between Small & Large Volume rate classes	Annual Volume Breakpoint of 50,000 m^3	Annual Volume Breakpoint of 5,000 m^3
(b) Harmonize the Rate 01 delivery commodity blocking structure with the current approved blocking structure for Rate M1	First 100 m^3 Next 200 m^3 Next 200 m^3 Next 500 m^3 All Over 1,000 m^3	First 100 m^3 Next 150 m^3 All Over 250 m^3
(c) Harmonize the Rate 10 delivery commodity blocking structure with the current approved blocking structure for Rate M2	First 1,000 m^3 Next 9,000 m^3 Next 20,000 m^3 Next 70,000 m^3 All Over 100,000 m^3	First 1,000 m^3 Next 6,000 m^3 Next 13,000 m^3 All Over 20,000 m^3
Contract Service - Bundled **Effective January 1, 2014**		
2. Lower Union South Bundled Mid-Market Contract rate class eligibility for Rates M4 & M5A	• Contract Demand of 4,800 to 140,870 m^3/day • Minimum Annual Volume of 700,000 m^3 • Rate M4 load factor of at least 40%	• Contract Demand of 2,400 to 60,000 m^3/day • Minimum Annual Volume of 350,000 m^3 • Rate M4 load factor of at least 40%
3. Introduction of a Rate M4 Interruptible Service Offering	Firm Contract Service only	Firm Contract Service with Interruptible Option
4. Lower Union South Bundled Large Volume Contract rate class eligibility for Rate M7	• Combined Firm, Interruptible, and Seasonal Contract Demand of at least 140,870 m^3/day • Annual volume of at least 28,327,840 m^3	• Contract Demand of at least 60,000 m^3/day

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	EB-2011-0210

VOLUME:	11	
DATE:	July 27, 2012	
BEFORE:	Marika Hare	Presiding Member
	Paul Sommerville	Member
	Karen Taylor	Member

MR. SMITH: Thank you.

--- Luncheon recess taken at 12:13 p.m.

--- On resuming at 1:30 p.m.

MS. HARE: Please be seated.

Are there any preliminary matters?

PRELIMINARY MATTERS:

MR. SMITH: Two preliminary matters, Madam Chair.

The first is we did work over the lunch hour to try to get an answer to Mr. Wolnik's question, without success thus far. We will continue to see if we can figure it out.

I do know that the numbers are pulled correctly from the TCPL website, but we are not in a position to independently confirm them, at least not yet, from what we have been able to figure out.

And I believe Mr. Tetreault has an answer to the load factor undertaking, in relation to the T3 load factor. It might make some sense to just put that on the record.

MS. HARE: Okay. Thank you.

MR. TETREAULT: Yes. This is part of Mr. Gruenbauer's request from this morning.

For Rate T3, the firm load factor in 2013 is approximately 32 percent. For the combined Rate T1 -- that is Rate T1 prior to our proposal to split Rate T1 and T2 -- the firm load factor is approximately 65 percent.

All of the data supporting those load factors can be found in Exhibit H3, tab 1, schedule 2, page 8. That was the page Mr. Gruenbauer referenced in his compendium.

For the proposed redesign of T1 into T1/T2, new T1 has a firm load factor of approximately 63 percent, and proposed T2 has a firm load factor of approximately 66 percent.

And the data supporting those calculations can be found in Exhibit H3, tab 11, schedule 1.

MS. HARE: Thank you. Mr. Thompson?

MR. THOMPSON: Yes, just a couple of points, Madam Chair. I have spoken to Mr. Smith about this, but we did leave open the question of submissions concerning the production of an unredacted -- production in confidence of an unredacted copy of J.0-whatever it was, J.0-4-15-1, until the words were available.

MS. HARE: Mm-hmm.

MR. THOMPSON: The words are available, but rather than take time now, my suggestion to Mr. Smith was that we do it Monday, and that he have an unredacted copy of the material here in case you rule that it should be produced in confidence. He's okay with that.

The second point, I just wanted to perhaps get some direction from you as to the issue of clean-up. There was some discussion of that the other day, and I took that to mean, if there were some follow-ups with undertakings, they should be dealt with by way of clean-up.

I have some undertakings with respect to days 6 and 7 are yet to come, and I have a couple of questions on ones that have been provided.

My plan was to submit these to the company in writing over the weekend so that they could deal with them quickly

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2011-0210**

VOLUME:	**12**	
DATE:	**July 30, 2012**	
BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

cost allocation to start off with, and I should note that all of the references that I will be referring to today are based on the July 13th updated evidence unless I indicate otherwise.

Now, am I correct that Union has made changes to basically all of the cost allocation figures in Exhibit G based on the July 13th update, and that these changes reflect the reduction in the revenue requirement as a result of the settlement agreement?

MR. TETREAULT: That's correct.

MR. AIKEN: Now, you've provided the allocation of the reduction in the revenue requirement of just under $18 million in a new schedule, schedule 4 of Exhibit G3, tab 1. I've included that at pages 1 and 2 of the compendium.

And looking at this schedule, most of the reduction gets allocated to rates M1, M12, and Rate 01. Are any of the reductions shown based on changes to the allocation methodology from the original filing?

MR. TETREAULT: No, they are not, Mr. Aiken.

MR. AIKEN: Does the update include any changes at all in the methodologies proposed from the original filing?

MR. TETREAULT: No, it doesn't.

MR. AIKEN: If you turn to Exhibit G1, tab 1, appendix B - this is pages 3 and 4 of the compendium - am I correct that line 7 -- sorry, line 8 is the sum of all the changes in the proposed cost allocation methodologies that you're proposing in this proceeding? Is that correct?

MR. TETREAULT: That's correct.

MR. AIKEN: And would you agree that the net impact is relatively minor in all rate classes, with the possible exception of the net allocation of costs away from Rate 10 to rates 20, 25, and 100, all of which are in the north?

MR. TETREAULT: Yes, that's fair.

MR. AIKEN: And I believe you had a discussion on Friday with Mr. Wolnik about what was driving these changes, so I'll not go over that ground. But for the rates in the south, all your proposed changes are quite minor in aggregate; is that true?

MR. TETREAULT: Correct.

MR. AIKEN: Now, at Exhibit H1, tab 1, page 3 of the updated evidence, which is at page 5 of my compendium, there's an updated deficiency of 56.58 -- sorry, an updated deficiency of 56.58 million for the Phase I revenue deficiency, and 54.524 million after the Phase II adjustments.

Now, in the March 27th update, these figures were 71.378 million and 71.318 million, respectively. So would you take it, subject to check, that the reduction between the March evidence and the July evidence is 14.797 million for Phase I and 16.794 for Phase II?

MR. TETREAULT: Yes, I would.

MR. AIKEN: Now, can you provide a reconciliation of those two figures, the 14.797 and the 16.794 with the 17.955 million reduction in the revenue requirement shown back on page 1 of the compendium?

MR. PANKRAC: Yes.

MR. AIKEN: So if that were reduced to 100 percent, which would be at roughly the $30, how would that impact your fixed cost percentage that you noted earlier?

MR. TETREAULT: It would increase slightly, by approximately $3.5 million, the volumetric recovery of fixed costs.

MR. AIKEN: All right. Has Union considered any rate mitigation measures for the customers that you propose to move from Rate 1 to M2, given the 34 percent increase for the small ones, anyways?

MR. TETREAULT: No, we have not, Mr. Aiken. As you know, our rate design proposals in total are revenue neutral, and the number of customers that are impacted adversely in some way by our rate design proposals in general service is a very small percentage of the overall customer base.

I believe it's in the neighbourhood of 58 to 60,000 customers out of a general service customer base of approximately 1.4 million, so somewhere in the order of, I'll say, 4 percent of the total customer base.

MR. AIKEN: Okay. Now I've got some general questions on the proposals for 2014. So if we go back to page 23 of the LPMA compendium, this is attachment 1 to J.H-1-14-2.

This schedule shows that, under your proposal, a customer using 5,000 cubic metres under rate M1 would pay $451.30, while a customer consuming one cubic metre more, and therefore in rate 2, would be paying $597.10.

Now, this is a jump of 32 percent or more than $145. Would you agree that's a very expensive cubic metre of gas on your continuum of rates?

MR. PANKRAC: It reflects the difference in the services between the small volume and the large volume. Most of that difference in the rate is due to the increase in the customer charge for the 5,001 cubic metre customer, and which, of course, at that volume is not offset by the volumetric rate reduction.

However, the other thing to note in that is that because it is a change in the customer charge, in fact most of that increase is in the summer months because of the nature of how the monthly charge operates, and, in fact, most of that increase is applied to bills that are the smallest customer bills within that 12-month period.

MR. AIKEN: Now, you mentioned the continuum of rates. Shouldn't good rate design provide for a smooth transition from one rate class to another? Isn't that what you mean by a good continuum between rates?

MR. TETREAULT: Yes. Yes, that's fair, balanced with the other fair rate design considerations, such as an appropriate recovery of fixed cost in a fixed charge.

Important to note, as well, Mr. Aiken, that in 2014 we are speaking about customers that are right at the boundary points between rate classes, and, as you know, class rate-making is all about the averages as opposed to the customers that may be outliers or on the extremities.

MR. AIKEN: So I guess my question is: This $145 increase, do you consider that impact to be a smooth transition between rates M1 and M2?

MR. TETREAULT: Overall, we do consider the continuity between classes to be appropriate. And, again, we're balancing continuum with a number of other considerations, largely, the fixed cost recovery in a monthly customer charge.

So, on balance, we are comfortable with the change we're seeing in '14, under the understanding, of course, that in aggregate, the proposals are revenue neutral and only impact a small portion of total M1/M2 customers.

MR. AIKEN: If we now go to page 24 of the compendium, this is attachment 1 to J.H-5-2-1. Am I correct that this shows that a large M2 customer that would qualify for an M4 contract could end up paying significantly more or less than under the M2 rate in 2014?

MR. PANKRAC: Yes. In this analysis, you can see that the crossover for a comparable customer between M2 and M4 occurs somewhere between the 40 and 50 percent load factor. I think I calculated that it's around 48 or 49 percent, where in fact there would be price equivalence.

MR. AIKEN: Now, we see that the rate impacts range from a drop of 16.6 percent to an increase of 9.5 percent in those four examples provided there.

MR. PANKRAC: Yes.

MR. AIKEN: Does Union have the same magnitude of changes in rates between, for example, M4 and M7, or T1 and T2, as the results based on Union's proposals for M1 and

M2, and now M2 and M4?

MR. PANKRAC: Our goal, as we mentioned earlier, is to maintain our rate continuum between firm services, to the extent possible. There are other balancing factors, as well. But, in general, we aim for a smooth rate continuum between M4 and M7, M4 and T1. And so all of those things are considerations in our review of the appropriate level of the rates.

MR. AIKEN: I guess what I'm asking is --

MR. PANKRAC: Mm-hmm?

MR. AIKEN: -- have you done a similar comparison as to what we've just gone through for large M1 to small M2, large M2 to M4, for M4 -- large M4 to small M7, T1 to T2, et cetera?

MR. PANKRAC: Yes. As part of our review of the appropriateness of that, we look at the average rate of classes and we profile some customers to determine if the average price is comparable.

MR. AIKEN: And how do those comparisons stack up with the 9.5 to a reduction of 16.6 percent or the 30-some-percent increase that we noted for M1 and M2? In other words, is the difference between the T1 and T2, for example, 10 percent or 30 percent in your comparison?

MR. PANKRAC: I would have to confirm that. Our comparison really just looks at the average unit price, which of course would be derived from the total bills.

But they are comparable. And as you'll notice on this schedule, the schedule points out that there is a load factor sensitivity, is that in fact it is the load factor, it is the efficiency that is producing those economies or those reductions at the 57.1 percent load factor and at the 49.5 percent load factor in this illustration.

And so what we do is we do say that the proper behaviour, that as load factor increases, as efficiency increases, you would expect the average unit price decrease.

MR. AIKEN: How does Union communicate to customers that they qualify for a contract rate? In other words, how do they advise an M2 customer that they may qualify to be an M4 customer?

MR. PANKRAC: That would be part of -- subject to approval, that would be part of our broad-based communication by a number of different tools, and also through a number of meetings with customers.

MR. AIKEN: Does Union advise customers that the M4 contract rate could end up costing them more than the non-contract M2 class?

MR. PANKRAC: Because it is really a function of how the customer selects their CD and their load factor, those things are very customer-specific. And so certainly to the extent that customers ask us, we do provide a comparison, and -- but really, at the end of the day, it is the customer's comfort level around whether he wants to pay in one rate structure or another.

MR. TETREAULT: Contract rate customers, Mr. Aiken, would typically have a sales rep or an account manager that utility costs to decrease.

MR. THOMPSON: Okay. And this is not your area, as I understand. This is somebody else's area?

MR. TETREAULT: It's better for the finance panel, yes.

MR. THOMPSON: And Mr. Quinn has been trying to get to the bottom of that, and hopefully we will.

Another area where costs might increase is in the step in the process where you allocate costs between the in-franchise and ex-franchise sectors of your utility operation.

And have there been any material changes in the approaches taken to that step of the allocation process?

MS. STEVENSON: I wouldn't say there's a material change. We've described in that IR response that the Oils Springs East and Tecumseh metering would have a shift between in-franchise and ex-franchise, but it's not a material difference.

MR. THOMPSON: Yes, that's in subparagraph (a); is it not?

MS. STEVENSON: That's correct.

MR. THOMPSON: There is an attachment that gives the details of this, but it's not a big ticket item. It's pretty small potatoes, as I recall it?

MR. TETREAULT: That's correct.

MR. THOMPSON: Okay. And am I correct that once the costs between regulated and unregulated storage have been dealt with, that you then move to the allocation as between in-franchise and ex-franchise? Is that step 2? And, if it is, is step 2 followed by the step 3, which is allocating in-franchise costs between north and south?

Have I got the steps right, or does the north and south come before in-franchise/ex-franchise?

MR. TETREAULT: I think in the totality, Mr. Thompson, you have the steps right. I'll describe them a little bit differently, perhaps.

MR. THOMPSON: Okay.

MR. TETREAULT: We see the utility cost of service only. In other words, we don't see non-utility costs, because we're only interested in utility costs for the purposes of utility rate-making. And where I would describe it slightly differently than you did is in the concept of allocating in-franchise, and then ex-franchise, and then between north and south.

MR. THOMPSON: Right.

MR. TETREAULT: Those steps are really one step, where we allocate costs across utility rate classes, both in-franchise and ex-franchise, based on the Board-approved cost allocation methodologies, with the exception of the handful of proposals that we've brought forward in this case.

So it's one step as opposed to a two-step approach.

MR. THOMPSON: Sorry. And the -- I take your point. And then the ex-franchise, in effect, ends up in the south; is that right, the ex-franchise costs and revenues?

MR. TETREAULT: Ex-franchise costs would be allocated

MR. THOMPSON: I thought cost allocation involved allocating revenues and costs?

MR. THOMPSON: Cost allocation involves allocating utility costs to rate classes.

MR. THOMPSON: But then when you determine revenue-to-cost ratios, you have to allocate revenues?

MR. TETREAULT: We receive forecasted revenues by rate class. We compare those revenues to the allocated costs by rate class. That will drive a revenue deficiency or sufficiency by rate class, and we design rates from that point.

MR. THOMPSON: Okay. So this -- I'm still puzzled. But suppose that St. Clair to Dawn revenue amount the Board considers other factors and the Board feels that should be 10 million, not 2 million? Does that then push it into the revenue requirement presentation, or does it still stay as some sort of phase II deficiency adjustment?

MR. TETREAULT: It would have no impact on cost. We would have another, in your scenario, $8 million of revenue. And that incremental $8 million would reduce the deficiency by $8 million, or if I could say it differently, we would have another 8 million of S&T margin to stream back into in-franchise rates.

MR. THOMPSON: I think you're doing this because, whatever these numbers are, you're going treat them as additions to the slush fund for rate design purposes?

MR. TETREAULT: No, we're managing this as a phase II update because of timing, Mr. Thompson. The settlement was filed, and in that settlement it was agreed to increase St. Clair to Dawn revenue by 2 million. That was not captured in the phase I deficiency as part of the settlement filing.

We obviously agreed to do it, so we needed to capture it ultimately in phase II with the settlement when we filed updated costs and updated rates.

If that amount had been in the phase I revenue deficiency, there would have been absolutely no change to -- relative to what we actually did.

MR. THOMPSON: Okay. So you're indifferent as to where it appears?

MR. TETREAULT: Exactly.

MR. THOMPSON: So you won't mind if I put it back into phase I for my purposes?

MR. TETREAULT: Was that a question?

MR. THOMPSON: Well, sort of.

MR. TETREAULT: It won't impact the revenue deficiency. It would not impact rate design.

MR. THOMPSON: Okay. I did ask a question, and I'll probably come to this at the end of my examination. I asked four questions -- well, before I get to that, is this number just given to you, the St. Clair revenue item? Do you have any idea whether it should be two or five or three or 10 or whatever?

MR. TETREAULT: It was provided to me as part of the settlement agreement.

MR. THOMPSON: All right. Then I won't take you where I was planning to take you.

line 14, Mr. Tetreault. Do you recall that discussion?

MR. TETREAULT: Yes, I do.

MR. SMITH: And I guess the question is: Union hasn't forecast anything in relation to those revenues now, and -- well, let me just ask it this way.

What is the impact of not having a forecast for those revenues?

MR. TETREAULT: The effect of the FT RAM forecast being zero is lower S&T margin than it would otherwise be.

MR. SMITH: And when you refer to "the alternative," what is it you're referring to in the alternative proposal?

MR. TETREAULT: The alternative is laid out in the response to J.H-1-1-2, and, in there, as a possible rate mitigation measure, we had discussed that if there were FT RAM revenue, the margin could potentially be streamed directly to north ratepayers to manage the 2013 proposed rate impacts, with the caveat that Union would require deferral account protection should TCPL be successful in eliminating the program.

MR. SMITH: You were asked -- or you used the expression "homogeneity", and this came out of a question urban asked by Mr. Millar, but, just broadly, what happens when you have a class that lacks homogeneity? What does that reflect inside the class?

MR. TETREAULT: Generally speaking, what that will result in is, frankly, unusual rate results or rate impacts for customers. You want to have -- you want to have sizeable homogeneous rate classes so that you have, on an ongoing basis, sustainable rates that represent the costs associated with that rate class.

Where you lack homogeneity, you will tend to have intra-class subsidies amongst the customers that are in the class, and that is something that you want to avoid when designing rate classes and rates.

MR. SMITH: And you mentioned size a number of times, but what happens when rate classes are not of a sufficient size, in your view?

MR. TETREAULT: When rate classes are not of a sufficient size, as customers for a variety of reasons join or leave that rate class, they obviously bring their costs, their revenues, their volumes, with them. And if you lack that class size, the impact of a customer entering or leaving the rate class can be dramatic on the rest of the customers in the rate class. And you want to avoid those type of circumstances, where possible.

MR. SMITH: Earlier in your examination, I believe it was by Mr. Wolnik, you were asked about whether or not you had taken the north proposals to senior management or if senior management were aware of them.

And I guess I'm going to ask you: What, if any, was the reaction of senior management to the north increases?

MR. TETREAULT: As we were, senior management was concerned. Specifically they asked us to review the cost allocation study and ensure that we were comfortable with the results, and that all of the data and all of the calculations in the cost study were working as they needed to, were working properly.

Further, we had to go back to source groups. And what I mean by that is we needed to make sure we had the right costs. So we needed to speak to finance to ensure that we were receiving the proper data from them and using that data properly.

And, likewise, the information that supports the allocators that allocates costs to rate classes, we had to review with source groups that information to, again, make sure we had accurate information and that we were using that information correctly.

MR. SMITH: And was that work done?

MR. TETREAULT: Yes, it was.

MR. SMITH: Thank you. Those are my questions.

PROCEDURAL MATTERS:

MS. HARE: Thank you. Before we move, then, into looking at this undertaking response and the source document, Mr. Quinn, you were going to draft some questions.

MR. QUINN: Yes.

MS. HARE: How do you intend to propose -- do you want to just read them into the record, and then Union can answer them in due course?

MR. QUINN: I actually provided written copies. That's what I thought the intent was. And I've provided Mr. Millar with copies, and I have some copies for our friends here.

Ideally, if I could have those distributed and maybe

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Answer to Interrogatory from
Board Staff

Ref: Exhibit H3, Tab 4, Schedule 1

Union's customer bill impacts reveal a significant difference between delivery rate impacts for southern customers as compared to the northern and eastern customers. While customers in the Southern Service area will experience an increase of $19, customers in the Northern, Eastern and Western Service areas will experience an increase anywhere between $59 and $76.

a) Please explain the reasons for the significant difference between rate impacts for southern customers as compared to customers of other service areas.

b) Has Union in the past cross-subsidized the residential rate classes. If yes, please provide details of the cross-subsidies and the period in which these occurred. Also, please explain the reasons for doing so.

c) Has Union considered any rate mitigation measures to reduce the impact for Northern, Eastern and Western Service area customers? If no, why not?

Response:

a) As shown at Exhibit H3, Tab 1, Schedule 1, Updated, column (i), proposed Union North delivery rates are increasing by an average of 20%. Union South delivery rates are increasing by an average of 7%. The result is an overall increase in proposed in-franchise delivery rates of approximately 10%.

   The delivery bill impact in Union North is $59 to $76 for the average residential customer. In Union South, the delivery bill impact is $19 for the average residential customer.

   There are two factors causing Union North delivery rates to increase by an average of 20%, while Union South delivery rates increase by an average of 7%. The first is that Union North delivery revenue has decreased as a percentage of total delivery revenue from 2007 Board-approved to 2013 forecast levels. At the same time, the Union North delivery-related revenue requirement has increased as a percentage of the total delivery-related revenue requirement. Please see Attachment 1.

   As shown at Attachment 1, lines 1-3, at 2007 Board-approved levels Union North delivery revenue represented 27% of total delivery revenue, while Union South represented 73%. In Union's 2013 revenue forecast, Union North delivery revenue represents 26% of total delivery revenue, while Union South represents 74%. In dollar terms, Union North delivery revenue has declined by $1.8 million while Union South delivery revenue has increased by $9.9 million.

Given that delivery rates have been essentially flat over the IR term, the decline in Union North delivery revenue demonstrates the loss of volumes in Union North compared to Union South. As shown at Attachment 1, lines 4-6, Union North Rate 01 volumes have decreased by approximately 5% from 2007 Board-approved to 2013 forecast levels, while Union South Rate M1 volumes have increased marginally. The relative change in the 2013 revenue forecast compared to 2007 Board-approved levels by operating area is driving an increase in Union North delivery rates relative to Union South delivery rates.

Concurrently, as described above, the Union North delivery-related revenue requirement has increased as a percentage of total delivery-related revenue requirement from 2007 Board-approved to 2013 forecast levels.

As shown at Attachment 1, lines 19-21, at 2007 Board-approved levels the Union North delivery-related revenue requirement represented 27% of the total revenue requirement, while Union South represented 73%. In Union's 2013 forecast, the Union North delivery-related revenue requirement represents 29% of the total revenue requirement, while Union South represents 71%. In dollar terms, the Union North revenue requirement has increased by $32.9 million while the Union South revenue requirement has increased by $33.8 million. Although the relative share of the Union North/South revenue requirement has only changed moderately, the increase in costs to Union North account for approximately 50% of the 2013 revenue deficiency.

As per Exhibit H3, Tab 1, Schedule 1, Updated, page 1, the Union North delivery-related revenue deficiency resulting from Union's 2013 cost of service forecast is $46.375 million, while the Union South delivery-related revenue deficiency is $46.066 million. After including the ratepayer portion of forecast S&T transactional service revenue in the revenue stream for ratemaking purposes, Union has proposed to recover a deficiency of $35.908 million in Union North delivery rates and $35.669 million in Union South delivery rates.

As forecast 2013 Union North delivery revenue is roughly 1/3 of Union South delivery revenue, the recovery of a $36 million deficiency in each operating area results in a Union North delivery rate increase of 20% that is approximately three times the Union South delivery rate increase of 7%.

Attachment 1 also provides a breakdown of capital and O&M-related revenue requirements from 2007 Board-approved to 2013 proposed levels. Further, Union has provided additional information on the drivers increasing the Union North delivery-related revenue requirement relative to Union South below:

- Local Storage Plant – Hagar LNG net utility plant has increased from the 2007 Board-approved levels due to plant additions of $8.2 million, a transfer of $1.0 million of assets, and a change in the depreciation due to the extended plant life from 2012. The increase in the 2013 Union North revenue requirement compared to 2007 Board-approved levels is approximately $0.9 million.

- Depreciation Expense – The Union North distribution depreciation expense has increased by $6.8 million and Union South distribution depreciation expense has increased by $7.2 million. The Union North depreciation expense is increasing at a higher percentage of Union North revenue requirement compared to Union South due to a variance between 2007 Board-approved levels and 2007 actuals.

  The 2007 Board-approved level of Union North depreciation expense was $0.7 million lower than 2007 actuals, while the 2007 Board-approved level of Union South depreciation expense was $1.7 million higher than 2007 actuals. The disproportionate increase to the Union North revenue requirement from 2007 Board-approved levels to the proposed 2013 revenue requirement is $1.7 million.

- Distribution O&M – Union North distribution O&M has increased by $3.8 million and Union South distribution O&M by $2.4 million from 2007 Board-approved levels to the 2013 forecast. The 2013 O&M budget includes more detail than the 2007 forecast, which makes a comparison between Union North and Union South difficult. One specific item which has increased for both Union North and Union South are line locates, which have both increased by approximately $1.5 million since the 2007 Board-approved forecast. The disproportionate increase to the Union North revenue requirement from Board-approved 2007 to the proposed 2013 revenue requirement is $2.8 million, which includes the allocation of direct and indirect costs. The difference calculation assumes that the Union North and Union South distribution O&M increased at same rate of 11% since the Board-approved 2007 forecast. Of this increase, the disproportionate increase of line locates results in a Union North revenue requirement increase of $0.7 million.

- Sales and Promotion Costs – In the 2007 Board-approved cost allocation study, 97% of sales and promotion supervision costs were allocated to Union South in-franchise customers, excluding gas supply and DSM direct assignments. The addition of DSM related costs to the Sales and Promotion category in the cost study resulted in most of the costs being classified to demand and allocated to only Union South in-franchise customers. In the 2013 cost allocation study, Union corrected the classification to exclude DSM. This change results in costs being classified as customer-related and allocated based on an analysis of sales activities. This correction results in 75% of the sales and promotion supervision costs being allocated to Union South and 25% to Union North, for a Union North revenue requirement increase of $1.9 million.

- General Operating and Engineering O&M Costs – The general operating and engineering operating expenses are functionalized based on an analysis of activities. Examples of the costs in this category include planning and dispatch, engineering, geology, capacity management, S&T sales, and gas control. In the 2007 Board-approved cost allocation study, the analysis was based on a sample of the internal work orders. In 2013, the analysis includes a larger sample size representing 91% of the operating expenses. The increased sample size results in a decrease of costs functionalized to transmission and purchase production functions and an increase to distribution. The functionalization update results in an increased allocation of $4.7 million delivery-related revenue requirement to Union North rate classes.

b) Union's historical revenue-to-cost ratios for General Service rate classes have minimized the cross-subsidization of residential customers in Union's rate classes.

c) Union has not proposed any rate mitigation measures to reduce the rate impacts on Union North customers specifically. Union's proposed 2013 rates for both Union South and Union North appropriately recover the 2013 test year revenue requirement and reflect the differing costs associated with serving each delivery area.

Notwithstanding Union's view that its 2013 rate proposals are appropriate, Union has considered a number of rate mitigation measures. They are:

1. At Exhibit F1, Tab 1, Union has proposed to increase the equity component of its capital structure from 36% to 40% to align with capital structures of other North American natural gas and electricity utilities of similar risk. The revenue requirement impact associated with this proposal is approximately $15 million. To manage the overall revenue requirement and rate impacts, increasing the equity component of Union's capital structure could be phased in over 2 to 4 years.

2. At Exhibit C1, Tab 5, Union is proposing to change its weather normalization method from the current 55:45 (55% 30 year average and 45% 20 year declining trend) method to 100% 20 year declining trend. This proposal increases Union's 2013 revenue deficiency by approximately $7 million. To manage the overall revenue requirement and rate impacts, implementation of the 20 year declining trend weather normalization methods could be phased in over 2 to 5 years.

3. As indicated at Exhibit C1, Tab 3, based on TCPL's proposal to eliminate the FT-RAM program, Union has not included any FT-RAM revenue in its 2013 short-term transportation and exchange revenue forecast. In the alternative, Union could partially mitigate 2013 rate impacts in Union North by including revenue associated with FT-RAM in Union North delivery rates on the assumption that TCPL is not successful in eliminating the FT-RAM program. If Union were to take this approach, Union would require deferral account protection to cover the possibility that the FT-RAM program is eliminated or materially changed as a result of TCPL's mainline rate proceeding.

4. Finally, the Board could find that, in the course of setting just and reasonable rates, it would be in the public interest to allow the 2013 revenue-to-cost ratios for Union South and Union North general service rate classes to be adjusted such that the gap between Union South and Union North delivery rates is reduced or eliminated.

Total In-franchise Delivery Revenue and Revenue Requirement
2007 Board-Approved vs. 2013 Forecast

Line No.	Particulars ($000's)	2007 Board-Approved		2013 Forecast		Difference 2013 less 2007		Difference % Δ
		(a)	(b)	(c)	(d)	(e) = (c-a)	(f)	(g) = (e/a)
	Revenue							
1	Union North Delivery (1)	180,861	27%	179,100	26%	(1,761)		-1%
2	Union South Delivery & Storage (2)	500,500	73%	510,391	74%	9,891		2%
3	Total In-franchise Delivery Revenue	681,361	100%	689,491	100%	8,130		1%
	Billing Units (10^3m^3)							
4	Rate 01 Delivery (3)	905,311	24%	855,598	23%	(49,713)		-5%
5	Rate M1 Delivery (4)	2,862,265	76%	2,876,411	77%	14,146		0%
6	Total Rate 01 and Rate M1 Delivery	3,767,576	100%	3,732,009	100%	(35,567)		-1%
	Revenue Requirement							
7	Union North Capital-Related Costs	122,605	30%	133,362	30%	10,757	30%	9%
8	Union South Capital-Related Costs	288,330	70%	313,030	70%	24,700	70%	9%
9	Total In-franchise Capital-Related Costs (5)	410,935	100%	446,392	100%	35,457	100%	9%
10	Union North O&M Costs	72,177	25%	94,886	27%	22,709	42%	31%
11	Union South O&M Costs	220,835	75%	252,601	73%	31,766	58%	14%
12	Total In-franchise O&M Costs	293,012	100%	347,487	100%	54,475	100%	19%
13	Union North Cost of Gas Costs	3,540	10%	2,763	25%	(777)	3%	-22%
14	Union South Cost of Gas Costs	32,137	90%	8,422	75%	(23,715)	97%	-74%
15	Total In-franchise Cost of Gas Costs (6)	35,677	100%	11,185	100%	(24,492)	100%	-69%
16	Union North Other Revenue	(5,770)	24%	(5,535)	24%	234	18%	-4%
17	Union South Other Revenue	(18,664)	76%	(17,596)	76%	1,068	82%	-6%
18	Total In-franchise Other Revenue	(24,434)	100%	(23,131)	100%	1,302	100%	-5%
19	Union North Revenue Requirement (1)	192,552	27%	225,475	29%	32,924	49%	17%
20	Union South Revenue Requirement (2)	522,637	73%	556,457	71%	33,820	51%	6%
21	Total In-franchise Revenue Requirement	715,189	100%	781,932	100%	66,744	100%	9%

Notes:

(1) Union North revenue and revenue requirement for delivery rates, as per EB-2005-0520, Rate Order, Working Papers, Schedule 5, page 1, line 7 and EB-2011-0210, Exhibit H3, Tab 1, Schedule 1, Updated, page 1, line 6.

(2) Union South revenue and revenue requirement for Union South delivery and storage rates, as per EB-2005-0520, Rate Order, Working Papers, Schedule 5, page 1, line 16 and EB-2011-0210, Exhibit H3, Tab 1, Schedule 1, Updated, line 17.

(3) Rate 01 delivery billing units, as per EB-2005-0520, Rate Order, Working Papers, Schedule 6, page 1, line 12, column (a) and EB-2011-0210, Exhibit H3, Tab 1, Schedule 2, Updated, page 1, line 7, column (a).

(4) Rate M1 delivery billing units, as per EB-2005-0520, Rate Order, Working Papers, Schedule 21, line 12, column (a) and EB-2011-0210, Exhibit H3, Tab 1, Schedule 2, Updated, page 5, line 5, column (a).

(5) Capital-related costs include return, taxes and depreciation expense.

(6) The Cost of Gas related costs include compressor fuel. The costs exclude gas supply commodity and gas supply commodity fuel.

UNION GAS LIMITED

Undertaking of Mr. Wolnik
To Mr. Tetreault

Reference: J.H.-1-13-1, J.H.-1-1-2

In the first reference Union was asked to provide a detailed explanation to support the increases for Rate classes 20, 25 and 100 of 43.5%, 43.4% and 29.1% respectively. These increases are relative to the rates currently in effect. Union's response was to see the response to J.H.-1.1.2 a) J.H.-1.1.2a). These responses provide general aggregate information about revenue requirement in the North and limit the comparison to changes from 2007, and do not provide any rate specific information for the rates requested.

a) Please provide a detailed explanation by rate class for these significant rate increases as requested. Please include (but do not limit the response to) the impact of the following items in explaining the overall increases:

   i) Forecast volumes by rate class.
   ii) The impact by rate class of the increase in rate of return.
   iii) The impact by rate class of the increase in the additional equity.
   iv) The impact by rate class of the \$22.7 increase in O&M from 2007 (see Attachment 1 to J.H.-1-1-2 line 10).
   v) The impact by rate class of Union's elimination of the FT-Ram Credits.
   vi) Changes by rate class referenced in G1 Tab 1 pages 11-15.
   vii) The impacts of DSM programs by rate class (include both the program costs and lost revenue impacts).
   viii) The impact by rate class of proposed changes to depreciation expense.

The Union North revenue requirement increase is driven by cost increases and cost allocation corrections since the 2007 Board-approved cost allocation study. A comparison between the 2007 Board-approved and the 2013 proposed cost allocation study by Union North rate class is provided at Attachment 1.

In J.H-1-1-2, part a), pages 3-4, Union provides a description of the drivers for the Union North revenue requirement increase, which includes local storage plant, distribution depreciation expense, distribution O&M, sales and promotion O&M and general operating and engineering O&M. The total revenue requirement increase to Union North rate classes for each of the cost drivers is provided at lines 1, 8, 12, 13, and 14, respectively on Attachment 1. The revenue requirement increase associated with interest and return by rate class is provided on lines 4 and 5 and the increase in Union North depreciation expense by rate class is provided at line 10.

The $22.7 million increase in O&M in J.H-1-1-2, line 10, is the delivery-related revenue requirement for the Union North rate classes. The total Union North O&M increase of $24.3 million is provided at line 17 and includes the allocation of administrative and general O&M expense. Administrative and general costs are allocated in proportion to the allocation of other O&M expenses in the cost allocation study. As both Union North O&M and total administrative and general O&M costs have increased from Board-approved 2007 levels, the allocation of administrative and general O&M costs to Union North rate classes have increased, as provided at line 15.

Union has also proposed several cost allocation methodology changes that impact the allocation to Union North rate classes. The revenue requirement impact of those changes by rate class is provided at J.G-1-3-1, Attachment 2.

Union North rate classes are also impacted by customer changes by rate class. The 2013 forecasted number of customers, contracted demands, and annual volumes relative to 2007 and 2011 Board-approved levels are provided at Attachment 2. The impact of DSM program cost changes by Union North rate class relative to 2007 and 2011 Board-approved levels are provided at Attachment 3.

FT-RAM revenue was not included in either 2007 Board-approved rates or 2013 proposed rates and accordingly is not driving an increase in Union North rates.

Union North In-franchise Revenue Requirment Comparison by Rate Class
Filed 2013 vs. 2007 Board-Approved Cost Study

Line No.	Particulars ($000's)	2007 R01	2007 R10	2007 R20	2007 R100	2007 R25	2007 Total	2013 R01	2013 R10	2013 R20	2013 R100	2013 R25	2013 Total	2013 less 2007 Board-Approved R01	R10	R20	R100	R25	Variance Total	%
		(a)	(b)	(c)	(d)	(e)	(f)=(a+b+c+d+e)	(g)	(h)	(i)	(j)	(k)	(l)=(g+h+i+j+k)	(m)=(g-a)	(n)=(h-b)	(o)=(i-c)	(p)=(j-d)	(q)=(k-e)	(r)=(l-f)	(s)=((l-f)/f)
	Net Plant																			
1	Local Storage Plant [1]	1,585	507	61	83	0	2,236	8,622	2,282	601	42	0	11,547	7,038	1,775	540	(41)	0	9,311	416%
2	Other Rate Base [2]	559,965	103,279	53,674	71,026	24,119	812,062	654,965	91,608	74,667	56,888	24,780	902,907	95,000	(11,671)	20,993	(14,138)	661	90,844	11%
3	Total Rate Base	561,550	103,786	53,736	71,109	24,119	814,298	663,587	93,890	75,268	56,930	24,780	914,454	102,037	(9,896)	21,532	(14,179)	661	100,156	12%
4	Return - Debt Component	26,433	4,885	2,529	3,347	1,135	38,331	25,772	3,646	2,923	2,211	962	35,515	(662)	(1,239)	394	(1,136)	(173)	(2,816)	(7%)
5	Equity Component	18,116	3,348	1,734	2,294	778	26,270	25,990	3,677	2,948	2,230	971	35,815	7,874	329	1,214	(64)	192	9,546	36%
6	Taxes	19,131	3,423	1,607	2,037	703	26,900	16,767	2,513	1,939	1,580	578	23,377	(2,364)	(911)	332	(457)	(125)	(3,523)	(13%)
7	Total Return and Taxes	63,680	11,657	5,870	7,678	2,616	91,501	68,529	9,836	7,810	6,021	2,511	94,707	4,849	(1,821)	1,940	(1,657)	(105)	3,206	4%
	Depreciation Expense																			
8	Union North Distribution Plant [3]	23,653	3,644	2,328	3,248	1,199	34,072	29,444	3,714	3,424	3,093	1,221	40,896	5,791	69	1,097	(155)	22	6,824	20%
9	Other Depreciation Plant	7,033	1,246	595	714	213	9,802	9,609	1,586	949	591	282	13,016	2,575	340	353	(123)	69	3,214	33%
10	Total Depreciation Expense	30,686	4,890	2,923	3,962	1,412	43,874	39,053	5,299	4,373	3,684	1,503	53,912	8,367	409	1,450	(278)	91	10,038	23%
11	Cost of Gas [4]	200,362	58,275	13,444	2,441	13,760	288,283	145,807	41,021	8,747	46	8,031	203,652	(54,555)	(17,255)	(4,697)	(2,396)	(5,728)	(84,631)	(29%)
	O&M																			
12	Distribution North [5]	12,943	1,544	1,137	2,304	332	18,260	16,137	1,653	1,874	1,837	656	22,157	3,194	109	736	(467)	324	3,896	21%
13	Sales and Promotion [6]	2,904	1,392	1,024	1,584	55	6,959	5,924	1,294	1,395	2,053	439	11,105	3,020	(98)	371	468	384	4,145	60%
14	General Operating & Engineering [7]	4,730	642	401	365	235	6,373	7,225	854	919	608	368	9,973	2,494	211	518	243	134	3,600	56%
15	Administrative and General	20,780	2,254	1,390	2,066	438	26,929	31,919	2,824	2,640	2,177	1,215	40,775	11,139	570	1,249	111	777	13,846	51%
16	Other O&M	16,081	1,291	231	165	187	17,955	15,254	1,107	247	31	121	16,761	(827)	(184)	16	(134)	(66)	(1,194)	(7%)
17	Total O&M	57,439	7,123	4,184	6,483	1,247	76,476	76,460	7,731	7,074	6,706	2,799	100,771	19,021	608	2,890	223	1,552	24,294	32%
18	Total Revenue Requirement	352,167	81,946	26,420	20,565	19,035	500,133	329,848	63,887	28,004	16,457	14,845	453,042	(22,319)	(18,058)	1,584	(4,108)	(4,190)	(47,092)	(9%)
19	Other Revenue	5,708	60	1	0	1	5,770	5,490	43	1	0	1	5,535	(218)	(17)	0	(0)	0	(234)	(4%)
20	Total Revenue Requirement (line 18 - line 19)	346,459	81,886	26,419	20,565	19,035	494,364	324,358	63,844	28,003	16,457	14,844	447,506	(22,101)	(18,042)	1,584	(4,108)	(4,191)	(46,857)	-9%
	Revenue Requirement in Rates																			
21	Delivery [8]	136,196	20,675	12,474	18,043	5,144	192,531	164,862	19,246	18,330	16,337	6,701	225,475	28,666	(1,429)	5,856	(1,706)	1,557	32,945	17%
22	Storage and Transmission	51,577	18,492	6,003	755	941	77,768	71,774	23,299	6,931	(12)	2,117	104,109	20,196	4,807	928	(766)	1,176	26,341	34%
23	Other Cost of Gas	158,686	42,719	7,942	1,768	12,950	224,065	87,723	21,300	2,743	131	6,026	117,922	(70,963)	(21,420)	(5,200)	(1,636)	(6,924)	(106,143)	(47%)
24	Total Revenue Requirement	346,459	81,886	26,419	20,565	19,035	494,364	324,358	63,844	28,003	16,457	14,844	447,506	(22,101)	(18,042)	1,584	(4,108)	(4,191)	(46,857)	(9%)

Notes:
(1) Description of the local storage plant cost increase is provided at J.H-1-1-2, page 3.
(2) Other rate base includes net plant excluding local storage plant (line 1), working capital, and accumulated deferred taxes.
(3) Description of the Union North depreciation expense increase is provided at J.H-1-1-2, page 3.
(4) Cost of Gas costs include compressor fuel.
(5) Description of the Union North Distribution O&M cost increase is provided at J.H-1-1-2, page 3.
(6) Description of the cost allocation correction for sales and promotion O&M is provided at J.H-1-1-2, page 3.
(7) Description of the general operating and engineering O&M cost allocation update is provided at J.H-1-1-2, page 4.
(8) 2007 delivery-related revenue requirement excludes Rate 77.

Union North
Forecast Number of Customers, Contracted Demands, and Annual Volumes by Rate Class

Line No.	Particulars ($000's)	R01	R10	R20	R100	R25	R77	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = sum (a to f)
	Number of Customers							
1	2013 Proposed	319,406	2,048	62	19	70	-	321,605
2	2011 Board-approved	295,672	2,962	64	19	79	1	298,797
3	2007 Board-approved	295,672	2,962	64	19	79	1	298,797
4	Difference (line 1 - line 3)	23,734	(914)	(2)	-	(9)	(1)	22,809
	Contracted Demands ($10^3m^3/d$)							
5	2013 Filed	-	-	3,580	5,998	-	-	9,578
6	2011 Board-approved	-	-	2,423	7,782	-	-	10,205
7	2007 Board-approved	-	-	2,423	7,782	-	-	10,205
8	Difference (line 5 - line 7)	-	-	1,157	(1,784)	-	-	(627)
	Annual Volumes (10^3m^3)							
9	2013 Filed	855,598	316,269	628,164	1,895,488	129,481	-	3,825,000
10	2011 Board-approved	870,427	422,932	526,116	2,254,074	104,645	-	4,178,194
11	2007 Board-approved	905,311	381,370	525,588	2,275,112	104,645	-	4,192,026
12	Difference - 2013 vs. 2011 (line 9 - line 10)	(14,829)	(106,663)	102,048	(358,586)	24,836	-	(353,194)
13	Difference - 2013 vs. 2007 (line 9 - line 11)	(49,713)	(65,101)	102,576	(379,624)	24,836	-	(367,026)

Union North
DSM Amounts by Rate Class

Line No.	Particulars ($000's)	R01	R10	R20	R100	R25	R77	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = sum (a to f)
	DSM Amounts in Rates							
1	2013 Proposed	3,755	1,194	981	1,809	-	-	7,739
2	2011 Board-approved	2,380	2,053	1,477	2,375	-	-	8,285
3	2007 Board-approved	1,626	1,402	1,009	1,622	-	-	5,659
4	Difference - 2013 vs. 2011 (line 1 - line 2)	1,375	(859)	(496)	(566)	-	-	(546)
5	Difference - 2013 vs. 2007 (line 1 - line 3)	2,129	(208)	(28)	187	-	-	2,080

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Association of Physical Plant Administrators ("OAPPA")

Reference: Exhibit H3, Tab 1, Schedule 3

a) Please provide the unit delivery rate changes and the associated percentage changes for a typical small customer and a typical large customer in each of the following rate groups: Rate 10 and Rate 20 in the Northern and Eastern Operations Area and Rates M2, M4 and M5 in the Southern Operations Area.

b) For Rate 10, Rate 20, M2, M4 and M5 Interruptible, please describe any factors, in addition to the increased cost of service, driving the average percentage increases of 15.5%, 43.5%, 15.5%, 19.8%, and 45.2%, respectively.

c) Has Union considered rate mitigation measures for customers in the groups listed in a) and b)? If yes, please describe the measures that have been considered. If not, please explain why increases of the magnitude shown in Schedule 3 are considered appropriate.

Response:

a) For a typical small commercial/industrial customer in Rate 10 (Eastern Zone) with an annual volume of 60,000 m^3, the unit delivery rate will increase by approximately 0.8180 cents/m^3 or 11.6%.

   For a typical large commercial/industrial customer in Rate 10 (Eastern Zone) with an annual volume of 250,000 m^3, the unit delivery rate will increase by approximately 0.8180 cents/m^3 or 15.5%.

   For a typical small commercial/industrial customer in Rate 20 (Eastern Zone) with a firm demand of 14,000 m^3 per day and an annual volume of 3,000,000 m^3, the unit delivery rate will increase by approximately 0.7653 cents/m^3 or 42.3%.

   For a typical large commercial/industrial customer in Rate 20 (Eastern Zone) with a firm demand of 60,000 m^3 per day and an annual volume of 15,000,000 m^3, the unit delivery rate will increase by approximately 0.6083 cents/m^3 or 44.5%.

   For a typical small commercial/industrial customer in Rate M2 with an annual volume of 60,000 m^3, the unit delivery rate will increase by approximately 0.7167 cents/m^3 or 12.7%.

   For a typical large commercial/industrial customer in Rate M2 with an annual volume of 250,000 m^3, the unit delivery rate will increase by approximately 0.7167 cents/m^3 or 16.4%.

For a typical small commercial/industrial customer in Rate M4 with a firm demand of 4,800 m^3 per day and an annual volume of 875,000 m^3, the unit delivery rate will increase by approximately 0.5747 cents/m^3 or 15.0%.

For a typical large commercial/industrial customer in Rate M4 with a firm demand of 50,000 m^3 per day and an annual volume of 12,000,000 m^3, the unit delivery rate will increase by approximately 0.4968 cents/m^3 or 25.1%.

For a typical small commercial/industrial customer in Rate M5 with an interruptible demand of 7,500 m^3 per day and an annual volume of 825,000 m^3, the unit delivery rate will increase by approximately 0.9916 cents/m^3 or 39.7%.

For a typical large commercial/industrial customer in Rate M5 with an interruptible demand of 70,000 m^3 per day and an annual volume of 6,500,000 m^3, the unit delivery rate will increase by approximately 0.7042 cents/m^3 or 44.5%.

The calculation of bill impacts for typical small and large customers in Rates 10, 20, M2, M4 and M5 is provided in Attachment 1.

b) Please see the response at Exhibit J.H-1-1-2 part a).

c) Please see the response at Exhibit J.H-1-1-2 part c).

Calculation of Annual Bill Impacts for Typical Small and Large Customers in Rates 10, 20, M2, M4 and M5

		Current Approved		2013 Proposed		Impact		
Line No.	Particulars	Bill ($)	Unit Rate (cents/m^3)	Bill ($)	Unit Rate (cents/m^3)	Unit Rate (cents/m^3)	Bill ($)	Bill (%)
		(a)	(b)	(c)	(d)	(e) = (d-b)	(f) = (c-a)	(g) = (f/a)
	Small Rate 10							
1	Delivery Charges	4,224	7.0394	4,714	7.8574	0.8180	491	11.6%
2	Gas Supply Charges	12,188	20.3141	12,360	20.5998	0.2857	171	1.4%
3	Total Bill	16,412	27.3535	17,074	28.4572	1.1037	662	4.0%
	Large Rate 10							
4	Delivery Charges	13,228	5.2912	15,273	6.1091	0.8180	2,045	15.5%
5	Gas Supply Charges	50,785	20.3141	51,500	20.5998	0.2857	714	1.4%
6	Total Bill	64,013	25.6053	66,772	26.7089	1.1037	2,759	4.3%
	Small Rate 20							
7	Delivery Charges	54,251	1.8084	77,211	2.5737	0.7653	22,960	42.3%
8	Gas Supply Charges	605,494	20.1831	598,915	19.9638	(0.2193)	(6,579)	-1.1%
9	Total Bill	659,745	21.9915	676,126	22.5375	0.5460	16,381	2.5%
	Large Rate 20							
10	Delivery Charges	204,868	1.3658	296,109	1.9741	0.6083	91,241	44.5%
11	Gas Supply Charges	2,865,317	19.1021	2,837,130	18.9142	(0.1879)	(28,186)	-1.0%
12	Total Bill	3,070,185	20.4679	3,133,240	20.8883	0.4204	63,055	2.1%
	Small Rate M2							
13	Delivery Charges	3,387	5.6453	3,817	6.3621	0.7167	430	12.7%
14	Gas Supply Charges	10,694	17.8227	10,630	17.7174	(0.1053)	(63)	-0.6%
15	Total Bill	14,081	23.4680	14,448	24.0794	0.6114	367	2.6%
	Large Rate M2							
16	Delivery Charges	10,906	4.3623	12,698	5.0790	0.7167	1,792	16.4%
17	Gas Supply Charges	44,557	17.8227	44,293	17.7174	(0.1053)	(263)	-0.6%
18	Total Bill	55,463	22.1850	56,991	22.7964	0.6114	1,528	2.8%
	Small Rate M4							
19	Delivery Charges	33,628	3.8432	38,656	4.4179	0.5747	5,028	15.0%
20	Gas Supply Charges	155,949	17.8227	155,027	17.7174	(0.1053)	(921)	-0.6%
21	Total Bill	189,577	21.6659	193,684	22.1353	0.4694	4,107	2.2%
	Large Rate M4							
22	Delivery Charges	237,903	1.9825	297,518	2.4793	0.4968	59,616	25.1%
23	Gas Supply Charges	2,138,724	17.8227	2,126,088	17.7174	(0.1053)	(12,636)	-0.6%
24	Total Bill	2,376,627	19.8052	2,423,606	20.1967	0.3915	46,980	2.0%
	Small Rate M5							
25	Delivery Charges	20,602	2.4972	28,782	3.4887	0.9916	8,180	39.7%
26	Gas Supply Charges	147,037	17.8227	146,169	17.7174	(0.1053)	(869)	-0.6%
27	Total Bill	167,639	20.3199	174,951	21.2061	0.8863	7,312	4.4%
	Large Rate M5							
28	Delivery Charges	102,925	1.5835	148,697	2.2876	0.7042	45,772	44.5%
29	Gas Supply Charges	1,158,476	17.8227	1,151,631	17.7174	(0.1053)	(6,845)	-0.6%
30	Total Bill	1,261,401	19.4062	1,300,328	20.0050	0.5989	38,927	3.1%

UNION GAS LIMITED

Undertaking of Mr. Tetreault
To Mr. Wolnik

Please explain what other measures, by order of priority, could be used to reach 10 percent threshold, if the four mitigation tools were insufficient.

The Board's guidance to electricity distributors regarding rate mitigation contemplates a mitigation plan where a customer class or group **total** bill increase exceeds 10%. There is no comparable guidance provided to gas distributors. Union's proposed deficiency and the associated total bill impacts for each rate class fall below the 10% threshold. Please see Attachment 1.

Union does not consider mitigation to be necessary. If mitigation were ordered by the Board, any one of the mitigation measures included in Exhibit J.H-1-1-2 would keep the total bill impact below 10%.

Notwithstanding the fact that the total bill impacts provided in Attachment 1 do not exceed 10% for any in-franchise rate class, Union has provided Attachment 2. Attachment 2 provides the delivery rate impact associated with the expected reduction in return on equity ("ROE") from 9.58% to 9.10%, the impact of an alternative allocation of the distribution-related rate base reduction agreed to at Issue 1.4 of the EB-2011-0210, Settlement Agreement ("Settlement") and the mitigation measures discussed at Exhibit J.H-1-1-2.

ROE Reduction 9.58% to 9.10%

Based on the June 2012 Consensus of 2012 actual and forecast bond yields, the Board's formula produces an ROE of 9.10%. The ROE included in the revenue requirement underpinning delivery rate impacts provided at Exhibit H1, Tab 1, Schedule 1, revised for the Settlement is 9.58%. Before considering the impact of mitigation measures on delivery rates it is appropriate to adjust for the reduced ROE. The revenue requirement impact of going from 9.58% to 9.10% is approximately $8.6 million.

FT-RAM Revenue

At Exhibit J.C-4-7-9, Union indicated that if TCPL's RAM program is not eliminated on November 1, 2012, Union's 2013 revenue forecast attributable to FT-RAM would be $11.6 million. In preparing Attachment 2, Union has reduced delivery rates by $11.6 million to reflect the continuation of TCPL's RAM program beyond November 1, 2012.

Should the Board order the inclusion of FT-RAM revenue in delivery rates, Union would require deferral account protection, including the attributes as described at Transcript Volume 7 pp. 35-37, against the risk of elimination of the RAM program.

Alternative Allocation of Distribution-Related Rate Base Adjustment

At Issue 1.4 of the Settlement, parties agreed to reduce distribution-related rate base by $12 million. The effect of the reduction was a revenue requirement reduction of approximately $1.7 million.

To implement the distribution-related rate base reduction, Union reduced distribution mains, the largest distribution-related plant type. In cross-examination, parties requested that Union consider an alternative method for incorporating the distribution-related rate base adjustment and provide the impact of that alternative.

For the purposes of preparing Attachment 2, rather than attributing the rate base adjustment to distribution mains, Union allocated the adjustment using total distribution rate base. The impact of the alternative allocation is provided at column (h) of Attachment 2.

Phase In of Increase in Common Equity Ratio

For the purposes of preparing Attachment 2, Union was asked to assume that its proposal to increase its common equity ratio from 36% to 40% would be phased in over four years starting in 2013. Phasing in the increase in common equity thickness over four years reduces the 2013 revenue deficiency by approximately $11.1 million.

Phase In of the 20-Year Declining Trend Weather Methodology

As described in J.H-1-1-2 part c) Union's proposal to change its weather normalization method from the current 55:45 method to 100% 20-year declining trend increases its revenue deficiency by approximately $7 million. For the purposes of preparing Attachment 2, Union was asked to assume that the change in the weather normalization method would be implemented over five years starting in 2013. Phasing in the weather normalization method over five years reduces the 2013 revenue deficiency by approximately $5.8 million.

Adjustments to Revenue to Cost Ratios and Other Mitigation Methods

The mitigation measures above were sufficient to reduce the delivery rate impacts below 10%. Accordingly, there were no additional amounts to be deferred for future recovery and no need to adjust revenue to cost ratios. Union's view is that no further adjustments should be made to the revenue to cost ratios between North and South unless the Board was to set a longer term direction for Union to harmonize rate levels as well as rate structures between North and South customers.

Union North
Calculation of Annual Bill Impacts for Typical Small and Large Customers

		Current Approved		2013 Proposed		Impact			
Line No.	Particulars	Bill ($)	Unit Rate (cents/m^3)	Bill ($)	Unit Rate (cents/m^3)	Unit Rate (cents/m^3)	Bill ($)	Bill (%)	Volumes Used for Rate Calcs
		(a)	(b)	(c)	(d)	(e) = (d-b)	(f) = (c-a)	(g) = (f/a)	
1	Small Rate 01								
2	Delivery Charges	404	18.3500	459	20.8509	2.5009	55	13.6%	2,200
3	Gas Supply Charges	469	21.3359	480	21.7968	0.4609	10	2.2%	2,200
	Total Bill	873	39.6859	938	42.6477	2.9618	65	7.5%	2,200
4	Small Rate 10								
5	Delivery Charges	4,224	7.0394	4,699	7.8320	0.7925	476	11.3%	60,000
6	Gas Supply Charges	12,188	20.3141	12,334	20.5563	0.2422	145	1.2%	60,000
	Total Bill	16,412	27.3535	17,033	28.3883	1.0348	621	3.8%	60,000
7	Large Rate 10								
8	Delivery Charges	13,228	5.2912	15,209	6.0837	0.7926	1,981	15.0%	250,000
9	Gas Supply Charges	50,785	20.3141	51,391	20.5564	0.2423	606	1.2%	250,000
	Total Bill	64,013	25.6053	66,600	26.6401	1.0348	2,587	4.0%	250,000
10	Small Rate 20								
11	Delivery Charges	54,251	1.8084	71,780	2.3927	0.5843	17,529	32.3%	3,000,000
12	Gas Supply Charges	605,494	20.1831	595,032	19.8344	(0.3488)	(10,463)	-1.7%	3,000,000
	Total Bill	659,745	21.9915	666,811	22.2270	0.2355	7,066	1.1%	3,000,000
13	Large Rate 20								
14	Delivery Charges	204,868	1.3658	271,339	1.8089	0.4431	66,471	32.4%	15,000,000
15	Gas Supply Charges	2,865,317	19.1021	2,818,008	18.7867	(0.3154)	(47,308)	-1.7%	15,000,000
	Total Bill	3,070,185	20.4679	3,089,348	20.5957	0.1278	19,163	0.6%	15,000,000
	Average Rate 25								
16	Delivery Charges	33,278	1.7988	42,569	2.3010	0.5022	9,291	27.9%	1,850,000
17	Gas Supply Charges	326,112	17.6277	344,766	18.6360	1.0083	18,654	5.7%	1,850,000
18	Total Bill	359,391	19.4265	387,335	20.9370	1.5105	27,945	7.8%	1,850,000
	Small Rate 100								
19	Delivery Charges	207,338	0.7679	272,804	1.0104	0.2425	65,466	31.6%	27,000,000
20	Gas Supply Charges	5,508,162	20.4006	5,481,147	20.3005	(0.1001)	(27,015)	-0.5%	27,000,000
21	Total Bill	5,715,500	21.1685	5,753,951	21.3109	0.1424	38,451	0.7%	27,000,000
	Large Rate 100								
22	Delivery Charges	1,713,524	0.7140	2,208,728	0.9203	0.2063	495,204	28.9%	240,000,000
23	Gas Supply Charges	48,118,849	20.0495	47,877,126	19.9488	(0.1007)	(241,724)	-0.5%	240,000,000
24	Total Bill	49,832,373	20.7635	50,085,853	20.8691	0.1056	253,480	0.5%	240,000,000

Union South
Calculation of Annual Bill Impacts for Typical Small and Large Customers

	Small Rate M1								
25	Delivery Charges	340	15.4464	355	16.1350	0.6886	15	4.5%	2,200
26	Gas Supply Charges	392	17.8227	390	17.7073	(0.1155)	(3)	-0.6%	2,200
27	Total Bill	732	33.2691	745	33.8423	0.5732	13	1.7%	2,200
	Small Rate M2								
28	Delivery Charges	3,387	5.6453	3,738	6.2306	0.5853	351	10.4%	60,000
29	Gas Supply Charges	10,694	17.8227	10,624	17.7070	(0.1157)	(69)	-0.6%	60,000
30	Total Bill	14,081	23.4680	14,363	23.9376	0.4696	282	2.0%	60,000
	Large Rate M2								
31	Delivery Charges	10,906	4.3623	12,369	4.9476	0.5853	1,463	13.4%	250,000
32	Gas Supply Charges	44,557	17.8227	44,268	17.7070	(0.1157)	(289)	-0.6%	250,000
33	Total Bill	55,463	22.1850	56,637	22.6547	0.4696	1,174	2.1%	250,000
	Small Rate M4								
34	Delivery Charges	33,628	3.8432	38,172	4.3626	0.5193	4,544	13.5%	875,000
35	Gas Supply Charges	155,949	17.8227	154,936	17.7070	(0.1157)	(1,012)	-0.6%	875,000
36	Total Bill	189,577	21.6659	193,109	22.0696	0.4036	3,532	1.9%	875,000
	Large Rate M4								
37	Delivery Charges	237,903	1.9825	291,342	2.4278	0.4453	53,439	22.5%	12,000,000
38	Gas Supply Charges	2,138,724	17.8227	2,124,840	17.7070	(0.1157)	(13,884)	-0.6%	12,000,000
39	Total Bill	2,376,627	19.8052	2,416,182	20.1348	0.3296	39,555	1.7%	12,000,000
	Small Rate M5								
40	Delivery Charges	20,602	2.4972	27,525	3.3363	0.8392	6,923	33.6%	825,000
41	Gas Supply Charges	147,037	17.8227	146,083	17.7070	(0.1157)	(955)	-0.6%	825,000
42	Total Bill	167,639	20.3199	173,608	21.0433	0.7235	5,969	3.6%	825,000
	Large Rate M5								
43	Delivery Charges	102,925	1.5835	141,680	2.1797	0.5962	38,754	37.7%	6,500,000
44	Gas Supply Charges	1,158,476	17.8227	1,150,955	17.7070	(0.1157)	(7,521)	-0.6%	6,500,000
45	Total Bill	1,261,401	19.4062	1,292,635	19.8867	0.4805	31,234	2.5%	6,500,000
	Small Rate M7								
46	Delivery Charges	579,244	1.6090	611,959	1.6999	0.0909	32,715	5.6%	36,000,000
47	Gas Supply Charges	6,416,172	17.8227	6,374,520	17.7070	(0.1157)	(41,652)	-0.6%	36,000,000
48	Total Bill	6,995,416	19.4317	6,986,479	19.4069	(0.0248)	(8,937)	-0.1%	36,000,000
	Large Rate M7								
49	Delivery Charges	2,298,408	4.4200	2,337,963	4.4961	0.0761	39,556	1.7%	52,000,000
50	Gas Supply Charges	9,267,804	17.8227	9,207,640	17.7070	(0.1157)	(60,164)	-0.6%	52,000,000
51	Total Bill	11,566,212	22.2427	11,545,603	22.2031	(0.0396)	(20,608)	-0.2%	52,000,000
	Small Rate M9								
52	Delivery Charges	130,944	1.8841	124,832	1.7962	(0.0879)	-6,112	-4.7%	6,950,000
53	Gas Supply Charges	1,238,678	17.8227	1,230,637	17.7070	(0.1157)	(8,041)	-0.6%	6,950,000
54	Total Bill	1,369,622	19.7068	1,355,469	19.5032	(0.2036)	(14,153)	-1.0%	6,950,000
	Large Rate M9								
55	Delivery Charges	388,775	1.9267	370,961	1.8384	(0.0883)	-17,815	-4.6%	20,178,000
56	Gas Supply Charges	3,596,264	17.8227	3,572,918	17.7070	(0.1157)	(23,346)	-0.6%	20,178,000
57	Total Bill	3,985,040	19.7494	3,943,879	19.5454	(0.2040)	(41,160)	-1.0%	20,178,000
	Small Rate T1								
58	Delivery Charges	94,362	1.2520	126,861	1.6832	0.4312	32,500	34.4%	7,537,000
59	Gas Supply Charges	1,343,297	17.8227	1,334,577	17.7070	(0.1157)	(8,720)	-0.6%	7,537,000
60	Total Bill	1,437,658	19.0747	1,461,438	19.3902	0.3155	23,780	1.7%	7,537,000
	Average Rate T1								
61	Delivery Charges	154,443	1.3353	196,360	1.6977	0.3624	41,917	27.1%	11,565,938
62	Gas Supply Charges	2,061,362	17.8227	2,047,981	17.7070	(0.1157)	(13,382)	-0.6%	11,565,938
63	Total Bill	2,215,805	19.1580	2,244,341	19.4047	0.2467	28,536	1.3%	11,565,938
	Large Rate T1								
64	Delivery Charges	373,237	1.4566	441,716	1.7238	0.2672	68,479	18.3%	25,624,080
65	Gas Supply Charges	4,566,903	17.8227	4,537,256	17.7070	(0.1157)	(29,647)	-0.6%	25,624,080
66	Total Bill	4,940,140	19.2793	4,978,971	19.4308	0.1515	38,831	0.8%	25,624,080
	Small Rate T2								
67	Delivery Charges	501,369	0.8461	510,436	0.8614	0.0153	9,067	1.8%	59,256,000
68	Gas Supply Charges	10,561,019	17.8227	10,492,460	17.7070	(0.1157)	(68,559)	-0.6%	59,256,000
69	Total Bill	11,062,389	18.6688	11,002,896	18.5684	(0.1004)	(59,492)	-0.5%	59,256,000
	Average Rate T2								
70	Delivery Charges	1,377,649	0.6965	1,172,515	0.5928	(0.1037)	-205,134	-14.9%	197,789,850
71	Gas Supply Charges	35,251,492	17.8227	35,022,649	17.7070	(0.1157)	(228,843)	-0.6%	197,789,850
72	Total Bill	36,629,140	18.5192	36,195,164	18.2998	(0.2194)	(433,976)	-1.2%	197,789,850
	Large Rate T2								
73	Delivery Charges	2,366,153	0.6393	1,907,986	0.5155	(0.1238)	-458,168	-19.4%	370,089,000
74	Gas Supply Charges	65,959,852	17.8227	65,531,659	17.7070	(0.1157)	(428,193)	-0.6%	370,089,000
75	Total Bill	68,326,006	18.4620	67,439,645	18.2225	(0.2395)	(886,361)	-1.3%	370,089,000
	Large Rate T3								
76	Delivery Charges	2,940,945	1.0784	3,111,819	1.1411	0.0627	170,873	5.8%	272,712,000
77	Gas Supply Charges	48,604,642	17.8227	48,289,114	17.7070	(0.1157)	(315,528)	-0.6%	272,712,000
78	Total Bill	51,545,587	18.9011	51,400,932	18.8481	(0.0530)	(144,654)	-0.3%	272,712,000

Union Gas Limited
2013 Cost of Service - Rate Impacts of Potential Rate Mitigation Measures

Line No.	Particulars	Per Settlement Filing: Current Approved Revenue ($000's)	Per Settlement Filing: Proposed Revenue ($000's)	Per Settlement Filing: Proposed Rate Change (%)	Reduction in ROE: Impact ($000's)	Reduction in ROE: Impact (%)	FT RAM Revenue: Impact ($000's)	FT RAM Revenue: Impact (%)	Distribution Rate Base Alternative: Impact ($000's)	Distribution Rate Base Alternative: Impact (%)	Common Equity Thickness Phase-In: Impact ($000's)	Common Equity Thickness Phase-In: Impact (%)	20-Year Declining Trend Weather Phase-In: Impact ($000's)	20-Year Declining Trend Weather Phase-In: Impact (%)	Rate Mitigation: Proposed Revenue ($000's)	Rate Mitigation: Proposed Rate Change (%)	
		(a)	(b)	(c) = (b/a)	(d)	(e) = (d/a)	(f)	(g) = (f/a)	(h)	(i) = (h/a)	(j)	(k) = (j/a)	(l)	(m) = (l/a)	(n) = (b+d+f+h+j+l)	(o) = (n/a)	
	North Delivery																
1	Rate 01	137,746	158,311	14.9%	(1,341)	-1.0%	(3,797)	-2.8%	(31)	0.0%	(1,730)	-1.3%	(1,905)	-1.4%	149,507	8.5%	
2	Rate 10	16,637	19,144	15.1%	(160)	-1.0%	(437)	-2.6%	17	0.1%	(206)	-1.2%	(299)	-1.8%	18,058	8.5%	
3	Rate 20	9,721	12,961	33.3%	(159)	-1.6%	(1,987)	-20.4%	(58)	-0.6%	(205)	-2.1%	-	0.0%	10,552	8.5%	
4	Rate 25	2,337	2,988	27.8%	(57)	-2.4%	(301)	-12.9%	(20)	-0.8%	(74)	-3.2%	-	0.0%	2,537	8.5%	
5	Rate 100	12,658	16,326	29.0%	(131)	-1.0%	(2,238)	-17.7%	(50)	-0.4%	(169)	-1.3%	-	0.0%	13,738	8.5%	
6	Total North Delivery	179,100	209,730	17.1%	(1,848)	-1.0%	(8,760)	-4.9%	(141)	-0.1%	(2,385)	-1.3%	(2,205)	-1.2%	194,392	8.5%	
	South Delivery & Storage																
7	Rate M1	379,511	397,160	4.4%	(3,337)	-0.9%	-	0.0%	(18)	0.0%	(4,307)	-1.1%	(2,784)	-0.7%	386,714	1.9%	
8	Rate M2	44,036	49,680	12.7%	(506)	-1.1%	-	0.0%	76	0.2%	(653)	-1.5%	(767)	-1.7%	47,831	8.6%	
9	Rate M4	10,841	12,773	17.8%	(125)	-1.2%	(625)	-5.8%	23	0.2%	(162)	-1.5%	-	0.0%	11,884	9.6%	
10	Rate M5	8,874	12,149	36.9%	(107)	-1.2%	(2,215)	-25.0%	32	0.4%	(138)	-1.6%	-	0.0%	9,722	9.6%	
11	Rate M7	3,951	4,076	3.2%	(44)	-1.1%	-	0.0%	4	0.1%	(57)	-1.4%	-	0.0%	3,980	0.7%	
12	Rate M9	819	768	-6.3%	(8)	-1.0%	-	0.0%	(0)	0.0%	(11)	-1.3%	-	0.0%	749	-8.6%	
13	Rate M10	5	6	15.6%	(0)	-6.7%	-	0.0%	(0)	-0.4%	(0)	-8.6%	-	0.0%	5	-0.1%	
14	Rate T1	57,783	54,272	-6.1%	(474)	-0.8%	-	0.0%	25	0.0%	(611)	-1.1%	-	0.0%	53,212	-7.9%	
15	Rate T3	4,571	4,662	2.0%	(51)	-1.1%	-	0.0%	(0)	0.0%	(66)	-1.4%	-	0.0%	4,545	-0.6%	
16	Total South Delivery & Storage	510,391	535,546	4.9%	(4,652)	-0.9%	(2,840)	-0.6%	142	0.0%	(6,004)	-1.2%	(3,551)	-0.7%	518,641	1.6%	
17	Total In-Franchise Delivery	689,491	745,276	8.1%	(6,499)	-0.9%	(11,600)	-1.7%	0	0.0%	(8,388)	-1.2%	(5,755)	-0.8%	713,033	3.4%	
	North Transportation & Storage																
18	Rate 01	68,509	71,411	4.2%	(183)	-0.3%	-	0.0%	-	0.0%	(236)	-0.3%	-	0.0%	70,991	3.6%	
19	Rate 10	22,677	23,194	2.3%	(55)	-0.2%	-	0.0%	-	0.0%	(71)	-0.3%	-	0.0%	23,068	1.7%	
20	Rate 20	8,815	7,736	-12.2%	(15)	-0.2%	-	0.0%	-	0.0%	(19)	-0.2%	-	0.0%	7,702	-12.6%	
21	Rate 25	1,685	2,118	25.7%	(0)	0.0%	-	0.0%	-	0.0%	(0)	0.0%	-	0.0%	2,117	25.7%	(1)
22	Rate 100	197	129	-34.7%	(1)	-0.6%	-	0.0%	-	0.0%	(1)	-0.7%	-	0.0%	126	-36.0%	
23	Total North Transport & Storage	101,882	104,588	2.7%	(255)	-0.3%	-	0.0%	-	0.0%	(329)	-0.3%	-	0.0%	104,004	2.1%	
24	Total In-Franchise	791,374	849,864	7.4%	(6,754)	-0.9%	(11,600)	-1.5%	0	0.0%	(8,717)	-1.1%	(5,755)	-0.7%	817,037	3.2%	
	Ex-Franchise (2)																
25	Rate M12	161,163	162,785	1.0%	(1,774)	-1.1%	-	0.0%	-	0.0%	(2,289)	-1.4%	-	0.0%	158,722	-1.5%	
26	Rate M13	373	423	13.5%	(1)	-0.3%	-	0.0%	-	0.0%	(2)	-0.4%	-	0.0%	420	12.7%	
27	Rate M16	748	759	1.5%	(2)	-0.3%	-	0.0%	-	0.0%	(3)	-0.4%	-	0.0%	754	0.8%	
28	Rate C1	40,698	40,482	-0.5%	(69)	-0.2%	-	0.0%	-	0.0%	(89)	-0.2%	-	0.0%	40,324	-0.9%	
29	Total Ex-Franchise	202,982	204,449	0.7%	(1,846)	-0.9%	-	0.0%	-	0.0%	(2,383)	-1.2%	-	0.0%	200,220	-1.4%	
30	Total Union Gas	994,355	1,054,313	6.0%	(8,600)	-0.9%	(11,600)	-1.2%	0	0.0%	(11,100)	-1.1%	(5,755)	-0.6%	1,017,258	2.3%	

Notes:
(1) Rate changes in Rate 25 Transportation mainly reflect gas cost pass-through items.
(2) Union is not proposing any rate mitigation measures in the Ex-franchise market.

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Mr. Tetreault

Ref: J.E-2-15-4

Please explain how Union is responding to the declining revenues and volumes in the North delivery area.

Union looks to increase revenues and volumes in both Union South and Union North by expanding gas services through customer conversions, attracting new communities (e.g. Red Lake) and new customers (e.g. OPG Thunder Bay). Union also works with existing customers to encourage the use of natural gas through the installation of efficient natural gas technologies.

Also, as indicated at Exhibit J.H-1-1-2, there are a number of factors contributing to rates increases in the North. The costs allocated to Union North rate classes are reflective of the costs to provide service to the North. Union has responded to the increases and allocated costs as part of the rate design process by allocating approximately 50% of the transactional margins available for rate making to the North. This compares with 2007 Board-approved North rates which included an allocation of 36% of the available transactional margins.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Ref: Exhibit A1, Tab 3, Schedule 2
Exhibit H1, Tab 1

CME wishes to obtain a better understanding of the impacts of Union's proposed Rate Design changes on the manufacturers being served under the auspices of Union's rates. Union's manufacturer customers will be more specifically identified when Union provides its response to Interrogatory C3.1 herein. For the purposes of the information requests that follow, CME assumes that one or more manufacturers are currently being served under the auspices of Rates 01 and 10 in the Northern Zone and Rates M4, M5A, M7 and T1 in Union's Southern operations area. In connection with proposals that Union is making will affect customers served under the auspices of these existing rates, please provide the following information:

a) Identify the total number of commercial and industrial customers who will receive an annual bill impact in excess of 2% as a result of moving from current Rate 01 and M1 to proposed Rates 10 and M2;

b) Table 14 in Exhibit H1, Tab 1 indicates that the annual bill impacts on existing M1 customers that will move to proposed Rate Class M2 with annual volumes between 7,000 and 60,000 M^3/year will face very significant annual bill increases. Have the customers who will be affected by Union's proposal been notified of the steep bill increases they will face if Union's proposals are approved? If so, then please provide copies of such notices and the responses from customers, if any.

c) Please broaden Table 14 in Exhibit H1, Tab 1 to include annual volumes of 6,000 M^3/year, 60,000 M^3/year and 70,000 M^3/year.

d) With respect to the proposal to lower the Rate 7 eligibility to capture 5 customers currently forecast on Rate M4 at 17 customers currently on Rate M5A, please provide information that will show the rate and annual bill impacts on each of the 22 customers that will be brought within the ambit of Rate M7 under Union's proposal.

e) What will be the impact on rates and annual bills of customers who choose to utilize Union's proposed Rate M4 interruptible service offering?

f) With respect to Union's proposal to split current Rate T1 into two rate classes, please provide the following:

   i. A Schedule that will show the range of rate and annual bill impacts on the 59 customers currently served under Rate T1 if Union's proposal is adopted;

ii. Identify by letter or number each customer to be served under proposed Rate T1 and proposed Rate T2 that will be facing either a rate or a total annual bill impact increase that is 2% or greater;

iii. Any specific notice that Union has provided to T1 customers of the rate and/or annual bill impacts that they will likely face if Union's proposed Rate Design change is approved and the responses that Union received to these notices, if any.

Response:

a) Based on 2010 actual customer data, Union estimates the number of accounts and the financial impact on each of the four rate classes is as follows:

Union North - Rate 01 and Rate 10

1) 281,246 accounts with annual volume up to 5,000 m^3 will see no impact at 100 m^3 and an annual decrease of approximately \$2 at 5,000 m^3. These existing Rate 01 accounts will continue to take service under the proposed Rate 01 in 2014.

2) 18,163 accounts with annual volume between 5,000 m^3 and 50,000 m^3 represent existing Rate 01 accounts that will take service under the proposed Rate 10 in 2014. Financial impacts are as follows:

   i) An annual bill increase for 6,816 accounts with annual volumes between 5,000 m^3 and 7,000 m^3. The annual increase ranges from approximately \$43 at 5,001 m^3 to \$4 at 7,000 m^3.

   ii) An annual bill decrease for 11,347 accounts with annual volumes between 7,001 m^3 and 50,000 m^3. The annual decrease ranges from approximately \$5 at 7,500 m^3 to \$816 at 50,000 m^3.

3) 1,735 accounts with annual volume over 50,000 m^3 represent existing Rate 10 accounts that will continue to take service under the proposed Rate 10 in 2014. Financial impacts are as follows:

   i) 1,142 accounts with annual volume between 50,000 m^3 and 117,000 m^3 will see an annual decrease from approximately \$266 at 50,001 m^3 to approximately \$1 at 117,000 m^3.

   ii) 593 accounts with annual volume over 117,000 m^3 will see an annual increase of from approximately \$14 at 120,000 m^3 to approximately \$42,153 at 3,000,000 m^3.

Union South - Rate M1 and Rate M2

1) 941,737 accounts with annual volume up to 5,000 m^3 will see no impact at 100 m^3 and an annual increase of up to $2 at 5,000 m^3. These existing Rate M1 accounts will continue to take service under the proposed Rate M1 in 2014.

2) 50,847 accounts with annual volume between 5,000 m^3 and 50,000 m^3 will see an annual bill increase from approximately $148 at 5,001 m^3 to $48 at 50,000 m^3. These existing Rate M1 accounts will now take service under the proposed Rate M2 in 2014.

3) 6,228 accounts with annual volume over 50,000 m^3 will see an annual bill decrease from approximately $771 at 50,001 m^3 to approximately $13,800 at 3,000,000 m^3. These existing Rate M2 accounts will continue to take service under the proposed Rate M2 in 2014.

b) No. On approval of its rate redesign proposals, Union will advise customers in anticipation of 2014 rate implementation. This approach is consistent with the implementation used in EB-2005-0520 in which Union advised customers in 2007 prior to the 2008 implementation.

c) Please see Attachment 1.

d) Please see Attachment 2.

Rate M5A customers will move to Rate M7 on a revenue neutral basis on the interruptible portion of their bill. There is no bill impact as the Rate M7 interruptible rate will be set to recover the same revenue calculated using the Rate M5A bill provided interruptible customers maintain the same contractual MAV commitment.

For firm Rate M4 and interruptible Rate M5A customers with an optional firm service, the firm service will be re-priced using the firm contract parameters priced at the Rate M7 firm rates.

e) The introduction of an interruptible service offering in Rate M4 will have no impact on rates. Interruptible pricing in Rate M4 will match the rates calculated under Rate M5A, which will ensure that customers in Rate M4 and Rate M5A pay the same price for the same interruptible service.

The annual bill of customers who choose to utilize Union's proposed Rate M4 interruptible service offering will depend on the level of interruptible service elected by the customer.

For example, a current Rate M5A customer with an interruptible contracted demand of 4,800 m^3 and an annual volume of 700,000 m^3 has a bill, based on current approved rates, consisting of:

a. A monthly customer charge of $498.20
b. A daily interruptible delivery commodity charge of 2.1435 cents/m^3 for all interruptible volumes used, and
c. An interruptible day's use discount of 0.2035 cents/m^3 based on 146 days use of contracted demand.

A Rate M4 customer exercising the Rate M4 interruptible offering will pay exactly the same price as a Rate M5A customer.

f) i) Please see Attachment 3 for the annual firm transportation bill impacts related to the 2013 proposed redesign. The bill impacts have been calculated using 2013 forecast billing units and include the monthly customer charge, firm transportation demand and firm transportation commodity portions of the bill only.

ii) Please see Attachment 3, note (2). For proposed Rate T1, the bill impacts range from an increase of 11.3% to an increase of 39.3%. For proposed Rate T2, the bill impacts range from a decrease of 18.9% to an increase of 37.0%.

iii) In 2011, at customer meetings in London and Burlington, Union made preliminary presentations about some of the Rate Design proposals in its 2013 Cost of Service hearing. No additional detailed or specific information about the rate or annual bill impacts of the Rate Design changes have been shared through broad based customer communication at this time. Union historically has communicated this information at customer meetings after the evidence has been filed with the Board. Consistent with past practices Union will be presenting this information at customers meetings in 2012.

Annual General Service Delivery Bill Impacts - Union South
of Proposed 2014 Change in Annual Volume Breakpoint (1)

	2013 Proposed with Annual Volume Breakpoint of 50,000 m^3		2014 Proposed with Annual Volume Breakpoint of 5,000 m^3		Bill Impacts	
Annual Volume	Rate M1	Rate M2	Rate M1	Rate M2	$	%
1,800	327.69		328.98		1.29	0.4%
2,200	343.16		344.58		1.42	0.4%
2,600	358.55		360.08		1.53	0.4%
3,000	373.82		375.47		1.65	0.4%
5,000	449.13		451.34		2.21	0.5%
5,001	449.17			597.10	147.93	32.9%
6,000	486.16			632.34	146.18	30.1%
7,000	523.15			667.37	144.22	27.6%
10,000	633.91			771.65	137.74	21.7%
20,000	999.67			1,117.24	117.58	11.8%
30,000	1,364.94			1,461.55	96.62	7.1%
50,000	2,095.47			2,143.84	48.37	2.3%
60,000		3,316.76		2,478.58	(838.18)	-25.3%
70,000		3,717.42		2,812.62	(904.79)	-24.3%
80,000		4,117.07		3,146.02	(971.06)	-23.6%
100,000		4,911.88		3,809.88	(1,102.00)	-22.4%
200,000		8,736.83		7,084.44	(1,652.39)	-18.9%
300,000		12,470.81		10,332.91	(2,137.89)	-17.1%
500,000		19,846.07		16,797.86	(3,048.22)	-15.4%

Notes:
(1) Grey shading represents all changes when compared to Exhibit H1, Tab 1, Updated, Table 12, page 27.

Annual Bill Impact of Rate M4 and Rate M5A customers moving to Rate M7
per Union's 2014 Rate Design Proposal

Particulars ($)	2013 Delivery Bill	2014 M7 Delivery Bill	Bill Impact	
	(a)	(b)	(c) = (b-a)	(d) = (c/a)
Rate M4				
Customer 1	329,400	247,319	(82,080)	-24.9%
Customer 2	340,573	250,206	(90,367)	-26.5%
Customer 3	369,878	268,438	(101,440)	-27.4%
Customer 4	439,357	318,328	(121,029)	-27.5%
Customer 5	525,126	398,254	(126,871)	-24.2%
Rate M5A				
Customer 1	274,177	274,177	-	0.0%
Customer 2	98,931	98,931	-	0.0%
Customer 3	142,822	142,822	-	0.0%
Customer 4	255,200	255,200	-	0.0%
Customer 5	97,733	82,502	(15,231)	-15.6%
Customer 6	62,021	62,021	-	0.0%
Customer 7	129,731	102,642	(27,089)	-20.9%
Customer 8	220,261	220,261	-	0.0%
Customer 9	98,224	98,224	-	0.0%
Customer 10	439,276	439,276	-	0.0%
Customer 11	225,251	225,251	-	0.0%
Customer 12	215,550	215,550	-	0.0%
Customer 13	180,323	180,323	-	0.0%
Customer 14	392,773	392,773	-	0.0%
Customer 15	418,369	418,369	-	0.0%
Customer 16	630,803	630,803	-	0.0%
Customer 17	409,338	409,338	-	0.0%

Estimated Rate T1 Firm Transportation
Bill Impacts of 2013 Proposed Redesign

Particulars ($)	Proposed Rate Class	Current Approved Firm Transportation Bill (1)	2013 Proposed Firm Transportation Bill with Redesign (1)	Annual Bill Impact	% Change (2)
		(a)	(b)	(c) = (b-a)	(d) = (c/a)
Customer 1	Rate T1	21,544	23,986	2,442	11.3
Customer 2	Rate T1	42,848	58,662	15,814	36.9
Customer 3	Rate T1	86,361	114,892	28,531	33.0
Customer 4	Rate T1	94,362	125,382	31,021	32.9
Customer 5	Rate T1	90,389	124,545	34,156	37.8
Customer 6	Rate T1	89,619	124,245	34,627	38.6
Customer 7	Rate T1	93,975	127,359	33,384	35.5
Customer 8	Rate T1	94,708	131,900	37,192	39.3
Customer 9	Rate T1	101,427	140,409	38,981	38.4
Customer 10	Rate T1	112,669	148,957	36,288	32.2
Customer 11	Rate T1	108,539	147,973	39,434	36.3
Customer 12	Rate T1	121,229	155,790	34,561	28.5
Customer 13	Rate T1	128,922	166,458	37,536	29.1
Customer 14	Rate T1	159,639	199,770	40,131	25.1
Customer 15	Rate T1	136,169	175,034	38,865	28.5
Customer 16	Rate T1	135,386	175,641	40,255	29.7
Customer 17	Rate T1	144,358	182,058	37,701	26.1
Customer 18	Rate T1	146,602	186,769	40,167	27.4
Customer 19	Rate T1	148,354	188,410	40,056	27.0
Customer 20	Rate T1	155,364	193,057	37,693	24.3
Customer 21	Rate T1	160,855	199,990	39,135	24.3
Customer 22	Rate T1	154,782	198,586	43,804	28.3
Customer 23	Rate T1	161,311	202,086	40,775	25.3
Customer 24	Rate T1	154,536	202,327	47,791	30.9
Customer 25	Rate T1	173,537	216,437	42,900	24.7
Customer 26	Rate T1	197,783	249,149	51,366	26.0
Customer 27	Rate T1	194,137	247,729	53,592	27.6
Customer 28	Rate T1	191,458	238,760	47,302	24.7
Customer 29	Rate T1	193,218	241,364	48,145	24.9
Customer 30	Rate T1	188,705	240,758	52,053	27.6
Customer 31	Rate T1	214,011	259,049	45,038	21.0
Customer 32	Rate T1	243,463	286,113	42,651	17.5
Customer 33	Rate T1	248,168	289,610	41,442	16.7
Customer 34	Rate T1	254,468	293,981	39,513	15.5
Customer 35	Rate T1	251,359	293,013	41,654	16.6
Customer 36	Rate T1	332,148	400,055	67,908	20.4
Customer 37	Rate T1	371,724	441,887	70,163	18.9
Customer 38	Rate T1	354,402	440,310	85,909	24.2
Customer 39	Rate T1	407,264	473,683	66,418	16.3
Customer 40	Rate T2	422,269	475,738	53,469	12.7
Customer 41	Rate T2	532,573	729,420	196,847	37.0
Customer 42	Rate T2	501,369	512,914	11,545	2.3
Customer 43	Rate T2	516,698	526,565	9,867	1.9
Customer 44	Rate T2	564,066	560,266	(3,800)	(0.7)
Customer 45	Rate T2	662,646	696,598	33,951	5.1
Customer 46	Rate T2	820,330	762,447	(57,883)	(7.1)
Customer 47	Rate T2	1,192,074	1,168,246	(23,828)	(2.0)
Customer 48	Rate T2	1,073,332	1,006,110	(67,222)	(6.3)
Customer 49	Rate T2	1,312,872	1,309,569	(3,303)	(0.3)
Customer 50	Rate T2	1,394,087	1,194,373	(199,714)	(14.3)
Customer 51	Rate T2	2,154,750	2,053,372	(101,378)	(4.7)
Customer 52	Rate T2	1,897,176	1,654,410	(242,766)	(12.8)
Customer 53	Rate T2	2,129,710	1,806,544	(323,166)	(15.2)
Customer 54	Rate T2	2,366,153	1,919,752	(446,401)	(18.9)
Customer 55	Rate T2	2,225,734	1,962,540	(263,194)	(11.8)
Customer 56	Rate T2	2,483,231	2,143,945	(339,287)	(13.7)
Customer 57	Rate T2	3,938,286	3,344,998	(593,288)	(15.1)
Customer 58	Rate T2	4,981,287	4,283,886	(697,401)	(14.0)
Customer 59	Rate T2	4,637,274	4,032,344	(604,930)	(13.0)

Notes:
(1) Calculation of bill includes monthly customer charge, firm transportation demand and firm transportation commodity portions only.
(2) Grey shading includes customers with a bill impact greater than 2%.

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Association of Physical Plant Administrators ("OAPPA")

Reference: Exhibit H1, Tab 1

Please list the factors that Union considered in deciding whether a rate design proposal, if approved, should take effect January 1, 2013 or January 1, 2014.

Response:

Union is proposing to implement its in-franchise rate design proposals, with the exception of the Rate T1 redesign, effective January 1, 2014 rather than January 1, 2013 to allow sufficient time to modify Union's billing and administrative systems.

Union will not begin modifications to its billing and administrative systems until the Board approves Union's in-franchise rate design proposals.

Union's proposal to implement its in-franchise rate design proposals, with the exception of the Rate T1 redesign, on January 1, 2014 is consistent with the approach used to implement the split of the former Rate M2 rate class. In EB-2005-0520 (Union's 2007 rate case), Union proposed and the Board approved the rates and rate structures for the new Rate M1 and Rate M2 rate classes for implementation effective January 1, 2008.

Union is proposing to implement the Rate T1 redesign on January 1, 2013 rather than January 1, 2014 because of the small number of customers impacted by the Rate T1 redesign and the minimal impacts on billing and administrative systems.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh H1/Tab 1/pp.14-27

Union proposed a reduction to the annual volume breakpoint for its North - Rate 01 / Rate 10 and South - Rate M1 / Rate M2 customers and the harmonization of the delivery rate block structures for the same rate classes. Union has proposed that this proposal take effect as of January 1, 2014.

These proposals, combined, can result in significant rate impacts for certain customers (depending on consumption levels) that fall in the above noted rate classes (as shown in Table 11 and 12 in Exhibit H1).

For example, a Northern customer consuming approx 30,000 M3/year that would have been served under the Rate 01 class would move to the Rate 10 class and see an annual decrease of approximately 14.9% from 2013 to 2014.

A Southern customer consuming approx. 7,000 M3/year that would have been served under the M1 rate class would move to the M2 rate class and see an annual increase of approximately 27.6% from 2013 to 2014.

a) Please explain why Union has proposed to implement this change in 2014 (as opposed to 2013)? Please provide a discussion of any communication activities that Union would undertake in 2013 to inform customers of the rate class changes.

b) Please provide the number of customers that would see rate impacts of greater than 10% (both upwards and downwards) resulting from Union's proposal.

c) Please discuss whether Union has considered creating a new medium volume general service rate class to resolve some of the issues discussed in its proposal. Please explain why lowering the volume threshold for the Rate 10 and Rate M2 classes is preferable to establishing a new medium volume general service rate class.

d) Please explain why Union is proposing to use its M1 and M2 rate blocking structures for its Rate 01 and Rate 10 classes. Please include discussion of the impacts of using the Rate 01 and Rate 10 rate blocking structures for the M1 and M2 rate classes instead. Please provide bill impact tables that use the Rate 01 and Rate 10 rate blocking structures for the Rate M1 and M2 rate classes (combined with Union's volume threshold change proposal).

Response:

a) Please see the response at Exhibit J.H-1-11-1.

b) Based on Union's 2010 actual data, the number of customers that would see rate impacts of greater than 10% are as follows:

Union North

11 customers with annual volumes over 1,020,000 m^3 would see an increase of greater than 10%.

4,283 customers with annual volumes between 16,000 m^3 and 50,000 m^3 would see a decrease of greater than 10%.

4,294 customers would see rate impacts of greater than 10% resulting from Union's proposal. This represents approximately 1.4% of Union North general service customers.

Union South

43,744 customers with annual volumes between 5,000 m^3 and 23,000 m^3 would see an increase of greater than 10%.

6,228 customers with annual volumes over 50,000 m^3 would see a decrease of greater than 10%.

49,972 customers would see rate impacts of greater than 10% resulting from Union's proposal. This represents approximately 5.0% of Union South general service customers.

c) As part of its 2013 rate design proposals, Union has not considered or analyzed the creation of a third rate class in addition to Rate M1 and Rate M2 and Rate 01 and Rate 10.

The creation of a third rate class was considered, at a high level, in EB-2005-0520 (Union's 2007 rate case) as part of the Navigant Consulting Inc. ("NCI") review of options to split the General Service M2 rate class. However, Union proposed and the Board approved the separation of the former single Rate M2 class into two new General Service rate classes, Rate M1 and Rate M2.

Union's 2013 rate proposal to lower the annual volume breakpoint between small volume General Service rate classes Rate 01 and Rate M1 and large volume General Service rate classes (Rate 10 and Rate M2) to 5,000 m^3 from 50,000 m^3 will improve the rate class composition of Rate 01 and Rate M1 and achieve more homogeneous rate classes. Union's proposal will also improve the rate class size in Rate 10 and Rate M2, which will ensure viable large volume General Service rate classes and improve rate stability.

d) Union is proposing to use the Union South (Rate M1 and Rate M2) blocking structures for Union North (Rate 01 and Rate 10) as opposed to using Union North blocking structures for Union South, as the Union South blocking better achieves a reasonable distribution of volumes amongst the blocks and better reflects the rate class composition of the proposed rate classes.

Attachment 1 compares the volumes distribution by block using Union South blocking structures to the volume distribution by block using Union North blocking structures, based on Union's proposal annual volume breakpoint of 5,000 m^3. Using the Rate 01 and Rate 10 blocking structures for Rate M1 and Rate M2 shows the following deficiencies:

1. The Rate 01 blocking structure, initially developed using the 50,000 m^3 breakpoint, is not appropriate for a 5,000 m^3 breakpoint. The Rate M1 table shows no volume in the "Over 1,000 m^3" block and less than 20% of annual volume in the last three blocks which represent the volumes over 300 m^3.

2. The Rate 10 blocking structure applied to Rate M2 has similar deficiencies. The "Over 100,000 m^3" block represents about 2.1% of annual volume. The last two blocks of the rate represent only 11.4%.

Based on this review Union finds the application of North blocking structures is not suitable for Union South Rate M1 and Rate M2 and does not provide a reasonable basis for rate design. Consequently bill impact tables illustrating this scenario are not applicable.

Comparison of Blocking Structure
for Union South General Service Rates
(combined with Union's volume threshold change proposal)

Line No.	Rate M1 using Rate 01 Blocking Structure		Annual Volume	Percent of Total Volume	Rate M1 Profile Using Rate M1 Blocking Structure		Annual Volume	Percent of Total Volume
1	No. of Meters	(1)	941,737		No. of Meters	(1)	941,737	
2	First 100 m³		910,296,584	44.5%	First 100 m³		910,296,584	44.5%
3	Next 200 m³		806,001,850	39.4%	Next 150 m³		668,202,390	32.7%
4	Next 200 m³		265,839,821	13.0%	All over 250 m³		465,384,946	22.8%
5	Next 500 m³		61,745,665	3.0%	Total	(1)	2,043,883,921	100.0%
6	Over 1,000 m³		-	0.0%				
7	Total	(1)	2,043,883,921	100.0%				

Line No.	Rate M2 using Rate 10 Blocking Structure		Annual Volume	Percent of Total Volume	Rate M2 Profile Using Rate M2 Blocking Structure		Annual Volume	Percent of Total Volume
8	No. of Meters	(1)	57,075		No. of Meters	(1)	57,075	
9	First 1,000 m³		471,767,212	29.4%	First 1,000 m³		471,767,212	29.4%
10	Next 9,000 m³		674,052,113	41.9%	Next 6,000 m³		571,022,530	35.5%
11	Next 20,000 m³		267,561,700	16.6%	Next 13,000 m³		283,956,246	17.7%
12	Next 70,000 m³		155,091,180	9.7%	All over 20,000 m³		280,291,401	17.4%
13	Over 100,000 m³		38,565,184	2.4%	Total	(1)	1,607,037,388	100.0%
14	Total	(1)	1,607,037,388	100.0%				

Notes:
(1) Exhibit H1, Tab 1, Updated, Table 5 , page 16, line 8.

Comparison of Blocking Structure
for Union North General Service Rates
(combined with Union's volume threshold change proposal)

Line No.	Rate 01 using Rate 01 Blocking Structure				Rate 01 Profile Using Rate M1 Blocking Structure			
1	No. of Meters	(1)	281,246		No. of Meters	(1)	281,246	
			Annual Volume	Percent of Total Volume			Annual Volume	Percent of Total Volume
2	First 100 m^3		271,574,173	44.6%	First 100 m^3		271,574,173	44.6%
3	Next 200 m^3		244,887,148	40.2%	Next 150 m^3		204,346,778	33.5%
4	Next 200 m^3		75,405,422	12.4%	All over 250 m^3		133,450,369	21.9%
5	Next 500 m^3		17,504,577	2.9%	Total	(1)	609,371,320	100.0%
6	Over 1,000 m^3		-	0.0%				
7	Total	(1)	609,371,320	100.0%				

Line No.	Rate 10 using Rate 10 Blocking Structure				Rate 10 using Rate M2 Blocking Structure			
8	No. of Meters	(1)	19,898		No. of Meters	(1)	19,898	
			Annual Volume	Percent of Total Volume			Annual Volume	Percent of Total Volume
9	First 1,000 m^3		162,813,984	34.4%	First 1,000 m^3		162,813,984	34.4%
10	Next 9,000 m^3		200,488,770	42.4%	Next 6,000 m^3		173,929,921	36.8%
11	Next 20,000 m^3		62,967,143	13.3%	Next 13,000 m^3		69,518,860	14.7%
12	Next 70,000 m^3		36,042,994	7.6%	All over 20,000 m^3		66,717,282	14.1%
13	Over 100,000 m^3		10,667,155	2.3%	Total	(1)	472,980,046	100.0%
14	Total	(1)	472,980,046	100.0%				

Notes:
(1) Exhibit H1, Tab 1, Updated, Table 6, page 18, line 8.

UNION GAS LIMITED

Undertaking of Mr. Pankrac
To Mr. Shepherd

Please compare increase proposed for 2013 for a user with 30,000 and a user with 2,000 cubic meters for Rates 01 and M1.

Annual General Service Delivery Bill Impacts
Current Approved vs. 2013 Proposed

Line No.	Particulars ($)	EB-2010-0359 Current Approved Bill	EB-2011-0210 2013 Proposed Bill	Annual Bill Impacts ($)	Annual Bill Impacts (%)
		(a)	(b)	(c) = (b-a)	(d) = (c/a)
1	Rate 01 @ 2,000 m^3/year	389.47	440.58	51.11	13.1%
2	Rate 01 @ 30,000 m^3/year	2,182.14	2,780.82	598.68	27.4%
3	Rate M1 @ 2,000 m^3/year	311.79	330.38	18.59	6.0%
4	Rate M1 @ 30,000 m^3/year	1,177.95	1,288.78	110.82	9.4%

In Rate 01, the 2013 average annual volume per customer is 2,678 m^3. In Rate M1, the 2013 average annual volume per customer is 2,716 m^3.

As shown at Exhibit H3, Tab 1, Schedule 1, page 1, the average delivery rate change for Rate 01 is 14.9%, while the average delivery rate change for Rate M1 is 4.4%.

Delivery bill impacts at an annual volume of 2,000 m^3 will be similar to the average rate change for the rate class as that volume is similar to the average annual volume per customer.

Delivery bill impacts at an annual volume of 30,000 m^3 will differ significantly from the average rate change for the rate class as that volume is approximately 11 times the average annual volume per customer. Based on 2010 actuals, customers with an annual volume of 30,000 m^3 or more represent approximately 1% of the Rate 01 and Rate M1 rate classes.

UNION GAS LIMITED

Undertaking of Mr. Pankrac
To Mr. Shepherd

Please provide the analysis done to show customers clustered near the average.

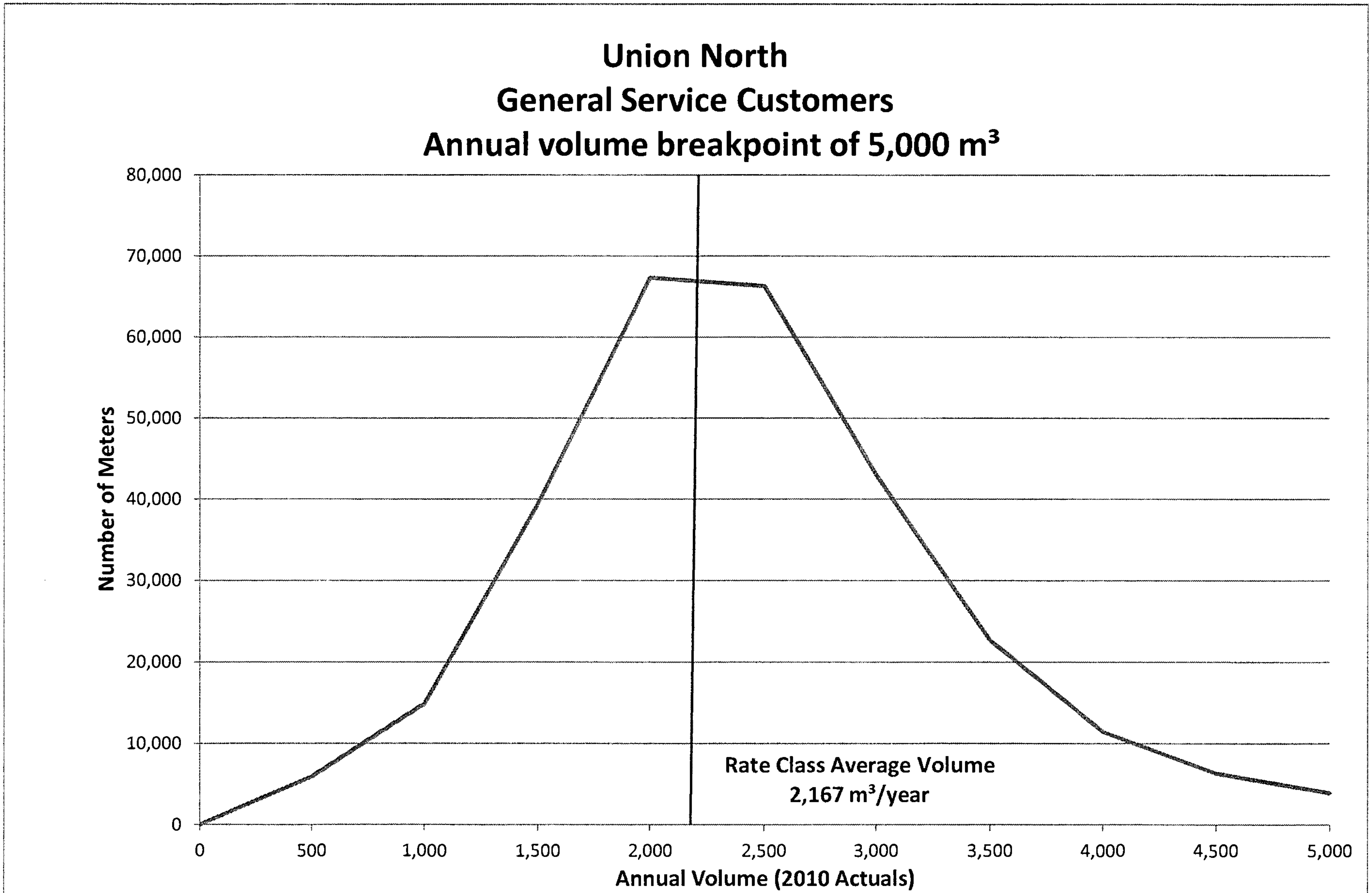
Please see Attachment 1 for Union North General Service Customers and Annual Volume Breakpoint of 5,000 m^3.

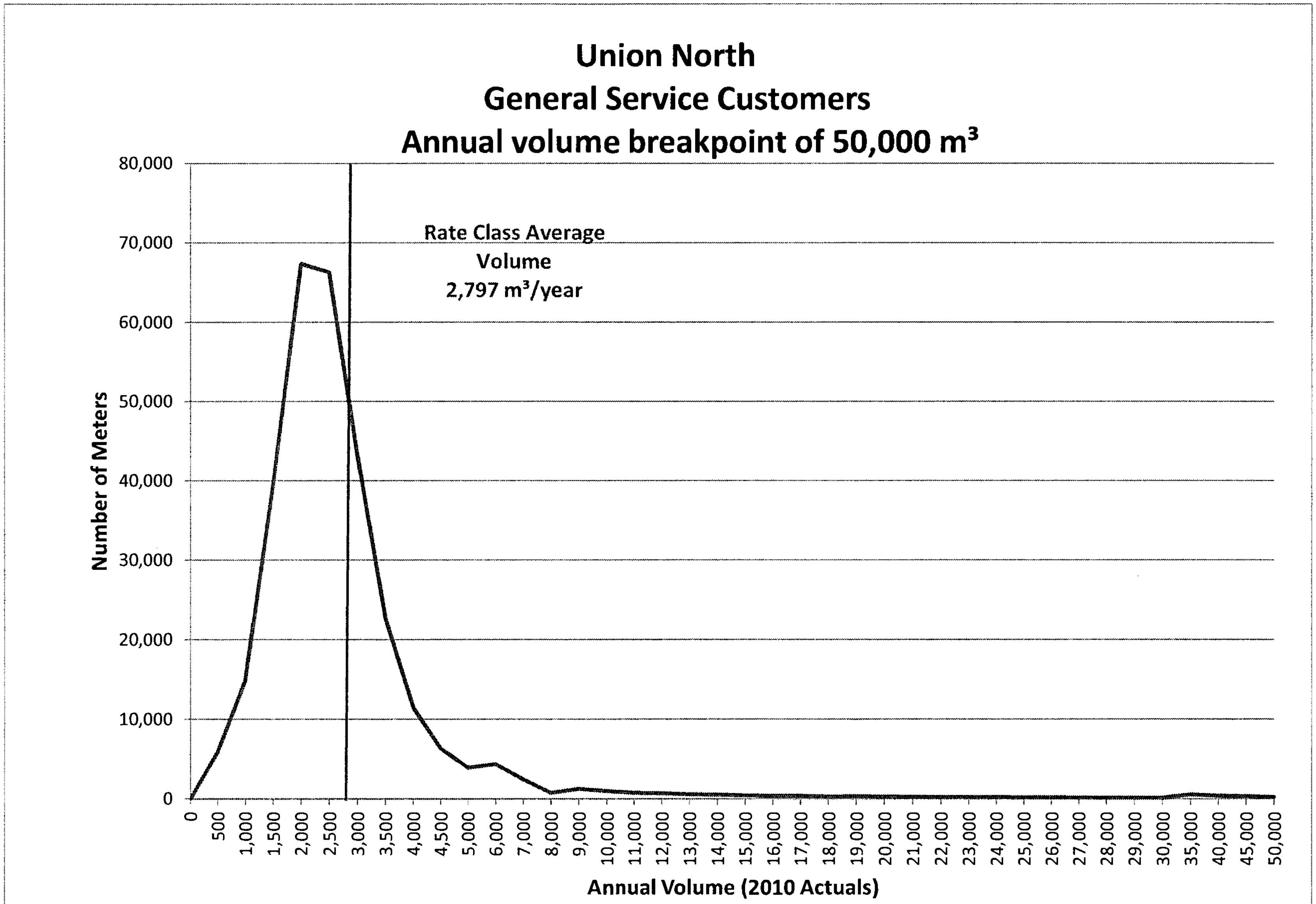
Please see Attachment 2 for Union North General Service Customers and Annual Volume Breakpoint of 50,000 m^3.

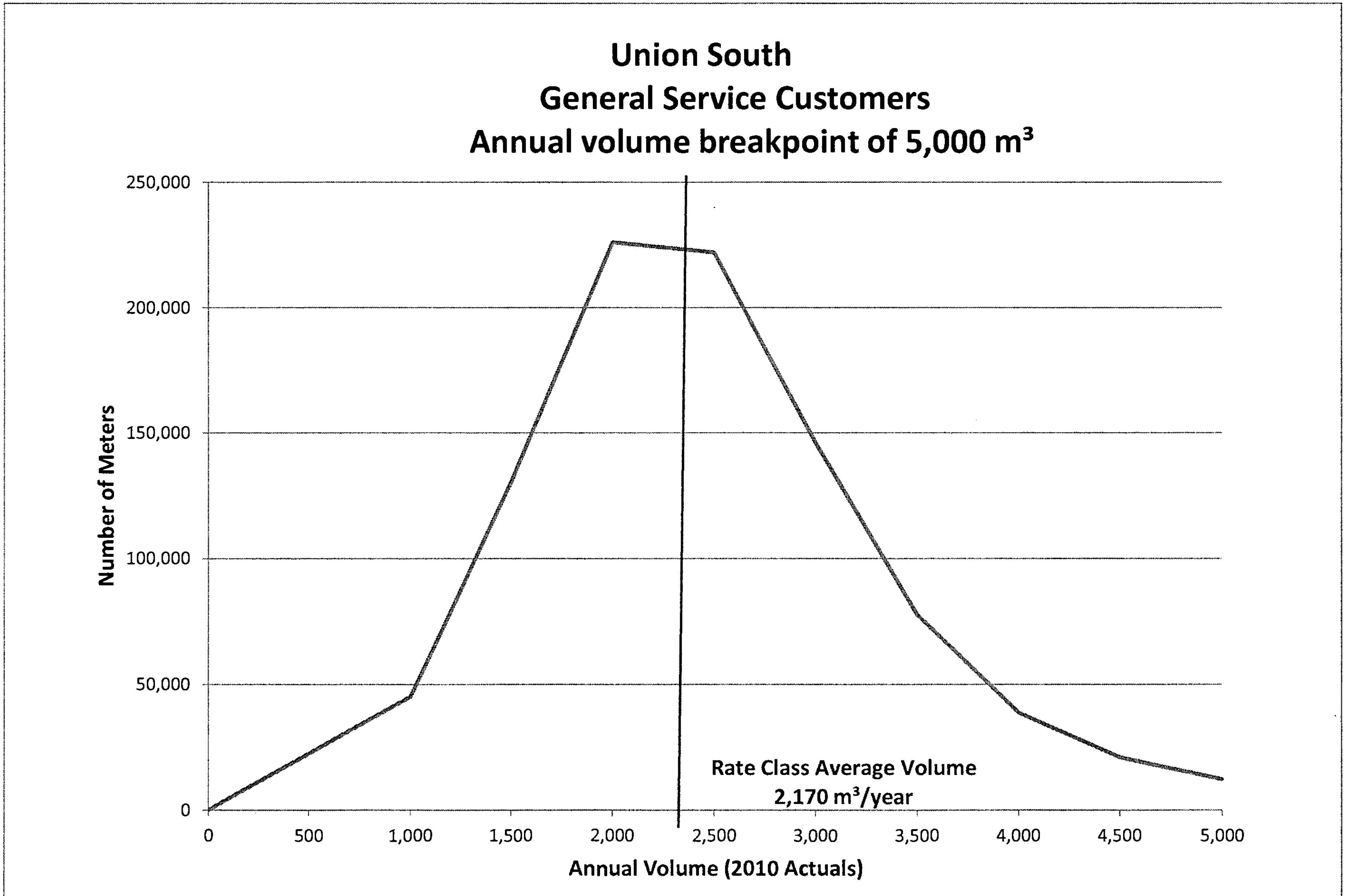
Please see Attachment 3 for Union South General Service Customers Annual Volume Breakpoint of 5,000 m^3.

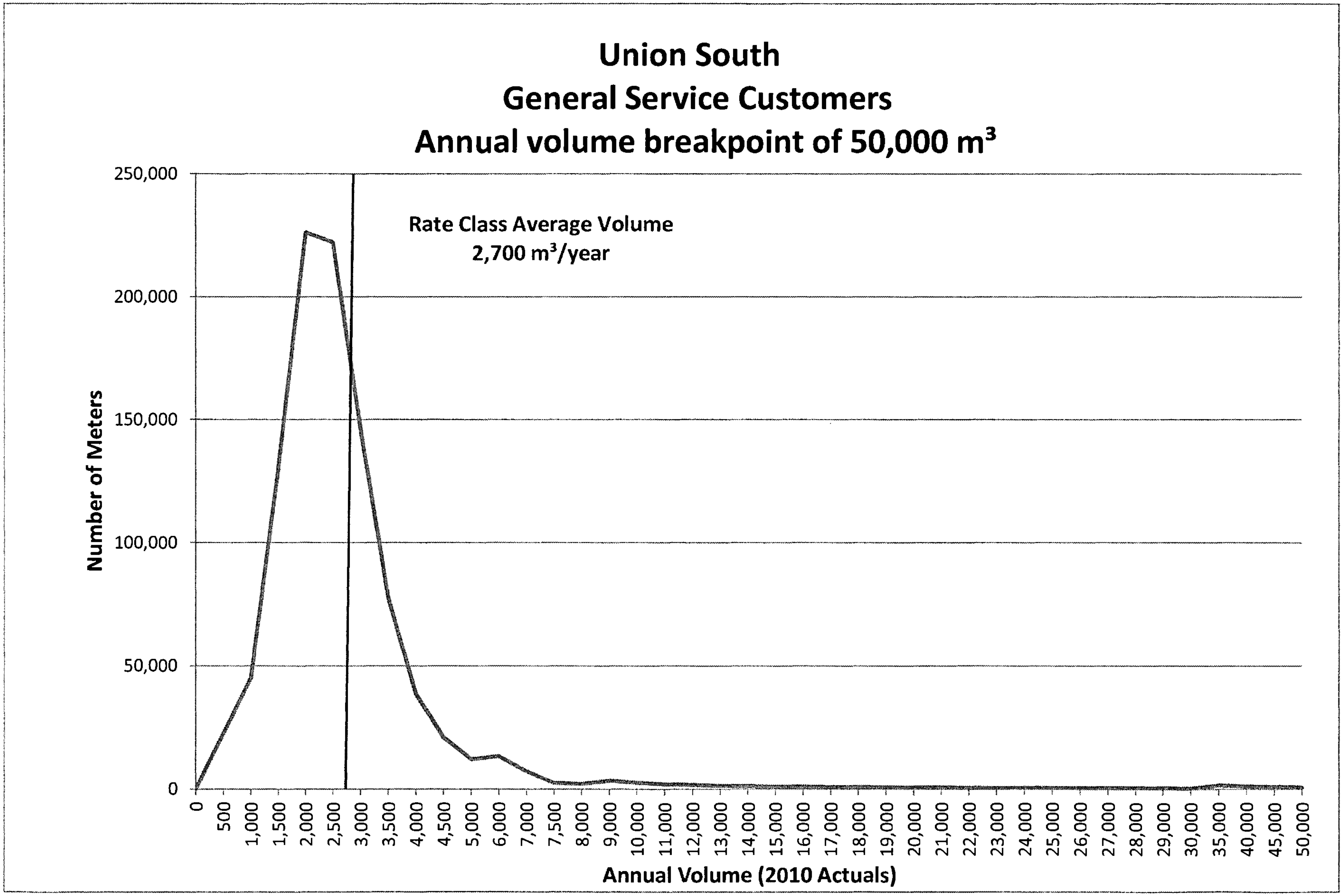
Please see Attachment 4 for Union South General Service Customers Annual Volume Breakpoint of 50,000 m^3.

The charts attached demonstrate that by moving to a 5,000 m^3 breakpoint for both the North and South results in a more normal distribution of customers around the mean.


Union North
General Service Customers
Annual volume breakpoint of 5,000 m³
Number of Meters
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
4,500
5,000
Annual Volume (2010 Actuals)
Rate Class Average Volume
2,167 m³/year


Union North
General Service Customers
Annual volume breakpoint of 50,000 m³
Rate Class Average
Volume
2,797 m³/year
Number of Meters
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
4,500
5,000
6,000
7,000
8,000
9,000
10,000
11,000
12,000
13,000
14,000
15,000
16,000
17,000
18,000
19,000
20,000
21,000
22,000
23,000
24,000
25,000
26,000
27,000
28,000
29,000
30,000
35,000
40,000
45,000
50,000
Annual Volume (2010 Actuals)


Union South
General Service Customers
Annual volume breakpoint of 5,000 m³
Number of Meters
250,000
200,000
150,000
100,000
50,000
0
Rate Class Average Volume
2,170 m³/year
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
4,500
5,000
Annual Volume (2010 Actuals)


Union South
General Service Customers
Annual volume breakpoint of 50,000 m³
Rate Class Average Volume
2,700 m³/year
Number of Meters
250,000
200,000
150,000
100,000
50,000
0
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
4,500
5,000
6,000
7,000
7,500
8,000
9,000
10,000
11,000
12,000
13,000
14,000
15,000
16,000
17,000
18,000
19,000
20,000
21,000
22,000
23,000
24,000
25,000
26,000
27,000
28,000
29,000
30,000
35,000
40,000
45,000
50,000
Annual Volume (2010 Actuals)

VT INCEPIT FIDELIS SIC PERMANET

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	EB-2011-0210	
VOLUME:	7	
DATE:	July 20, 2012	
BEFORE:	Marika Hare	Presiding Member
	Paul Sommerville	Member
	Karen Taylor	Member

It would be perfectly defensible under NGEIR to take the position -- because this has already been granted -- that the short-term and long-term distinction should be abolished, but Union hasn't proposed that in this proceeding, and the outcome is better for ratepayers from a dollars perspective than strict application of NGEIR.

And that's what is laid out in the prefiled evidence.

MR. QUINN: I know that is what is in the prefiled evidence, Mr. Smith, but I think you missed the corollary of that, in that if -- not necessarily now, but if in the future it is better to sell the utility space, a portion of the utility space long-term, two or three years if you've got a five-year gas supply plan that says you are not going to use these 10 pJs, you could sell five of them for two or three years in the long-term market if there is a better margin.

Is it Union's position that that ought not occur?

MR. ISHERWOOD: The market research that we have done, Mr. Quinn, is highest value for storage is generally short-term, being one-year, and that is exactly the reason why we're asking to be able to change our deferral account to reflect the ability for us to sell our non-utility balances one-year.

So I don't see the day where it would be preferential to sell utility space long-term; the better value is selling it short-term.

MR. QUINN: Why do you sell non-utility space long-term, then?

MR. ISHERWOOD: Because the current accounting order accounts for two years and longer.

MR. QUINN: So before NGEIR you sold space long-term. Why did you sell space long-term?

MR. ISHERWOOD: I'm not -- sorry, I'm not that familiar with the deferral accounts treatment prior to NGEIR.

MR. QUINN: Okay. Would you agree with me that selling excess space longer-term is -- there is a way of managing your risk on the values of storage going up and down over time?

MR. ISHERWOOD: There would be some value to that.

MR. QUINN: Okay. So in this last year, you have experienced and your evidence states that you have experienced some slim margins on storage transactions, slimmer margins?

MR. ISHERWOOD: I think 2012 is a little bit better than 2011. I think it has actually gotten a little bit better.

MR. QUINN: So in 2011, you had slim margins on storage transactions?

MR. ISHERWOOD: We definitely went through a bit of a trough on storage.

MR. QUINN: Right. So if we were to suggest that, if somebody were taking care of just the utility storage, both the -- that applied to serve the customers and the excess space, and that person chose that it would be in their best interests to sell some of that space long-term to manage

And in some cases, if firm is not readily available, they would have to pay an aid-to-construct to get firm, and it is an economic decision they make in terms of firm versus IT. It is a customer choice.

MR. SMITH: Mr. Fay, we haven't heard from you for a while. I will ask you a question.

There was some discussion yesterday about compression, as it relates to the Dawn-to-Dawn TCPL service; do you recall that?

MR. FAY: Yes, I do.

MR. SMITH: And when is compression required in the circumstance where you are taking gas from Vector?

MR. FAY: To facilitate the TransCanada service from Dawn-to-Dawn TCPL, we diverted -- we were diverting volume 700-pound gas from Vector to the Great Lakes for delivery.

As a result of that, it displaces volumes from storage, which meant that there was a required compression to go from the storage to the 700-pound level, to replace that volume.

MR. SMITH: Thank you, Mr. Fay.

Mr. Isherwood, you were asked a question by Mr. Quinn about selling excess utility space. And just pausing there, I just want to make sure for the record we have the right terminology.

By "excess utility space" what space are you are referring to?

MR. ISHERWOOD: The Board has set aside 100 pJs of space for in-franchise use, and each year when we do our gas supply plan, we calculate how much space they will need based on the current loads of the system or the forecasted loads of the system.

And every year it changes a little bit. We had talked about 10 pJs being kind of a round number, but it can be ell, 12 pJs. It depends on the market, the markets.

So it is actually setting aside full hundred, only needing 98 -- or, sorry, 88 or 87, you would have 12 or 13 or some number like that excess.

MR. SMITH: Okay. And the non-utility is the amount over the 100 pJs.

MR. ISHERWOOD: Non-utility is the amount above 100.

MR. SMITH: Just returning to my question, you were asked a question about whether you would sell the excess utility space long-term; do you recall that?

MR. ISHERWOOD: I do.

MR. SMITH: Now, in fairness, you indicated you would consider it.

Can you just -- hopefully this isn't too soon -- tell us what you think might be the advantages or disadvantages of doing that?

MR. ISHERWOOD: Of selling it long-term?

MR. SMITH: Yes.

MR. ISHERWOOD: The disadvantage is the Board has set aside the 100 pJs, and to the extent that the gas plan for this year is indicating you only need 88 or 89, we wouldn't want to sell that space longer-term, in that it would be unavailable in year 2 or 3 or 4 in case the gas supply plan changed or a new customer came on or a new power plant came on.

It has been set aside for in-franchise customers, and we can manage that by going yearly; it becomes more difficult to managing it going multiple years.

MR. SMITH: Mr. Isherwood, Mr. Thompson in his cross-examination indicated the distinction between exchanges done by Union and those done by a marketer; do you recall that?

MR. ISHERWOOD: I do.

MR. SMITH: And what, if any, distinction -- well, first of all, do you agree that there is a distinction? And what, if any, distinction do you draw?

MR. ISHERWOOD: An exchange done by Union Gas or an exchange done by a marketer would be the same transaction.

MR. SMITH: Why do you say that, sir?

MR. ISHERWOOD: The definition of the exchange that we even presented in the very opening examination-in-chief talks about party A and party B.

So whether we're party A or the marketer is party A, it is the same transaction.

MR. SMITH: And what about the gas flows?

MR. ISHERWOOD: In terms of gas flows?

MR. SMITH: Yes.

MR. ISHERWOOD: So in terms of an exchange, it can be -- we can be selling exchange where we're using an exchange to move the gas for a third party, or we can be buying an exchange in terms of wanting to move gas from point A to

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complete.

[Laughter]

MR. SMITH: Mr. Rosenkranz, it's actually Crawford Smith. Good to see you again, sir.

[Laughter]

MR. SMITH: Just a few questions for you. I would ask you to turn up your report dated May 16th, 2012. And I would ask you to turn to page 10 of that -- 10 of that report.

And you say at page 10 at the very bottom paragraph, line 26:

> "Even though Union's storage assets are operated on an integrated basis, Union is still able to tie an individual storage transaction to either the utility storage account or the non-utility storage account."

And you are of course aware that that comes from the 0038 case?

MR. ROSENKRANZ: That was something that Union confirmed. It is also based on my understanding of the way that transactions can be tracked in separate books, as a general course, in terms of a market or a gas supply management firm.

MR. SMITH: Now, is it your view, sir, that revenue from the sale of excess utility space up to 100 petaJoules should go to ratepayers, subject to the 10 percent incentive for Union, as found in NGEIR?

MR. ROSENKRANZ: Could you repeat that, sorry?

MR. SMITH: Simply storage revenue, as I understand your evidence, storage revenue relating to transactions using the excess utility space - so that space up to 100 petaJoules - would go to ratepayers subject to the incentive of 10 percent. It is 90/10 sharing?

MR. ROSENKRANZ: I just wanted to be careful to -- that I understood which storage space, utility storage space, we're discussing.

It is my view that the optimization of all of the -- any or all of the 100 pJs of storage space that's -- the costs of which are included in utility rates, should be for the benefit of customers or the margins on those transactions, and that the Board has determined that there is a 10 percent incentive that would be retained by Union Gas.

MR. SMITH: Okay.

MR. ROSENKRANZ: So I think I'm agreeing with you.

MR. SMITH: I think you are, as well. And then the amount over 100 petaJoules, the non-utility space, would go to Union and its shareholders?

MR. ROSENKRANZ: Correct. The costs of that additional space is the responsibility of the non-utility business, and the margins on those transactions are retained by the non-utility business.

MR. SMITH: And I take it your view is the same with respect to either side, regardless of the length of the transaction?

MR. ROSENKRANZ: Exactly. I think that's one of the points I tried to make, that, as a principle, it depends on what the assets are that underpin the transaction, not what the transaction itself is.

MR. SMITH: Right. So we have your evidence, whether it is a short-term or long-term transaction under 100 pJs, that would be 90-10 for ratepayers, and if it's a long-term or short-term transaction over 100 pJs, that would be to the shareholder; correct?

MR. ROSENKRANZ: That's my opinion, yes.

MR. SMITH: And that's true regardless of what the price is of any particular transaction on either side of the 100 pJs?

MR. ROSENKRANZ: I'm not sure what you mean regardless of the price. My concern is with the 100 pJs of utility storage space, the fact that there is value there when those -- either long term, short term, day to day, if space is available and can be a value obtained in the secondary market, that should be tracked and pursued on behalf of utility ratepayers.

MR. SMITH: Well, I just wanted to pin this down.

Let's say that the price obtained and the margin earned on transactions that use up the excess utility space, so up to the 100 pJs, are a price of $4.00, hypothetically.

And then let's say that it so happens the prices later in the year go up and that the value of transactions that are taking place and using the non-utility storage space are higher.

You are not suggesting any sort of adjustment for that, are you?

MR. ROSENKRANZ: I am not suggesting any sort of allocation of costs or margins from a pool of transactions.

I think that in order to protect ratepayers, the assets themselves should be identified and it should be noted at the time the transaction is made whether that is being made from the utility space or non-utility space.

MR. SMITH: Okay, that is helpful. Thank you. Can I ask you -- I had given to your counsel, and I think you have a copy, a compendium, and I believe Board Staff should have a copy. If I could just have that marked as an exhibit?

MR. MILLAR: Mr. Smith, can you show me which...

MR. SMITH: It says "Union Gas Limited Cross-Examination Compendium for Mr. John Rosenkranz".

MR. MILLAR: Yes, we have it. Thank you. K11.3.

EXHIBIT NO. K11.3: UNION GAS LIMITED CROSS-EXAMINATION COMPENDIUM FOR MR. JOHN ROSENKRANZ.

MS. HARE: Mr. Millar, I don't think we have that.

MR. MILLAR: Yes. I will bring it up.

[Mr. Millar distributes compendium to Board Panel]

MR. SMITH: Mr. Rosenkranz, just a couple of -- one preliminary matter. Can I ask you to turn in the compendium to page 21? Yes, page 21.

So you will see here the cover page for Union's RP-2003-0063 case, which was Union's 2004 cost of service proceeding. Do you have that?