K1.1

UNION GAS LIMITED

Argument-in-Chief Compendium

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TAB 1

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2012-0087

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 amending or varying the rate or rates charged to customers as of October 1, 2012.

PROCEDURAL ORDER NO. 3
August 15, 2012

Union Gas Limited ("Union") filed an application dated April 13, 2012 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Schedule B, for an order of the Board amending or varying the rate or rates charged to customers as of October 1, 2012 in connection with the sharing of 2011 earnings under the incentive rate mechanism approved by the Board as well as final disposition of 2011 year-end deferral account and other balances (the "Application"). The Application also requests approval for the disposition of the variance between the Demand Side Management ("DSM") budget included in 2012 rates and the revised budget approved by the Board in EB-2011-0327. The Board has assigned file number EB-2012-0087 to the Application.

The Board issued a Notice of Application and Procedural Order No.1 on April 19, 2012 in which it adopted the intervenors in the EB-2011-0025 and EB-2011-0038 proceedings as intervenors in this proceeding. The Board also set out a timetable for the filing of interrogatories, responding to interrogatories, and for informing the Board regarding plans to file intervenor evidence.

In Procedural Order No. 2, dated June 27, 2012, the Board established a Technical Conference so that parties would have the opportunity to explore emerging issues such as the use of transportation contract attributes to yield shareholder margins. The Board directed intervenors to file letters scoping the issues that will be pursued at the Technical Conference. The Board also established a Settlement Conference to be held on August 28 and 29, 2012.

On July 10, 2012, the Board issued a letter rescheduling the Settlement Conference to August 21 and 22, 2012.

On August 3, 2012, the Canadian Manufacturers and Exporters ("CME") and the Federation of Rental-housing Providers of Ontario ("FRPO") filed a letter which proposed that the following issues related to Union's treatment of Upstream Transportation Services be dealt with at the Technical Conference:

1. Have all of the amounts Union received to December 31, 2011 to mitigate Upstream Transportation Demand Charges been properly recorded in Union Gas Supply Deferral Accounts, including Unabsorbed Demand Charges ("UDC") Deferral Account 179-108?

2. If not, then what additional amounts that Union received to mitigate Upstream Transportation Demand Charges should be recorded in these deferral accounts as of December 31, 2011 and cleared to ratepayers?

3. What is the impact on the amount of 2011 earnings to be credited to ratepayers of clearing to ratepayers the foregoing total amounts?

CME and FRPO noted that the issues in this case relate to the manner in which Union should account for the profits that it has derived from unauthorized demand charge conversion activities. CME and FRPO stated that the conceptual question of whether Union is obliged to account to ratepayers for these profits will be determined in Union's 2013 rate case (EB-2011-0210). CME and FRPO submitted that a final determination on the noted issue in this proceeding will need to await the Board's determination of issues of fact in Union's 2013 rebasing proceeding pertaining to the validity of Union's treatment of the noted revenues.

CME and FRPO proposed that the current balances in the UDC and other Gas Supply Deferral Accounts be cleared to ratepayers with an express recognition of the fact that there may be an additional amount for 2011 to be cleared to ratepayers through Union's Gas Supply Deferral Accounts following the release of the Board's Decision in Union's 2013 rebasing case. CME and FRPO noted that, at this stage, the amount of 2011 earnings sharing to be cleared for ratepayers should be calculated on the basis of an assumption that utility earnings could be reduced by $14.0 million as a consequence of the Board's determination of issues of fact in Union's 2013 rebasing case. In addition, CME and FRPO noted that the undisputed balances in all other 2011 Deferral Accounts can be cleared at this time.

Union filed a letter on August 10, 2012 responding to the letter of CME and FRPO. Union submitted that the Technical Conference should be adjourned to a later date as the same issues raised by CME and FRPO in this proceeding have been raised in Union's 2013 rebasing case. Union submitted that the issue of the treatment of upstream transportation optimization revenue should not be considered until after the Board has rendered its decision on the 2013 rebasing application. Union stated that having the matter determined at this time risks inconsistent decisions by the Board in relation to the same issue in two different proceedings.

Union submitted that the Board should continue with the proceeding in relation to all other issues while adjourning the upstream transportation optimization revenue and related earnings sharing issues to a date to be determined following the release of the Board's decision in the 2013 rebasing proceeding. Union noted that it is not aware of any concerns in relation to the other issues, nor did any party request a Technical Conference in relation thereto. Union submitted that the other issues can be dealt with expeditiously either by way of settlement or brief hearing.

The Board does not agree with the submissions of CME, FRPO, or Union to the effect that the treatment of upstream transportation optimization revenue should not be considered until after the Board has rendered its decision on the 2013 rebasing application. The Board is of the view that there are two distinct issues before the Board. In Union's 2013 rebasing case (EB-2011-0210), the Board will be determining how upstream transportation optimization revenue should be treated in 2013 and going forward. In this proceeding (EB-2012-0087), the Board will be determining whether Union treated the upstream transportation optimization revenues appropriately in 2011 under the auspices of Union's existing IRM framework.[1] The Board is of the view that these are two different issues and that a decision on one of the issues does not necessarily require the same decision on the other.

For the above reasons, the Board has determined that it will address the issue of Union's treatment of upstream transportation revenues in 2011 as a distinct issue in this proceeding. The Board has decided that it will hear this single issue as a Preliminary Issue in this proceeding and will issue a decision on it prior to holding a Settlement Conference.

The Preliminary Issue is:
"Has Union treated the upstream transportation optimization revenues appropriately in 2011 in the context of Union's existing IRM framework?"

[1] The Board would like to make it clear that it is only considering the treatment of the upstream transportation optimization revenues as it impacts the 2011 rates being determined in this proceeding.

The Board will still hold the Technical Conference scheduled on August 21, 2012 so that parties have an opportunity for further discovery in this proceeding. The focus of the Technical Conference will be on the issues laid out by CME and FRPO in their letter cited above. However, the Board notes that this will be the only Technical Conference held in this proceeding. As such, if parties have other issues that they would like to discover at the Technical Conference they may do so. In order for Union to be properly prepared for the Technical Conference, any parties that wish to ask questions on issues other than the upstream transportation optimization revenue treatment issue shall file letters noting the issues they plan to canvass in advance of the Technical Conference. The Board would also like to advise Union that it is expected to make witness panels available at the Technical Conference that are knowledgeable in the areas that parties indicate will be canvassed.

The Board will establish dates for oral argument on the Preliminary Issue after the Technical Conference has concluded.

The Board will make provision for procedural matters. Please be aware that further procedural orders may be issued from time to time.

THE BOARD ORDERS THAT:

1. Parties that are seeking information on issues other than the upstream transportation optimization revenue treatment issue at the Technical Conference shall file letters with the Board and copy all parties describing the issues they wish to address on or before **August 17, 2012**.

2. The Technical Conference scheduled for **August 21, 2012** will still be convened at 9:30 am on that date and will be held in the Board's hearing room at 2300 Yonge Street, 25th Floor, Toronto.

3. The Settlement Conference scheduled for **August 21 and 22, 2012** is postponed until after the Board's Decision on the Preliminary Issue and a date will be set by the Board in a subsequent Procedural Order.

All filings to the Board must quote file number **EB-2012-0087**, be made through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Please use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available you may email your document to the BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file seven paper copies. If you have submitted through the Board's web portal an e-mail is not required.

All parties must also provide the Case Manager, Lawrie Gluck, Lawrie.Gluck@ontarioenergyboard.ca, with an electronic copy of all comments and correspondence related to this case.

ISSUED at Toronto, August 15, 2012

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

TAB 2

sharing associated with both the forecast and any variances experienced on an actual basis relative to the forecast.

Union's proposal to eliminate the S&T transactional services deferral accounts is consistent with and supports the Board's policy direction as outlined in its NGF policy paper dated March 30, 2005, to move to an Incentive Regulation ("IR") framework. The Board made several references to its views on earnings sharing mechanisms in its NGF report including the following:

1. *"Board does not intend for earning sharing mechanisms to form part of IR plans"* (Pg. 28)
2. *"an appropriate balance of risk and reward in an IR framework will result in reduced reliance on deferral or variance accounts"* (Pg. 31).

The current S&T transactional service regulatory framework includes deferred accounts and a revenue sharing mechanism. Union agrees with the Board that, in a true IR framework, there should be no earnings sharing, and transactional services revenues should not receive special treatment. Union 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. This position is also consistent with Union's stated NGF position (in its November 10, 2004 submission) that S&T deferral accounts should be eliminated.

Union requires an appropriate balance of risks and rewards in order to manage weather variances, in-franchise customer annual usage, and increasing competition for S&T services within an IR framework. The forecast of S&T revenue is no different than the forecast of any other source of revenue. All other revenues are considered as part of the rate setting process and the utility bears the risk of variances relative to forecast levels.

Union has advanced this proposal in this proceeding because there may not be another opportunity or forum to deal with this issue prior to the beginning of the proposed IR framework (January 1, 2008). This proposal provides consistency with the Board's IR policy statements. Union's proposal has been reflected in its 2007 forecast, with the forecast 2007 S&T transactional margin of $36.5 million included in the revenues used to determine 2007 rates. The evidence of Mark Kitchen, filed at Exhibit H, updates the margin estimate identified above to reflect the allocation of costs from the 2007 cost allocation study when it is completed. This is consistent with the existing rate making treatment with the exception that there would be no 90/10 sharing of the 2007 forecast, which is also consistent with Union's proposal to eliminate the deferral accounts.

5.0 Storage Market Premiums

The position that Union outlined in its November 10, 2004 NGF submission was that the market premium derived from offering storage services at market rates should flow to Union as the owner of the underlying storage assets. This position was based on Union's view that the storage

TAB 3

UNION GAS LIMITED

Accounting Entries for
TCPL Tolls and Fuel – Northern and Eastern Operations Area
Deferral Account No. 179-100

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.179-100
Other Deferred Charges - TCPL Tolls and Fuel – Northern and Eastern Operations Area

Credit - Account No. 623
Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-100, the difference in the costs between the actual per unit TCPL tolls and associated fuel and the forecast per unit TCPL tolls and associated fuel costs included in the rates as approved by the Board.

Debit - Account No. 623
Cost of Gas

Credit - Account No.179-100
Other Deferred Charges - TCPL Tolls and Fuel – Northern and Eastern Operations Area

To record, as a credit (debit) in Deferral Account No. 179-100, the benefit from the temporary assignment of unutilized capacity under Union's TCPL transportation contracts to the Northern and Eastern Operations Area. The benefit will be equal to the recovery of pipeline demand charges and other charges resulting from the temporary assignment of unutilized capacity that have been included in gas sales rates.

Debit - Account No. 179-100
Other Deferred Charges - TCPL Tolls and Fuel – Northern and Eastern Operations Area

Credit - Account No. 623
Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-100 charges that result from the Limited Balancing Agreement with TCPL.

Debit - Account No. 500
Sales Revenue

Credit - Account No. 179-100
Other Deferred Charges - TCPL Tolls and Fuel – Northern and Eastern Operations Area

To record, as a credit (debit) in Deferral Account No. 179-100 revenue from T-Service customers for load balancing service resulting from the Limited Balancing Agreement with TCPL.

Debit	-	Account No. 179-100 Other Deferred Charges - TCPL Tolls and Fuel – Northern and Eastern Operations Area
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-100 interest expense on the balance in Deferral Account No. 179-100. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
North Purchase Gas Variance Account
Deferral Account No. 179-105

This account is applicable to the Northern and Eastern Operations area 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. 179-105 Other Deferred Charges – North Purchase Gas Variance Account
Credit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-105, the difference between the unit cost of gas purchased each month for the Northern and Eastern Operations area and the unit cost of gas included in the gas sales rates as approved by the Board, including the difference between the actual heat content of the gas purchased and the forecast heat content included in gas sales rates.

Debit	-	Account No. 179-105 Other Deferred Charges - North Purchase Gas Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-105, interest expense on the balance in Deferral Account No. 179-105. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
South Purchase Gas Variance Account
Deferral Account No. 179-106

This account is applicable to the Southern Operations area 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. 179-106 Other Deferred Charges – South Purchase Gas Variance Account
Credit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-106, the difference between the unit cost of gas purchased each month for the Southern Operations and the unit cost of gas included in the gas sales rates as approved by the Board, including the difference between the actual heat content of the gas purchased and the forecast heat content included in gas sales rates.

Debit	-	Account No. 179-106 Other Deferred Charges - South Purchase Gas Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-106, interest expense on the balance in Deferral Account No. 179-106. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

**Accounting Entries for
Spot Gas Variance Account
Deferral Account No. 179-107**

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-107 Other Deferred Charges –Spot Gas Variance Account
Credit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-107, the difference between the unit cost of spot gas purchased each month and the unit cost of gas included in the gas sales rates as approved by the Board on the spot volumes purchased in excess of planned purchases.

Debit	-	Account No. 623 Cost of Gas
Credit	-	Account No. 179-107 Other Deferred Charges –Spot Gas Variance Account

To record, as a credit (debit) in Deferral Account No. 179-107, the approved gas supply charges recovered through the delivery component of rates.

Debit	-	Account No. 179-107 Other Deferred Charges – Spot Gas Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-107, interest expense on the balance in Deferral Account No. 179-107. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Unabsorbed Demand Cost (UDC) Variance Account
Deferral Account No. 179-108

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-108 Other Deferred Charges – Unabsorbed Demand Cost Variance Account
Credit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-108, the difference between the actual unabsorbed demand costs incurred by Union and the amount of unabsorbed demand charges included in rates as approved by the Board.

Debit	-	Account No. 179-108 Other Deferred Charges – Unabsorbed Demand Cost Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-108, interest expense on the balance in Deferral Account No. 179-108. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

**Accounting Entries for
Inventory Revaluation Account
Deferral Account No. 179-109**

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-109 Other Deferred Charges – Inventory Revaluation
Credit	-	Account No. 152 Gas Stored Underground - Available for Sales
Credit	-	Account No. 153 Transmission Line Pack Gas

To record, as a debit (credit) in Deferral Account No. 179-109, the decrease (increase) in the value of gas inventory available for sale to sales service customers due to changes in Union's weighted average cost of gas approved by the Board for rate making purposes.

Debit	-	Account No. 179-109 Other Deferred Charges – Inventory Revaluation Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-109, interest expense on the balance in Deferral Account No. 179-109. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

TAB 4

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.

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.

TAB 5

INCENTIVE REGULATION

EXHIBIT LIST

Exh.	Tab	Sch.	Contents
A			ADMINISTRATION
	1		Exhibit List
	2		Application
B			PRE-FILED EVIDENCE
	1		Union Incentive Regulation Evidence - page 16 updated August 2, 2007
	2		Supplemental Weather Normalization Evidence
C			INTERROGATORIES
	1		Board Staff
	2		APPrO
	3/16/33		BOMA/LPMA/WGSPG
	4		CCC
	5		Coral
	7		Direct Energy
	9		Enbridge
	10		Energy Probe
	11		GEC
	13		IGUA
	15		Kitchener
	17		OAPPA
	20		Pollution Probe
	22		Power Workers' Union
	23		School Energy Coalition
	27		TransAlta
	28		TCE
	32		VECC

Union Gas Limited
Incentive Regulation Proposal
Prefiled Evidence

7. Administer Z factor rate adjustments outside of the price cap as described in Section 5.9.

5.0 PROPOSAL PARAMETERS

5.1 BASE RATES

Union's 2007 rates will set the base for the IR term. These base rates meet the Board's requirements for a robust set of cost-based rates, based on a thorough and transparent review (page 25, NGF Report). As detailed below, adjustments yet to be made to the 2007 base rates include:

- Items from previous Board Decisions
    1. Splitting the M2 rate class into two rate classes (M1 and M2)
    2. Adjustments for the 2008 GDAR capital costs
    3. Treatment of S&T deferral accounts
    4. Demand Side Management ("DSM")
- A one time adjustment to reflect the 20-year trend weather normalization method

Items from Previous Board Decisions

Union will be required to implement the outcomes of previous Board Decisions during the plan term. In 2008, Union will be implementing changes to rates based on the Board Decisions in the EB-2005-0520 (2007 cost of service proceeding) and EB-2005-0551 Natural Gas Electricity Interface Review ("NGEIR") proceedings.

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

Table 3
Union's Proposed PCIs by Service Group

	Recent GDPIPI Trend	X Factor Excluding Stretch and AU	Adjusted AU Factor	Net X Factor	PCI
General Service	1.86	0.74	-1.12 [5]	-0.38	2.24
All other	1.86	0.74	0.00	0.74	1.12

5.8 Y FACTOR

Y factor items are those components of a utility's rate structure adjusted by something other than the IR index formula, and are treated as periodic pass-through items. Management typically has little or no control over these items. Union proposes the following Y factor items:

- Cost of gas and upstream transportation
- DSM cost increases and other affects (e.g. throughput affects)
- Elimination of long-term storage deferral account
- Other deferral accounts

5.8.1 Cost of Gas and Upstream Transportation

The cost of gas supply, upstream transportation and gas supply related balancing will continue to be passed through to customers through the Quarterly Rate Adjustment Mechanism ("QRAM"), including the prospective disposition of gas supply related deferral accounts.

[5] Summary COS AU -0.72 divided by Union's general service 2005 revenue share 0.644.

The NGF Report identified that the Board will develop guidelines through a consultation process to standardize the QRAM process across gas utilities. Union expects that the Board will complete this process during the price cap plan term. If necessary, Union will modify the meth used to establish commodity prices to reflect any changes approved by the Board as a result of that process.

5.8.2 DSM

In 2006, the Board convened a generic proceeding to address a number of common issues related to DSM activities for natural gas utilities (EB-2006-0021). During the three phases of that proceeding the following were developed: i) generic plan parameters, ii) input assumptions, and iii) a specific plan for each utility. As agreed to in the Partial Settlement agreement, and as confirmed by the Board in its August 25, 2006 Decision, Union's 2007 DSM budget of $17.0 million will be increased to $18.7 million beginning January 1, 2008 and to $20.6 million beginning January 1, 2009. In addition, the DSMVA, LRAM and SSM deferral accounts will continue throughout the three-year term of the DSM plan (2007-2009). Consequently, Union's rates for 2008 and 2009 should be adjusted for the increase in the annual DSM budget and future rates will be adjusted for the disposition of any DSM-related deferral account balances.

5.8.3 Long-Term Peak Storage Services Account (179-72)

Union will be increasing its share of long-term storage transaction margins by increments of 25% starting in 2008. The Board approved the phase-out of long-term margin sharing in its EB-2005-0551 Decision with Reasons, Section 7.3, dated November 7, 2006 (see Appendix H for the excerpt from the Board Decision). Therefore, Union's rates for 2008-2011 will be adjusted to reflect this phase-out.

5.8.4 Other Deferral Accounts

There will be no additions to the deferral accounts established in the base year unless an account is established in another Board proceeding or an item would otherwise qualify as a Z factor during the price cap plan term. If an item like permit fees (discussed in Section 5.9) qualifies as a Z factor, it would be logical that this item would also qualify for a deferral account. A deferral account may be required until rates can be adjusted to incorporate the adjustment. A deferral account may also be required in instances where it takes longer than a year to quantify the annualized impact accurately.

5.9 Z FACTOR

A Z factor provides for rate adjustments intended to safeguard customers and the gas utility against unexpected costs that are outside of management's control and therefore not included in the proposed price cap. A Z factor is any amount that satisfies the four criteria summarized in Table 4:

TAB 6

EB-2007-0606

UNION GAS LIMITED

SETTLEMENT AGREEMENT

January 3, 2008

4.3 **IF SO, HOW SHOULD THE IMPACT OF CHANGES IN AVERAGE USE BE APPLIED (E.G., TO ALL CUSTOMER RATE CLASSES EQUALLY, SHOULD IT BE DIFFERENTIATED BY CUSTOMER RATE CLASSES OR SOME OTHER MANNER)?**

(Complete Settlement)

See 4.1 above and 12.3.1 below.

Evidence Reference:
1. B/T1, p. 36-37.
2. C1.8, C1.9, C13.5, C32.13, C32.14, C32.17.
3. L/T1/S2.

5 <u>Y FACTOR</u>

5.1 **WHAT ARE THE Y FACTORS THAT SHOULD BE INCLUDED IN THE IR PLAN?**

(Partial Settlement on the treatment of any temporary revenue deficiencies associated with customer additions; Complete Settlement on the remainder of the issue.)

The parties agree that identified Y factors will not be adjusted by the price cap index but will be passed through to rates.

Items that will be treated as Y factors are:

- Upstream gas costs
- Upstream transportation costs
- Incremental DSM costs (as determined in EB-2006-0021 and in any subsequent DSM proceeding) and volume reductions
- Storage margin sharing changes (as determined in EB-2005-0551)

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.

5.2 WHAT ARE THE CRITERIA FOR DISPOSITION?

(Complete Settlement)

See 5.1 above.

Evidence References:
1. C3.20, C3.21, C11.04.

6 Z FACTOR

6.1 WHAT ARE THE CRITERIA FOR ESTABLISHING Z FACTORS THAT SHOULD BE INCLUDED IN THE IR PLAN?

(No Settlement on whether tax changes resulting from changes to federal and/or provincial legislation and/or regulations thereunder qualify as a Z factor in years 2008 and beyond; Complete Settlement on all other aspects of the issue.)

The parties agree that Z factors generally, have to meet the criteria established in Union's evidence, i.e.,

1. the event must be causally related to an increase/decrease in cost;
2. the cost must be beyond the control of the utility's management, and not a risk for which a prudent utility would take risk mitigation steps;
3. the cost increase/decrease must not otherwise be reflected in the price cap index;
4. any cost increase must be prudently incurred; and
5. the cost increase/decrease must meet the materiality threshold of $1.5 million annually per Z factor event (i.e., the sum of all individual items underlying the Z factor event).

If a proceeding is instituted before the Board, before the term of this IR plan expires, in which changes to the methodology for determining return on equity is requested, then all parties

14 ADJUSTMENTS TO BASE YEAR REVENUE REQUIREMENTS AND/OR RATES

14.1 ARE THERE ADJUSTMENTS THAT SHOULD BE MADE TO BASE YEAR REVENUE REQUIREMENTS AND/OR RATES?

(No Settlement on the risk management component of this issue or the amount of taxes payable by Union as a result of tax changes resulting from changes to federal and/or provincial legislation and/or regulations thereunder; Complete Settlement on all other aspects of the issue.)

All parties agree that only the following additional adjustments (other than those adjustments otherwise set out in this Agreement) should be made to reduce the 2008 base revenue requirement and/or 2008 rates prior to the application of the price cap index:

1. Increase to S&T revenues/margin	$4.3 million*
2. Deferred tax drawdown	$1.9 million
3. Reduction to regulatory cost budget	$1.0 million
4. Phase II GDAR costs that will not be incurred	$1.6 million **

* This adjustment has been made to reflect the elimination of certain S&T revenue deferral accounts, described in 5.1 above. The parties agree that 100% of this amount will be allocated to in-franchise customers, as described in Exhibit D/T1, p. 7 of Union's evidence.

** This adjustment to base rates is being made as a result of the Board's decision to amend the GDAR to treat bill ready distributor-consolidated billing in the same manner as split billing and gas vendor-consolidated billing as described in the Board's December 11, 2007 letter, attached as Appendix D. Union notes that these costs were incorporated into the 2008 interim rates approved by the Board. They will be eliminated from rates when final 2008 rates are implemented.

When implementing final 2008 rates, Union will calculate what the final 2008 rates need to be to reflect all of the adjustments referenced in this Agreement and the Board's findings on those issues that are proceeding to hearing had they been implemented prospectively January 1, 2008. Differences between what was charged to customers during the period interim 2008 rates were in place and what should have been charged had final 2008 rates been in place will be recovered/rebated either as a one-time charge/credit or over the remainder of 2008 in rates.

The following parties agree with the settlement of this 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 issue: Coral, EGD, GEC, PP, PWU, TCPL.

Evidence References:
1. B/T1 p.10, B/T2, B/T3, B/T4.
2. C1.19, C1.20, C3.2, C3.3, C3.9, C3.27, C3.28, C10.2, C10.3, C10.4, C10.5, C10.6, C10.7, C10.8, C15.7, C15.8, C15.9, C15.10, C13.11, C13.12, C13.13, C13.14, C23.44, C23.45, C23.46, C23.52, C23.53, C28.1, C32.1, C32.3, C32.18, C32.19, C32.24.
3. JTA.6, JTA.8, JTA.10, JTA.12, JTA.13, JTA.16, JTA.17, JTA.18, JTA.19, JTA.22, JTA.23, JTA.25, JTA.26, JTA.27, JTA.32, JTA.37, JTA.38, JTA.39, JTA.41, JTA.42, JTA.46, JTA.47, JTA.50.

There is no settlement of the commodity risk management component of this issue but all parties have agreed that the Board should deal with commodity risk management by way of written submission and that no oral evidence is required.

There is no settlement of the base rate adjustments that flow from the amount of taxes payable by Union as a result of tax changes resulting from changes to federal and/or provincial legislation and/or regulations thereunder.

14.2 IF SO, HOW SHOULD THESE ADJUSTMENTS BE MADE?

(Complete Settlement)

The parties agree that the base rate adjustments in 14.1 will be implemented effective January 1, 2008. These adjustments will be allocated as follows:

1. increases to S&T revenues / margin ($4.3 million) will be allocated in proportion to the allocation of 2007 approved in-franchise revenue less DSM, upstream transportation, compressor fuel, unaccounted for gas and storage (as identified in Exhibit D/T3/Schedule 2);
2. deferred tax drawdown ($1.9 million) will be allocated in proportion to the allocation of 2007 deferred tax drawdown;
3. reduction to regulatory cost budget ($1.0 million) will be allocated in proportion to the allocation of 2007 administrative and general expenses; and
4. reduction to GDAR implementation cost ($1.6 million) was to be an increase so that this increase will simply not be implemented.

The following parties agree with the settlement of this 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 issue: Coral, EGD, GEC, PP, PWU, TCPL.

Evidence References:
1. C3.32, C3.33, C3.34, C13.11, C13.12, C13.13, C13.14, C23.47, C32.2.
2. D/T1 p.7.
3. JTA.5.

TAB 7

d. Permanent demand destruction, offsetting the contract revenue increases described above, of $3.0 million is a direct result of significant additional plant closures in Union's large infranchise contract markets.

2008 General Service Revenues

The actual total general service delivery revenue in 2008 was $574.9 million (Appendix A, Schedule 9, Column (r), line 6), prior to adjustments, compared to the 2007 Board approved forecast of $565.2 million (Appendix A, Schedule 9, Column (f), line 6). The primary contributors to the variance of $9.7 million were colder than normal weather in 2008 ($3.6 million) and rate class migration from contract rate classes to general service rate classes ($2.1 million). The remaining variance of $4.0 million was due to variances in the forecast level of customer additions, demand price elasticity related normalized average consumption ("NAC") variances, non demand side management ("DSM") related energy conservation, the Average Use ("AU") factor and the unbilled revenue accrual.

TRANSPORTATION REVENUE

Revenue from exfranchise transportation services increased by $37.7 million in 2008 relative to 2007 Board approved levels. This was primarily driven by increases in short-term transportation and exchange revenue of $23.3 million. Increases in long-term transportation revenue of $14.5 million as a result of the expansion of Union's Dawn Trafalgar transmission system, offset by increases in depreciation and cost of capital identified below, also contributed to the increased transportation revenue in 2008. The increase in short-term transportation and exchange revenue is explained in more detail below.

Short-Term Transportation and Exchange Revenue

As noted above, short-term transportation and exchange revenues accounted for \$23.3 million of the \$37.7 million increase in exfranchise transportation revenue in 2008 over 2007 Board approved levels. The increased revenue was a result of increased customer activity and service values due to colder than normal weather late in the year and new market opportunities. In addition, Union put a greater focus on the gas supply transportation portfolio optimization starting in 2007. This focus continued through 2008. Union also invested in incremental sales staff to capture the incremental revenue opportunities and deliver these services to customers. Union's approach to the marketing of transactional services and the financial results for 2008 were the direct result of the IR framework and the elimination of the transportation deferral accounts.

Union notes that Board approved distribution rates in 2008 include \$6.9 million in short-term transportation and exchange margin. To achieve the total net margin of \$6.9 million as embedded in the 2008 distribution rates, Union must achieve gross transactional revenue (before deduction of costs) of approximately \$10 to \$12 million.

EXPENSES

Expenses include operating and maintenance expenses, depreciation, and property and capital taxes. The increase in expenses of $0.9 million (Appendix A, Schedule 2) is driven by an increase in depreciation of $6.5 million as a result of the expansion of Union's system offset by reductions in O&M of $2.9 million, and property and capital taxes of $2.7 million.

INCOME TAXES

The increase in income tax expense from 2007 Board approved levels of $8.7 million (Appendix A, Schedule 14, Column (a), line 13) to $26.1 million (Appendix A, Schedule 14, Column (c), line 13) is attributable to higher earnings in 2008.

COST OF CAPITAL

The decrease in return of $1.9 million (Appendix A, Schedule 4, line 6) is driven by reductions in interest rates that decreased costs by $8.0 million offset by increases in rate base investment that increased costs by $6.1 million.

STORAGE PREMIUM ADJUSTMENT

Union's financial results from utility operations for 2008 are further adjusted to recognize the benefit of the storage margin incorporated into approved rates. The 2007 rates approved by the Board for utility services included storage margin of $33.5 million (EB-2005-0520, Rate Order Working Papers, Schedule 24). This represented 90% of the

CALCULATION OF THE INCENTIVE REGULATION REVIEW THRESHOLD PROVISION

Union's 2008 weather normalized utility earnings for the purposes of the IR review threshold calculation include all the adjustments made to arrive at utility earnings for sharing purposes as well as an adjustment to reduce revenues by $6.9 million as a result of colder than normal weather. The calculation of earnings for the purposes of the IR review threshold is provided at Appendix B, Schedule 2.

The 2008 ROE related to the IR review threshold is 12.11% (Appendix B, Schedule 2, column (d), line 24). This compares to the benchmark ROE of 8.81% resulting in earnings that are 330 basis points above the Board's benchmark ROE.

NEED FOR REVIEW OF THE INCENTIVE REGULATION MECHANISM

As indicated above, Union's 2008 normalized earnings exceed the 300 basis point review threshold, triggering the requirement to file an application with the Board for review of the IR mechanism. It is Union's view that the existing IR parameters agreed to as part of the EB-2007-0606, Settlement Agreement remain appropriate and should not be adjusted as a result of this application. Specifically, Union does not believe that the base upon which rates are set or the pricing formula, including the approved X factor of 1.82 %, should be adjusted based on 2008 actual results.

Union takes this view for a number of reasons. The drivers of 2008 actual utility earnings do not point to any fundamental flaw in the IR framework. The primary drivers of 2008 earnings are increased distribution revenue in the general service and infranchise contract market and increased short-term transportation and exchange revenue. The increase in infranchise distribution revenue experienced in 2008 arose from unusual circumstances, and, in any event, not expected to continue in 2009 or 2010 as a result of the global economic recession. Customers will continue to receive half of all actual earnings over the sharing threshold, should the threshold be exceeded in subsequent years.

The increase in short-term transportation and exchange revenue in 2008 was the result of increased customer activity and service values due to colder than normal weather late in the year and new market opportunities. Further, Union put a greater focus on the gas supply transportation portfolio optimization starting in 2007 and continuing through 2008. Union invested in incremental sales staff to capture the incremental revenue opportunities and deliver these services to customers. Union's proactive approach to optimizing short-term transportation opportunities is the behaviour that IR and the associated elimination of the short-term transportation deferral accounts was intended to drive. As a result of the IR framework both customers and the company are benefiting in 2008 through earnings sharing.

The revenue growth in 2008 will not continue in 2009 and 2010 because of the global economic recession. The recession will continue to put significant downward pressure on

Union's earnings over the remainder of the IR term. Union has provided its 2009 -2010 forecast below. In neither 2009 nor 2010 is Union expected to exceed the earnings sharing threshold of 200 basis points or the 300 basis points IR review threshold. The recession will also result in lower GDP IPI FDD over the remainder of the IR term. With a fixed productivity factor of 1.82% rates may actually decline over the IR term. At the very least rates are expected to be flat, as is the case in 2009. Given the economic outlook and the expected impact on Union's earnings, no adjustment to the current IR framework is required.

It is Union's view IR is working as it was intended. Ratepayers will not be harmed by continuing with the existing parameters. In fact, for 2008, ratepayers will receive $15.2 million benefit associated with earnings sharing and will continue to be in a position to share in any benefits should the earnings thresholds be exceeded in subsequent years. An assessment of the 5-year parameters on the basis of a single year's results is not appropriate. The OEB, utilities and intervenors have invested significant time and money to arrive at these parameters.

Finally, the current IR framework creates an environment of regulatory certainty for Union and Spectra that supports and enables longer term investment strategies. Regulatory certainty also allows Union to maintain its employment level across Ontario in the current economic environment. Any significant change to the IR framework will increase regulatory uncertainty which could negatively impact the potential to attract as a result of demand growth. This increase is offset by expected reductions in short-term transactional revenue in 2009 and 2010.

Short-Term Transportation and Exchange Revenue

In 2009, short-term transportation and exchange revenue is forecast to be $18 million (Appendix C, Schedule 4, Column (b), line 6). This represents a $5 million reduction to the 2008 actual revenue of $23 million. The demand for transactional services are very dependant on market conditions and weather. Colder weather in the first two month of 2009 supported the activity generating higher revenues in the 2009 than expected. The 2009 forecast reflects Union's continued focus and proactive approach to optimization of transportation assets by selling services early in 2008, prior to the precipitous decline in the markets and commodity prices. Those contracts will sustain higher revenues into the 2009 winter season.

In 2010, transactional revenue is forecast to be $14 million (Appendix C, Schedule 4, Column (c), line 6) which is a $4 million reduction to the 2009 forecast of $18 million. The reduction in the 2010 forecast reflects the continued downward pressure on transactional activity and service values due to the economic downturn. Overall the recession is expected to place significant downward pressure on Union's ability to sustain or exceed the growth achieved in 2008. Union's customers are experiencing tighter credit constraints, which raises the cost of capital and results in a higher cost of doing business. Some counterparties, including major banks, have already completely withdrawn from does not anticipate that it will exceed the earnings sharing threshold or the IR review threshold in either year.

It is Union's view that there are no fundamental flaws with the current IR mechanism. IR is working as it was intended to the benefit of ratepayers and the company. Ratepayers will receive $15.2 million of earnings sharing in 2008. Union does not believe that it is appropriate to change the current IR mechanism based on a single year's financial results. The current IR mechanism should be allowed to continue to operate without any change to IR parameters or the basis on which rates are set.

2008 EARNING SHARING: ALLOCATION AND DISPOSITION

Union is proposing to allocate the 2008 earnings sharing of $15.2 million to rate classes based on the allocation of the 2007 approved ROE. The allocation of earnings sharing to rate classes appears at Appendix D, Schedule 1. Union's allocation proposal is consistent with how Union allocated, and the Board approved, earnings sharing for 2003, 2005 and 2006.

Consistent with Section 11.1 of the EB-2007-0606 Settlement Agreement, Union is proposing to dispose of the earnings sharing amount July 1, 2009. The timing is consistent with the timing proposed for disposition of Union's 2008 deferral account balances. For General Service rate classes Rate M1, Rate M2, Rate 01 and Rate 10,

TAB 8

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.

TAB 9

EB-2009-0101

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 for an order or orders amending or varying the rate or rates charged to customers as of July 1, 2009 in connection with the sharing of 2008 earnings under the incentive rate mechanism approved by the Ontario Energy Board on January 17, 2008

SETTLEMENT AGREEMENT

June 4, 2009

This Settlement Agreement ("Agreement") is for the consideration of the Ontario Energy Board ("the Board") in its determination, under Docket No. EB-2009-0101, of the disposition of Calendar 2008 earnings sharing under a settlement agreement approved by the Board on January 17, 2008 in EB-2007-0606 (the "IR Settlement Agreement") for Union Gas Limited ("Union"). By Procedural Order No.1 dated April 28, 2009, the Board scheduled a Settlement Conference to commence May 27, 2009. The Settlement Conference was duly convened, in accordance with Procedural Order No. 1, with Mr. George Dominy as facilitator. The Settlement Conference proceeded until May 28, 2009.

The settlement presented in this Agreement is comprehensive in that the agreement that has been reached settles all issues in this proceeding.

The Agreement is supported by the evidence filed in the EB-2009-0101 proceeding.

The purpose of this proceeding was:

(a) to provide Union's calculation of its 2008 utility earnings for the purposes of earnings sharing pursuant to Section 10.1 of the IR Settlement Agreement. Section 10.1 of the IR Settlement Agreement provides:

> *"If in any calendar year Union's actual utility return on equity is more than 200 basis points over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan, then such excess earnings will be shared 50/50 between Union and its customers. For the purposes of the earnings sharing mechanism, Union shall calculate its earnings using the regulatory rules prescribed by the Board from time to time, and shall not make any material changes in accounting practices that have the effect of reducing utility earnings. All revenues that would be included in revenues in a cost of service application shall be included in the earnings calculation and only those expenses (whether operating or capital) that would be allowable as deductions from earnings in a cost of service application shall be included in the earnings calculation.*
>
> *Parties acknowledge that the DSM related Shared Savings Mechanism (SSM) and Lost Revenue Adjustment Mechanism (LRAM) and storage related deferral accounts are outside of the earnings sharing mechanism identified above."*

(b) to consider Union's application pursuant to section 9.1 of the IR Settlement Agreement. Section 9.1 provides:

> *"The parties agree that if there is a 300 basis point or greater variance in weather normalized utility earnings above or below the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan, Union will file an application to the Board, with appropriate supporting evidence, for a review of the price cap mechanism. During the course of that review, the Board may be asked to determine whether it is appropriate to continue the price cap mechanism for future years and, if so, with or without modifications. All parties including Union will be free to take such positions as they consider appropriate with respect to that application, including without limitation; a) proposing that a component of the IR Plan, including the X factor, be adjusted, b) proposing that IR plan be terminated, and c) taking any other positions as the party may consider relevant and the Board agrees to hear. Union shall file such application as soon as reasonably possible in the year following the year in which the over earnings threshold is met, unless all parties to this Agreement agree otherwise at that time."*

It is acknowledged and agreed that none of the provisions of this Agreement is severable. If the Board does not, prior to the commencement of the hearing of the evidence in EB-2009-0101, accept the Agreement in its entirety, there is no Agreement (unless the parties to the Agreement agree that any portion of the Agreement the Board does accept may continue as a valid agreement).

It is further acknowledged and agreed that parties to the Agreement will not withdraw from this Agreement under any circumstances except as provided under Rule 32.05 of the Board's Rules of Practice and Procedure.

The participants in the Settlement Conference agree that all positions, negotiations and discussion of any kind whatsoever which took place during the Settlement Conference and all documents exchanged during the conference which were prepared to facilitate settlement discussions are strictly confidential and without prejudice, and inadmissible unless relevant to the resolution of any ambiguity that subsequently arises with respect to the interpretation of any provision of this Agreement.

The role adopted by Board Staff in Settlement Conferences is set out on page 5 of the Board's Settlement Conference Guidelines. Although Board Staff is not a party to this Agreement, as noted in the Guidelines, "Board Staff who participate in the settlement conference are bound by the same confidentiality standards that apply to parties to the proceeding".

The evidence supporting the Agreement is set out in the Agreement. Abbreviations will be used when identifying exhibit references. For example, Exhibit B1, Tab 4, Schedule 1, Page 1 will be referred to as B1/T4/S1/p1. There are Appendices to the Agreement which provide further evidentiary support. The structure and presentation of the settled issues is consistent with settlement agreements which have been accepted by the Board in prior cases. The parties agree that this Agreement and the Appendices form part of the record in the proceeding.

In Procedural Order No. 1 in this proceeding, the Board granted intervenor status to all intervenors of record in EB-2007-0606 and EB-2008-0220. The following entities participated in the Settlement Conference:

Building Owners and Managers Association of the Greater Toronto Area ("BOMA")
Canadian Manufacturers & Exporters ("CME")
Consumers Council of Canada ("CCC")
Industrial Gas Users Association ("IGUA")
City of Kitchener ("Kitchener")
London Property Management Association ("LPMA")
School Energy Coalition ("SEC")
The City of Timmins ("Timmins")
Union Gas Limited ("Union")
Vulnerable Energy Consumers Coalition ("VECC")
Wholesale Gas Services Purchasers Group ("WGSPG")
Energy Probe ("EP")
Federation of Rental-housing Providers of Ontario ("FRPO")

The parties to this Agreement include all of the above noted entities except IGUA (the "parties"). The parties to this Agreement represent major stakeholders and constituencies with an interest in Union's rates.

The parties to this settlement encourage the Board to accept this Agreement in its entirety. The parties to this Agreement also support finalization of the rate order in these proceedings to enable implementation of this Agreement in Union's July 1 QRAM.

1. Earnings Sharing Calculation and Off Ramp Amendments

(Complete Settlement)

The parties agree that, upon approval of this Agreement by the Board, the IR Settlement Agreement shall, for the entire IR term, 2008 to 2012, be amended as follows (for the assistance of parties and the Board, the agreed upon amendments to the IR Settlement Agreement are blacklined below):

9.1 [Section 9.1 of the IR Settlement Agreement shall be deleted in its entirety.]

10.1 The parties agree that there will be an earnings sharing mechanism, based on actual utility earnings. If in any calendar year Union's actual utility return on equity is more than 200 basis points <u>but not more than 300 basis points</u> over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan, then such excess earnings will be shared 50/50 between Union and its customers. <u>In addition to the above, if in any calendar year Union's actual utility return on equity is more than 300 basis points over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan, then such earnings in excess of 300 basis points will be shared 90/10 between customers and Union (i.e., customers will be credited 90% and Union will be credited 10%).</u> For the purposes of the earnings sharing mechanism, Union shall calculate its earnings using the regulatory rules prescribed by the Board from time to time, and shall not make any material changes in accounting practices that have the effect of reducing utility earnings. All revenues that would be included in revenues in a cost of service application shall be included in the earnings calculation and only those expenses (whether operating or capital) that would be allowable as deductions from earnings in a cost of service application shall be included in the earnings calculation. For greater clarity, Union's one time accounting adjustment in 2008 to true up an unbilled revenue accrual to reflect Union's current rate structure and billing cycles, in the amount of $3.6 million, is an adjustment that is excluded from the calculation of actual utility earnings, whereas the use of actual unaccounted for gas volume is an expense that would be recorded in the calculation of actual utility earnings.

The parties believe that these amendments to the Board-approved IR Settlement Agreement are in the public interest. The amendments are intended to modify the IR formula so as to in produce rates which are just and reasonable during the IR term. The Agreement:

1. clarifies possible ambiguities in the calculation of earning sharing in section 10.1 of the IR Settlement Agreement arising from the relationship between the use of actual utility earnings and the *proviso* in section 10.1 restricting any adjustments in the calculation of actual utility earnings to those adjustments to actual earnings that would be made in a cost of service filing. Intervenors took the position, for example, that none of the adjustments proposed by Union in the calculation of 2008 actual utility earnings were appropriate. Union took the position that all of its proposed adjustments were in accordance with the IR Settlement Agreement. This Agreement avoids the cost and uncertainty of litigation over these disputes, now and in the future, by resolving which adjustments to the calculation of actual utility earnings, for the purposes of earnings sharing, are appropriate;

2. provides additional potential benefits to customers during the term of the IR plan, 2008 to 2012, in circumstances where Union's actual utility income exceeds the amount

calculated by the application of the Board's ROE formula in any year of the IR plan by over 300 basis points, by crediting 90% of such earnings to customers.[1] The consumer protection afforded by the "off ramp" provision for review in section 9.1 of the IR Settlement Agreement has been replaced with crediting 90% of earnings over the 300 basis point threshold to customers, i.e., Union will have a modest incentive to pursue even greater productivity initiatives and customer bills will go down, all else equal, to the extent Union delivers earnings in excess of the 300 basis point threshold. The parties acknowledge that the elimination of the "off ramp" review in section 9.1 is without prejudice to all rights afforded under section 6.1 (Z Factors) of the IR Settlement Agreement;

3. provides greater certainty and incentive for Union to explore and make investments in productivity improvements during the term of the 2008 to 2012 IR plan;

4. continues to provide for annual reviews during the term of the IR plan during which intervenors will be able to carefully review the reasons and calculation of sharing for all earnings in excess of 200 basis points over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan.

5. avoids complex, lengthy and highly controversial and contested disputes over the potential for termination of the IR plan and the need for a new full cost of service proceeding. In this case, intervenors took the position, for example, that the proper calculation of weather normalized utility earnings in 2008 was materially in excess of the 300 basis point threshold which gave intervenors the right to seek a review of the IR plan, the consideration of adjustments to the components of the IR plan, including base rates, and the termination of the IR plan and a return to cost of service rates, just as Union would have had the right to take the same position had the company under-earned by an equivalent amount. Union took the position that the IR plan was working as contemplated and producing significant benefits for customers and that the termination of

1 Union does not currently forecast exceeding the 300 basis point threshold in 2009 or 2010.

incentive regulation after the first year of the five year plan was premature and inappropriate. Union will be applying in 2012 for 2013 cost of service rebasing in any event; and

6. avoids complex, lengthy and highly controversial and contested disputes over 2007 base rates and the potential for further adjustments to those base rates during the IR plan. For example, intervenors took the position that Union's 2007 normalized utility earnings were materially higher than the forecast available during the period in which the IR Settlement Agreement was negotiated and that adjustments to the IR plan, such as altering the size of the earnings sharing deadband, altering the level of earnings sharing, and adjustments to 2008 earnings sharing and/or to base rates during the IR term could be made to take account of this positive variance. Union took the position that such variances were not relevant to 2008 earnings sharing and that no adjustments to the IR plan or to base rates during the IR term, except those, such as Z factors, expressly contemplated by the IR Settlement Agreement, should be made. This issue involved a number of potentially controversial disputes, including disputes over the appropriate calculation methodology, the extent to which the likelihood of favourable variances, and the extent of those variances, was, or ought to have been, known to all parties when the IR Settlement Agreement was negotiated and whether base rate adjustments of this kind are appropriate during the IR term.

The financial consequences of this Agreement for the calculation of 2008 earnings sharing under the IR Settlement Agreement are set out in Appendix A attached to this Agreement. The adjustments in the Agreement to Union's original proposal are the result of compromise by the agreeing parties of their respective positions on the matters listed above. In all of the circumstances, the parties have agreed to increase the customer share of Union's 2008 earnings from the proposed $15.2 million to $34.2 million, as outlined in Appendix A.

Consistent with past practice, the customer portion of the amount calculated in Appendix A shall be allocated to rate classes in proportion to Board approved return on equity as set out in the allocation schedule in Appendix B attached to this Agreement. Of the $34.2 million customer share of earnings for 2008, approximately $19.6 million will be allocated to small volume general service customers and approximately $3.2 million will be allocated to large volume general service customers. Approximately $4.7 million will be allocated to the large volume contract customers and approximately $6.7 million to M12 shippers such as Enbridge Gas Distribution Inc. ("EGD"), Gaz Métropolitain inc. ("GMi"), and TransCanada PipeLines Limited ("TCPL"). Approving the settlement reflected in the Agreement, therefore, will benefit all customers but, in particular, will provide benefits to small volume general service customers.

Evidence References:

1. A/p.9-20, A/p.27-29, A/App. B/S.1, A/App. B/S.2, A/App. B/S.3, A/App. D/S.1, A/App. D/S.2
2. Technical Conference, pp. 19-28, 33-34
3. B/T1/S6, B/T2/S1, B/T2/S3, B/T4/S7, B/T4/S8, B/T5/S3
4. J1.1

UNION GAS LIMITED
Earnings Sharing Calculation
Year Ended December 31, 2008

Line No	Particulars ($000's)	2008 (a)	Non-Utility Storage (b)	Adjustments (c)		2008 Utility (d)=(a)-(b)+(c)
	Operating Revenues:					
1	Operating revenue	$ 1,869,283	$ -	$ (3,654)	i	1,865,629
2	Storage & Transportation	243,317	78,230	-		165,087
3	Other	33,818	-	(7,530)	ii	26,288
4		2,146,418	78,230	(11,184)		2,057,004
	Operating Expenses:					
5	Cost of gas	1,171,320	8,082	-		1,163,238
6	Operating and maintenance expenses	335,115	12,028	(516)	iii	322,571
7	Depreciation	185,219	4,966	-		180,253
8	Other financing	-	-	535	iv	535
9	Property and capital taxes	65,895	953	-		64,942
10		1,757,549	26,029	19		1,731,539
11	Earning Before Interest and Taxes	$ 388,869	$ 52,201	$ (11,203)		$ 325,465
	Financial Expenses:					
12	Long-term debt					143,546
13	Unfunded short-term debt					2,805
14						146,351
15	Utility income before income taxes					179,114
16	Income taxes					31,300
17	Preferred dividend requirements					5,088
18	Utility earnings					142,726
19	Long term storage premium subsidy (after tax)					10,676
20	Short term storage premium subsidy (after tax)					7,484
21						18,160
22	Earnings subject to sharing					$ 160,886
23	Common equity					1,205,196
24	Return on equity (line22 / line 23)					13.35%
25	Benchmark return on equity					10.81%
26	50% Earnings sharing %					1.00%
27	90% Earnings sharing to ratepayer % (line 24 - line 25 - line 26)					1.54%
28	50% Earnings sharing $ (line 26 x line 23 x 50%)					6,026
29	90% Earnings sharing to ratepayer $ (line 27 x line 23 x 90%)					16,697
30	Total earnings sharing $ (line 28 + line 29)					22,723
31	Pre-tax earnings sharing (line 30 / (1 minus tax rate))					$ 34,170

Notes:

i) Accounting adjustment

ii) Shared Savings Mechanism

iii) Donations (394)
EB-2008-0304 costs (122)
(516)

iv) Customer deposit interest

UNION GAS LIMITED
Allocation of 2008 Earning Sharing to Rate Classes

Line No.	Particulars	Rate Class	C2007 Return on Equity Allocation (1) ($000's) (a)	2008 Earning Sharing ($000's) (b)
	Northern & Eastern Operations Area			
1	Small Volume General Firm Service	01	44,549	(5,867)
2	Large Volume General Firm Service	10	8,234	(1,084)
3	Medium Volume Firm Service	20	4,263	(561)
4	Large Volume High Load Factor Firm Service	100	5,641	(743)
5	Large Volume Interruptible Service	25	1,913	(252)
6	Wholesale Transportation Service	77	8	(1)
7	Total Northern & Eastern Operations Area		64,608	(8,509)
	Southern Operations Area			
8	Small Volume General Service Rate	M1	104,130	(13,715)
9	Large Volume General Service Rate	M2	15,828	(2,085)
10	Firm Industrial and Commercial Contract Rate	M4	4,220	(556)
11	Interruptible Industrial & Commercial Contract Rate	M5A	2,587	(341)
12	Special Large Volume Industrial & Commercial Contract Rate	M7	2,617	(345)
13	Large Wholesale Service Rate	M9	219	(29)
14	Small Wholesale Service Rate	M10	10	(1)
15	S & T Rates for Contract Carriage Customers	T1	12,835	(1,691)
16	S & T Rates for Contract Carriage Customers	T3	1,548	(204)
	Storage and Transportation			
17	Cross Franchise Transportation Rates	C1	186	(24)
18	Storage & Transportation Rates	M12	50,557	(6,659)
19	Transportation of Locally Produced Gas	M13	39	(5)
20	Storage & Transportation Services - Transportation Charges	M16	55	(7)
21	Total Southern Operations Area		194,830	(25,661)
22	Total		259,438	(34,170) (2)

Notes:
(1) Allocated costs per 2007 Decision in EB-2005-0520
(2) Earning Sharing balance for Disposition as per EB-2009-0101, Settlement Agreement, Appendix A

uniongas
A Spectra Energy Company

June 4, 2009

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 26th Floor
Toronto, ON
M4P 1E4

Dear Ms. Walli:

Re: EB-2009-0101 – Settlement Proposal
Union Gas Earnings Sharing and Incentive Regulation Review

Please find enclosed two copies of Union's Settlement Proposal.

If you have any questions, please contact me at (519) 436-5275.

Yours truly,

[original signed by]

Mark Kitchen
Director, Regulatory Affairs

cc M. Penny (Torys)
EB-2009-0101 (Intervenors)

TAB 10

RP-1999-0017

IN THE MATTER OF the *Ontario Energy Board Act*, 1998,

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 in accordance with a performance based rate mechanism commencing January 1, 2000;

AND IN THE MATTER OF an Application by Union Gas Limited for an order approving the unbundling of certain rates charged for the sale, distribution, transmission and storage of gas.

BEFORE: George Dominy
Presiding Member and Vice Chair

Malcolm Jackson
Member

DECISION WITH REASONS

July 21, 2001

Board Findings - Treatment of Market-Priced Storage

2.499 The Board notes that in EBRO 494-03, issued in 1997, the Board gave approval to the application of market-based rates to certain ex-franchise storage contracts, under certain terms and conditions. The Board also notes that in that proceeding Union provided, among other things, an updated 10-year peak storage availability and utilization forecast that the Board found was "reasonable under a business-as-usual scenario".

2.500 The Board notes that with the exception of VECC no parties argued against the renewal of M12 contracts at market-based rates. VECC's opposition was based on the concern that this action would open the door to the use of market-based rates for in-franchise customers. The Board notes Union's acknowledgment that this would only be possible were the Board to approve such rates for in-franchise customers. The Board has also heard concerns about the ability of parties who have "rights" to storage at cost-based rates to take advantage of the arbitrage opportunity that may exist in the market directly or indirectly. In the Board's view one potential approach might be to apply market-based rates for all storage with a mechanism to fairly distribute any premium over cost-based rates. The Board would require more complete information on the storage market before adopting such an approach.

2.501 At issue in this proceeding was the treatment of any premium that exists due to the differential between market price and the embedded cost of storage. The Board notes that in a previous hearing, EBRO 486-02, Union argued that the premiums resulting from market-based rates for storage services rightfully belonged to ratepayers because the ratepayers had "substantiated" the asset; i.e., that since the ratepayers had taken on the risk and paid rates designed to cover the costs, they should receive any reward. The Board also notes that the market price referred to in discussing this issue is not necessarily a surrogate for a market price in a competitive market.

2.502 The Board notes that it has in the recent past provided an incentive to Union, through a sharing of the premium on transactional services, to encourage the Company to pursue opportunities to increase the efficient use of the assets. The Board has not to date applied any sharing with regard to the premium on storage. The Board recognizes that there should also be an incentive to efficiently manage the existing storage capacity in Ontario. With respect to the development of new storage during a PBR plan period, incentives will be dealt with within the related applications.

2.503 The Board notes that on the one hand, if it had a reliable current forecast of service volumes for the PBR plan period and a reasonable forecast of market prices for storage during the plan period, there would be no need for any deferral account to capture the variance arising from the difference between market-based rates and fully distributed cost-based rates. On the other hand, given the service volume uncertainty and the lack of a reasonable forecast for market-based prices for storage the approach of deferring the variance (premium) seems prudent.

2.504 The Board grants Union's proposal to renew existing ex-franchise cost-based storage contracts (M12) at market prices. However, with respect to Union's proposal to eliminate the deferral account for recording the market premiums from these arrangements, the Board finds it appropriate, given the volume and price uncertainties expected during the term of the Board-approved PBR plan maintain a deferral account for recording market premiums. The Board notes that in Chapter 4 the Board denies Union's request to close the transactional services deferral accounts.

2.505 The Board recognizes that the assets necessary to provide both transactional services and long-term storage services have been paid for by Union's customers. Providing the Company with a financial incentive to maximize revenues for these services should increase benefits to both the customer and the shareholder. Consequently the Board authorizes a sharing of net revenues for transactional services and market premium for long term storage services in the ratio of 75:25 between ratepayers and shareholder as an incentive to maximize the revenue associated with both these services. The balance in the Long-Term Storage Premium Deferral Account (179-72)

TAB 11

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™, 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:

- 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.

TAB 12

Exhibit J20.10

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

TAB 13

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?

TAB 14

Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2011-0210

VOLUME: 7

DATE: July 20, 2012

BEFORE:

BEFORE:	Marika Hare	Presiding Member
	Paul Sommerville	Member
	Karen Taylor	Member

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

TAB 15

VT INCEPIT FIDELIS SIC PERMANET

Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2012-0087

VOLUME: Technical Conference

DATE: August 21, 2012

brief compendium of additional materials which we rely on in this proceeding and which we would ask be marked as an exhibit.

MR. MILLAR: KT1.2.

EXHIBIT NO. KT1.2: COMPENDIUM OF ADDITIONAL MATERIALS OF UNION GAS LIMITED.

PRESENTATION BY MR. SMITH:

MR. SMITH: Just by way of opening comments, we have the Board Procedural Order No. 3, so parties are aware, in Union's view, this proceeding concerns optimization or transportation revenues in 2011; does not concern earlier or subsequent years.

So to the extent evidence from the 2013 proceeding has been incorporated by Union, it comes with that caveat. Union's view is the 2011 revenues are relevant to this proceeding, whereas other years, be they subsequent or preceding, are not relevant.

As I indicated a minute ago, we incorporated the transcripts from the 2013 rate proceeding that relate to the issues, as we understand them, reflected in the Board's procedural order, and certainly it is Union's position that this technical conference is not an opportunity to re-conduct examination that has already taken place.

So we are obviously -- want to be as efficient as possible. The Board has heard a good deal of evidence in relation to these matters already and we make that observation.

I did have, Mr. Millar, just a couple of brief questions I am going to ask the panel. They are to Mr. Isherwood.

Mr. Isherwood, at KT1.2, there is a reference to a TCPL news release and a service on page 2 referred to as FT make-up. Do you have that, sir?

MR. ISHERWOOD: I do.

MR. SMITH: Can you just describe for me what is or what was FT make-up?

MR. ISHERWOOD: FT make-up was a service that TCPL introduced for the year 2002 only. When you read the description there, it reads very similar to FT RAM. And why it is similar is that FT make-up essentially allowed for any unused demand charges in any given month to be used as a credit towards any IT volume shipped on the same month.

So that is exactly the same at FT RAM. This is an earlier version of it, but it is really the first time you saw this type of service was 2002.

MR. SMITH: And can tell me whether or not this was a service that Union made use of?

MR. ISHERWOOD: Yes. We would have used it the same as we would use FT RAM today. So we would have taken any credits that we created, and we would have used those towards IT service exchange, sort of paying for an IT service that we would have used to underlie or underpin an exchange service.

MR. SMITH: And did Union, in fact, make use of FT make-up?

MR. ISHERWOOD: We would have, yes.

MR. SMITH: And how were they treated, from a regulatory perspective, these transactions that you undertook?

MR. ISHERWOOD: They would have been treated exactly the same as FT RAM is treated today. They would have been treated through the transportation exchange account as revenue.

MR. SMITH: And we have in Mr. Thompson's compendium - I will just read it, but I believe this was also marked - actually, this was marked in Exhibit K6.4 from the 2013 case, so I will just read the reference.

But Union indicated in RP -- or EB-2003-0087 and RP-2003-0063 at page 6 of 16:

> "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."

Is the FT make-up that is referred to in your evidence at page 6 of EB-2003-0063 the FT make-up you have just described?

MR. ISHERWOOD: Yes, it is.

MR. SMITH: And, Ms. Elliott or perhaps Mr. Isherwood, just picking up on my question about regulatory treatment, were these amounts recorded in a deferral account at the time?

MS. ELLIOTT: Yes. At the time those revenues were earned, we had a deferral account for short-term transportation and exchange revenues.

MR. SMITH: Which deferral account was that?

MS. ELLIOTT: 179-69.

MR. SMITH: And, Mr. Isherwood, can you provide or, if it is possible, can you describe how an exchange using FT RAM or an exchange that takes advantage of FT make-up are similar or vary?

MR. ISHERWOOD: There was an undertaking taken actually, JT1.6, where we described an exchange, a base exchange, where we actually provided an exchange from Dawn to Niagara, and we actually paid -- had to pay cash for the underlying IT that supported that transaction.

There was a second example in the same undertaking where we actually paid for the underlying IT transportation on TransCanada using the credits.

MR. SMITH: Which credits?

MR. ISHERWOOD: The credits from FT RAM. That was an example where we were trying to compare base exchange with and without FT RAM.

And we would have done or could have done the same type of transaction in 2002, and, instead of using the credits from FT RAM, we would have used the credits from either FT make-up or AOS.

MR. SMITH: Just picking up on your last answer, can you describe what the AOS service was?

MR. ISHERWOOD: AOS is basically TCPL was providing free transportation, essentially, IT transportation, equivalent to 4 percent of all your demand charges you were paying TransCanada in that month.

So if you were paying a dollar of demand charge, you would get 4 percent or 4 cents of equivalent credit on IT. So we would use that IT again to fund transactional activity.

MR. SMITH: And was this a service that Union took advantage of?

MR. ISHERWOOD: It was.

MR. SMITH: And how was it treated, from a regulatory perspective?

MR. ISHERWOOD: It would have been treated the same as the FT make-up credits, the same transportation exchange deferral account.

MR. SMITH: How does it compare, mechanically or conceptually, to FT RAM?

MR. ISHERWOOD: Conceptually it is very similar, in that you are given credits to use in the month. So you have a firm transportation contract, and, based on that firm contract, you are given credits that can be used on IT transportation in the same month on any path.

So very similar in concept to what FT RAM is today.

MR. SMITH: And, Ms. Elliott, we talked earlier about FT make-up transactions. Can you just describe the regulatory and deferral account treatment, if any, in relation to AOS?

MS. ELLIOTT: Again, to the extent that they were tools used to facilitate exchange services for revenue, that revenue would have been captured in the short-term transportation and exchange revenue deferral account.

MR. SMITH: Those are the questions I intended to ask, Mr. Millar.

MR. MILLAR: Thank you, Mr. Smith. Mr. Thompson, did you want to go first?

MR. THOMPSON: Yes, please.

QUESTIONS BY MR. THOMPSON:

MR. THOMPSON: I did circulate electronically a compendium of materials on behalf of CME last night, and I assume the company has been able to download that stuff. Am I right, Mr. Isherwood?

MR. ISHERWOOD: Yes, that's correct.

MR. MILLAR: Should we mark that, Mr. Thompson?

MR. SMITH: Mr. Millar, I think we should mark it. I do not agree -- and this was an observation I made during the 2013 case, but I do not agree that all of the material incorporated in Mr. Thompson's compendium is appropriate, at least to put to Union witnesses.

There are, for example, partial excerpts from the decisions -- Consumers Gas decisions. They're not obviously facts that the Union panel, at least, is aware of.

So it is -- I am prepared to have it marked as an exhibit, but it is with the caveat that I don't agree all of the materials necessarily are appropriate, although we will have to see what Mr. Thompson says as we go through his questions.

MR. MILLAR: Thank you. We will mark it for identification purposes. To the extent there are objections or refusals, we will deal with those as they arise. It will be Exhibit KT1.3, and that is the CME compendium for the technical conference.

EXHIBIT NO. KT1.3: CME TECHNICAL CONFERENCE COMPENDIUM.

MR. THOMPSON: Thank you.

Now, just to put my examination in context, I will pose my questions to you, Mr. Isherwood, and if others need to jump in, please don't hesitate to do so.

If you go to tab 36 of the compendium, you will see the Procedural order No. 3 that the Board issued that gave rise to this technical conference.

And the preliminary issue that the Board has framed for consideration in this proceeding is expressed at page 3 of the procedural order.

Do you see that, Mr. Isherwood?

MR. ISHERWOOD: I am on page 3, yes.

MR. THOMPSON: And the issue that the Board has framed for determination in this proceeding is:

"Has Union treated the upstream transportation optimization revenues appropriately in 2011 in the context of Union's existing IRM framework?"

I hope I read that correctly.

Then on the next page, the Board says:

"The focus of the technical conference will be on

MR. SMITH: That is the amount recorded on line 3.
MR. THOMPSON: Thank you.
And then the amount, the net RAM revenue for 2011, is, at line 1, 22 million; have I got that straight?
MR. ISHERWOOD: That's correct.
MR. THOMPSON: And if those are classified as reduction in gas costs, that is the amount that should go back to ratepayers?
MR. ISHERWOOD: I think this table describes how FT RAM credits are used and how ratepayers benefit in other ways, including earnings sharing, which is 14.5 on line 2.
On line 4, there is funding of LBA balance, as well, of 0.6.
MR. THOMPSON: I'm sorry. I think the 0.6 has already gone back to ratepayers at line 4.
That is what J3.2 tells us, I believe, which you can find at tab 46.
MR. SMITH: Mr. Thompson, I don't know whether this will help or not, but -- Ms. Elliott may be able to make this observation, but I am not sure it is as simple as taking out the $7.5 million, in that if were you to reclassify exchange revenue as you are positing, that would have an impact on total earnings, which would have an impact potentially on earnings sharing.
MR. THOMPSON: Right. I was coming to that.
I was suggesting, first of all, the 22 million would go back to ratepayers, but our suggestion is earnings sharing would be reduced by $14.5 million. That is what we

say in our letter, and I am just trying to see if we have a disagreement there.

MS. ELLIOTT: That's correct, as far as it goes.

There are probably some costs, as well, incurred to earn the $22 million that need to be considered. But if you are just looking at the revenue, the revenue difference is the $22 million worth of revenue, exchange revenue related to the RAM activities.

MR. THOMPSON: What do you mean their costs? It is net RAM revenue already.

MS. ELLIOTT: There is actually some O&M costs incurred that are part of the cost of delivering those revenues.

MR. THOMPSON: But they're not netted out in net RAM revenues?

MS. ELLIOTT: Not in the net revenue, no. The net revenue refers to netting off upstream transportation costs incurred to facilitate the service.

MR. THOMPSON: So what is the O&M we're talking about?

I mean, is it material? And how -- where does it come from?

MS. ELLIOTT: I am actually looking at two exhibits that were filed in the rate case. Exhibit 6.1 and 6.2 were calculations of the deferral account if the deferral account had been maintained, one excluding RAM and one including RAM.

And the difference there is 19.8, not the 22 million.

MR. THOMPSON: Those are responses to Mr. Aiken, I to the document at tab 9 of the brief.

MR. ISHERWOOD: That's correct.

MR. THOMPSON: Then this describes:

"An exchange it 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."

MR. ISHERWOOD: That's correct.

MR. THOMPSON: And if Union is receiving the gas - in other words, if Union is Party B - is Union providing the exchange?

MR. ISHERWOOD: It depends on the transaction. So Union could be receiving the gas and still selling the exchange. We could still be earning a revenue even though we're receiving the gas. So it really depends on the actual -- on the actual transaction.

MR. THOMPSON: Okay. Well, that is not a typical exchange, is it?

MR. ISHERWOOD: Typical with FT RAM.

MR. THOMPSON: Pardon?

MR. ISHERWOOD: It is typical with FT RAM.

MR. THOMPSON: I'm talking typical historically.

MR. ISHERWOOD: Before FT RAM, it would not be typical, but with FT RAM it is typical.

MR. THOMPSON: I'm dealing with history. We will get to FT RAM in a minute.

So are we on common ground when I suggest that exchange revenues are the outcome of a transactional service provided by Union to a third party?

MS. ELLIOTT: Yes. That would be the definition of an exchange revenue.

MR. THOMPSON: All right. Now, I would like to turn, then, to the nature of the gas supply assets that support transactional service, and I think this -- a transactional service, and this takes us to tab 8, as well as tab 10.

This is, again, an historical presentation by Union in the 0063 case, and we have the prefiled evidence at tab 8. Have I got that straight, Mr. Isherwood?

MR. ISHERWOOD: Not quite yet. Okay.

MR. THOMPSON: This, again, now talks about the forecast -- this is a section entitled "Transactional Services Forecast". Do you see that?

MR. ISHERWOOD: Yes.

MR. THOMPSON: Referencing exchanges and the other services, and then it talks about forecast methodology.

Down at the bottom, it starts to talk about the gas supply plan?

MR. ISHERWOOD: Yes.

MR. THOMPSON: Do you see that?

MR. ISHERWOOD: I do.

MR. THOMPSON: And over on the second page, it says:

> "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."

Is that the way it works?

MR. ISHERWOOD: That's the way it worked in May 2003; that's correct.

MR. THOMPSON: Well, when did that change?

MR. ISHERWOOD: I think FT RAM, as we testified to in the 2013 case, provided a whole different framework to operate within. But back in 2003, when FT RAM did not exist, then there were few assets available.

MR. THOMPSON: All right. So when did you start changing your -- from a balanced gas supply portfolio?

MR. ISHERWOOD: We always had the gas supply portfolio balanced. We have never changed that at all. It was changed as to how we optimize that portfolio.

And as I mentioned with Mr. Crawford's earlier cross-examination, there was some of that happening in 2002. That was really introduction of the FT make-up and AOS, which had characteristics similar to FT RAM. We would have done a bit of it that year, but certainly not until FT RAM got up and running in 2008, 2009 before we got into it in a big way.

MR. THOMPSON: Okay. Well, moving down in testimony here, the statement is made at line 14:

> "The actual assets available for S&T transactional services will change on an ongoing basis, dependent upon actual weather and market factors..."

Do you see that?

MR. ISHERWOOD: I do.

MR. THOMPSON: And that indicates to me that the gas supply capacity available to support transactional services depends on factors beyond the company's control, i.e., weather and market?

MR. ISHERWOOD: That's true. And I would add to that services of TransCanada, as well, like FT RAM. That certainly wasn't expected in 2003.

MR. THOMPSON: So you're characterizing a service from TransCanada as a factor beyond somebody's control?

MR. ISHERWOOD: I would say that service attribute was beyond our control in terms of it coming into place.

MR. THOMPSON: Well, let's put it this way. Can we agree that these FT RAM opportunities have not been prompted by changes in weather or market factors?

MR. ISHERWOOD: I think they were partly derived because of market factors. TCPL was trying to encourage people to maintain FT capacity in their pipeline. So the fact they were losing large volumes to do contracting, it drove them to think of things like FT make-up, AOS and FT RAM. So it was driven by market factors.

MR. THOMPSON: Well, I guess we can agree they're not caused by weather --

MR. ISHERWOOD: Not by weather.

MR. THOMPSON: -- unpredictable weather? All right. We will have to argue the market factors point.

Now I would like to move, if I could, to another part of the history, which is the closure of -- matters pertaining to the closure of four of these transactional features of FT, as well, that we would transact around, for example, diversion rights.

So FT has a lot of flexibility in it, and we would use that flexibility to optimize.

MR. THOMPSON: All right. Is what you have here -- well, let's just turn to what you do with this.

One of the steps that you -- or one of the ways that, as you say, "optimize" FT RAM is that you simply use the IT service that is available if you decide not to use your FT and, instead, use the IT?

MR. ISHERWOOD: Yes. An example of that would be we would leave empty our Empress -- our Empress to EDA capacity, FT capacity empty, and that would create FT RAM credits.

MR. THOMPSON: Right.

MR. ISHERWOOD: And we would purchase an IT service on the day that would go from Empress to, say, the WDA or NDA. And the remaining credits we would use to offset the cost of an exchange. So we would be providing an exchange to a third party and partially or wholly fund that through the credits we got from the FT RAM.

MR. THOMPSON: And I think you describe this in J7.6, which is at tab 42 and it is on the second page. You say a similar transaction could have been completed had Union retained the capacity, leave the Empress eastern zone empty, earn credits and so on.

MR. ISHERWOOD: Yes.

MR. THOMPSON: Use the IT. That is not an exchange?

MR. ISHERWOOD: Leaving the pipe empty is not an exchange. Buying the -- or using the IT service on TransCanada from Empress to the NDA is not an exchange.

But the exchange is then the part where we actually move a third party's gas from somewhere on Union's system to somewhere off our system, or, likewise, off our system onto our system.

MR. THOMPSON: But in terms of the IT, the credits that you get access to in and the IT that you use, that is merely exercising your contractual rights with TransCanada?

MR. ISHERWOOD: But the only reason we're doing that is because of FT RAM. If we didn't have FT RAM, there would be no economic incentive to do that transaction. And, as we testified in the 2013 rebasing, it is all based on the fundamental premise that the gas supply plan is there to serve the needs of all of our customers in all of the different delivery areas.

And to the extent we can move gas to different delivery areas and optimize, then we can take advantage of the RAM credits we create.

MR. THOMPSON: Well, you are getting cheaper transportation under the FT contract, are you not?

MR. ISHERWOOD: No. We are optimizing the long haul contract.

MR. THOMPSON: Well, optimizing means you are reducing the costs.

MR. ISHERWOOD: Optimizing means we're finding different ways of serving the end-use customers. They still get the gas that they require. We are still buying the gas that we have planned to buy.

We are just optimizing how we deliver them to them, and that creates credits that we can use for exchanges and it gets flowed through our exchange account.

MR. THOMPSON: All right. Well, we will argue what it all means, that's for sure.

MR. MILLAR: Mr. Thompson, we're about 11 o'clock and probably looking to take a break soon. I am not sure how long you have. Would this be a good point or...

MR. THOMPSON: I would be about 15 minutes longer.

MR. MILLAR: Why don't we take our break, then? Is 15 minutes long enough for a break?

MR. SMITH: Oh, yes.

MR. MILLAR: 11:15, then.

--- Recess taken at 11:00 a.m.

--- On resuming at 11:22 a.m.

MR. MILLAR: Are we ready to get started again? Everybody?

Would you like to continue, Mr. Thompson?

MR. THOMPSON: Yes, thanks.

Let me move from the one form of transaction that we were discussing to the other form, which is capacity assignments. And you discussed that in this Exhibit J7.6, as well as a number of other documents that have been filed in the 0210 proceeding.

Now, in terms of a situation where the market rendered FT service temporarily surplus, does the company have an obligation to minimize the UDC that arises?

MR. SMITH: Sorry, can you just repeat that question? I missed the first part of it.

MR. THOMPSON: In a situation where the market renders FT service as surplus, temporarily surplus, does the company have an obligation to mitigate the UDC?

MR. SMITH: No, we don't agree with that.

MR. THOMPSON: Well, I am just asking the question. Do you have an obligation?

MR. SMITH: And I am -- I mean, if the general proposition, Mr. Thompson, you are trying to suggest is that the company has a legal obligation to optimize for the benefit of ratepayers, as you have put it in this case, we obviously don't agree with that.

And so I don't agree with the way in which you have asked the question.

MR. THOMPSON: All right. You have provided evidence and it is in the material that if you forecast UDC and effect an assignment of TCPL capacity with respect to that UDC, that flows through to ratepayers; am I right?

MR. ISHERWOOD: I think the differentiation here is: Does the system need the molecule to actually gas supply? So our gas supply plan will anticipate us having to buy a volume of gas based on the plan to each of the different delivery areas, and to the extent we don't need the gas supply - there had been a warm winter, for example, and we no longer need a gas supply - we will assign away capacity and try and obtain some value for that capacity. And that is flowed through back to the ratepayers.

MR. THOMPSON: That flows through back to the ratepayers?

So when weather prompts the action, the consequences of mitigating UDC flows back to ratepayers?

MR. ISHERWOOD: So if you have to mitigate UDC relative to gas supply plan, then that would flow back to the ratepayers.

MR. THOMPSON: All right. So let's, then -- and in capacity assignment mechanism that you use to monetize FT RAM credits, you have told us in the 0210 case that it is a bundled transaction?

MR. ISHERWOOD: I guess I would be -- I think that word was used, but be careful with the word "bundled." It is really two independent transactions.

We still assign away the TCPL pipe, which is a standard TCPL assignment, which we -- on their paper, essentially, that we do.

That is the first step, if you want, of the transaction.

MR. THOMPSON: Right?

MR. ISHERWOOD: The second step of the transaction is we actually sell an exchange where they would deliver that gas to a different delivery area.

MR. THOMPSON: Well, are you selling or acquiring an exchange?

This is where I get a little confused.

MR. ISHERWOOD: The actual transaction, the actual paperwork would -- it would be viewed as a selling of an exchange. We actually earn revenue from that -- that second piece of the transaction.

MR. THOMPSON: Well, but the way I understood it when you described it previously is that the amount that is received for the assignment, less the amount you need for the exchange, produces revenues, produces a positive amount for Union; is that a fair way of putting it?

MR. ISHERWOOD: So looking at the two individual steps, we would pay the marketer for the value of the long-haul FT contract. So if it was to the EDA, it would be the 2.24 per gJ; we would pay them the 2.24.

And then for the exchange, where they would -- we would give them gas at Empress and they would give us gas in the NDA, they would pay us whatever, whatever the negotiated rate is, 20 cents, 30 cents.

And that exchange revenue then flows into our transportation exchange account.

MR. THOMPSON: But am I right the amount you get from the marketer is greater than the 2.24? It would have to be to produce revenue?

MR. ISHERWOOD: We pay the marketer, on the first step, 2.24. We pay them that, because that is what our gas supply plan had us paying to TransCanada.

We assign the pipe to the marketer, and therefore we owe the marketer the 2.24 to keep them whole on that pipe.

Likewise, our customers are kept whole, as well. That is the same number that they were expected to pay for that transportation.

The second phase of that transaction is we do an exchange where we give them gas at Empress, they give us gas back at the NDA or WDA, and we get paid for that. So it's actually we're selling an exchange.

MR. THOMPSON: So what is the amount, though? Is it more than the 2.24?

MR. ISHERWOOD: No. It is going to be a negotiated amount. It will be the value -- it's going to be the value of the exchange. It would be 20 cents, 30 cents, 40 cents, depending on what path we're using and what the value of it is in the market.

MR. THOMPSON: I don't understand why you pay someone to whom you assign the FT, 2.24. I mean the whole purpose of assigning it is to have the assignee take responsibility for the 2.24.

MR. ISHERWOOD: But the pipe is being kept empty. So in that transaction, what we're -- what the gas plan was calling for was for us to pay TransCanada 2.24.

And instead of paying TransCanada, we're paying the marketer 2.24, and we're still buying the gas at Empress.

MR. THOMPSON: Well, the -- what's the 2.24 for?

MR. ISHERWOOD: I'm just using that as a reference point; I may be off by a penny or so. But 2.24 is TCPL's toll to go from Empress to the EDA.

MR. THOMPSON: Yes. And you are paying to that to a marketer?

MR. ISHERWOOD: The same -- we pay the marketer the same 2.24.

MR. THOMPSON: Why, when you have assigned them the capacity?

MR. ISHERWOOD: That's why I said at the beginning you have to look at this as being really a two-phase transaction.

So how it is papered is step one, which is we pay them the 2.24. That keeps our gas costs whole and keeps our customers whole.

Then for the transactional revenue, they pay us the 30 cents or 40 cents or whatever the number negotiated is.

MR. THOMPSON: Strange transaction.

Well, when you assign unused FT capacity in a scenario where the monies flowing -- the benefits from the assignment are flowing back to ratepayers, the assignee gets the FT RAM credits, right?

MR. ISHERWOOD: That's right.

MR. THOMPSON: And that adds value to the assignment?

MR. ISHERWOOD: It does.

MR. THOMPSON: So are you paying the marketer anything in that scenario?

MR. ISHERWOOD: Yes. Typically, we would.

So we typically look at UDC but assume that we're exposed to the full 2.24, but when we go to release that pipe into the market, the market would have a value on the pipe, and it won't typically be 2.24. It might be $1.50 or $1.80 or $2.

The difference between what the marketer is willing to pay and the 2.24, we would pay that amount to the marketer, because they're ultimately responsible to TCPL for the 2.24.

MR. THOMPSON: So what are the savings, then, in the assignment that flows through to the benefit of ratepayers? How do you achieve them?

MR. ISHERWOOD: Because of FT RAM? Is that your question?

MR. THOMPSON: No. Just a normal assignment of unused capacity, my understanding is the market pays a spread?

MR. ISHERWOOD: Market value, that's right.

MR. THOMPSON: Pays the market value. And that market value would go into the deferral account and be credited to ratepayers. Now you are describing a scenario that sounds very strange to me, but maybe I am missing something.

MR. ISHERWOOD: I think ultimately the person we assign the pipe to has to pay 2.24. So --

MR. THOMPSON: That's why they're buying the pipe.

MR. ISHERWOOD: Right. But if the market value is only $1.80, we would pay the difference, and that is true with or without RAM. It is whatever the difference is between market value and the full toll, the utility would have to pay that to the marketer.

MR. THOMPSON: All right. So the difference, then, between what you get from the marketer and the 2.24 is the credit to ratepayers in a traditional assignment of surplus capacity. I mean, TransCanada is going to get 2.24. The way I understood it was the marketer -- you, in effect, give that capacity to the marketer for a discount.

Do you keep paying the 2.24 to TransCanada and receive $1.70 from the marketer, the $1.70 goes into the deferral account and flows back to ratepayers?

MR. ISHERWOOD: I think where we're missing each other is, when we assign the pipe to the marketer, the marketer assumes the obligation to pay the TransCanada bill. So they have to pay the 2.24.

MR. THOMPSON: Right.

MR. ISHERWOOD: But if the market value is a buck 84, then there is 40 cents still to be paid by somebody. So it would be paid by Union.

MR. THOMPSON: Right. But the ratepayers are relieved of $1.84?

MR. ISHERWOOD: That's correct.

MR. THOMPSON: So that's the credit. And so why isn't that the same situation in this bundled transaction that you have described?

MR. ISHERWOOD: In the bundled transaction, there is no need for the ratepayer to have UDC. The plan is in balance. We are optimizing the plan.

So the plan is working perfectly. There is a market opportunity, largely created by FT RAM, that allows us to go in and optimize the plan. So we're creating the UDC, if you want. We're creating the opportunity to gather the FT RAM credits.

MR. THOMPSON: Yes. So that is not a transactional service.

MR. ISHERWOOD: Absolutely.

MR. THOMPSON: You actually create UDC?

MR. ISHERWOOD: But that is part of the transaction. The transaction is to create the UDC, to create the credits to sell the exchange.

MR. THOMPSON: I thought we had agreed at the outset that if -- that the gas supply plan assets that are needed to support transactional services are those that are freed up by weather or market forces. Now you're saying we can create it ourselves.

MR. ISHERWOOD: Well, but I also said back in that line of cross-examination, back in 2003 before FT RAM -- FT RAM has opened up a larger scope of optimization than we had prior to -- than we had prior to 2007.

MR. THOMPSON: All right. Well, I will move on.

You mentioned some of these prior cases where you talked about -- I forget what it was. There is the TransCanada release that you referenced.

Has the company ever, at any time, obtained explicit approval from the Board to convert FT RAM credits to profits?

MR. SMITH: I don't think that this is a factual question, Mr. Thompson. I don't think we are under an obligation to tell you that.

MR. THOMPSON: All right.

MR. SMITH: But, as you know, it was -- optimization by Union Gas, including optimization using FT RAM, was explicitly adverted to by Union in the 2009-0101 case.

Dawn at a fixed amount for the whole winter, it was variable amount month to month, and it was actually an Emerson-to-Dawn service that -- they wanted us to fill their pipe between Emerson and Dawn.

How we treated -- or how we extracted transaction revenue was much different between those two years.

This is the subject of the first year, this one, but I just want to point out that we did things differently the second year.

MR. THOMPSON: But am I right that what you have done here is -- what was in your forecast was the purchase of some commodity at Dawn, and then what you did was you decided: Well, I'll lend my gas at Dawn using DOS MN and displace the commodity cost that I had forecast?

That is what this is telling me.

MR. ISHERWOOD: So the gas supply plan would have had us buying gas at Dawn that winter.

MR. THOMPSON: Right. That would be a commodity spot price at Dawn? Is that the way it would work?

MR. ISHERWOOD: It would have been a monthly price at Dawn, probably. Maybe seasonal, but at least monthly.

Instead of that, we bought the gas at Empress and flowed it using the DOS MN service, which was a very inexpensive transportation path.

MR. THOMPSON: So you got lower commodity landed cost at Dawn, and that displaced what you had forecast by way of commodity. So this is now optimizing commodity?

MR. ISHERWOOD: Through this optimization activity, we're able to land gas at Dawn cheaper than we otherwise would have.

MR. THOMPSON: But the element of the plan that is being, if you will, substituted for is commodity. This is not a transportation switch, this is commodity displacement; is that right?

MR. ISHERWOOD: In this example, I would say we're still buying the same amount of gas, so not unlike what we do with FT RAM. We're finding a different way of getting it delivered for the customer, that is cheaper.

MR. THOMPSON: Is the element of the forecast that is being, if you will, substituted for or displaced a commodity forecast, as opposed to a transportation forecast?

MR. ISHERWOOD: I think we're finding a different way of getting gas to Dawn, that is cheaper.

MR. THOMPSON: All right. Now, finally with respect to earnings sharing and whether this activity does or does not lead to earnings sharing, the -- in 2011, the dead band, am I right the dead band was 200 basis points before -- on earnings sharing?

MS. ELLIOTT: That's correct.

MR. THOMPSON: And what does 200 basis points translate into in terms of revenue requirement, roughly? Two hundred basis points on equity?

MS. ELLIOTT: About 36 million.

MR. THOMPSON: Thanks very much. Those are my -- oh, sorry. Just with respect to this package that you have

MR. QUINN: Rough numbers. I'm talking hypothetically.

So what holds Union back from delivering 20 percent more commodity at virtually no cost to Dawn using that same type of construct?

MR. ISHERWOOD: Because of the gas supply plan, you don't need the commodity.

MR. QUINN: Okay. Presuming that you had the foresight to plan ahead for this opportunity, what, if anything, would hold you back from delivering 20 percent more at Dawn?

MR. ISHERWOOD: You have to go back, Mr. Quinn, to the gas supply plan, and the gas supply plan is based on the premise of firm assets, as you know.

And as I said earlier on, if this gas were to naturally flow to FT RAM, it would go to the EDA and back to Dawn using STS. It is really two things that are in play here. One is the fact we have FT RAM, which creates more opportunity than otherwise, but the most important factor is you have a market need to do an exchange.

If the market need for the exchange didn't happen, this gas would flow to the EDA and will come back to Dawn on STS, and that would be the end of it.

MR. QUINN: Is the market need paramount to your gas supply plan?

MR. ISHERWOOD: No, but the market need is paramount to the optimization plan.

MR. QUINN: It is paramount to the optimization plan, but you have purchased these assets for the primary benefit of getting gas to your customers here in Ontario; is that right?

MR. ISHERWOOD: No, but the other interest here obviously is we have transactional revenue built into our forecast, which goes to offset rates, and we have an incentive, through the incentive regulation mechanism on a couple of different fronts, to actually try to do as much optimization as possible.

MR. QUINN: So you can do that optimization instead of serving the gas supply program with your assets?

MR. ISHERWOOD: The gas supply program is served through the gas supply plan, which was extensively discussed in the last proceeding.

MR. QUINN: Right. So does that gas supply plan take into account the opportunities created by FT RAM?

MR. ISHERWOOD: It does not. The gas supply plan is based on the premise of needing firm assets in a firm -- firm delivery areas.

MR. QUINN: But you said earlier it was firm assets to meet a peak day need, plus having the seasonal ability to deliver the amount of gas you need to Ontario; correct?

MR. ISHERWOOD: There was the one graph that Mr. Shorts and, I think, Mr. Quigley had gone through extensively, that showed sort of the average day being delivered on FT. And STS is really the swing that is used for both filling storage in the summer and meeting peak winter demands.

for the exchange.

So either FT RAM went away or the market need for the exchange at the end of this all went away. We would just flow naturally to the EDA and back on STS.

MR. QUINN: You keep coming back to this; it is driven by the market need. I thought the assets were purchased for gas supply need primarily.

MR. ISHERWOOD: But the optimization activity is driven by the market need.

MR. QUINN: Correct, but these assets were purchased for supply need.

MR. ISHERWOOD: If you go back to even 1993, as we talked about, this transactional and exchange account, we've had a long history of using exchanges to optimize the gas supply plan. And those exchanges are always being driven by a market need.

MR. QUINN: They may be driven by a market need, but that wasn't the primary purpose for entering into the contract; is that correct?

MR. ISHERWOOD: It was the primary purpose of doing the exchange and optimizing that.

MR. QUINN: Why was the contract purchased in the first place?

MR. SMITH: Which contract are you talking about?

MR. QUINN: We're talking about the same contracts that Mr. Isherwood is saying there is a market need here. I'm saying if you --

MR. SMITH: Mr. Isherwood is saying there is a market need for an exchange.

MR. ISHERWOOD: For the exchange itself.

MR. QUINN: But the contract is not entered into for the purposes of meeting the market need --

MR. ISHERWOOD: No, but the optimization opportunity is created by the market need for the exchange transaction.

MR. QUINN: So when you enter into a contract, the 20,000 units to the EDA, what is the purpose for entering into that contract?

MR. ISHERWOOD: I will go back to the beginning.

The gas supply plan -- you're asking the same question over and over again, so I'll give you the same answers.

MR. QUINN: No. I am asking: Why did you get the contract?

MR. SMITH: Let Mr. Isherwood answer the question, sir.

MR. ISHERWOOD: The gas supply plan is designed to meet the market needs in each of the different delivery areas.

As we have talked about, Mr. Quigley runs his modelling and he does his evaluation and comes up with the total amount of asset, upstream asset that he needs, and storage asset for that matter, as well.

And that becomes the gas supply plan, which is the foundation of where we start from.

MR. QUINN: You use market need in the answer to that question and the previous one.

MR. SMITH: He clearly means customer need.

MR. ISHERWOOD: Customer need, and -- well, it's the market need. It's a market need in the EDA, a market need in the NDA. They all have --

MR. QUINN: There is a difference between market need driven for optimization purposes and market need by your customers needing gas to consume.

MR. QUINN: Let me start at the beginning.

The gas supply plan is to meet the system supply customer need in each of the delivery areas.

MR. QUINN: And that is why entered into the contract?

MR. ISHERWOOD: That's why you enter into the contract.

MR. QUINN: That's one, to start with.

So you have now entered into a contract. You have a choice of what to do with the contract; you're choosing to assign it?

MR. ISHERWOOD: No. The gas supply plan is intended to be fulfilled as per the plan.

MR. QUINN: But in this case of 20,000 that is part of J6.5, you've chosen to assign it?

MR. ISHERWOOD: That's a different activity, though. Now we're into the optimization of the assets.

And we have a long history of going back to '93, and we have the transportation exchange account that allows us for that activity. We have revenue built into our rates that encourage us to at least get that level of revenue through exchanges, and even to exceed that through sharing, earlier on, deferral accounts, and later on, through earnings sharing.

MR. QUINN: And you've made the choice to optimize and assign the contract to somebody else and specify the delivery point? That is what we're seeing in J6.5?

MR. ISHERWOOD: And to my earlier point -- and to be clear on my market need this time -- there is always a secondary market where people want to go from point A to point B.

And in this case, a market has a need for the exchange, and it is that market need that is creating the need for the other activity. It is the optimization activities create the exchange.

MR. QUINN: Well, I will just put it on the record. We would like that to be completed. I have your answer that you are not going to complete it -- sorry, to be fair, you are going to consider completing it.

We will act accordingly.

I'm on the record as saying, though, I would accept that undertaking Monday if that precludes any risk of me using it for rebasing, because that was the presumed intent that Mr. Smith said, but that wasn't my intent.

MR. SMITH: Okay.

MR. QUINN: So I want to cover a couple of more things, and you might be happy to say none of these are hypothetical, or maybe some of these would be categorized that way.

In talking to Mr. Thompson this morning, he was trying to understand the table that he was referring to, and you

TAB 16

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.

TransCanada

TransCanada PipeLines Limited
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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,

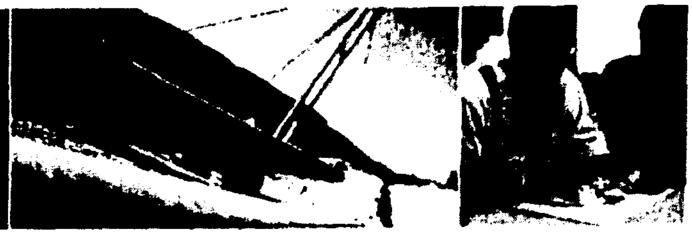
Original Signed by

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).

TransCanada
In business to deliver

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).

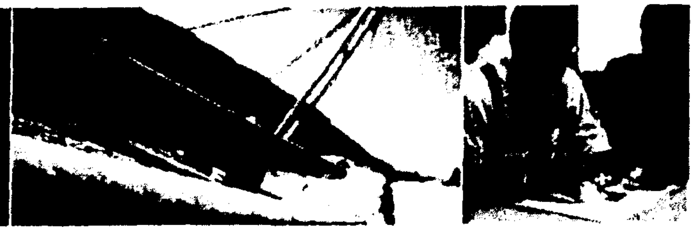
On February 9, 2007 the TTF approved, as an unopposed resolution, an extension of the FT-RAM pilot for an additional two-year term commencing November 1, 2007 and ending October 31, 2009 (Resolution 03.2007)

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.

TAB 17

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.

TAB 18

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.

TAB 19

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

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	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

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	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

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	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

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	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]	**UNION GAS LIMITED**
Authorized Signatory	*Authorized Signatory*
______________________	______________________

TAB 20

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.

TAB 21

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

TAB 22

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.

Question: December 9, 2008
Answer: December 16, 2008
Docket: EB-2008-0220

TAB 23

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.

ARGUMENT OF CANADIAN MANUFACTURERS & EXPORTERS ("CME")

December 31, 2008

Borden Ladner Gervais LLP
World Exchange Plaza
100 Queen Street
Suite 1100
Ottawa ON K1P 1J9

Peter C.P. Thompson, Q.C.
Vincent J. DeRose
Counsel for CME

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D. Y Factor Adjustments

(a) Upstream Transportation Costs

33. In Exhibit B2.2, Union indicates that it has contracted for what CME understands to be some cheaper upstream transportation made available by TCPL. The interrogatory response states "Union is not treating any benefit associated with the use of the DOS-MN as a Y Factor." CME questions why reductions in upstream transportation costs are not being flowed through to the benefit of Union's ratepayers.

34. CME requests that Union explain in its Reply Argument why these cost reductions in upstream transportation are not being passed through to ratepayers as part of the upstream transportation costs Y Factor.

(b) Storage Margin Sharing Changes

35. In Exhibit B3.5, Union reports that the actual 2007 long term peak storage revenues were $32.22M, compared to the $21.405M forecast embedded in base rates, for a variance of $10.817M. The response indicates that, as a result of the Board's Decision in EB-2008-0154, ratepayers will be credited with an additional $5.917M for 2007 as part of the 2008 deferral account disposition. CME questions why ratepayers should have to wait until the 2nd quarter of 2009 to receive the balance of their 2007 share of storage premiums.

36. CME also considered whether the $21.405M forecast embedded in rates is materially low, and considered making a submission to the effect that the amount embedded in base rates for storage margin sharing in 2009 be increased.

TAB 24

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, 2009

REPLY ARGUMENT OF UNION GAS LIMITED

1. This is Union's Reply argument. It follows the headings used in Union's Argument in Chief. As the Reply endeavors not to repeat arguments already made, it should be read in conjunction with Union's Argument in Chief.

2009 Inflation Factor and Productivity Factor

2. Intervenors universally accepted Union's application with respect to the inflation and productivity factors as filed. Accordingly Union's proposals for the 2009 inflation and productivity factors should be accepted.

Z Factor Adjustments

3. Union is proposing Z factor adjustments for two matters in 2009: 1) the cost consequences associated with changes in taxation levels, as determined by the Board in EB-2008-0292; and 2) the cost consequences of adopting International Financial Reporting Standards ("IFRS").

4. Intervenors universally accepted Union's proposed Z factor treatment of the taxation levels. Accordingly, Union's proposals for the pass through of tax savings should be accepted.

28. By letter dated December 19, 2008, the Board indicated that Union should file a motion to vary if it wished to change the third condition of approval established in EB-2008-0304. Union filed a motion to vary the EB-2008-0304 Decision in this respect on January 7, 2008. Accordingly, while that issue is outstanding, it would be inappropriate and premature to implement any rate change based on this condition.

Y Factor Adjustments

29. Intervenors either accepted Union's evidence or did not provide comment with respect to the proposed Y factor adjustments.

30. In addition, CME and IGUA invited Union to comment on the treatment of the revenues from the DOS-MN service offered by TCPL.

31. The DOS-MN service is part of Union's transportation portfolio that is available for optimization through S&T transactional activity. Benefits resulting from transactions to optimize transportation capacity have historically been and will, in the future, continue to be recognized as part of Union's regulated S&T transactional activity. The forecast margin from this type of transactional activity has long been recognized in the determination of rates.

32. The forecast margin from all S&T transactional activity included in rates was increased significantly in the 2007 rates settlement agreement. This margin was further increased in the incentive regulation settlement agreement when certain deferral accounts were eliminated (IR settlement agreement, p.33). The entire updated forecast was included in the determination of rates in 2008 for the benefit of ratepayers. The net result of these changes was to provide ratepayers with a fixed level of benefits from S&T transactional activity through the incentive regulation period, and to provide 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.

33. Actual results for the year will be included in Union's determination of utility earnings, and will be subject to any earnings sharing, thereby providing the potential for further ratepayer benefit.

Long-Term Peak Storage Margin

34. Union confirms that rate payer credit related to 2008 long-term peak storage margins will be disposed of as part the 2008 deferral disposition proceeding.

Average Use Factor

35. Intervenors either accepted Union's proposal or did not provide comment with respect to the average use factor. Accordingly, Union's proposals for the AU factor should be accepted.

Annual Adjustment to General Service Monthly Charges

36. Intervenors either accepted Union's proposal or did not provide comment with respect to the general service monthly charge adjustments. Accordingly, Union's proposals for these adjustments should be approved.

Other Rate Schedule Changes

37. Intervenors either accepted Union's proposal or did not provide comment with respect to the other rate schedule changes. Accordingly, Union's proposals should be accepted.

Recovery of Rate Changes from January 1, 2009

38. Intervenors either accepted Union's proposal or did not provide comments with respect to the approval of rates effective January 1, 2009 and the recovery of rate changes from between the implementation date and January 1, 2009. Accordingly, these rate changes should be approved.

Conclusion

39. In conclusion, Union asks the Board to issue a rate order effective January 1, 2009 to reflect the proposed changes in rates as submitted by Union in this proceeding.

TAB 25

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.

The Board granted intervenor status to the Consumers Council of Canada ("CCC"), the Industrial Gas Users Association ("IGUA"), the Energy Probe Research Foundation ("Energy Probe"), the Vulnerable Energy Consumers Coalition ("VECC"), the School Energy Coalition ("SEC"), the Association of Power Producers of Ontario ("APPrO"), the Ontario Association of Physical Plant Administrators ("OAPPA"), Ontario Power Generation, Sithe Global Canadian Power Services Limited, Jason Stacey, Ontario Energy Savings L.P., TransCanada Pipelines Limited, TransCanada Energy Limited, the London Property Management Association ("LPMA"), Kitchener Utilities ("Kitchener"), Canadian Manufacturers and Exporters ("CME"), Direct Energy Marketing Limited, ECNG Energy L.P., Enbridge Gas Distribution Inc., and Hydro One Networks Inc.

On November 28, 2008 the Board issued Procedural Order No.1 which set the dates for the filing of interrogatories, interrogatory responses, submissions and argument for the written proceeding.

On December 10, 2008 Union filed a Notice of Motion seeking an order declaring Union's rates interim effective January 1, 2009 on the basis that the proceeding timetable did not contemplate the Board's issuance of a 2009 rate order in time for January 1, 2009 implementation. On December 16, 2008 the Board issued an order making Union's rates in effect as at January 1, 2009 interim.

THE APPLICATION

Union said that the rates proposed under the Incentive Rate Mechanism ("IRM") for 2009 were determined in accordance with the Board approved EB-2007-0606 Settlement Agreement and Addendum (collectively the "Settlement Agreement"). The topics covered in Union's evidence included the 2009 Inflation and Productivity Factors, Y and Z factor Adjustments, Average Use Adjustments and Annual Adjustments to General Service Monthly Charges as defined in the Settlement Agreement

Union's proposals and requested approvals included:

- An increase of $1.00 in the monthly fixed charge (from $17.00 to $18.00) for the residential classes M1 and Rate 01 on a revenue neutral basis;

- A specification that under Delayed Payment the monthly late payment charge of 1.5% equates to an effective annual interest rate of 19.56%;

- Maintenance of existing deferral/variance accounts;

- Unchanged miscellaneous non-energy charges;

- Y factor amounts of $1.84 million for DSM and $5.351 million for the reduction in the in-franchise ratepayers share of long-term storage margins;

- General Service class Average Use of Gas adjustments for 2009;

- 2009 Inflation Factor of 1.54% and a 1.82% productivity factor used to calculate the proposed rates; and

- Z factor adjustment of the costs associated with the conversion to International Financial Reporting Standards ("IFRS") for recovery in rates.

Union also noted in the Application that it had filed a motion for review and variance of the Board's EB-2007-0606 decision, dated July 31, 2008, related to treatment of tax changes and risk management. The Board heard the Motion, under docket EB-2008-0292, and issued its decision on December 10, 2008. Union, in its Argument-in-Chief dated December 19, 2008, recognised that the proposed 2009 rates, as originally filed, would have to be adjusted downward to reflect the Board's decision.

Subsequent to the filing of interrogatory responses, Union, by way of a letter dated December 18, 2008, advised the Board that its proposed Average Use adjustment was in error. Union confirmed that the draft rate order which Union will file following the Board's decision will incorporate the correct calculation.

THE ISSUES

CCC, SEC, IGUA, CME, Board Staff, APPrO, LPMA, Kitchener and VECC filed submissions. Except for the following, the submissions accepted Union's evidence or remained silent on non-contentious matters.

Parties questioned Union's proposed Z factor treatment of IFRS costs. Union described the conversion to IFRS as a Canadian Accounting Standards Board requirement that all publicly accountable enterprises adopt IFRS in place of Canadian Generally Accepted Accounting Principles. Union forecasted the conversion costs (pre-tax) to be $1.511 million in 2009, $1.510 million in 2010, $.691million in 2011 and $.497 in 2012. For the most part, the intervenors took issue with the appropriateness of using forecasted rather than actual costs and the assertion that the $1.5 million Z factor threshold was met each year.

Other issues raised by intervenors included Union's reluctance to file the schedules pertaining to its 2007 actual financial results as required by the Settlement Agreement and Union's failure to implement the Board's direction in EB-2008-0304 decision to reduce 2009 rates by $1.3 million. In EB-2008-0304 Union sought the Board's leave for a proposed transfer in controlling interest and reorganization.

IGUA and CME also asked Union to comment on and explain Union's treatment of TransCanada Pipelines' new "Dawn Overrun Service-Must Nominate ("DOS-MN"). DOS-MN was described as a cheaper transportation service. IGUA and CME questioned why Union considered DOS-MN as related to Storage and Transportation Revenue rather than Upstream Transportation. Under the Settlement Agreement, Upstream Transportation costs are considered as Y factor adjustment items, and, as such, their cost impact flows through to rates. In instances when Upstream Transportation costs decrease, ratepayers would benefit, and, correspondingly, ratepayers would bear the costs when the costs increase. Under the Settlement Agreement variances in Storage and Transportation Revenue items do not flow through to rates.

Board Findings

International Financial Reporting Standards

Union is proposing Z factor treatment of IFRS costs. On this basis, Union is seeking to recover in rates, starting in 2009, the revenue requirement impact of the costs Union forecasts to incur associated with the transition to IFRS. The forecasted conversion costs are summarized in Table 1.

Table 1: IFRS Conversion Costs

(in millions)	2008	2009	2010	2011	2012
Capital Investment	$ .592	$ 1.334	$ .283	-	-
Annual Carrying Cost *	$ .086	$ .363	$ .581	$ .595	$ .497
Operating & Maintenance	$ .882	$ 1.148	$ .929	$ .096	-
Total Annual (pre-tax) Cost	$ .968	$ 1.511	$ 1.510	$ .691	$ .497

* comprised of depreciation and interest

Source: Exhibit A-1 p6 table 1

Union indicated, in its response to Interrogatory B5.1, that the forecasted Operating and Maintenance costs include expenses for consulting, additional staff, project management administration and audit fees. A component of the consulting and the project management expenses will be shared equally with Union's Canadian affiliate, Westcoast. In this regard, Union stated that its share of the costs in 2008, 2009 and 2010 would be $.0578 million, $.222 million and $.0788 million respectively, which are subcomponents of the OMA.

Parties, for the most part, questioned the appropriateness of Union's proposed Z factor treatment for three reasons. First, costs were being claimed for recovery in years where the annual costs did not meet the $1.5 million Z factor threshold. Second, the amount proposed for recovery was based on forecasted rather than actual costs. Third, when the annual threshold was exceeded, it was by a small amount. These three concerns highlighted the need to examine the forecasted cost components, including timing, and the basis of any cost sharing with Union's affiliates. In the event that the Board approved Union's proposal, many parties advocated the establishment of a variance account to capture differences between forecasted and actual costs.

In order to succeed in its proposal, Union must demonstrate that its claim for Z factor treatment conforms with the terms of the Settlement Agreement of January 3, 2008. Section 6 of that Settlement Agreement defines the criteria that govern consideration of Z factors. Most notably for our consideration of Union's proposal is the requirement that:

> *"...the cost increase/decrease meets the materiality threshold of $1.5 million annually for Z factor event (ie. the sum of all individual items underlying the Z factor event)."*

There are two components of this definition which are directly relevant to Union's proposal.

First is the requirement that the Z factor is to be considered on an annual basis. Union's proposal would extend Z factor treatment of expenses associated with IFRS transition to 2009, 2010, 2011 and 2012. In the Board's view it is premature to consider the application of Z factor treatment to any cost increases associated with IFRS transition to any year beyond 2009. If Union believes that Z factor treatment is appropriate for 2010, or any of the other years of the IRM plan, it must make application year by year.

Second is a requirement that the cost increase or decrease meet the materiality threshold of $1.5 million. In this case Union has asserted that the costs associated with the transition to IFRS accounting methodology in 2009 would amount to barely $11,000 over the materiality threshold of $1.5 million. This is a very slender margin.

In advancing a claim for Z factor treatment for a category of increased cost, the Board expects an applicant to provide convincing and compelling evidence supporting the proposal. Of course the most compelling evidence for Z factor treatment is the actual expenditures associated with the category of expense. That is not available here. Instead Union has provided forecast costs associated with the transition. Although Union's evidence stated that Ernst and Young LLP ("E&Y") assisted in the development of the forecast, Union did not provide any documentation authored by E&Y in its evidence.

The forecast also includes the proposed 50/50 split of some of the associated cost as between Union and its relevant affiliate Westcoast, discussed earlier. Union's evidence outlined the rationale for the 50-50 sharing of these costs based on the assets of the companies involved. Although these shared elements are small, we note that the extent to which the annual threshold is exceeded is less than these amounts. This may be a reasonable method to allocate the costs. However, due to the absence of any detailed evidence on the nature of the costs, the Board cannot determine if the allocation is appropriate.

In the Board's view, Union has not provided convincing and compelling evidence in support of its claim for Z factor treatment. Given that its proposal is based exclusively on forecasts of costs it is incumbent upon the applicant to provide as full and as convincing a record as possible supporting these forecasts. It is a meaningful burden, which reflects the extraordinary nature of Z factor treatment and is coloured in part by the very slender margin by which Union's own projection exceeds the threshold.

Accordingly the Board denies Union's application for Z factor treatment for the costs associated with the transition to IFRS accounting.

Given this finding, it is unnecessary for the Board to consider any other ground urged upon it by the intervenors which may have the effect of disqualifying Union's proposal.

Implementation of the Board's Decision in EB-2008-0304

Under docket EB-2008-0304, Union had applied to the Board for leave to transfer the voting shares of Union to a limited partnership, contemplated as a Nova Scotia unlimited liability company, the entire interest in which would be held by Westcoast Energy Inc. In the decision approving the re-organization, the Board made the approval subject to the condition that Union's rates will be reduced effective January 1, 2009 to reflect $1.3 million in savings related to the redemption of preferred shares that had been identified in the proceeding.

A number of intervenors in this proceeding submitted that Union had failed to follow this direction and that Union's proposed 2009 rates should be adjusted to reflect this ratepayer credit. Union responded that since it had filed a Motion to vary the EB-2008-0304 decision, it would be inappropriate and premature to implement any rate change concerning the $1.3 million in savings.

The Board acknowledges that Union has filed a motion for the review and variance of the Board's EB-2008-0304 decision. The Board has assigned file number EB -2009-0022 to this motion. The Board also acknowledges Union's earlier correspondence which indicated that the reorganization underpinning the Board's decision and which gave rise to the requirement that a $1.3 million reduction in the revenue requirement be reflected in the 2009 rates has not been implemented.

However, as of the date of this decision, the Board's order requiring the reduction in revenue requirement for 2009 rates stands. Accordingly, the 2009 revenue requirement 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.

The Filing of 2007 Financial Information

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.

Upstream Transportation Changes

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 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.

DATED at Toronto, January 29, 2009

ONTARIO ENERGY BOARD

Original Signed By

Pamela Nowina
Presiding Member and Vice Chair

Original Signed By

David Balsillie
Member

Original Signed By

Paul Sommerville
Member

TAB 26

UNION GAS LIMITED

Undertaking of Ms. Elliott
To Mr. Quinn

To provide the evidence related to the derivation of the SPCD from the Generic QRAM Proceeding (EB-2008-0106) and, if necessary, the 2004 Rate Proceeding (EB-2003-0063)

The North PGVA captures gas cost variances in gas supply commodity only. The balance is calculated by deferring actual Empress gas costs against the Alberta Border Reference Price each month. North transportation deferred costs are not included in the North PGVA but instead are accounted for in the TCPL Tolls & Fuel - Northern & Eastern Operations deferral account (No. 179-100). Account No. 179-100 captures variance between actual TCPL tolls and those approved in rates.

The South PGVA captures variances between the forecasted landed cost of gas (both gas supply and transportation costs) to serve sales service customers in Union South and the Ontario Landed Reference Price. The Ontario Landed Reference Price is calculated by adding the TCPL EDA toll and fuel to the Alberta Border Reference Price. As the forecasted landed cost of serving South sales service customers based on Union's South Portfolio will differ from the landed cost of serving those customers from Empress to the TCPL EDA, the South PGVA will always have a debit or credit balance. This debit or credit balance is recovered from South sales service customers through the South Portfolio Cost Differential ("SPCD").

As noted above, the SPCD is determined by comparing the forecasted landed cost of serving South sales service customers, based on Union's South Portfolio, to the cost of serving these customers from Empress to the TCPL EDA. An example of the calculation can be found at Attachment 1. The SPCD is added to or subtracted from the TCPL EDA toll to determine the South transportation rate. Please see Attachment 2 column g). The result is sales service customers in the South are charged a rate for regulated gas supply service equivalent to the expected landed cost over the forward 12-month period.

Please see Attachment 3 for Exhibit E2 page 8-15 from Union's prefiled evidence from the Generic QRAM proceeding (EB-2008-0106).

Please see Attachment 4 for Exhibit D1, Tab 1 page 21-23 and D1, Tab 3, page 7-9 from prefiled evidence from Union's 2004 rates application (RP-2003-0063).

Union has also attached Tab 1 from the prefiled evidence for Union's July 2012 QRAM application (EB-2012-0249) as Attachment 5.

UNION GAS LIMITED
Calculation of South Portfolio Cost Differential & South Transportation Rate
For the 12 month period ending June 30, 2013

Line No.	Particulars				
1	South Purchased Gas Variance Account (SPGVA) ($000's)	$	106,472		(1)
2	South Consumption Volumes (PJ's)		112.0		(2)
3	South Portfolio Cost Differential (Line 1/Line 2)	$	0.951	/GJ	
4	TCPL Transportation EDA Toll	$	2.243	/GJ	
5	South Portfolio Cost Differential (Line 3)	$	0.951	/GJ	
6	South Transportation Rate (Line 4 - Line 5)	$	1.292	/GJ	

Notes:
(1) Tab 1, Schedule 3, page 4, Column (g), Line 27.
(2) Demand forecast for South sales service customers for the period July 2012 to June 2013.

Filed: 2012-08-29
EB-2012-0087
Exhibit JT1.2
Attachment 2

Filed: 2012-06-06
EB-2012-0249
Tab 1
Schedule 3
Page 4 of 6

UNION GAS LIMITED
Deferral Account for
South Purchased Gas Variance Account
(Deferral Account 179-106)

Line No.	Particulars	Purchase Cost ($000's)	Volume (GJ)	Weighted Avg. Price ($/GJ)	Reference Price ($/GJ) (1)	Unit Rate Difference ($/GJ)	Monthly Deferral Amount ($000's)	Southern Portfolio Cost Differential Adjustment ($000's)	Deferral Amount Before Interest ($000's)	Adjustments ($000's)	Total Deferral Before Interest ($000's)	Interest ($000's) (2)	Total Deferral Amount ($000's)
		(a)	(b)	(c) = (a)/(b)	(d)	(e) =(c) - (d)	(f) = (b) x (e)	(g)	(h) = (f) + (g)	(i)	(j) = (h) + (i)	(k)	(l) = (j) + (k)
1	Cumulative to end of June, 2011						$ (426,279)	$ 122,912	$ (303,367)	$ 4,558	$ (298,810)	$ (1,195)	$ (300,005)
2	July, 2011 *	$ 39,839	7,928,411	$ 5.025	$ 6.114	$ (1.089)	$ (8,635)	$ 6,511	$ (2,123)	$ -	$ (2,123)	$ (3)	$ (2,127)
3	August *	$ 46,043	9,861,439	$ 4.669	$ 6.114	$ (1.445)	$ (14,250)	$ 6,511	$ (7,739)	$ -	$ (7,739)	$ (11)	$ (7,750)
4	September *	$ 36,972	7,973,324	$ 4.637	$ 6.114	$ (1.477)	$ (11,777)	$ 6,302	$ (5,476)	$ -	$ (5,476)	$ (25)	$ (5,501)
5	October, 2011 *	$ 43,563	9,094,325	$ 4.790	$ 5.808	$ (1.018)	$ (9,257)	$ 8,071	$ (1,186)	$ -	$ (1,186)	$ (36)	$ (1,222)
6	November *	$ 38,586	8,845,637	$ 4.362	$ 5.808	$ (1.446)	$ (12,789)	$ 7,796	$ (4,993)	$ -	$ (4,993)	$ (36)	$ (5,029)
7	December *	$ 38,909	9,173,964	$ 4.241	$ 5.808	$ (1.567)	$ (14,374)	$ 8,071	$ (6,303)	$ -	$ (6,303)	$ (35)	$ (6,338)
8	January, 2012 *	$ 35,390	9,179,200	$ 3.855	$ 5.386	$ (1.531)	$ (14,049)	$ 8,230	$ (5,819)	$ -	$ (5,819)	$ (27)	$ (5,846)
9	February *	$ 29,664	8,587,890	$ 3.454	$ 5.386	$ (1.932)	$ (16,590)	$ 7,699	$ (8,891)	$ -	$ (8,891)	$ (16)	$ (8,907)
10	March *	$ 24,993	8,347,826	$ 2.994	$ 5.386	$ (2.392)	$ (19,969)	$ 8,230	$ (11,738)	$ -	$ (11,738)	$ (12)	$ (11,750)
11	April, 2012	$ 20,115	7,329,657	$ 2.744	$ 4.665	$ (1.921)	$ (14,078)	$ 8,044	$ (6,034)	$ -	$ (6,034)	$ (20)	$ (6,054)
12	May	$ 20,642	7,453,674	$ 2.769	$ 4.665	$ (1.896)	$ (14,129)	$ 8,312	$ (5,818)	$ -	$ (5,818)	$ (43)	$ (5,861)
13	June	$ 22,592	7,218,522	$ 3.130	$ 4.665	$ (1.535)	$ (11,083)	$ 8,044	$ (3,039)	$ -	$ (3,039)	$ (48)	$ (3,088)
14	Total (Lines 1 to 13)	$ 397,307	100,993,869				$ (587,259)	$ 214,733	$ (372,527)	$ 4,558	$ (367,969)	$ (1,508)	$ (369,477)
	Current QRAM Period												
15	July, 2012	$ 28,429	8,923,397	$ 3.186	$ 4.823	$ (1.637)	$ (14,609)	$ 9,043	$ (5,566)	$ -	$ (5,566)	$ -	$ (5,566)
16	August	$ 28,971	8,923,397	$ 3.247	$ 4.823	$ (1.576)	$ (14,066)	$ 9,043	$ (5,023)	$ -	$ (5,023)	$ -	$ (5,023)
17	September	$ 28,793	8,635,546	$ 3.334	$ 4.823	$ (1.489)	$ (12,856)	$ 8,751	$ (4,105)	$ -	$ (4,105)	$ -	$ (4,105)
18	October, 2012	$ 30,420	8,923,397	$ 3.409	$ 4.823	$ (1.414)	$ (12,618)	$ 9,043	$ (3,575)	$ -	$ (3,575)	$ -	$ (3,575)
19	November	$ 31,745	8,477,272	$ 3.745	$ 4.823	$ (1.078)	$ (9,141)	$ 8,751	$ (390)	$ -	$ (390)	$ -	$ (390)
20	December	$ 35,062	8,759,847	$ 4.003	$ 4.823	$ (0.820)	$ (7,187)	$ 9,043	$ 1,856	$ -	$ 1,856	$ -	$ 1,856
21	January, 2013	$ 36,109	8,759,847	$ 4.122	$ 4.823	$ (0.701)	$ (6,139)	$ 9,043	$ 2,903	$ -	$ 2,903	$ -	$ 2,903
22	February	$ 33,367	7,912,120	$ 4.217	$ 4.823	$ (0.606)	$ (4,793)	$ 8,168	$ 3,374	$ -	$ 3,374	$ -	$ 3,374
23	March	$ 36,079	8,759,847	$ 4.119	$ 4.823	$ (0.704)	$ (6,170)	$ 9,043	$ 2,873	$ -	$ 2,873	$ -	$ 2,873
24	April, 2013	$ 34,638	8,477,272	$ 4.086	$ 4.823	$ (0.737)	$ (6,248)	$ 8,751	$ 2,503	$ -	$ 2,503	$ -	$ 2,503
25	May	$ 35,681	8,759,847	$ 4.073	$ 4.823	$ (0.750)	$ (6,567)	$ 9,043	$ 2,476	$ -	$ 2,476	$ -	$ 2,476
26	June	$ 34,808	8,477,272	$ 4.106	$ 4.823	$ (0.717)	$ (6,078)	$ 8,751	$ 2,674	$ -	$ 2,674	$ -	$ 2,674
27	Total (Lines 15 to 26)	$ 394,103	103,789,061				$ (106,472)	$ 106,472	$ 0	$ -	$ 0	$ -	$ 0

* Reflects actual information.

Notes:

(1) The reference price from July 2011 to September 2011 is as approved in EB-2011-0135.
The reference price from October 2011 to December 2011 is as approved in EB-2011-0297.
The reference price from January 2012 to March 2012 is as approved in EB-2011-0382.
The reference price from April 2012 to June 2012 is as approved in EB-2012-0070.
The reference price from July 2012 to June 2013 is as proposed in EB-2012-0249.

(2) Interest is computed on the deferral amount balance net of the actual prospective recovery amount for the quarter prior to the current QRAM period.

methodologies. Union acknowledges that further standardization and streamlining is possible and this evidence will propose some changes to that end.

Union's Current QRAM Methodology

Calculation of Gas Supply Reference Price

Union's quarterly gas supply reference price represents an average cost for gas at Empress (the Alberta Border Reference Price) for the next 12 months. Union determines this price by applying a forward Empress basis differential to the future 12-month NYMEX market prices, applying a foreign exchange rate and weighting these monthly prices by the volume Union plans to buy in each of the 12 months. The result is an average cost per gigajoule in Canadian dollars that represents the forward market price at Empress. The reference price is, therefore, essentially a rolling 12-month price that is updated quarterly. This 12-month average price is intended to smooth seasonal prices or cost anomalies that may be present in any of the individual months, so that customers see a more stable rate on their bills. Quarterly updates to this rate are intended to ensure that the reference price adequately reflects any changing market dynamics.

To set the gas supply commodity charge for both the North and South customers, Union adds compressor fuel and the gas supply administration charge to the Empress reference price specific to each delivery area.

Calculation of PGVA Deferred Balances

Union currently maintains separate PGVA's for the North and South. In the North, Union serves its sales service customers using Western Canadian supplies transported to the North on TransCanada Pipelines ("TCPL"). Accordingly, in the North, actual Empress gas costs are deferred against the Empress reference price each month and the cost variances accumulate in the North PGVA account for disposition to the sales service customers at the next QRAM period. The North transportation deferred costs are not included in the PGVA, but instead are accounted for in separate accounts. The separation is necessary because Union provides transportation services in the North to both sales service and DP customers and the deferred balances are disposed of to this combined group.

The South PGVA captures cost variances in both gas supply commodity and upstream transportation. This treatment is appropriate because DP customers in the South do not pay Union for either the gas supply commodity or upstream transportation. Accordingly, the South PGVA is entirely related to sales service activity and is recovered/refunded from only sales service customers. To calculate the South PGVA reference price Union adds the forward forecast of all gas supply and upstream transportation costs to determine the Ontario landed reference price. Actual gas supply and upstream transportation costs are added together (actual landed cost) and are deferred against this Ontario landed reference price to calculate the South PGVA deferral account balances.

Prospective Recovery of the PGVA Deferred Balances

Each quarter Union identifies the debits/credits that have accumulated in both PGVA accounts during the previous quarter and calculates commodity price adjustments (also referred to as rate riders) that recover/refund accumulated deferral account balances prospectively over the next 12 months. Union also includes in the rate rider any variances between the actual and forecast amounts recovered/refunded from the previous quarter as a result of actual consumption varying from planned consumption over the quarter.

Calculation of Transportation Reference Price and Disposition of Deferred Balances

For customers in the North, Union recovers the approved TCPL tolls for each delivery area as part of the gas supply transportation charge. Any variance between actual TCPL tolls and those approved in rates are deferred to the TCPL Tolls and Fuel deferral account. Like the PGVA accounts, disposition of the deferred balances in these accounts is accomplished through a 12-month price adjustment that is initiated in the subsequent quarter.

As indicated above, Union provides the transportation services to all bundled customers, both sales service and DP customers, in the North. The actual transportation costs, therefore, reflect services to both sales service and DP customers and transportation deferred balances are disposed of to both sales service and DP customers. The North PGVA balances are disposed only to sales service customers.

Under Union's approved QRAM process, gas supply transportation rates are adjusted once new TCPL tolls are approved by the National Energy Board.

The South sales service customer rate for transportation services is determined by comparing the average forecasted landed cost of the South portfolio to what the cost would have been had all the South supplies been purchased at Empress and transported on TCPL. This cost differential, referred to as the South Portfolio Cost Differential ("SPCD"), is added to or subtracted from the Eastern Zone TCPL toll to derive the South transportation rate. The result is sales service customers in the South are charged a rate for regulated gas supply service equivalent to the expected landed cost over the forward 12-month period.

As indicated above, in the South Union provides transportation services to sales service customers only. As a result, the South PGVA captures variances between the Ontario landed reference price and the actual landed cost as associated with serving sales service customers in the South. The balances in the South PGVA are disposed only to sales service customers.

Other Gas Supply-Related Deferral Accounts

In addition to the North PGVA, the TCPL Tolls and Fuel deferral account and the South PGVA, Union maintains the following gas supply related deferral accounts that are disposed of as part of the QRAM process:

- Inventory Revaluation Deferral Account – records the change of inventory value that results when the gas supply reference price is reset each quarter.
- Spot Gas Variance Account – records costs incurred to balance Union's operating system beyond what was forecast in rates.

Both accounts are disposed of prospectively over 12 months.

Distribution Rate Adjustments

Reference price changes driven by Union's QRAM process do not currently cause Union to update its revenue requirement and, as a result, its distribution rates. Union's delivery rate includes the costs associated with gas in inventory, compressor fuel and unaccounted for gas ("UFG"). These delivery-related costs of gas items are not currently updated through the QRAM process. Instead, the price variance between the cost of gas included in Board approved rates and the WACOG determined in the QRAM is captured in the Intra-Period WACOG deferral account. The Intra-Period WACOG deferral account is not disposed of as part of the QRAM process. This account is disposed of annually.

Rate Stability for Customers

It is Union's view that the QRAM provides customers with the appropriate balance between rate stability and market price sensitivity. Rate stability is achieved through Union's QRAM methodology because forecast costs are averaged over the forward 12 months and any past cost variances are also recovered/refunded over the forward 12 months. Changing the gas supply commodity charge quarterly is sufficiently responsive to changing market conditions.

Approximately 35 percent of customers are enrolled in the Equal Billing Plan to achieve further bill stability. In this program, Union averages anticipated monthly bill costs for each customer over a 12-month period starting in September. Customers pay the equal billing amount each month from September to July with a true-up amount in August. Union will adjust the equal billing amount through the year, if required, to accommodate any significant changes in either gas commodity charges or consumption.

At page 17 of the Board's EB-2007-0606/EB-2007-0615 Decision (dated July 31, 2008), the Board commented on the importance both the QRAM and the equal billing plan have on reducing price volatility and smoothing customer impacts. The Board concluded that:

> *"...in the event of price volatility customers are subject to the price impacts, but the use of the QRAM process and the equal billing plan have the effect of smoothing customer impacts generally in any event."*

Examination of Possible Alternatives to Price-Setting Forecast and Disposition Periods

To compare the attributes of Union's current QRAM methodology to other alternative methodologies that may be considered in this proceeding, Union prepared an analysis of what the Empress reference price and the price adjustment (rate rider) would have been under different price adjustment scenarios if these scenarios had been in place over the last four years.

Specifically, Union considered three alternative QRAM scenarios and compared the results to Union's current QRAM process. The scenarios considered were:

1. Monthly Updates with a 12-month Outlook period and a 12-month Deferral Disposition Period.
2. Quarterly Updates with a 3-month Outlook period and a 3-month Deferral Disposition Period.
3. Monthly Updates with a 1-month Outlook period and a 1-month Deferral Disposition Period.

The purpose of this exercise was to determine whether or not, with the benefit of actual information, a better alternative to the current QRAM exists. A better alternative is defined as one that offers improved balance between price stability and market price sensitivity. Stability is measured through a volatility calculation, defined as the range in which prices occurred within one standard deviation of the mean, or 68 percent of the time. Market price sensitivity was measured by calculating the absolute difference between Union's actual cost of gas and the rate approved each quarter through the QRAM process. The actual cost of gas was intended to generally represent market prices. Ideally a preferred QRAM would have low volatility and a low variance to the actual cost of gas. Since these two attributes often move in different directions, it is necessary to strive for a reasonable balance between the two.

The following graphs show the results of the comparative analysis. Union concludes that the current QRAM methodology continues to offer the best balance of stability and price sensitivity.

Joint South/North Accounts

- create joint Spot Gas account
- create joint Inventory Revaluation account
- create joint Unabsorbed Demand Charge account

North Accounts

A separate North PGVA will be established. The North PGVA combined with the North Tolls and Fuel accounts will capture cost variances related to commodity and transportation variance for Union's North customers. Similarly, the Heat Value account is applicable to North customers and will capture costs related to heat value variances. The Firm PGVA account will be closed.

South Accounts

Union has eliminated the OPGCA in response to the load balancing/flexibility directive and to reflect new balancing requirements for direct purchase contracts. Union has also eliminated the South Tolls and Fuel account, also to reflect the load balancing/flexibility directive and associated changes. In place of these accounts, Union will establish the South PGVA, which will track Union's South Portfolio gas cost (including tolls and fuel). As a result of load balancing changes, all gas costs associated with the South Portfolio will flow to South sales service customers.

Since the reference price for the South PGVA is based on the Ontario Landed Reference Price rather than the South Portfolio cost, inappropriate debits/credits will accumulate in the South PGVA on a forecast and actual basis. Credits, for example are created when the South Portfolio costs are less expensive than the Ontario Landed Reference Price. To correct for this, Union proposes the introduction of the South Portfolio Cost Differential ("SPCD"). The SPCD is defined as the difference between the Ontario Landed Reference Price and the South Portfolio cost. Union proposes to adjust the transportation component of the Total Gas Supply Charge for the South by the amount of the SPCD, to reflect the costs of delivering sales service supplies to the South. This adjustment will offset any forecast debits (or credits) projected to accumulate in the South PGVA. Table 2 illustrates the deferral account impact on the South PGVA after the application of the SPCD mechanism, on one unit of volume (see Appendix B – Calculation of Alberta Border and Ontario Landed Reference Price for more detail).

Table 2 - Impact of SPCD on South PGVA

Ontario Landed Reference Price	$6.32
Less:	
Forecast South Portfolio Cost	6.18
South Portfolio Cost Differential (SPCD)	0.14
Net South PGVA Balance	$0.00

Union will continue to use the Alberta Border Reference Price as the basis for the gas supply commodity rate for all customers in the North and South. For the North, the transportation rate will be based on the TCPL tolls to each delivery area. For the South customers, the transportation rate will be based on the TCPL tolls to the EDA, adjusted by the SPCD. This mechanism will ensure all Union's sales service customers will have the same Alberta Border Reference Price. The difference in landed costs to sales service customers in different delivery areas will be primarily reflected in the transportation rates. This is not a new concept, since Union already has multiple transportation rates across the North to reflect the different landed costs in the various delivery areas.

The result will be the elimination of the classification of Flexibility related costs and the recovery of these same costs from South sales service customers through the SPCD.

1. REFERENCE PRICE AND PRICE ADJUSTMENT MECHANISM

As part of the QRAM, Union determines the price of natural gas at Empress. The Empress price forms the basis of the gas supply deferral account reference prices as well as the gas supply commodity rates in both the South and the North.

Under the currently approved QRAM mechanism, Union uses a consensus forecast method to calculate the Empress price. For the purposes of calculating the Empress price, Union is proposing to discontinue the use of the consensus forecast and replace this method with a 21-day average of the NYMEX one-year strip [1] (i.e. for the next 12 months). The 21-day average of the NYMEX one-year strip would be calculated based on a simple average of 21 consecutive days of the closing NYMEX price for the 12 month strip, ending no earlier than 45 days prior to the QRAM implementation date. In this regard the calculation would mirror that used by Enbridge. Union will also add the Empress basis [2] valuation, using sources such as CIBC or TD Bank, to the average NYMEX strip to calculate the Empress one-year futures price. Finally, Union will apply its forecast of risk management costs to the Empress one-year futures price to calculate the Alberta Border Reference Price. The Ontario Landed Reference Price is then calculated as the

[1] Market Strip Price -- The market strip price refers to the average future price over a specified term. The most common strips are the one-year strip (12 months), the summer strip (7 months April to October), and the winter strip (5 months November to March). For example the one-year NYMEX strip starting Nov03 is the average price of the month November 2003 to October 2004 inclusive divided by twelve.
[2] Basis -- The differential that exists at any time between the future or forward price for a given commodity and the comparable cash or spot price for the commodity. Basis can reflect different times periods, product qualities, or locations. For example an Empress basis of minus forty cents US/MMBtu indicates that the value of gas at Empress is worth 40 cents US/MMBtu less than the value of NYMEX gas for the same period.

Alberta Border Reference Price plus 100% load factor TCPL tolls (to the Eastern Delivery Area) plus fuel.

Union also proposes to replace the consensus forecast with market strips, to forecast gas cost deferral balances. The NYMEX one-year market strip plus appropriate market basis will be applied to the planned forecast volumes for each basin where Union acquires supply to determine the projected gas cost deferral balance.

To illustrate, for the January 1, 2004 QRAM, the one year NYMEX strip used to calculate the Empress price will consist of the simple average of the one year futures price for the January 2004 to December 2004 period. This will be calculated at the close of NYMEX trading for 21 consecutives days with the last trading day being no earlier than November 17, 2003. The result of this calculation is then adjusted by the Empress basis valuation to arrive at the Empress one-year futures price. As noted above, Union will then apply the impacts of forecast risk management activity to the Empress one-year futures price to determine the Alberta Border Reference Price.

As noted above, the Alberta Border Reference price, forms the basis of the gas supply commodity rates in the South and the North. This will continue to be the case under Union's proposed QRAM process. As noted at Exhibit D1, Tab 1, Appendix B, Union is proposing to adjust the transportation component of the Total Gas Supply Charge in the South to account for the fact that the South is largely served with non-TCPL supplies. The Southern Portfolio Cost

Differential (SPCD), described in more detail at Exhibit D1, Tab 1, pp. 21 - 23, will also be adjusted as part of the QRAM process. At each QRAM, Union will calculate the difference between the landed cost of the Southern Portfolio and the Ontario Landed Reference Price, and will update the SPCD at each QRAM. Any change in the SPCD will be reflected in the transportation component of the South Total Gas Supply Charge and will impact the "Transportation" line on the customer bill.

Union is proposing that the reference prices and associated gas supply commodity rates be updated quarterly to reflect changes in the one-year market futures price at Empress, inclusive of forecast impacts of risk management activity. Union will update the reference price, SPCD and associated gas supply commodity rates quarterly regardless of the amount of the change, thus eliminating the QRAM price adjustment trigger that is currently $0.05/GJ.

2. Prospective Recovery of Deferral Balances

Under Union's current QRAM, the prospective recovery of deferral account balances is not automatic. The current process does, however, contemplate the prospective recovery of deferral account balances once the approved deferral account trigger balance is exceeded. This has been the case since E.B.R.O. 493/494. In the Board's E.B.R.O. 493/494 Decision with Reasons (dated March 20, 1997) the Board said:

PREFILED EVIDENCE OF

MARY EVERS, MANAGER, GAS SUPPLY

INTRODUCTION

The purpose of this evidence is to set deferral account reference prices to reflect Union's gas cost forecast for the 12-month period commencing July 1, 2012 pursuant to the Quarterly Rate Adjustment Mechanism ("QRAM") as approved by the Board.

1. CURRENT GAS MARKET OUTLOOK

The NYMEX strip has decreased by $0.018 (US$/mmbtu) or approximately 1% since the Board approved April 1, 2012 QRAM filing (EB-2012-0070). The Empress basis has changed from negative $0.669 (US$/mmbtu) to negative $0.557 (US$/mmbtu) while foreign exchange has strengthened (Canadian dollar weakening) from $1.002 to $1.016 over the same period. These factors result in a net increase of $0.168 (CAD$/GJ) to the Alberta Border Reference Price.

2. PRICING

2.1 Alberta Border Reference Price

The approved method for calculating the Alberta Border Reference Price uses the 21-day average of the twelve month NYMEX strip. The NYMEX strip used in this application is for July 2012 to June 2013. The one-year NYMEX strip is converted to an Alberta Border Reference Price by taking into account the Empress-NYMEX basis and the foreign exchange rate for the July 2012 to June 2013 period. (See Tab 1, Schedule 1 for the details of this calculation.)

Based on the approved method, the Alberta Border Reference Price for the period July 1, 2012 to June 30, 2013 is $2.527/GJ. This represents an increase of $0.168/GJ from the Alberta Border Reference Price of $2.359/GJ last approved by the Board in EB-2012-0070.

The Alberta Border Reference Price will be the reference price for the North Purchased Gas Variance Account ("NPGVA") (Deferral Account No. 179-105), and in the TCPL Tolls and Fuel – Northern and Eastern Operations Area deferral account (Deferral Account No. 179-100) with respect to fuel gas. It will also be the reference price for the Spot Gas Variance Account (Deferral Account No. 179-107) for incremental purchases made at Empress.

2.2 Ontario Landed Reference Price

The Ontario Landed Reference Price is $4.823/GJ and is calculated by adding the TCPL EDA toll and fuel to the Alberta Border Reference Price as shown on Tab 1, Schedule 1. This represents an increase of $0.158/GJ from the Ontario Landed Reference Price of $4.665/GJ last approved by the Board in EB-2012-0070. This change includes the increase in the Alberta Border Reference Price of $0.168/GJ plus the associated changes in TCPL compressor fuel costs.

The Ontario Landed Reference Price will be the reference price for the South Purchased Gas Variance Account ("SPGVA") (Deferral Account No. 179-106), and the Spot Gas Variance Account (Deferral Account No. 179-107), for incremental purchases made at Dawn.

2.3 South Portfolio Cost Differential

The South Portfolio Cost Differential ("SPCD") is determined by comparing the projected cost of serving South sales service customers, based on Union's South Portfolio, to the cost of serving South sales service customers based on the Ontario Landed Reference Price. This difference is divided by forecast South Sales Service Demand to derive the SPCD. For the 12-month period beginning July 1, 2012 the SPCD is projected to be $0.951/GJ as shown on Tab 1, Schedule 2. The SPCD results in a South Transportation Sales Rate of $1.292/GJ calculated by subtracting the SPCD of $0.951/GJ from the TCPL EDA toll of $2.243/GJ. This calculation ensures that South sales service transportation rates are appropriately set at a level equal to the projected average cost over the 12-month forecast period.

3. Deferral Accounts

3.1 Impact on Gas Supply Deferral Account Balances

The current forecast of gas cost related deferral account balances at June 30, 2012 is shown on Tab 1, Schedule 3. The opening deferral account balances are the projected deferral account balances at July 1, 2012 plus the projected inventory revaluation adjustment at July 1, 2012.

The deferral account forecast is based on the actual and forecast gas costs for the period July 1, 2012 to June 30, 2013 and on the proposed Alberta Border Reference Price and the Ontario Landed Reference Price effective July 1, 2012.

3.2 Deferral Account Adjustments

To ensure that there is continued alignment between the QRAM deferral account schedules and Union's general ledger, a reconciliation of each deferral account occurs on a monthly basis and any adjustments are included in the QRAM deferral account schedules.

3.3 Prospective Recovery of Deferral Account Balances

July 1, 2012 deferral account balances relating to the North PGVA, North Tolls and Fuel, South PGVA, Inventory Revaluation, and Spot Gas accounts are identified in Tab 1, Table 1.

Table 1
Proposed Prospective Recovery of Deferral Account Balances
Effective July 1, 2012

Line No.	Particulars ($000's)		Total Deferral	
1	North PGVA		(137,727)	(1)
2	North Tolls and Fuel:			
3	Northern Tolls	16,678		
4	Northern Fuel Costs	(2,274)		
5	Total North Tolls and Fuel		14,404	(2)
6	South PGVA		(369,477)	(3)
7	Inventory Revaluation		(4,888)	(4)
8	Spot Gas Variance Account:			
9	Spot Gas	(7,289)		
10	Load Balancing	1		
11	Total Spot Gas Variance Account		(7,288)	(5)
12	Total		(504,975)	

Notes:
(1) North PGVA Account (Deferral No. 179-105) as identified in Schedule 3, Page 2.
(2) North Tolls and Fuel Account (Deferral No. 179-100) as identified in Schedule 3, Page 3.
(3) South PGVA Account (Deferral No. 179-106) as identified in Schedule 3, Page 4.
(4) Inventory Revaluation Account (Deferral No. 179-109) as identified in Schedule 3, Page 5.
(5) Spot Gas Variance Account (Deferral No. 179-107) as identified in Schedule 3, Page 6.

3.4 UDC Account

The Joint Unabsorbed Demand Costs Account balances are not prospectively recovered in accordance with the current Board-approved QRAM process. Union will dispose of any deferral account balances through the annual deferral account disposition process.

TAB 27

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.

<u>Exchanges</u>

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.