EB-2011-0210

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

AND IN THE MATTER OF an application filed by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2013.

CANADIAN MANUFACTURERS & EXPORTERS ("CME") COMPENDIUM OF DOCUMENTS re: Upstream Transportation Cost Reductions

TAB 1

Ontario Energy Board

Ontario

E.B.R.O. 492

IN THE MATTER OF THE
ONTARIO ENERGY BOARD ACT

AND

IN THE MATTER OF AN APPLICATION BY

THE CONSUMERS' GAS COMPANY LTD.

FOR RATES

DECISION WITH REASONS

September 10, 1996

3.3 TRANSACTIONAL SERVICES

3.3.1 The Company provides the following services under the general title of transactional services:

- Gas Loans - the Company delivers a volume of gas to a third party during a defined period, subject to the third party returning an equivalent volume to Consumers Gas at a later pre-defined period.

- Off-Peak Storage - storage service under which no inventory is carried over the peak storage inventory period (typically October 1 to November 15). The storage is offered under Rate 330.

- Released Storage - offered for terms of varying duration, and only if Consumers Gas has existing capacity available in excess of its in-franchise requirements and existing commitments to ex-franchise markets. The service provides for release of firm storage space with firm or interruptible injection and withdrawal rights, pursuant to Rate 330.

- Exchanges - Consumers Gas receives gas from a third party at a receipt point under one of the Company's transportation arrangements, or directly into its distribution system, and causes a like volume of gas to be delivered to the third party at another interconnecting pipeline.

- Assignments - some of the Company's transportation service entitlements are made available to third parties through assignments or through sub-shipper arrangements, when the market demand of the Company's in-franchise customers does not require use of the Company's full contractual transportation entitlement on upstream pipelines such as the TCPL system or the Union Gas system.

3.3.2 The Company stated that the objective of offering transactional services is to make additional use in off-peak periods of the Company's physical and contractual storage and transportation assets acquired in the first place to serve the in-franchise customers. These services have been offered in the past, with any revenues generated credited to the ratepayers. The Company now proposes to market these services more aggressively, and proposes a revenue sharing of the proceeds between the ratepayers and the shareholders.

3.3.3 An associated change in Rate 330 is proposed to allow the Company to charge a broader range of rates to ex-franchise purchasers of transactional services. (See Changes to Rate 330 in Chapter 7) In addition, the Company proposes to modify its queuing policy to allow timely response to market demands, permitting the Company to sell storage capacity to the highest bidder, with queue position used only to determine the purchaser among tied bids. In particular, the Company is proposing:

- elimination of the existing definitions of Short-Term and Long-Term service and creation of new Released Capacity and New Capacity Service categories. The two categories are distinguished by whether or not new storage capability is constructed to provide the service;

- implementation of a bidding process to ensure that the Company receives full market value for its storage services while maintaining a queue to allocate service between parties willing to pay the market rate; and

- implementation of processes to refresh the queues periodically in order to improve the quality of the queues. The Released Capacity Queue will be refreshed annually and the New Capacity Queue refreshed following each offering of new capacity to the queue.

3.3.4 In the case of a tie bid between an Ontario bidder and one from outside the province, the queuing policy proposed would give priority to the Ontario bidder.

3.3.5 Consumers Gas forecast revenues from transactional services of approximately \$1.2 million. The Company proposed to guarantee ratepayers revenues of \$0.6 million, allocate \$0.2 million to shareholders, and absorb \$0.4 million in associated O&M costs. Gross margin, defined by the Company as gross revenues less any direct costs incurred plus any avoided costs, earned in excess of forecast would be split 50/50 between the Company and the shareholder. The Company proposed a deferral account for the ratepayer portion (50 percent) in which of any positive variance over the forecast gross margin received from gas loans, exchanges, off-peak storage, released storage capacity and assignments would be recorded in the deferral account and applied to cost of service in the following year.

3.3.6 The unforecast gross margin includes activities which were previously recorded in either the PGVA or the OPSDA, which the Company has historically distributed 100 percent to the benefit of the ratepayer.

3.3.7 Direct Energy's witness, S. Chown, expressed the view that the price the Company charges for these services should be the same price it implicitly charges itself, if the potential for market distortions is to be avoided. In this witness' view, a generic review is required to determine what services should be offered by the regulated utilities and whether the rates for these services should be cost-based or market-based rates.

Positions of the Parties

3.3.8 Board Staff, CAC, Direct Energy, ECNG, Energy Probe, IGUA, OAPPA, and OCAP participated in the discussion of this issue during the ADR meetings. All parties except Direct Energy and ECNG agree that the Company should offer transactional services. It was agreed that the Board should hear in full the issues of the sale of the services at market-based rather than cost-based rates, and the appropriateness of an incentive or revenue sharing mechanism.

3.3.9 It was recognized in the ADR Agreement that aspects of the Company's proposal to offer transactional services in a competitive environment would expose the Company to additional risks. These aspects include the exclusion of marginal O&M costs associated with transactional services from the 1997 fiscal year cost of service, and guaranteeing a level of revenue (at market-driven rates) to the ratepayer.

3.3.10 Board Staff regarded the Company's risk as confined to forecasting the extent of revenues which, if no guarantee were made to ratepayers, would result in a

3.3.24 With respect to the proposed changes in the queuing policy, the Company noted the arguments of Board Staff and CAC that the policy should be eliminated, and agreed the policy is not essential.

Board Findings

3.3.25 The Board notes the Company's agreement with Board Staff and the CAC that the queuing policy is not essential. If the queuing policy is necessary to ensure that Ontario customers have priority over out of province customers in the same circumstances, it is the Board's view that it should be retained; if other means are available to ensure this priority, the queuing policy can be eliminated.

3.3.26 The Board has some sympathy with the Company's argument that it may be unrealistic to wait until all questions relating to diversification, deregulation of storage, and other general matters have been determined before embarking on any new programs. However, the Board does recognize that the proposals amount to a move to market-based pricing for the use of facilities that are part of the regulated utility, and for which the ratepayers provide a fair rate of return to the shareholder. In that circumstance, one must examine carefully the need for additional financial returns to the shareholder from the same capital assets. On the other hand, to the extent that there are any risks to the shareholder in marketing the unused assets, an additional return may be justified.

3.3.27 The Board has examined the Company's proposals to offer transactional services with the clear understanding that these proposals relate to the utilization of existing facilities. While persuaded that it is reasonable to utilize these facilities to the extent that they are not required to serve the in-franchise customers, the Board is concerned that market-based contracts may be entered into for periods of time which might result in making storage, for example, unavailable to serve future in-franchise needs, resulting in an unacceptable increase in gas costs to the system customers. The Board believes it is important to avoid such an outcome. (See discussion under Rate 330 in Chapter 7).

3.3.28 Having considered all of these factors, the Board is prepared to approve the offering of transactional services. The Company should structure the contracts for the sale of transactional services so as to ensure that the use of utility assets by ex-franchise purchasers does not result in increased gas costs to ratepayers. The Board requires the Company to provide, as part of the information filed at its next rates case, a detailed report on the progress to date in marketing transactional services, and to provide sufficient details concerning demand and supply balances for the Board to be satisfied that the ratepayer is indeed being kept harmless by the shareholder from potential increased gas costs due to the provision of these services to others. In addition, the Board will review at that time the status of these services within the regulated utility and the degree of competition in storage markets in Ontario.

3.3.29 The Board approves the Transactional Services Deferral Account, given the uncertainty involved in the forecast revenues associated with this service. The Board does not agree that an incentive to provide these services should be necessary, and notes that the Company has offered both peak and off-peak storage, along with assignments and exchanges in prior years without the need for an incentive. However, the Board acknowledges that the Company does incur some risk associated with its participation in these activities, and finds that a 10 percent incentive will be adequate to address these modest additional risks.

3.3.30 The Board is of the view that the parties involved did not seem to dispute the $1.2 million forecast for this activity and, while the final level of activity in this account is uncertain, the use of a forecast generally reduces the intergenerational inequity that would result from crediting the balance to cost of service in the subsequent year. Using $1.2 million as the revenue forecast, and $0.4 million as the direct costs associated with generating this level of revenue, and a 90 percent ratepayer proportion, the net cost of service credit is approximately $0.7 million, rather than the $0.6 million currently included in the Company's forecast. The reduction of $0.1 million in cost of service is included in Appendix A.

3.3.31 The Board directs the Company to adjust the wording for the Transactional Services Deferral Account in its draft rate order so that this account reflects variances from forecast, and that the disposition of the balance will subsequently be determined by the Board.

TAB 2

Ontario Energy Board

Ontario

E.B.R.O. 495

IN THE MATTER OF THE
ONTARIO ENERGY BOARD ACT

AND

IN THE MATTER OF AN APPLICATION BY

THE CONSUMERS' GAS COMPANY LTD.

FOR RATES

DECISION WITH REASONS

1997 August 21

Revenues from Gas Sales, Transmission and Storage

4.1.3 The Company is forecasting a net increase of 44,274 Rate 1 and 3,636 Rate 6 customers in fiscal 1998 over fiscal 1997. Coincident with the growth in Rates 1 and 6 customers is a shift from system gas to T-Service for both rate classes which is attributable to the ABC T-Service initiative. Rate 1 T-Service for 1998 is forecast to increase by 378,232 customers over 1997 estimates. Rate 6 T-Service for 1998 is forecast to increase by 8,962 customers over 1997 estimates.

4.1.4 The Company forecast a total throughput volume of 11,710.0 10^6m^3 in 1998 which includes an increase of 102.4 10^6m^3 in Rate 1 due to customer growth of 134.4 10^6m^3, partially offset by lower average use per customer of 32.0 10^6m^3. Growth in Rate 6 is due to customer growth of 72.7 10^6m^3 and a slightly higher average use per customer of 3.6 10^6m^3. The total Contract Sales and T-Service increase of 162.1 10^6m^3 is primarily due to increases in the commercial sector of 55.0 10^6m^3, industrial sector of 60.4 10^6m^3 and Rate 200 sales of 51.7 10^6m^3, partially offset by lower apartment volumes of 5.0 10^6m^3.

Revenues from Transactional Services

4.1.5 Under Transactional Services, the Company provides: (i) Full Cycle and Short Cycle Storage from Released Capacity; (ii) Gas Loans; (iii) Exchanges; and (iv) Assignments. The Company's evidence was that it markets these services mainly to ex-franchise customers and only if the Company's physical assets and contractual transportation assets are in excess of the requirements of the Company's in-franchise and ex-franchise firm customers. A short description of the transactional services follows:

- Short Cycle Storage, both Peak and Off-Peak, applies to Released Capacity only and allows for injection and withdrawal over some portion of the year.
- A Gas Loan is a service under which the Company delivers a volume of gas to a third party during a defined period and the third party returns to the Company an equivalent volume of gas at a later pre-defined period.

- An Exchange is a service under which the Company receives gas from a third party at a receipt point and delivers the same amount of gas to the third party at a different point.
- An Assignment involves making some of the Company's transportation entitlements available to third parties.

The Market

4.1.6 In E.B.R.O. 492, the Board indicated that it would review in the present proceeding the status of the transactional services within the regulated utility and the degree of competition in storage markets in Ontario.

4.1.7 The Company provided an assessment of the competitiveness of the market in which the Company provides transactional services. It concluded that it provides these services in a competitive market on the basis that:

- in providing storage services the Company operates a relatively small share of the storage facilities and contracted transportation capacity in the geographic market of its services;
- the Company does not control any of its transportation paths to deliver its services to market;
- there are adequate alternatives available in the market; and
- there are no significant barriers to entry by competitors.

No Harm to Ratepayers

4.1.8 In E.B.R.O. 492 the Board stated that it has to be satisfied that the ratepayer is being kept harmless by the shareholder from potential increased gas costs due to the provision of transactional services.

4.1.9 In response, the Company's evidence outlined the interaction between the Transactional Services group and the Gas Supply group before the latter approves or rejects a Transactional Services request from the former. The Company also outlined the process followed by the Gas Supply group in rejecting or accepting

TAB 3

PREFILED EVIDENCE OF

G.D. BLACK

GENERAL MANAGER, MARKETING AND SALES - STORAGE AND TRANSPORTATION

L.M. EDWARDS

MANAGER, MARKETING AND SALES

This evidence provides an overview of Union's storage and transportation business and addresses actual storage and transportation revenues for 1997 and forecast revenues for 1998 and 1999. The actual storage and transportation revenue for 1997 is filed at Exhibit C5, Tab 5. The storage and transportation forecasts for 1999 and 1998 are filed at Exhibit C3, Tab 5 and Exhibit C4, Tab 5 respectively.

This evidence will cover the following topics:

I. Forecast Customer Demands

II. Transactional Services Forecast

III. Deferral Account Balances

IV. Margin Sharing Proposal

V. Longer Term Storage Market Premium Deferral Account

VI. Status of Board Directives

VII. Extension of E.B.O. 166 Blanket Approval for Storage Proposal

VIII. Rate Proposals

IX. Gas Industry Standards Board (GISB) Compliance

June 12, 1998

M13 - Local Production

M13 Local Production is the rate charged to Consumers' Gas and other local producers to transport their volumes to Dawn. In 1997, Union recognized revenue of $744,000 for this service and has forecast this same level of revenue for 1998 and 1999. Any other services required by producers to balance production volumes to market demand on both a forecast and actual basis have been included in the appropriate transactional service in Section II.

M15 - Dow A

M15 is the rate charged to the Dow A joint venture between Union and Dow Chemical Canada Inc. for transportation service to and from the Dow A storage pool. Revenue earned for this service in 1997 was $421,000. Union is forecasting revenue of $428,000 for both 1998 and 1999.

II. Transactional Services Forecast

Union offers a range of transactional services including transportation, short term peak storage, balancing services, exchanges, Hub2Hub™, offsystem transportation capacity, name changes & redirections, and Ontario Production Services.

Forecast Methodology

While it has been established that transactional services are difficult to predict, Union developed the forecast for 1998 and 1999 using the process as described below.

First, Union forecast the resources required to meet its infranchise and exfranchise firm requirements. Any remaining resources are the basis for the sale of transactional services. Once the assets available for transactional services have been determined, an assessment of market demand is completed. This is done by a review of market forces, discussions with customers, and historical analysis.

In particular, Union evaluates the impact of pricing differentials, the availability of competitive alternatives, and changes in regulation affecting transactional services. In completing its forecast for 1998 and 1999, Union has assumed that the legislative change allowing burner tip sales and title transfers in Ontario will be enacted and that these legislative changes will significantly increase competition and change the role of Ontario LDC's. Generally, these changes will reduce Union's control of its storage and transmission facilities by providing exfranchise customers and aggregators of infranchise customers, the opportunity to broker their own capacity. In addition, Union's system gas supplies will continue to decline as it exits the merchant function which will reduce the assets available to provide transactional services such as loans and load balancing.

Taking these impacts into account, 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.

Transportation and Exchanges

Both of these services allow customers to move gas from one location to another. Transportation service transports gas between any 2 points on Union's system on a short term firm, limited firm, or interruptible basis. Under an exchange agreement, gas is typically received by Union at a point on the Union system in exchange for gas delivered to the other party at a point outside the Union system. To provide these interruptible services, Union brokers available capacity on its system which is not being utilized by firm shippers. The table below summarizes the revenue, cost and margin details for these services for 1997, 1998 and 1999:

Particulars ($000's)		Actual 1997	Forecast 1998	Forecast 1999
C1 Interruptible Transportation	Revenue	$ 1,220	$ 1,294	$ 647
	Less: Costs	332	233	126
	Gross Margin	888	1,061	521
	Less: Approved Forecast	1,032	1,032	521
	Deferred Margin	$ (144)	$ 29	$ -
Exchanges	Revenue	$ 1,006	$ 1,000	$ 500
	Less: Costs	471	239	176
	Gross Margin	535	761	324
	Less: Approved Forecast	578	578	324
	Deferred Margin	$ (43)	$ 183	$ -
C1 Short Term Transport	Revenue	$ 715	$ -	$ -
	Less: Costs	-	-	-
	Gross Margin	715	-	-
	Less: Approved Forecast	-	-	-
	Deferred Margin	$ 715	$ -	$ -
M12 Limited Firm	Revenue	$ 91	$ -	$ -
	Less: Costs	13	-	-
	Gross Margin	78	-	-
	Less: Approved Forecast	-	-	-
	Deferred Margin	$ 78	$ -	$ -
M12 Transport Overrun	Revenue	$ 404	$ 380	$ 380
	Less: Costs	17	87	94
	Gross Margin	387	293	286
	Less: Approved Forecast	937	937	286
	Deferred Margin	$ (550)	$ (644)	$ -
Total Service Block	Revenue	$ 3,436	$ 2,674	$ 1,527
	Less: Costs	833	559	396
	Gross Margin	2,603	2,115	1,131
	Less: Approved Forecast	2,547	2,547	1,131
	Deferred Margin	$ 56	$ (432)	$ -

In forecasting volume and margin for this service block, Union examined total transportation and exchange activity. All transportation revenue for purposes of the forecast has been classified as interruptible. As realized in 1997, any short term firm or M12 limited firm transportation is generally realized on a shorter time horizon and replaces interruptible business.

For 1998, Union has forecast total C1 interruptible transportation and exchange revenue of $2,674,000, compared to revenue of $3,436,000 experienced during 1997. Union has forecast this reduction in the total service block as result of legislative changes, expected to be implemented October, 1998. Deregulation of burner tip sales and title transfers in Ontario will allow Union's firm shippers to broker their own capacity, thereby limiting the resources available to Union to sell exfranchise. In addition to reduced assets, Union will also face increased competition from firm shippers and aggregators. Union expects the 1999 revenue for these services to decrease to $1,527,000, reflecting a full year impact of the above noted legislative and market changes.

Offpeak Storage/Balancing/Loans

This service block offers customers the flexibility to balance their supplies to meet market demands or to capitalize on existing or expected market conditions using offpeak storage, loans, or balancing.

Offpeak storage service is generally available for injection and withdrawal, except during critical storage periods in October and November. Union offers this service in offpeak periods when storage for infranchise customers is not fully utilized.

Another service available to customers is a gas loan. Under this service, Union will lend its gas to a customer who has an immediate need for such gas and the ability to repay an equivalent volume at a later point in time. This service is only provided when Union is satisfied that it can lend its gas without impairing its ability to meet infranchise customers' needs or its ability to meet firm obligations for daily withdrawals from storage.

The next service in this block is balancing, which is a combination of offpeak storage (or parking) and loans. Balancing can be viewed as a bank account that allows for a line of credit to the user. When the customer has drawn on the line of credit, his account is negative or in a "loan" position. Similarly when the customer has deposited gas, the account is positive or in a "parked" position. Customers use this service to balance swings on a daily or monthly basis. Historically, balancing revenues have been identified explicitly. However, forecast revenues in 1998 and 1999 for balancing are now included as part of the offpeak storage and loan forecast.

Each of these services are highly dependent on similar factors such as weather, system operations, and market forces. However, the demand for specific services is usually non-symmetrical. For example, in a year where loans are in high demand, parking normally has less value. Therefore, by viewing these services as a group, the forecast should exhibit less volatility than if each service was forecast and analyzed independently.

Details for this service block are illustrated in the table below:

Particulars ($000's)		Actual 1997	Forecast 1998	Forecast 1999
Offpeak Storage	Revenue	$ 1,706	$ 960	$ 672
	Less: Costs	419	307	185
	Gross Margin	1,287	653	487
	Less: Approved Forecast	1,125	1,125	487
	Deferred Margin	$ 162	$ (472)	$ -
Balancing	Revenue	$ 915	$ -	$ -
	Less: Costs	265	-	-
	Gross Margin	650	-	-
	Less: Approved Forecast	34	34	-
	Deferred Margin	$ 616	$ (34)	$ -
Loans	Revenue	$ 3,028	$ 1,989	$ 1,589
	Less: Costs	677	244	209
	Gross Margin	2,351	1,745	1,380
	Less: Approved Forecast	2,561	2,561	1,380
	Deferred Margin	$ (210)	$ (816)	$ -
Consumers' LBA	Revenue	$ -	$ 500	$ 500
	Less: Costs	-	-	-
	Gross Margin	-	500	500
	Less: Approved Forecast	-	-	500
	Deferred Margin	$ -	$ 500	$ -
Total Service Block	Revenue	$ 5,649	$ 3,449	$ 2,761
	Less: Costs	1,361	551	394
	Gross Margin	4,288	2,898	2,367
	Less: Approved Forecast	3,720	3,720	2,367
	Deferred Margin	$ 568	$ (822)	$ -

In 1998, Union is forecasting revenue of $3,449,000, corresponding to the use of 807,344 10*3 m*3 (28.5 BCF) of storage space or loaned gas. In 1999, revenue is forecast at $2,761,000 relating to volumes of 585,962 10*3 m*3 (20.7 BCF). Union is expecting this reduction over time due to changes in the role of Ontario LDC's. As Union exits the merchant function, gas purchases will be limited to its role as distribution system operator and supplier of last resort. As a result, Union will have a significantly reduced gas purchase portfolio upon which to offer balancing and loan services. In addition, offpeak storage resources available to Union will be restricted as a result of greater competition among firm shippers and aggregators, who will broker their own under-utilized space.

Peak Storage

Historically, peak storage included in Union's transactional forecast was only short-term. However, commencing in 1997 with the Bentpath Rosedale development, this forecast now includes revenue from long term storage contracts as well.

Short term revenue included in the forecast for 1998 and 1999 is $1,050,000 and $1,734,000 respectively. Union forecast withdrawals of 113,312 10*3 m*3 (4.0 BCF) in 1998, relating to contracts which commenced in 1997. In addition, a full cycle of 56,656 10*3 m*3 (2.0 BCF) of storage is forecast.

In 1999, short term peak injections of 206,793 10*3 m*3 (7.3 BCF) have been forecast. This includes 113,312 10*3 m*3 (4.0 BCF) of contingency space which Union keeps available for its infranchise markets. It is unlikely that this space will be released by Union's Gas Supply department for sale by storage and transportation. The remaining 93,481 10*3 m*3 (3.3 BCF) includes 56,656 10*3 m*3 (2.0 BCF) for an existing contract, and 36,825 10*3 m*3 (1.3 BCF) related to the expected development of new storage pools. Details of the C1 peak storage forecast are included in the table below:

Particulars ($000's)			Actual 1997		Forecast 1998		Forecast 1999
Peak Storage	Short Term Revenue	$	3,994	$	1,050	$	1,734
	Long Term Cost Based Revenue		1,890		2,762		
	Long Term Market Premium		(531)		1,164		1,657
	Total Revenue		5,353		4,976		3,391
	Less: Costs		1,611		488		833
	Gross Margin		3,742		4,488		2,558
	Less: Approved Forecast		3,279		3,279		2,558
	Deferred Margin	$	463	$	1,209	$	-
C1 Firm Short Term Deliverability							
	Revenue	$	64	$	-	$	-
	Less: Costs		-		-		
	Gross Margin		64		-		-
	Less: Approved Forecast		56		56		-
	Deferred Margin	$	8	$	(56)	$	-
Total Service Block	Revenue	$	5,417	$	4,976	$	3,391
	Less: Costs		1,611		488		833
	Gross Margin		3,806		4,488		2,558
	Less: Approved Forecast		3,335		3,335		2,558
	Deferred Margin	$	471	$	1,153	$	-

As shown in the table above, the long term revenue forecast for 1998 is $3,926,000 including a market premium of $1,164,000. The market premium is calculated as the difference between the revenue earned at the market bid rate, and the M12 cost based rate at the time of the forecast. The forecast is based on a full cycle of 178,466 10*3 m*3 (6.3 BCF) of storage as based on the contracts approved in E.B.R.O. 494-03.

In 1999, long term peak storage revenue increases to $5,354,000, including a market premium of $1,657,000, for storage space of 11.4 BCF (322,938 10*3 m*3). This increase is attributable to the expected development of the Century pools project (Phase I), commencing April 1, 1999. Details regarding this development are contained in the evidence of Ms. Patterson at Exhibit B1, Tab 6. Union anticipates filing an application shortly respecting these new storage developments.

The volumes and rates included in the 1999 forecast for the Century pools project (Phase I) were based on Union's assessment of the market for storage at the time the forecast was prepared in late 1997. However, since this forecast was completed, Union has tested demand for this incremental storage through an open season process initiated in December, 1997. The results of the open season bids were compiled in February, 1998. Union will update the 1999 test year forecast at a later date to reflect the impact of the open season bids.

Hub2Hub™/Offsystem Transportation Capacity

In the spring of 1995, Union and Alberta Energy Corporation ("AEC") developed a new service. The impetus for this service was a desire to provide suppliers of gas in the Alberta basin an alternate way to deliver and sell their product to users in Eastern Canada. This service is a substitute for transportation from a point intra-Alberta (AECO Hub) to a point in Ontario (Dawn). Under the Hub2Hub™ service, a customer delivers its gas at the AECO Hub and simultaneously receives its gas at Dawn. From a customer's viewpoint, the service is similar to traditional transportation but offers the additional advantages of administrative ease and convenience. Union and AECO manage this service jointly. Details of the operation of the service are confidential.

In addition to Hub2Hub™, Union's storage and transportation group periodically acquires capacity, usually on TCPL, and markets this capacity to third parties.

A summary of the revenues, costs and margin for the Hub2Hub™ service and offsystem capacity marketing are included in the table below:

Particulars ($000's)		Actual 1997	Forecast 1998	Forecast 1999
Hub2Hub™	Revenue	$ 2,863	$ 750	$ 700
	Less: Prior Year True-up	703	-	-
	Less: Costs	-	67	40
	Gross Margin	2,160	683	660
	Less: Approved Forecast	1,000	1,000	660
	Deferred Margin	$ 1,160	$ (317)	$ -
Offsystem Capacity	Revenue	$ 37	$ 500	$ 500
	Costs		500	500
	Net Revenue	37	-	-
	Less: Costs	-	-	-
	Gross Margin	37	-	-
	Less: Approved Forecast	-	-	-
	Deferred Margin	$ 37	$ -	$ -
Total Service Block	Net Revenue	$ 2,900	$ 750	$ 700
	Less: Prior Year True-up	703	-	-
	Less: Costs	-	67	40
	Gross Margin	2,197	683	660
	Less: Approved Forecast	1,000	1,000	660
	Deferred Margin	$ 1,197	$ (317)	$ -

In 1997, $2,900,000 of net revenue was earned from the Hub2Hub™ service and marketing of offsystem capacity. These revenues exceeded expectation due to the availability of additional assets in 1996/1997, the increased premium on TCPL capacity, and improved knowledge and expertise.

Union is forecasting revenue of $750,000 and $700,000 for 1998 and 1999 respectively. As additional physical transportation capacity is developed from Western Canada to eastern markets, the premium on TCPL capacity is expected to diminish significantly, thus reducing demand for Hub2Hub™. In addition, the forecast reflects the recent loss of experienced staff and an expected reduction in assets that both Union and AECO will bring to the partnership.

Name Changes/Redirects

A redirection/name change is an administrative service provided by Union whereby Union facilitates a transfer of gas volumes between contracts or accommodates a title transfer for customers at any one of Union's interconnects. Redirected gas never enters Union's system but the transfer is required in order to meet upstream or downstream transporters' requirements. Union also accommodates name changes. In this case, gas may be owned by and redelivered to one party but enters Union's system under the account and in the title of a different party who holds the contract on the Union system. The revenue generated from this service will be relatively constant year over year regardless of volumes as this service fee is capped at a maximum per month per customer.

For 1997, Union realized revenue of $422,000 from name changes and redirection services. For 1998 and 1999, revenues have been forecast at $500,000 and $525,000 respectively.

Ontario Production

Ontario Production is a service for natural gas produced within Union's franchise area. Union purchases volumes from Ontario Producers as a source of supply; these volumes are delivered as they are produced. Since production is uneven and unmatched to demand, Union charges Ontario Producers a commodity fee to recover the cost of balancing production volumes. Revenue earned for this service in 1997 was $189,000 and is forecast for 1998 and 1999 for $571,000 and $541,000 respectively. The forecast was based on historical data, prior to the decrease in Ontario Production activity later in 1997.

New Product Lines

Union is forecasting $250,000 and $500,000 in 1998 and 1999 related to new product lines. While Union has not yet identified or created these new product lines, it anticipates something will be initiated late in 1998. These amounts are speculative and intended to recognize the storage and transportation department's historic ability to be creative in responding to changing market needs.

Details for namechanges, redirections, Ontario Production, and new products are included in the following table:

Particulars ($000's)		Actual 1997		Forecast 1998		Forecast 1999
Name Changes/Redirects						
Revenue	$	422	$	500	$	525
Less: Costs		422		-		-
Gross Margin		-		500		525
Less: Approved Forecast		453		453		525
Deferred Margin	$	(453)	$	47	$	-
Ontario Producers						
Revenue	$	189	$	571	$	541
Less: Costs		-		31		31
Gross Margin		189		540		510
Less: Approved Forecast		549		549		510
Deferred Margin	$	(360)	$	(9)	$	-
New Product Development						
Revenue	$	-	$	250	$	500
Less: Costs		-		-		-
Gross Margin		-		250		500
Less: Approved Forecast		-		-		500
Deferred Margin	$	-	$	250	$	-
Total Service Block						
Revenue	$	611	$	1,321	$	1,566
Less: Costs		422		31		31
Gross Margin		189		1,290		1,535
Less: Approved Forecast		1,002		1,002		1,535
Deferred Margin	$	(813)	$	288	$	-

III. Deferral Account Balances

The balances for all storage and transportation deferral accounts have been summarized in Appendix A of this evidence. This chart details, by service, the deferral account balances as at December 31, 1997, and as forecast for December 31, 1998. The balances for 1997 and 1998 are driven by variances against the forecast approved by the Board in E.B.R.O. 493/494.

The total storage and transportation transactional margin forecast for 1997 and 1998 was approximately $23.2 million. As shown in Appendix A, the margin forecast to be earned in excess of this benchmark for transactional services has been captured in deferral accounts, with a combined projected balance of $716,000 as at December 31, 1998. Union proposes this balance for all storage and transportation transactional margin accounts be disposed of 75:25 in favour of customers. Union's proposal to dispose of the transactional margin deferral accounts on this basis would result in customers receiving an additional $537,000 and the remaining $179,000 accruing to Union.

IV. Margin Sharing Proposal

Union currently has five deferral accounts relating to storage and transportation services, four of which deal specifically with transactional services (as outlined in Appendix A). Currently, 100% of all margin forecast for these services is credited against cost of service, and any variances from the Board Approved forecast are deferred and shared based on the Board's decision at the time of disposition.

For 1999, Union proposes to change the margin sharing mechanism with respect to both transactional services and the market premium resulting from long term C1 peak storage. The following section deals with the transactional services sharing proposal and Section V addresses the sharing proposal for the long term C1 peak storage market premium.

In determining its transactional margin sharing proposal, Union considered the following goals of a sharing mechanism:

i) to provide a direct incentive to maximize transactional revenues;
ii) to provide a benefit to customers who contributed to Union's ability to provide transactional services;
iii) to provide certainty regarding sharing of revenue to aid in economic decision-making during the test year;
iv) to be consistent with sharing mechanisms for other utilities in Ontario and in Canada;
v) to be relatively easy to understand and administer.

Based on these goals and a review of other sharing mechanisms, Union proposes the following:

i) The forecast margin for the test year is to be shared 90:10 between customers and shareholders respectively. Union feels this provides some incentive to continue to market existing services, and to forecast the development of new transactional services. This sharing proposal acknowledges and balances the contribution of ratepayers, and the shareholder risk of O&M variances against budget.

ii) The sharing of deferral account balances should be predetermined and pre-approved. Union believes that such approval is appropriate and will ensure clarity and a meaningful incentive while decisions are being made during the test year. For example, Union would be able to pursue opportunities with the knowledge that the shareholder portion of the deferral account will offset incremental O&M expenditures that are required. This will ensure there is a balanced incentive to maximize transactional revenues. In addition, Union notes that the Board has approved a predetermined sharing mechanism for Consumers Gas.

iii) Union proposes that all variances up to and including an amount of $1.2 million over forecast would be shared 90:10 with customers: shareholders. This represents variability from the forecast margin for 1999 of up to 20% and recognizes a level of forecast variability due to changes in market conditions, asset availability, and weather that is difficult to predict. In Union's view, it is reasonable that these variances should be shared at the same level (ie. 90/10) as the forecast. The shareholder portion of 10% motivates Union to respond to unforecast circumstances and to maximize returns on all available assets. In addition, Union bears the risk of doing so within predetermined operating and maintenance expenditures and spending over forecast to pursue opportunities accruing to the deferral account are borne by the shareholder.

iv) Union proposes that variances in excess of $1.2 million over the approved forecast be shared 67:33 in favour of the customer. This provides a direct incentive for Union to aggressively market and develop new transactional products to attain a higher level of sharing. It also recognizes that variances in excess of this level are the result of superior performance, other foregone opportunities, and possible additional resources on behalf of Union.

v) Union proposes that four new deferral accounts be established that correspond to the service blocks described above and as outlined in Appendix B. Grouping services in these blocks will remove some of the variability that occurs between complementary/substitute services, and will simplify tracking and reporting of account balances. In addition, disposal of account balances would be simplified as each service within the block would be treated consistently. Union further proposes to maintain the separate account for heat value adjustments, and to move infranchise load balancing services (T1) to a new account. Further details regarding the restructuring of these deferral accounts can be found in the evidence of Mr. Byng at Exhibit D1, Tab 8.

Union notes this sharing proposal is consistent with those approved in other Canadian and U.S. jurisdictions. One common element to all sharing plans Union investigated was the preapproval of sharing levels for a predetermined timeframe. Union also notes that some decisions approved a sharing of revenues/margin up to a benchmark level, while others established no benchmark, thereby effectively sharing all margin earned from transactional services. Union also observed that sharing levels were often tiered to differentiate between variances that were uncontrollable, or driven by exceptional performance by the LDC.

Union has quantified the impact of this sharing proposal for 1999 in Appendix B of this evidence. As reflected in this schedule, Union proposes that $5,935,000 of transactional margin remain in Union's revenue forecast, with the remaining $659,000 accruing to Union.

V. Longer Term Storage Market Premium Deferral Account

In E.B.R.O. 494-03, Union obtained Board approval to contract for long term storage space resulting from the Bentpath-Rosedale development. These contracts were the result of a bidding process to establish market-based rates. Consistent with the Board's decision in that same hearing, the premium over cost based rates has been captured in deferral account 179-39 for 1997 and 1998. This amount is a charge of $531,000 for 1997 and a credit of $1,164,000 for 1998, for a balance at December 31, 1998 of $633,000, as reflected in Appendix C of this evidence. Union notes the market premium for 1997 is a debit due to a timing difference when demand charges were invoiced to customers. This difference will reverse in 1998 as actual activity is recorded.

For 1999, the forecast market based premium of $1,657,000 arises from the Bentpath Rosedale storage contracts as well as the proposed Century storage development project (Phase I). This premium is reflected in the 1999 forecast.

The disposition of the market premium was originally addressed in E.B.R.O. 494-03 when Union proposed a deferral account to accumulate these premiums. Union suggested that one option for disposing of the deferral account balance was to utilize these funds to maintain rate stability or to improve the economics of future storage related projects. While this was not a proposal tabled for approval, concerns were raised during the hearing that such an option would distort market signals for storage by giving Union unfair advantage in developing less economic projects. Union would like to address these concerns by reviewing the following proposal for the deferral account and its disposition.

In recommending how the market premium should be disposed of, Union considered the following objectives:

i) to ensure facilities are developed in response to demand as indicated by true market signals;
ii) to ensure storage is developed in a manner that minimizes unfavourable impacts on rates;
iii) to provide an incentive to develop storage, a scarce resource;
iv) to be able to respond to market forces in a timely manner.

Based on these goals, Union proposes that 60% of the market premium continue to be recorded in the deferral account and 40% be rebated to infranchise customers through a one-time adjustment.

In addition to providing infranchise customers with immediate benefit of the market premium, this proposal also recognizes the risk being borne by this group of customers. It recognizes that infranchise customers are taking the risk on future shortfalls in cost coverage. This situation could arise due to the expiry of initial storage contracts, the recontracting of storage below cost, or the implementation of higher cost alternatives required to meet infranchise requirements.

Union also proposes that funds from the deferral account be used to achieve rate stability. Specifically, Union proposes the deferral account balance to be used to maintain the M12 storage demand rate at a level not greater than the E.B.R.O. 494-02 level of $14.113/10*3m*3. This represents the cost based storage rate, assuming 1.11% deliverability, prior to the implementation of the Bentpath-Rosedale project. In addition, Union proposes that the deferral account could be disposed of through any future proposal that is put forward by Union and approved by the Board.

Union further proposes that the deferral account maintain a three-year rolling balance. In the event that annual amounts accumulated in the deferral account are not disposed of by one of the mechanisms discussed above by the end of the third year, then it will be rebated to infranchise customers through a one-time adjustment.

The impact of this proposal has been quantified in Appendix C. Union proposes that the forecast premium of $1,657,000 for 1999 be removed from cost of service, with $663,000 (40%) to be rebated to infranchise customers through a one-time adjustment and the remaining $994,000 to be credited to the market premium deferral account.

VI. Status of Board Directives

In addition to the directives that have been noted above, Union would also like to update the Board on the status of six directives.

E.B.R.O. 499
Exhibit C1
Tab 3
Appendix A
UPDATED

Summary of Storage and Transportation Deferral Accounts
as at December 31, 1997 and as at December 31, 1998

		Balance as at December 31, 1997 (a)	Forecast 1998 (b)	Balance as at December 31, 1998 (c)
	Account #179-34			
1	C1 Interruptible Transportation	$ (144)	$ (314)	$ (458)
2	M12 Non-LCU Transportation			-
3	C1 Non-LCU Transportation			-
4	M12 Limited Firm Transportation	78	-	78
5	M12 Interruptible Transportation			-
6	C1 Firm Short Term Transportation	715	32	747
7	M12 Transportation Overrun	(550)	(704)	(1,254)
8	Energy Exchanges	(43)	235	192
9		$ 56	$ (751)	$ (695)
10	Reduction in C1 Margin Rebate (1)		61	61
11			$ (690)	$ (634)
	Account #179-39			
12	C1 Firm Peak Storage	$ 994	$ 1,417	$ 2,411
13	Long Term Peak Storage Market Premium	(531)	1,958	1,427
14	M12 Interruptible Deliverability			-
15	C1 Firm Short Term Deliverability	8	3	11
16	Supplemental Load Balancing Services			-
17	T1 Storage Inventory Demand Charge			-
18		$ 471	$ 3,378	$ 3,849
	Account #179-49			
19	C1 Offpeak Storage	$ 162	$ (174)	$ (12)
	Account #179-50			
20	Loans	$ (210)	$ (39)	$ (249)
21	Balancing	616	383	999
22	M12 Load Balancing (Consumers' LBA)	-	200	200
23	Namechanges/Redirects	(453)	436	(17)
24	Hub2Hub	1,160	(858)	302
25	Offsystem Capacity Brokering	37	1,800	1,837
26	New Product Development	-	250	250
27	Ontario Producers	(360)	(373)	(733)
28		$ 790	$ 1,799	$ 2,589
29	Transactional Services	$ 2,010	$ 2,355	$ 4,365
30	Long Term Market Premium	$ (531)	$ 1,958	$ 1,427
31		$ 1,479	$ 4,313	$ 5,792

32 (1) This adjustment reflects a reduction in C1 Margin Rebate creditted to customers due to a reduction in firm contract demand.

September 14, 1998

Summary of Storage and Transportation Deferral Accounts as at December 31, 1997 and as at December 31, 1998 (1)

Line No.	Particulars ($000's)	Balance as at December 31, 1997 (a)	Forecast 1998 (b)	Balance as at December 31, 1998 (c)
	Account #179-34			
1	C1 Interruptible Transportation	$ (144)	$ 29	$ (115)
2	M12 Non-LCU Transportation			-
3	C1 Non-LCU Transportation			-
4	M12 Limited Firm Transportation	78	-	78
5	M12 Interruptible Transportation			-
6	C1 Firm Short Term Transportation	715	-	715
7	M12 Transportation Overrun	(550)	(644)	(1,194)
8	Energy Exchanges	(43)	183	140
9		$ 56	$ (432)	$ (376)
	Account #179-39			
10	C1 Firm Peak Storage	$ 994	$ 45	$ 1,039
11	Long Term Peak Storage Market Premium	(531)	1,164	633
12	M12 Interruptible Deliverability			-
13	C1 Firm Short Term Deliverability	8	(56)	(48)
14	Supplemental Load Balancing Services			-
15	T1 Storage Inventory Demand Charge			-
16		$ 471	$ 1,153	$ 1,624
	Account #179-49			
17	C1 Offpeak Storage	$ 162	$ (472)	$ (310)
	Account #179-50			
18	Loans	$ (210)	$ (816)	$ (1,026)
19	Balancing	616	(34)	582
20	M12 Load Balancing (Consumers' LBA) (2)	-	500	500
21	Namechanges/Redirects	(453)	47	(406)
22	Hub2Hub	1,160	(317)	843
23	Offsystem Capacity Brokering	37	-	37
24	New Product Development	-	250	250
25	Ontario Producers	(360)	(9)	(369)
26		$ 790	$ (379)	$ 411
27	Subtotal Transactional Services	$ 2,010	$ (1,294)	$ 716
28	Subtotal Long Term Market Premium	$ (531)	$ 1,164	$ 633
30	Total Deferral Account Balance	$ 1,479	$ (130)	$ 1,349

NOTES:

(1) Positive deferral account balance represents credit.

(2) Consumers' LBA has been captured in Account # 179-50 due to similarity to other services included in this account. Union notes this as a change from the E.B.R.O. 494-08 application where it was proposed to be reflected in Account # 179-34.

Summary of Transactional Margin Sharing Proposal
1999 Test Year

	Particulars ($000's)	Forecast 1999 (a)	90% Customer Share (b)	10% Shareholder Share (c)
1	C1 Interruptible Transportation	509	458	51
2	Exchanges	314	283	31
3	M12 Transportation Overrun	202	182	20
4	M12 Non-LCU Transportation	-	-	-
5	C1 Non-LCU Transportation	-	-	-
6	M12 Limted Firm Transportation	-	-	-
7	M12 Interruptible Transportation	-	-	-
8	C1 Firm Short Term Transportation	-	-	-
9	TOTAL SERVICE BLOCK	$ 1,025	$ 923	$ 103
10	Consumers' LBA	500	450	50
11	Balancing	264	238	26
12	Offpeak Storage	316	284	32
13	Loans	1,196	1,076	120
14	TOTAL SERVICE BLOCK	$ 2,276	$ 2,049	$ 227
15	Short Term Peak	367	330	37
16	Long Term Peak			
17	M12 Interruptible Deliverability			
18	C1 Firm Short Term Deliverability	55	50	5
19	TOTAL SERVICE BLOCK	$ 422	$ 380	$ 42
20	Hub2HubTM	656	590	66
21	Offsystem Capacity	-	-	-
22	Namechanges/Redirects	525	473	53
23	New Product Development	500	450	50
24	Ontario Producers	157	141	16
25	TOTAL SERVICE BLOCK	$ 1,838	$ 1,654	$ 184
26	TOTAL TRANSACTIONAL SHARING	$ 5,561	$ 5,006	$ 555

Summary of Transactional Margin Sharing Proposal
1999 Test Year

Line No.	Particulars ($000's)	Forecast 1999 (a)	90% Customer Share (b)	10% Shareholder Share (c)
1	C1 Interruptible Transportation	521	469	52
2	Exchanges	324	292	32
3	M12 Transportation Overrun	286	257	29
4	M12 Non-LCU Transportation	-	-	-
5	C1 Non-LCU Transportation	-	-	-
6	M12 Limted Firm Transportation	-	-	-
7	M12 Interruptible Transportation	-	-	-
8	C1 Firm Short Term Transportation	-	-	-
9	TOTAL SERVICE BLOCK	$ 1,131	$ 1,018	$ 113
10	Consumers' LBA/Balancing	500	450	50
11	Offpeak Storage	487	438	49
12	Loans	1,380	1,242	138
13	TOTAL SERVICE BLOCK	$ 2,367	$ 2,130	$ 237
14	Short Term Peak	901	811	90
15	Long Term Peak			
16	M12 Interruptible Deliverability			
17	C1 Firm Short Term Deliverability			
18	TOTAL SERVICE BLOCK	$ 901	$ 811	$ 90
19	Hub2HubTM	660	594	66
20	Offsystem Capacity	-	-	-
21	Namechanges/Redirects	525	473	53
22	New Product Development	500	450	50
23	Ontario Producers	510	459	51
24	TOTAL SERVICE BLOCK	$ 2,195	$ 1,976	$ 220
25	TOTAL TRANSACTIONAL SHARING	$ 6,594	$ 5,935	$ 659

Summary of Longer Term Storage Market Premium for Calendar Years 1997 - 2000

	Particulars ($000's)	Actual 1997 (a)	Bridge Year 1998 (b)	Test Year 1999 (c)	Forecast 2000 (d)
1	Revenue - Total	$ 1,359	$ 4,628	$ 6,306	$ 9,982
2	Revenue - M12 Cost Based Rates	1,890	2,670	3,735	5,918
3	Market Premium	$ (531)	$ 1,958	$ 2,571	$ 4,064
4	Division of Market Premium:		not yet dispersed		
5	Infranchise Rebate (40%)	$ -	$ -	$ 1,028	$ 1,626
6	Deferral Account: (60%)	(531)	1,958	1,543	2,439
7		$ (531)	$ 1,958	$ 2,571	$ 4,065
8	Cumulative Deferral Account Balance	$ (531)	$ 1,427	$ 2,970	$ 5,409

60% 99
+ 1427 for 1998 ? future dispersal

	Volumes (10*3 m*3)				
9	Volumes (10*3 m*3)				
10	Injections/Withdrawals:				
11	for 9 months:	-	-	173,367	220,958
12	for 12 months:	-	212,729	356,935	645,880
13	Total Injections & Withdrawals	-	212,729	530,302	866,838

Summary of Longer Term Storage Market Premium
for Calendar Years 1997 - 2000

Line No.	Particulars ($000's)	Actual 1997 (a)	Bridge Year 1998 (b)	Test Year 1999 (c)	Forecast 2000 (d)
1	Revenue - Total	$ 1,359	$ 3,926	$ 5,354	$ 8,227
2	Revenue - M12 Cost Based Rates (1)	1,890	2,762	3,697	5,565
3	Market Premium	$ (531)	$ 1,164	$ 1,657	$ 2,662
	Division of Market Premium:				
4	Infranchise Rebate: (40%)	$ -	$ -	$ 663	$ 1,065
5	Deferral Account: (60%)	(531)	1,164	994	1,597
		$ (531)	$ 1,164	$ 1,657	$ 2,662
6	Cumulative Deferral Account Balance (2)	$ (531)	$ 633	$ 1,627	$ 3,224
	Volumes (10*3 m*3)				
	Injections/Withdrawals:				
7	for 9 months:	-	-	202,261	357,783
8	for 12 months:	-	356,930	356,930	645,874
9	Total Injections & Withdrawals	-	356,930	559,191	1,003,657

NOTES: (1) M12 cost based rate at the time forecast was completed.
(2) Positive deferral account balance represents credit.

EB-2011-0210

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

AND IN THE MATTER OF an application filed by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2013.

CANADIAN MANUFACTURERS & EXPORTERS ("CME") COMPENDIUM OF DOCUMENTS re: Upstream Transportation Cost Reductions

OTT01\5228536\v1

TAB 4

Ontario
Energy
Board

Ontario

E.B.R.O. 499

IN THE MATTER OF THE
ONTARIO ENERGY BOARD ACT

AND

IN THE MATTER OF AN APPLICATION BY

UNION GAS LIMITED

FOR RATES

DECISION WITH REASONS

1999 JANUARY 20

E.B.R.O. 499

UNION GAS

SETTLEMENT AGREEMENT

November 16, 1998

i) Transactional Service - 1997 and 1998

The 1997 Board approved level of storage and transportation transactional margin is $11.604 million. As such, the total margin returned to customers through rates in 1997 and 1998 is $23.203 million. The total transactional margin variance recorded in the various deferral accounts in relation to the $23.203 million is forecast to be $4.365 million as outlined at C1/T3/App B, line 29, Updated. This balance excludes the premium related to long-term storage sold under market rates which is addressed separately below. Union proposed to dispose of the actual December 31, 1998 balance 75:25 in favour of customers (ie. $3.274 million to customers and $1.191 million to Union). It was noted that in E.B.R.O. 493/494, the Board approved the disposition of the storage related deferral account balance on a 90:10 basis and the remaining transportation deferral account balances on a 75:25 basis. During the ADR, Union provided an analysis (Appendix F) which highlighted the total impact of the 1996 deferral account disposition approved by the Board in E.B.R.O. 493/494 as compared to the disposition being sought by Union for the 1997 and 1998 deferral amounts.

The parties agree that Union's evidence on this subject should be accepted and determined Union's proposed disposition of the 1997 and 1998 deferral balances reasonable in comparison to the disposition of the 1996 balances approved by the Board in E.B.R.O. 493/494.

ii) Transactional Services - 1999 and beyond

Union's evidence at C1/T3, Updated sought approval for transactional margin sharing proposal effective January 1, 1999. Union proposed to share the 1999 forecast margin of $5.561 million on a 90:10 basis in favour of customers (ie. $5.006 million to customers and $0.555 million to Union). Union's proposal further requested that any variance either below or up to $1.0 million above the 1999 forecast level be shared on the same 90:10 basis, while variances in excess of the $1.0 million threshold above forecast be shared 67:33 in favour of customers.

All parties agreed to the 1999 forecast of transactional services margin, excluding the 1999 forecast long term storage premium of $2.571 million (as discussed further below), of $5.561 million and further agreed that the sharing of S&T transactional services margin should be consistent with the mechanism approved by the Board for Consumers' Gas in E.B.R.O. 495. Specifically, this results in a sharing of the base forecast margin on a 90:10 basis while any variances in excess of the forecast are to be shared, on a pre-approved basis, 75:25 in favour of ratepayers. Negative variances will be to the account of the shareholder.

iii) Long-term storage under market-based rates

Union has forecast a market premium, in 1999, of $2.571 million related to long-term storage sold at market rates. This premium represents the amount of revenue earned in excess of the cost-based rates last approved by the Board under E.B.R.O. 493-04/494-06. The premium for a period will be determined relative to the cost based rates approved for 1999. Union proposed that the premium be removed from the determination of the revenue requirement with 60% (ie. $1.543 million) to be placed in a market premium deferral account for use in the future and the remaining 40% (ie. $1.023 million) to be provided to in-franchise customers by way of a one-time refund at the time Union disposes of all other 1998 deferral account amounts. Union noted that the specific purpose of the 60% deferred portion was not yet determined but that Board approval would be required prior to disposing of any amounts deferred. In any event, the 60% deferred portion would remain in the deferral account for a maximum of three years.

Given the lack of specificity associated with the 60% deferred portion, parties were not accepting of Union's proposal at this time. Consequently, the parties agreed that the full amount of the market premium will be provided to in-franchise customers by way of a one-time credit and as part of the disposition of Union's other 1998 deferral account balances. Union will continue to track the long term storage premium and any variances separately from other S&T transactional services.

Evidence References:

1. C1/T3 Written Direct Evidence of Mr. Black and Ms. Galbraith
2. Agreement, Appendix F

C.6. Extensions of E.B.O. 166 Blanket Approval

The following parties take no position on this issue: Alliance Gas Management; CENGAS; OAPPA; Tractebel; Consumersfirst Ltd.; the "Alliance"; GEC; HVAC; CAESCO; Comsatec; Nova; NRG; WGSPG; Ontario Hydro; Pollution Probe; TCPL; TCP; Northland Power; Energy Probe and Consumers.

The parties agree that the administration of storage contracts for storage volumes of up to 2 Bcf will be enhanced by the ability to extend the term for contracts falling within the E.B.O. 166 blanket approved parameters beyond one year to enable Union to contract for a term which covers two off peak periods. The terms of this extended blanket approval would be as follows:

a) the term of the contract may cover no more than one peak period; and

TAB 5

E.B.R.O. 499

ADR Agreement

Appendix H

Appendix H

Deferral Account Summary

Account Number		Account Name	One-Time Charge/ (Credit) to Customers	Evidence Cross-ref	Issues List Cross-ref	Action After 1998 Disposition
Gas Supply Related Accounts:				D1/T1	D.1.8	
179-24		PGVA	(28,796)			close (merge with 179-80)
179-X1	(1)	TCPL tolls/fuel				establish
179-X2	(1)	Other purchased gas costs				establish
179-80		Firm PGVA	733			extend (common account)
179-81		Spot commodity	(4,822)			continue
179-82		Spot transport				close (merge with 179-81)
179-83		Compressor fuel gas	(1,058)			continue
179-84		TCPL tolls	(2,228)			continue
179-85		Union tolls	(357)			close
179-86		CTH tolls	(16)			continue
179-87		CPM tolls	-			continue
179-88		Transportation capacity assignments	(888)			continue
179-89		Heating value	11			continue
179-98		TCPL Variance Charges (LBA)	455			continue
Storage and Transportation Deferral Accounts:				C1/T3	C.5.3	
179-34		C1 and M12 transportation net revenue	476			close
179-39		C1 and M12 storage net revenue	(1,817)			close
		Long-term storage premium	(1,427)			
179-49		C1 off-peak storage	9			close
179-50		Other S&T services	(1,942)			close
179-Y1	(1)	Transportation and exchange				establish
179-Y2	(1)	Balancing services				establish
179-Y3	(1)	Short-term storage services				establish
179-Y4	(1)	Long-term peak storage				establish
179-Y5	(1)	Other S&T services				establish
179-Y6	(1)	Other direct purchase services				establish
Other Deferral Accounts:						
179-26		Deferred customer rebates/charges	1,687			continue
179-36/37/94		Shared services	-			close
179-38		Heat value	(4,426)	C1/T2		extend/rename as Energy Balancing
179-43		EBO 188	-			close
179-45		High temperature plastic venting	294			close
179-46		Merger costs	-	D1/T9		close
179-47		Customer information package	-	C1/T4		close
179-48		Utility ancillary services studies	-	D1/T11		close
179-51		Stress corrosion cracking	-	B1/T5		close
179-52		UFG methodology studies	175			close
179-53		Ontario capital tax reassessment	-			close
179-54		TYMR	728			continue
179-56		Comprehensive CIP	-	C1/T4		continue
179-57	(1)	CIS affiliate payment account	(1,291)	D1/T10		continue
179-58	(1)	CIS support services account	(531)	D1/T6&10		close
179-59	(1)	1998 municipal taxes	3,300	D1/T17	D.8.3	continue
179-60		Direct purchase payments/revenue	(141)			continue
179-61		Year 2000 costs	3,200	D1/T16	D.8.2	continue
179-62		Deferred income tax reclassification	(27,159)	D1/T4	D.8.1	close
179-63	(1)	Incremental rental w/h revenue	(9,000)	D1/T11	D.8.4	close
179-64	(1)	Storage cost accounting change	-	D1/T15		continue/amortize
179-65	(1)	Union Energy support services	(812)	D1/T6		close
179-Z1	(1)	LRAM	-	D1/T5	D.5.2	establish
			(75,643)			
	(2)	Long-term storage premium (1999 forecast)	(2,290)		C.5.3	
			(77,933)			

Notes:

(1) account to be established in this proceeding

(2) amount subject to update of cost allocation study

TAB 6

Ontario Energy Board

Commission de l'Energie de l'Ontario

VT INCEPIT FIDELIS SIC PERMANET

Ontario

RP-1999-0017

IN THE MATTER OF AN APPLICATION BY

UNION GAS LIMITED

FOR RATES FOR FISCAL 2000 - 2004,
PERFORMANCE BASED REGULATION, UNBUNDLING OF STORAGE AND UPSTREAM TRANSPORTATION SERVICES

DECISION WITH REASONS Volume 1

2001 July 21

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) shall be allocated 100% to the ratepayer for 1999 and 2000, with the incentive sharing for the long term storage premium account to be effective January 1, 2001.

2.506 Based on the evidence in this proceeding the Board is unable to determine whether storage service can evolve to become workably competitive. The Board believes that it is wise to exercise care with respect to long-term contracting of storage and to keep options open for the design and development of the storage market in Ontario.

2.7.4 Treatment of New Services

2.507 New services may be developed by Union to enhance the storage, transportation, and delivery services now offered. If the new services are regulated, they will be placed into the appropriate service basket and priced subject to the price cap parameters; if unregulated, Union would price them competitively. In either case, Union will disclose all new services, introduced or proposed, so that they may be addressed in the customer review process and then brought before the Board for disposition.

Positions of the Intervenors - Treatment of New Services

2.508 CAC stated that "as a matter of policy only when the assets and costs of a particular service are removed from the utility it is appropriate to exclude revenues from flowing to the ratepayers " CAC submitted that since the assets have been paid for by ratepayers the revenue from those assets should accrue to those ratepayers. CAC also submitted that any new services developed by Union should be brought before the Board for determination of the appropriate revenue allocation.

2.509 CEED proposed that prior to providing new storage, transmission, or distribution services, Union should be required to obtain "either a rate order from the Board pursuant to section 36 of the *Ontario Energy Board Act, 1998* or an order from the Board to refrain from exercising its power to regulate rates for these services". Where new services other than storage, transmission, or distribution are contemplated by Union, CEED urged that these new services only be provided after Union has received prior approval of the Board as required by the Undertakings.

Ontario Energy Board

Commission de l'Energie de l'Ontario

Ontario

RP-1999-0017

IN THE MATTER OF AN APPLICATION BY

UNION GAS LIMITED

FOR RATES FOR FISCAL 2000 - 2004, PERFORMANCE BASED REGULATION, UNBUNDLING OF STORAGE AND UPSTREAM TRANSPORTATION SERVICES

DECISION WITH REASONS Volume 2

2001 July 21

4.1 ELIMINATION OF STORAGE AND TRANSPORTATION TRANSACTIONAL REVENUE ("S&T") AND LONG–TERM STORAGE PREMIUM DEFERRAL ACCOUNTS

4.58 Union proposed to eliminate the Storage and Transportation Transactional Revenue Accounts (179-69, 179-70,179-71, 179-73, 179-74) and Long-Term Storage Market Premium (179-72) Account.

4.59 In EBRO 499, the Board approved replacing the previously existing accounts for storage and transmission services to ex-franchise and direct purchase customers with six accounts corresponding to the service blocks under which storage and transmission services are sold. Five of the accounts are related to Union's transactional services and are used to record the difference between actual and forecast net revenue for each type of transactional service (eg. transportation and exchange services, balancing services). The variance in excess of the forecast amount in each account (credit balance) is shared on an approved 75:25 basis in favour of the ratepayer.

4.60 Union's evidence is that the ratepayer credits (or debits) corresponding to the balances in each account at December 1999 are listed below:

• Transportation and Exchange Services (179-69)	$1,509,000
• Balancing Services (179-70	$938,000
• Short-term Services (179-71)	$2,090,000
• Other S&T Services (179-73)	$(495,000)
• Other Direct Purchase Services	$1,187,000

4.61 These five deferral account balances result in an overall ratepayer credit of $5.229 million at December 1999.

4.62 The long-term peak storage deferral account is used to record differences between the actual and forecast premium over cost-based rates related to the sale of long-term storage under market-based rates. This account recorded a ratepayer debit, at December 31, 1999, of $884,000.

Positions of Parties

4.63 CAC submitted that the "S&T" deferral accounts should be maintained because Union had provided no justification for their elimination. CAC argued that since the assets used to provide these services are regulated assets that have been funded through rates, a cost-of-service approach should be applied to these revenues during the PBR term.

4.64 LPMA, MECAP, and WGSPG submitted that Union had provided no credible evidence to support a change in existing practices concerning these accounts. LPMA rejected Union's arguments that it required these revenues to manage the additional risks Union would face from its PBR plan, contending that Union could otherwise mitigate against these risks

4.65 Schools' view was the transactional services deferral accounts should be maintained, arguing that the existing revenue sharing arrangement should not be affected by a change to PBR. Schools commented that the 75:25 sharing was an historical arrangement that reflected both the use of utility assets and the need to provide an incentive to management to market the services from these assets. Schools noted that Union proposed that sharing would not apply to new storage developments.

4.66 VECC submitted that these accounts should be maintained and that the revenues "should not be surrendered on the simple assertion that assists Union and the management of its risks", and further considered it inconsistent to include capital assets in the rate base but exclude some associated revenues.

4.67 IGUA opposed the closure of these accounts, referring to its submissions under "Treatment of Market Priced Storage" but suggested that the ratepayers share of the long-term market premium deferral account be reduced to 75% in 2001.

4.68 NOVA supported IGUA's position stating that to "have Union benefit entirely from these revenues which are not currently part of its revenue requirements and then to layer the PBR price cap plan on top of those incremental revenues is ... a double benefit for Union."

4.69 Energy Probe argued that there was no connection established between the additional PBR plan risks and the S&T revenue benefits stating that the "PBR proposal should be introduced only to drive out lower costs, and should be judged on a stand-alone basis."

Union's Reply

4.70 Union reiterated its submissions discussed im Chapter 2 under "Treatment of Market Priced Storage", saying that its proposal to eliminate the S&T and long-term storage premium accounts are a necessary and integral component of its PBR plan.

Board Findings

4.71 The Board has previously authorized the continuation of Long Term Storage Services Deferral Account (179-72) to record the long-term market storage premium. The Board has also authorized the continuation of the five transactional services accounts set out above. The actual balances for 1999 and 2000, and a forecast of the balances for 2001, will be disposed of in conjunction with the other non-gas supply related deferral account balances to be reviewed in the 2001 customer review process.

4.2 INCREMENTAL UNBUNDLING COSTS DEFERRAL ACCOUNT (179-X2)

4.72 Union proposed to establish an account to record the costs incurred for system changes, process changes, and new information systems that are required to implement the unbundling of upstream transportation and storage and also of customer billing. Union proposed to allocate these balances, projected to be $1.0 million at December 31, 1999, to in-franchise rate classes in proportion to the weighted average number of customers.

Positions of Intervenors

4.73 CAC submitted that deferral accounts should be used to accumulate costs going forward. CAC opposed the collection of costs incurred prior to the establishment of the deferral account and also opposed prior approval for recovery of balances.

TAB 7

Ontario Energy Board | Commission de l'Énergie de l'Ontario

Ontario

RP-2001-0029

IN THE MATTER OF AN APPLICATION BY

UNION GAS LIMITED

FOR RATES FOR 2001 AND 2002, INCLUDING ANNUAL INFLATION FACTORS, TAX RATE, AND CERTAIN SPECIFIC RECOVERABLE COSTS, ALL WITHIN AN APPROVED PBR PLAN

DECISION WITH REASONS

2002 September 20

RP-2001-0029

UNION GAS

SETTLEMENT AGREEMENT

March 22, 2002

Union proposes to allocate the balances in its deferral accounts consistent with the allocation used and approved by the Board in previous years.

Parties have accepted the allocation methodology for Union's 2000 and 2001 deferral account balances except for the allocation of the Direct Purchase revenue and Payments deferral account (179-60) and the allocation of the Transportation and Exchanges deferral account (179.69).

Some parties do not agree with proposed allocation of the Direct Purchase Revenue and Payments deferral accounts on the basis that the allocation of this balance (which includes variances in the payment of the Delivery Commitment Credit ("DCC")) is in proportion to Dawn-Trafalgar design day demand while the elimination of the DCC from rates is allocated on the basis of DCC paid.

In respect of the Transportation and Exchanges deferral account, CCK raised a concern with respect to the allocation of margin earned from the sale of transportation capacity that may have become available as a result of direct purchase customers that did not opt to take advantage of the 20% system wide delivery point flexibility option.

The following parties agree with the partial settlement of this issue: CAC, CCK, IGUA, LPMA, Schools, VECC, Group

The following parties take no position on this issue: CME, CEED, ECG, GEC, HVAC, OAPPA, Pollution Probe, TCPL, Tobacco

Evidence References:

1. B/T13 – Deferral Accounts
2. C.1.11, C1.12, C5.20, C5.21, C5.22, C20.14, C30.3, C39.10

11.6 Sharing of S&T Revenues and Long-Term Storage Premium

[Complete Settlement]

Consistent with the Board's RP-1999-0017 Decision, Union proposes to share the amounts in the S&T transactional services deferral accounts 75:25 in favour of customers for both 2000 and 2001. Union's S&T transactional services deferral accounts include:

Transportation and Exchange Services (179-69)
Balancing Services (179-70)
Short-term Storage Services (179-71)
Other S&T Services (179-73)
Other Direct Purchase Services (179-74)

Consistent with the Board's RP-1999-0017 Decision, Union proposes to share the amounts in the S&T Long-Term Peak Storage deferral account 100:0 in favour of customers for 2000 and 75:25 in favour of customers for 2001.

The following parties agree with the settlement of this issue: CAC, CCK, IGUA, LPMA, Schools, VECC, Group

The following parties take no position on this issue: CME, CEED, ECG, GEC, HVAC, OAPPA, Pollution Probe, TCPL, Tobacco

Evidence References:

1. B/T13 – Deferral Accounts
2. C5.23

11.7 Incremental Unbundling Costs Deferral Account (179-101)

[Complete Settlement]

The balance and allocation of the balance in the Incremental Unbundling Costs deferral account will be dealt with by the Board in its RP-2000-0078 Decision. The results of that decision will be incorporated in the Rate Order resulting from the Customer Review Process.

The following parties agree with the settlement of this issue: CAC, CCK, ECG, IGUA, LPMA, Schools, VECC, Group

The following parties take no position on this issue: CME, CEED, GEC, HVAC, OAPPA, Pollution Probe, TCPL, Tobacco

Evidence References:

1. B/T13 – Deferral Accounts
2. C5.25, C39.27

11.8 Treatment of Rate Retroactivity and Deferral Account Balances

[Complete Settlement]

Parties acknowledge that rate implementation and deferral account disposition cannot be implemented at April 1, 2002. Union will put together a new implementation plan and circulate to parties for comment as soon as possible.

The following parties agree with the settlement of this issue: CAC, CCK, ECG, IGUA, LPMA, Schools, VECC, Group

The following parties take no position on this issue: CME, CEED, GEC, HVAC, OAPPA, Pollution Probe, TCPL, Tobacco

Evidence References:

1. B/T19 – Treatment of Rate Retroactivity and Deferral Account Balances
2. C5.28, C8.27, C8.28, C20.16, C20.17, C23.1, C25.16, C38.39

12. INVENTORY REVALUATION METHODOLOGY

[Complete Settlement]

Union is proposing a change in the treatment of inventory revaluations. Currently, Union revalues all the gas in inventory at the time Union's rates and deferral account reference prices are changed. This assumes that all gas in inventory is required to meet the sales requirements of Union's system customers. However, Union has a significant amount of gas in inventory to meet Union's requirement to balance bundled direct purchase customers. Since inventory revaluation amounts are cleared to sales customers only, sales customers may wind up paying more or less than Union's actual cost of gas.

With dramatic changes in gas prices during 2000 and 2001, the potential overstatement of inventory revaluations is significant. In addition, as more of Union's sales customers move to direct purchase, the inventory revaluation amount would be recovered from a smaller number of system sales customers.

Union is proposing that inventory revaluations should only be applied to the portion of gas in inventory that is related to meeting the needs of system customers. Union is also proposing that the accounting order be changed to record the gas required to balance direct purchase customers separately from gas in inventory that is available for sale so that Union will no longer revalue Union's gas required to balance direct purchase customers. In addition, Union will annually assess the inventory for balancing direct purchase and adjust the inventory accounts, as necessary.

Parties accept Union's proposal in respect of inventory revaluation subject to Union participating in a future review of system gas. This review will consider Union's system gas pricing, the QRAM process, inventory revaluations and triggers. This review is expected to occur in conjunction with the next Enbridge Consumers Gas ("ECG") rate case following ECG's fiscal 2002 or in a generic proceeding held specifically for that purpose subsequent to ECG's fiscal 2002.

The following parties agree with the settlement of this issue: CAC, CEED, CCK, IGUA, LPMA, Schools, Tobacco, VECC, Group

TAB 8

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 9

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 10

RP-2003-0063
EB-2003-0087
EB-2003-0097

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

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, storage, and transmission of gas for the period commencing January 1, 2004.

BEFORE: Paul B. Sommerville
Presiding Member

Art Birchenough
Member

DECISION WITH REASONS

March 18, 2004

Union stated that long term market revenue from the long term peak storage market would increase from the 2002 actual level of $18.7 million to forecast levels of $21.8 million in 2003 and $34.5 million in 2004 respectively. The long term market premium represents $5.2 million of this amount in 2002 and was forecast to represent $8.6 million and $20.6 million, respectively, for 2003 and 2004. Union attributed the increases in revenues and premiums to its expectation "that existing M12 contracts will renew under C1 market based rates as outlined above."

Transactional & Other Services Forecast

There are three components of this forecast. These are transportation and exchange revenues, balancing service block revenues, and other S&T services revenues. Short term services included in the forecast are transportation, peak storage, balancing services, exchanges, Hub2Hub™, name changes and redirections, and Ontario Production services.

Transportation and Exchange Revenues

Union's S&T transportation and exchange revenues for actual 2002 and updated forecast 2003 and 2004 are $12.5 million, $5.8 million and $2.5 million respectively. The corresponding deferred margins are $5.0 million, -$1.2 million and -$0.3 million respectively. The revenue minus costs yields the gross margin, while the gross margin minus the approved forecast yields the deferred margin.

Union stated that with a balanced gas supply portfolio that meets forecast in-franchise and ex-franchise demands, few firm assets are available on a planned basis to support these services. Asset availability is mainly influenced by weather and market variances. The latter variances include the amount of direct purchase switching, T-service switching, in-franchise growth, changes in customer use, market prices, and S&T demand. While actual results depend on actual weather conditions experienced, Union's forecast assumes normal conditions.

Union cited the following reasons for the decline in the S&T market:

1. a reduction in the number of potential counterparties following the Enron failure;

2. the imposition of more onerous credit requirements on remaining counterparties, reducing the number of transactions;

3. a decrease in peak storage value from $1.50/GJ in 2002, to between $0.45/GJ and $0.75/GJ in 2003, due to reduced summer/winter price differentials for gas; and

4. the expectation that high forecast commodity prices will reduce transactional services demand in the industrial and power generation markets.

Balancing Service Block Revenues

Union's balancing service revenues and deferred margins decreased from $37.1 million in 2002 to a forecasted 2003 and 2004 of $13.4 and $7.5 million respectively. The corresponding deferred margins were $12.3 million in 2002, decreasing to forecast 2003 and 2004 levels of $3.7 million and $1.5 million respectively.

Union attributed the decreased margins on this block for 2003 and 2004 to a number of events in 2002, which are unlikely recur in 2004 including:

1. historically high value of storage in 2002;

2. incremental gas loan revenues due to favourable market conditions in 2002;

3. comparatively lower seasonal loan activity in 2003 due to prior warmer than normal weather; and

4. incremental balancing activity in 2002 due to weather variations.

Other S&T Service Revenues

Union's other S&T Services revenue for actual 2002 and updated forecast 2003 and 2004 are $3.8 million, -$0.3 million and $0.9 million respectively. The corresponding deferred margins are $0.3 million, -$2.3 million and -$1.0 million respectively.

Union, in explaining the decline in these revenues, noted that it managed jointly with Encana a Hub2Hub™ service, whereby a customer delivers gas at the Alberta Energy Company price point ("AECO") hub and simultaneously receives gas at Dawn, so the service is a substitute for transportation. Union realized $3.1 million of revenue in 2002, and is forecasting $0.6 million in revenue for both 2003 and 2004. In response to an interrogatory, Union indicated that it agreed to wind down the service over 2003 and 2004 at Encana's request.

Position of the Parties

Intervenors expressed concerns about the appropriateness of Union's approach to embedding forecast S&T margins and long-term storage premiums into rates, including variance account treatment.

Numerous intervenors took the position that Union's proposed sharing ratios should be adjusted to provide a higher proportion for the ratepayer and less for the shareholder, including Kitchener, FONOM, LPMA, CAC, IGUA, CME, Schools and VECC.

Union's Position

Union asked the Board to accept its 2004 forecast of incremental S&T revenues of $20.8 million. Union noted that the Board has approved a 75:25 sharing for S&T transactional revenues since EBRO 499 and the same sharing proportion for the total of S&T revenues and the long-term storage premium since RP-1999-0017.

Union took the position that to embed a greater fraction of the forecast margins into rates would expose Union to an inappropriate level of risk, and not reflect the Board's statements regarding incentive levels. Union submitted that if any percentage of the 2004 deferred margins were put into rates, the S&T and market premium deferral accounts should record positive or negative variations shared 75:25 in favour of the ratepayer.

Union proposed to embed the 1999 forecast of S&T margins in rates with any additional margin shared 75:25. Should the Board decide to embed more of the 2004 forecasted margins in rates, Union requested that 75% of the forecast be put in rates with a symmetric deferral treatment, shared 75:25 in favour of the ratepayer, of any variances.

Board Findings

The Board continues to support the methodology approved in EBRO 499 with respect to embedding forecast S&T margins and the Long-Term storage premium in base rates on a 90:10 basis. However, in this regard and in respect of its finding above, amounts to be embedded apply to forecast 2004 amounts, not to EBRO 499 forecasts that were approved for the 1999 test year.

The Board finds that symmetrical variance account treatment of these revenues is appropriate to hold ratepayers and Union harmless from deviations between actual margins earned and those embedded in rates. The Board further accepts that any such variances be shared 75:25 in favour of the ratepayer.

4.4 OTHER ISSUES

There are two other issues falling into this section. The first of these relates to the concerns expressed, particularly by FONOM et al relating to storage allocations to the Northern and Eastern Operations area, while the second relates to Union's changes in presentation in successive rates cases, with respect to classifications of such items as S&T revenues and customer supplied fuel.

TAB 11

Ontario Energy Board

Commission de l'Énergie de l'Ontario

VT INCEPIT SIC PERMANET FIDELIS

Ontario

RP-2003-0203

IN THE MATTER OF AN APPLICATION BY

ENBRIDGE GAS DISTRIBUTION INC.

FOR RATES FOR FISCAL 2005

DECISION WITH REASONS

November 1, 2004

Positions of the Intervenors

2.4.4 Most of the Intervenors stated that the intent of the current sharing mechanism was to provide an overall 75/25, ratepayer/shareholder benefit for gross margin and therefore shared CAC's perspective that a continuation of the current sharing mechanism would involve embedding 75% of the current forecast in rates, allowing the shareholder to recover the next 25%, with the remainder subject to a 75/25 sharing. Given that the current TS revenue forecast for 2005 is $15 million, CAC submitted that $11.25 million should be embedded in rates, with the next $3.75 million going to the shareholder, and the 75/25 sharing mechanism would apply beyond that. Several Intervenors stated that the discontinuance of bundled transactions should not impact the sharing mechanism. CAC did accept that, if the Board should deny EGDI's request to pursue bundled commodity transactions, the amount embedded in rates should be adjusted to reflect a reduced forecast of gross margin.

2.4.5 SEC argued that the previous sharing mechanism was initially based on a split of 90/10 in favour of the ratepayers, and after that the split became 75/25. As a compromise between the 75/25 and 90/10 position, SEC suggested that $12 million be embedded into rates, with the next $4 million going to the shareholder and the remainder subject to a 75/25 sharing mechanism.

2.5 BOARD FINDINGS

2.5.1 The Board has decided that it is inappropriate for either EGDI, or EGS as an agent of EGDI, to acquire gas commodity to be bundled with utility assets, thus creating bundled products. The Board directs the Company to refrain from this activity within 60 days of issuance of this Decision.

2.5.2 The Board does not decide casually to forego the opportunity to reduce distribution rates; however, the Board acknowledges the legislative and regulatory efforts in Ontario to create competitive markets for natural gas commodity. While the physical delivery of gas is a natural monopoly, storage and transportation services could reasonably be provided by competitors. One of the key developments in this evolutionary process has been the unbundling of supply, storage and transportation services by local distribution monopolies.

2.5.3 The Company's request in this application for authorization to conduct bundled transactions in its own name is contrary to this direction in regulation and public policy. The practice it has followed in the past two years, where its affiliate has had exclusive access to surplus storage and transportation assets and has bundled those assets with commodity for sale in the ex-franchise market is also inconsistent with the development of a viable competitive market for these services. The Board notes that this practice was inconsistent with the terms of the agency agreement between EGDI and EGS that has been filed with the Board.

2.5.4 The Board agrees with Direct Energy that commodity is the subject of a competitive market, and allowing a monopoly product to be bundled with it has the potential to undermine competition. The Board is particularly concerned with the lack of transparency in these transactions that results in opportunities for EGDI and EGS that are not available to other market participants.

2.5.5 Some Intervenors argued that the bundled commodity transactions should be allowed because they provide a financial gain to ratepayers. The Board disagrees, both because of the competitive impact discussed above and because of the increased risk to ratepayers. The Board agrees with EGDI that the parties who share in the margin from the activities should also share in the credit risk. The Company gives conflicting evidence on the projected costs of these risks suggesting on the one hand that they are small, and yet asserting that an annual cost of $2 million is appropriate for notional credit cost recovery. For the Board, this provides an additional argument that commodity transactions should not be undertaken on behalf of EGDI, either directly or indirectly. It is inappropriate, as argued by Energy Probe, for the Company (and its ratepayers) to take on a significant and material change to the Company's risk profile in order to engage in these functions.

2.5.6 In this situation, where the Company is not engaged in bundled commodity transactions, the Company has proposed a sharing mechanism such that the ratepayers would have the guarantee of $4.5 million, the next $1.3 million above that would be to the account of the shareholder (less O&M costs). Any gross margin above the aggregate of these amounts would then be shared 75/25 percent in favour of the ratepayers. The Company based this calculation on the fact that in the past year, bundled transactions made up more than 50% of the total TS gross margin and the assumption that most of this margin will be lost without bundling. Some Intervenors take the position that unbundled TS gross margin continues to increase and, based on the Company's numbers, the budget should be in the range of $15 million, and the ratepayers guarantee should be $11 to $12 million. Some other Intervenors agreed that the budget should be reduced if bundled Transactional Services were not allowed.

2.5.7 The Board notes that the appropriate sharing mechanism for Transactional Services should be based on a reasonable and well-defended gross margin budget, 75% of the budget guaranteed to the ratepayers, the next 25% to the account of the shareholder who deducts O&M costs, and the remainder shared 75/25 percent in favour of the ratepayers. The Board finds that there is little clear evidence supporting the position of any party on the appropriate budget due to the lack of transparency and clarity in the details of the bundled transactions. A breakdown of the portion of gross margin attributable to commodity versus surplus TS assets was not available. Although the Company had anecdotal evidence that some surplus assets could not be utilized without a commodity component, there was no direct evidence as to the extent of this impact. The Board does not accept that the Intervenor proposed budget of $15 million can be achieved without commodity included in the transactions. However, the Board also does not accept that a greatly reduced budget of $5.8 million as put forward by the company is appropriate. The Board therefore finds that the Transactional Services sharing mechanism will remain unchanged at a budget of $10.7 million. The ratepayers will have a guarantee of $8 million of the gross margin, and the next $2.7 million above that will be to the account of the shareholder (less O&M costs). Any gross margin above the aggregate of these amounts will then be shared 75/25 percent in favour of the ratepayers.

2.5.8 It is the Board's view that if surplus transportation and storage assets, which form the basis for the Transactional Services, were made available or promoted on an open market basis to any and all interested and capable parties, commodity bundled transactions could be developed in the market. Accordingly, the Board expects the Company to develop a methodology for making such surplus assets known to, and available to, unrelated market participants on a non-discriminatory basis as soon as practicable and ideally within 60 days. This methodology should be developed with the input and participation of market participants interested in having access to such assets. The Board expects that EGS, acting on its own behalf, could be an active participant in this market, but it is imperative that there be fair, equitable and open market opportunities for others. The costs associated with management of risk in these transactions would be an integral part of the bid process for all participants.

2.5.9 On or before January 31, 2005, the Board expects the Company to provide:

i) Confirmation that commodity transactions on behalf of EGDI have ceased; and

ii) A status report on the development of a methodology aimed at providing interested parties with fair and non-discriminatory access to surplus utility assets with the objective of optimizing the value of those utility assets.

EB-2011-0210

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

AND IN THE MATTER OF an application filed by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2013.

CANADIAN MANUFACTURERS & EXPORTERS ("CME") COMPENDIUM OF DOCUMENTS re: Upstream Transportation Cost Reductions

OTT01\5228536\v1

TAB 12

Ontario

Natural Gas Regulation in Ontario:

A Renewed Policy Framework

Report on the Ontario Energy Board

Natural Gas Forum

March 30, 2005

As described above, the benefits of efficiencies can be shared with customers in two ways – during the term of the plan, through the adjustment mechanism, and in the base rates for the subsequent plan. With robust rebasing, all of the efficiency improvements achieved during the term of a plan would be built into the base rates for the subsequent plan. In this way, shareholders retain the benefits of any efficiency gains (that is, any achieved over and above the productivity factor) during the term of the initial plan, and all of the benefits flow to customers during the term of subsequent plans.

During rebasing, the Board will be particularly interested in determining whether the efficiency improvements achieved by the utility are temporary or sustainable, and it will expect to receive a thorough analysis of this issue. For example, the Board will be interested in the relationship between operation, maintenance and administration costs and capital expenditures, the timing of capital expenditures and the associated impacts on shareholders and customers. The Board will also expect to see, during the plan's term, measures that are designed to improve the utility's productivity on a sustained basis – not temporary, unsustainable budget cuts. The Board's determination of the new base rates and forward plan will reflect its assessment of all of these factors. The Board also cautions that it will take an unfavourable view of sudden and significant increases in costs at the time of rebasing, unless thoroughly justified.

Earnings Sharing Mechanisms

Earnings sharing mechanisms (ESMs) are sometimes employed in incentive-based ratemaking schemes to provide for the sharing of earnings in excess of a pre-established level between the utility's shareholders and ratepayers, usually during the term of the plan. That is, ESMs are intended to return some of the productivity improvements to ratepayers during the term of the plan.[6] ESMs are generally tied to the utility's return on equity (ROE), although the specific features of the ESM may vary from plan to plan. The features include the level at which sharing takes place, the ratio of sharing between shareholders and ratepayers and whether the ESM is symmetrical (that is, whether it

[6] In this discussion, the Board is not referring to the earnings sharing associated with transactional services, storage and transportation services or demand-side management.

applies when earnings are both above and below the target ROE). The issues we address here are whether there should be an ESM in the IR plans and, if so, what form it should take.

Stakeholders' Views

Stakeholders were divided on this issue. A number of stakeholders, primarily customer groups, were of the view that an ESM assures customers that they will benefit from the productivity gains made by the utilities. For example, the Consumers Council of Canada and the Vulnerable Energy Consumers Coalition suggested that earnings sharing could be incorporated into a COSR framework over a multi-year period. London Property Management Association and Wholesale Gas Service Purchasers Group made the point that an asymmetrical ESM applicable only to earnings above the target ROE would provide utilities with a significant incentive to increase efficiencies.

Union and Enbridge took the view that a symmetrical ESM could be developed around a benchmark ROE.

Others took the view that an ESM should not be adopted, because it would reduce the efficiency incentives of a PBR plan.

The Board's Conclusions

Customers can benefit from productivity improvements during the term of an IR plan in two ways: through the productivity factor in the price adjustment mechanism and/or through an ESM. If the productivity factor is low, customers may be dissatisfied with the expected level of benefits, and may view earnings sharing as an appropriate means by which to realize benefits within the plan's term. Stakeholders may also rely on an ESM as a way to mitigate the effects of an incorrect or uncertain productivity factor (which may be the result of utilities and stakeholders not having the same information).

In addition to the benefits that would accrue during the plan's term, customers could also benefit from productivity improvements through robust rebasing at the beginning of the next plan, as has already been described.

The regulatory challenge is to provide strong incentives to promote efficiency, while at the same time achieving customers' acceptance of the IR plan by ensuring that the benefits of the efficiencies flow to them. In the Board's view, ESMs would reduce the utility's productivity incentives and introduce a potentially costly additional regulatory process – results that are not in accordance with the Board's criteria for the regulatory framework. The Board recognizes that, without an ESM, the determination of the adjustment factor will be particularly important to ensure that customers benefit from productivity gains during the plan's term. For this reason, as noted earlier in this report, the Board has concluded that a generic hearing should be held to determine the annual adjustment mechanism.

The Board views the retention of earnings by a utility within the term of an IR plan to be a strong incentive for the utility to achieve sustainable efficiencies.

The Board does not intend for earnings sharing mechanisms to form part of IR plans.

The Term of the Plan

Stakeholders' Views

On the issue of the optimal term for the ratemaking plan, stakeholders were generally divided into two camps – customer groups generally favoured short terms of two to three years, while the utilities and the School Energy Coalition (SEC) favoured longer terms of five years or more.

Union submitted its view that the term of a plan should be long enough to provide the utility with incentives to pursue productivity improvements, and noted that the "payoff" for some productivity improvement measures may not be realized for some time. In recognition of these factors, the minimum term of plans approved in some jurisdictions is five years, with some terms as long as 10 years.

The Industrial Gas Users Association (IGUA) suggested that the term be one of the elements negotiated by the parties. IGUA indicated a preference for a shorter term, but said that a longer term may be acceptable if provision were made for an automatic review or reopening of the issue under defined circumstances. SEC proposed an initial five-year term, subject to a single off-ramp. SEC also proposed that, at the end of four years and before any rebasing application, the Board hold a hearing to determine whether it would be appropriate to extend the incentive plan for a further period of up to five years or to require a rebasing exercise.

The Board's Conclusions

The Board's view, shared by most stakeholders, is that the current system of annual rate cases is inefficient – it is costly and time consuming. The challenge for the Board is to implement a regulatory model that contains incentives for utilities to make productivity improvements and that reduces the annual regulatory burden, while ensuring both that customers benefit from productivity improvements and that an appropriate level of transparency is maintained. The Board believes that IR plans must contain longer rate-approval periods to ensure an incentive for utility shareholders to make productivity improvements and to benefit from them.

The Board expects that the term of IR plans will be between three and five years. The Board's view is that three years represents the minimum term that may be expected to give rise to productivity incentives, and its preference is for a plan of five years. The Board is reluctant to approve a term greater than five years at this time, given the importance of ensuring that productivity gains are passed on to customers in subsequent periods. The term of the plan will be determined in the generic hearing on the annual adjustment mechanism.

The Board is of the view that a plan should not be reopened during its term except for the most compelling reasons. Off-ramps are addressed below.

Off-Ramps, Z-Factors and Deferral or Variance Accounts

Various mechanisms can be established as part of the overall ratemaking framework, but designed to operate outside the plan itself. An *off-ramp* is a pre-defined set of conditions under which the plan would be terminated before its end date, usually because of some unforeseen event. A *z-factor* provides for a non-routine rate adjustment intended to safeguard customers and the utility against unexpected events outside of management control. *Deferral accounts* are formalized accounts that track an amount that cannot be forecast. *Variance accounts* are formalized accounts that track a variance around a forecast. These mechanisms are often called risk-mitigation tools, as they create a regulatory "buffer" against unforeseen circumstances.

Stakeholders' Views

Most stakeholders advocated limits on the use of off-ramps, z-factors and deferral or variance accounts. In their view, these mechanisms inappropriately mitigate the utility's risk in an incentive-based system. In general, customer groups would like to see utilities assume more risk by consenting to PBR agreements that eliminate deferral or variance accounts, as well as any side agreements that shelter the utility from unforeseen events. It is recognized that a balance exists between eliminating these mechanisms and allowing shareholders to reap the benefits of good performance. Striking this balance was viewed as more in keeping with the objectives of incentive-based ratemaking.

Union, on the other hand, argued that off-ramps are designed to protect both customers and the utility, and that customers benefit from being served by a financially viable utility. In Union's trial PBR, off-ramps were restricted to a serious decline or significant improvement in Union's financial position. Enbridge's view was that deferral or variance accounts and z-factors provide justifiable regulatory relief from cost elements beyond the control of management.

The Board's Conclusions

The Board's view of off-ramps, z-factors and deferral or variable accounts is guided by the need for an appropriate balance of risks and rewards in the incentive regulation model. As stated earlier, the Board believes that it is appropriate for the utility's shareholders to retain all earnings during the plan's period. The Board believes that this is a very strong incentive. The Board also believes that, as a balancing factor, the utility should assume an appropriate level of business and financial risk.

In the Board's view, an appropriate balance of risk and reward in an IR framework will result in reduced reliance on deferral or variance accounts, and reliance on off-ramps or z-factors in limited, well-defined and well-justified cases only.

Service Quality Monitoring

When a regulated utility seeks cost-saving (efficiency) initiatives under an incentive plan, there is a danger that the quality of service experienced by its customers will suffer. The Board has identified appropriate quality of service as one of its criteria for the ratemaking framework. Service quality indicators (SQIs) have been used in Ontario, but they have been limited to measures such as telephone response time, emergency response and pipeline corrosion surveys. The issue before the Board is how a service quality framework should be developed and regulated.

Stakeholders' Views

Stakeholders generally agreed that quality of service is an important matter. Union suggested that SQIs should relate to those aspects of the utility's service that are important to customers, and that SQI targets should be derived from the historical performance levels of the utility. Enbridge also generally supported SQIs, noting that they provide assurance that operating efficiencies are not achieved at the expense of either customer service or the safe operation of the distribution system.

Union maintained that performance rewards and penalties would be inappropriate. In its view, SQIs are intended to ensure that minimum standards are maintained in an

TAB 13

C1 Short Term Transportation and Exchange Services

Short term transportation and exchange revenues exceeded the Board approved amount by $5.1 million, as shown at line 14. The primary driver of the $5.1 million revenue increase was higher demands and service value due to a colder than normal winter.

M12 Transportation Overrun

M12 Transportation overrun revenues exceeded the Board approved amount by $4.8 million, as shown at line 15. Union does not forecast M12 transportation overrun revenues, since ex-franchise customers can use Union's system differently each year. Union does not expect customers to elect to use overrun services over the long run. To the extent customers have a long term need, Union would expect customers to contract appropriately for long term services.

4.0 S&T Deferral Account Proposal

Union began selling short term storage services to ex-franchise customers at market based rates under the C1 rate schedule in 1989. The first transactional S&T deferral account, which captured positive variances from the Board Approved forecast was approved by the Board in 1993, as part of the E.B.R.O. 476-03 ADR Settlement Agreement and related Board Decision. In that Decision, the Board also approved a 75/25 sharing of the fiscal 1995 deferral account balance between ratepayers and the utility respectively, which had also been agreed to in the ADR Settlement Agreement. This division of deferred margin was to recognize "Union's role in developing opportunities and facilitating arrangements under the proposed account" (page 4 of the E.B.R.O. 476-03 ADR Settlement Agreement). Any future disposition of margins in the deferral account was left to a future determination of the Board. In the E.B.R.O. 486 Decision, the Board reaffirmed a 75/25 sharing of deferred margin. The sharing of deferred margin on a 75/25 basis continued through subsequent rates applications and Decisions. In the E.B.R.O. 499 proceeding, the Board accepted an ADR Settlement Agreement that shared forecast margin on a 90/10 basis between ratepayers and Union respectively. Prior to that proceeding, the entire forecast of S&T transactional service margin went to the ratepayers' benefit.

In Union's last rates application (RP-2003-0063) the Board approved a 90/10 sharing of forecast S&T transactional service margin and a 75/25 sharing of any deferred S&T transactional service margin in favour of ratepayers. The Board also extended the 75/25 sharing to variances where the actual S&T transactional service margin is below forecast, thereby providing symmetrical treatment of positive and negative variances from forecast.

Union is proposing that S&T transactional service margin variances in 2005 and 2006 continue to be subject to deferral, consistent with the Board's RP-2003-0063 Decision.

Union is proposing to eliminate the S&T transactional service deferral accounts effective January 1, 2007 and to include the total forecast of S&T transactional service revenues (margins) in the determination of rates, consistent with the treatment of all other forecast revenues, including S&T core services revenues (i.e. no 90/10 sharing). Union's proposal would eliminate all margin 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 14

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 15

Ontario Energy Board

Commission de l'Énergie de l'Ontario

VT INCEPIT FIDELIS SIC PERMANET

Ontario

EB-2005-0001/EB-2005-0437

IN THE MATTER OF AN APPLICATION BY

ENBRIDGE GAS DISTRIBUTION INC.

2006 RATES

DECISION WITH REASONS

February 9, 2006

6. TRANSACTIONAL SERVICES

6.1 BACKGROUND

6.1.1 The Transactional Services ("TS") function was established in 1997 to enable Enbridge to trade in storage and transportation capacity which is surplus to its requirements to serve its in-franchise customers. Revenue is generated through the sale of this surplus capacity to in-franchise and ex-franchise markets. Examples of TS services include peak storage, off-peak storage, loans, exchanges, load balancing and transportation assignments for terms of one year or less. In the roughly 2-year period 2003 to early 2005, the Company also created bundled transactional services, using the gas commodity to enhance the standard service offerings. However, the Board ordered an end to this practice in its RP-2003-0203 Decision, citing a longstanding concern about the effect that this bundled trading could have on the competitive natural gas marketplace. In that Decision, the Board also ordered the Company to develop and implement a new methodology to ensure that surplus capacity was made available on a non-discriminatory basis.

6.1.2 There are two unsettled issues related to TS:

- the gross margin forecast
- the proposed new revenue sharing mechanism

6.1.3 A TS gross margin forecast and revenue sharing mechanism have been in place since TS was first established. This revenue sharing mechanism is designed to provide a return to ratepayers, in recognition of the fact that the costs of the assets have been included in rates. The Board has also always provided for a return to the shareholder as form of incentive, to encourage Enbridge to pursue the sale of the surplus assets vigorously.

6.1.4 The Board-approved sharing mechanism and forecast TS gross margin have remained basically unchanged for the past three years. For fiscal 2003, 2004 and 2005, Enbridge ratepayers were guaranteed $8 million in TS gross margin. The "guarantee" came about because the $8 million was credited to the Company's revenue requirement, as part of the prospective test year rate-setting process. The sharing mechanism further specified that the next $2.7 million in TS gross margin would be credited to the shareholder's account. Any amounts above $10.7 million were to be shared 75% to the account of the ratepayer and 25% to the account of the shareholder. The Transactional Services Deferral Account ("TSDA") captured the variance between the actual gross margin and the forecast amount. Amounts in the TSDA are disposed of and split according the 75:25 ratio, after the fiscal period ends. An exception to this rule would arise if the TSDA amount were negative, in which case the negative amount would be solely the responsibility of the shareholder.

6.1.5 Enbridge proposed a number of significant changes to the existing sharing mechanism for 2006. First, Enbridge proposed that the gross margin forecast be eliminated. This effectively means that there would be no ratepayer "guarantee" included in the rates. Second, the Company proposed that all of the amounts recorded in the TSDA would be shared equally between the ratepayer and the shareholder, instead of the current practice which affords ratepayers 75% of funds captured in the TSDA. Enbridge also proposed that the first $800,000 in gross margin be used to recover the incremental O&M costs associated with providing TS. This is in contrast to the current mechanism whereby the O&M costs of operating the TS function are borne by the shareholder.

6.1.6 The reasons cited by Enbridge for the proposed changes included the following:

- changes in the gas marketplace and the regulatory environment, especially the new TS methodology, which was approved by the Board in proceeding EB-2005-0244 in July 2005, and which Enbridge asserted introduces serious uncertainties;

- the need for new gas-fired power generation and its potential impact on load balancing services which may have the effect of materially curtailing the amount of surplus assets available for trade;

- weather uncertainty;
- the trend toward toll unbundling and its impact on which assets are held and used;
- possible TCPL service changes and the related potential impact on storage injections which have made accurate forecasting difficult;
- the risk/reward sharing of the current methodology which is asymmetrical and needs to be brought into balance in order to provide an appropriate incentive for Enbridge;
- the unfair asymmetrical risk faced by the Company if it fails to realize the guaranteed amount of revenue from TS sales; and
- other sharing mechanisms employed by the Board, for example, the 2004 earnings sharing which was struck on a 50:50 basis, which provide a sufficient incentive for the Company.

6.1.7 A number of intervenors made wide-ranging submissions about how the Board should proceed with Enbridge's TS proposals. Even though intervenors were united in their arguments that the Board should not accept the Company's TS proposals because they provide excessive returns to the shareholder, the intervenors' solutions were diverse. Most intervenors countered the Company's position that it is not possible to forecast the results of the TS business. Some accepted the Company's argument that the TS business faces uncertainty and revenue forecasts should be lower than recent practice; others said that the new TS methodology may actually increase gross margins.

6.1.8 There was significant variation among the intervenors' proposals for a solution to the TS revenue sharing question. The amounts suggested for inclusion in rates ranged from $6.5 million to $14 million. The proposals for the sharing of deferred amounts were even more disparate.

6.1.9 Some intervenors agreed with Enbridge that it should be able to recover its O&M expenses for running the TS business.

6.2 BOARD FINDINGS

6.2.1 In the Board's view, there are four questions that need to be answered:

1. Can a reasonable forecast be established and, if so, what is the appropriate amount?

2. Should ratepayers get a financial "guarantee" embedded in rates?

3. What sharing ratio provides an appropriate encouragement for Enbridge to optimize its TS activity, while providing a reasonable return to ratepayers?

4. Should TS O&M expenses be a ratepayer or shareholder responsibility or be shared?

6.2.2 The Board believes that these questions are linked. The resolution of all four questions should create an appropriate balance between Enbridge's obligation to optimize the use of the assets paid for by the ratepayer, and a reasonable inducement to encourage a vigorous approach to such optimization. The inducement should be no larger than is necessary to ensure that Enbridge dedicates sufficient resources to meet its obligation.

6.2.3 The first question is whether a reasonable forecast can be established for 2006 and if so, at what level. The Board does not question that forecasting for TS involves uncertainties. The Board accepts that the TS revenue forecast cannot be established with the same degree of confidence that can be attained in some other budget areas. However, a measure of uncertainty does not mean that a forecast cannot be developed, especially in light of eight years of actual experience in the activity. All businesses produce forecasts in the face of uncertainty. The Board does not accept that no forecast can be developed for TS.

6.2.4 In terms of the level of the forecast, the Board notes that in examining the historic numbers on TS, the pattern of TS gross margin results does, in fact, demonstrate some variability. Some of this variability was brought about by the introduction of bundled commodity transactions, a practice that, as noted above, has been terminated pursuant to a Board direction made in conjunction with its Decision in RP-2003-0203.

6.2.5 If the historic amounts are examined after excluding the gross margin amounts attributable to commodity transactions, the amounts would be as shown in the following table.

TS Gross Margin ($ millions)

2001	2002	2003	2004	2005
14.1	9.4	7.6	8.2	13.7

6.2.6 The amount provided for 2005 by Enbridge was an estimate as at the end of May 2005. On a "best efforts" basis, the Company asserted that its 2006 TS gross margin forecast would be between $5 million and $8 million.

6.2.7 The Board notes that the simple average of the numbers in the table is $10.6 million. With respect to Enbridge's "best efforts" forecast for 2006, the fact that the 2005 mid-year forecast for the year is well in excess of that, and in view of historic results, the "best efforts" number appears to the Board to be low. The Board therefore views a 2006 forecast of TS gross margin of $10.7 million as a reasonable estimate. This amount has been used for the gross margin forecast the last few years, without undue advantage or prejudice to ratepayers or the shareholder.

6.2.8 Rather than being a negative influence, as suggested by Enbridge, it is the Board's view that the new TS methodology, approved by the Board in 2005, is likely to increase market confidence, and support returns on the surplus assets. The new process, which is to be operational early in 2006, is characterized by increased transparency and enhanced access to the surplus assets for other market participants. This should have the effect of increasing the market value of the surplus assets.

6.2.9 As to the sharing mechanism, the Board supports now, as always, the existence of an appropriate inducement for the Company to ensure that it pursues its obligation to optimize realization on the surplus assets vigorously. The Board notes that the Company substantially out-performed the Board's gross margin targets for TS during 2003, 2004 and the portion of 2005 when it bundled commodity in the transactions. The Board recognizes that the Company's shareholder realized attractive profits during this period, even at the 25% level of sharing. Even in the absence of bundled commodity transactions, the Board views the activity as having the potential to exceed $10.7 million in gross margin per year.

6.2.10 In the RP-2003-0203 Decision concerning the Enbridge 2005 Test Year, the Board ruled that a 75:25 ratepayer to shareholder ratio was appropriate for amounts greater than the forecast gross margin of $10.7 million. In light of the fact that this ruling was handed down relatively recently, and in consideration of the evidence in this case, the Board sees no compelling reason why the current mechanism and amounts should be altered.

6.2.11 The Board, however, does see merit in providing for the Company's TS O&M costs to be reimbursed by ratepayers in 2006. As indicated above, the Board regards the optimization of the surplus assets to be an obligation of the Company. In consideration of this, and in light of the benefits the ratepayers realize, the Board finds that it is appropriate that the associated O&M costs be recovered from ratepayers. The Company has stated that this cost will be $800,000 in 2006, and the Board accepts this amount. The Board notes that there is a deduction of $800,000, related to TS costs, in the Company's statement of Other Operating Revenue. The Board therefore assumes that the $800,000 deduction reflects Enbridge's presumption that the Board would find as it has. If that is not so, an appropriate adjustment shall be made to the Company's revenue requirement to reflect the Board's finding.

6.2.12 Finally, the Board would like to comment on the longevity of this sharing mechanism. The Board views a TS sharing mechanism such as this as something that should endure for more than a single year. Indeed, the Company's proposal alluded to a mechanism for 2006 "and beyond". The Board does not see merit in arguing this issue year after year unless there is a fundamental shift in the TS marketplace. Therefore, the Board encourages Enbridge and the parties to adopt this methodology beyond 2006 unless a change is necessitated as a result of conclusions reached in the Natural Gas Electricity Interface Review.

TAB 16

EB-2005-0520

UNION GAS LIMITED

SETTLEMENT AGREEMENT

May 15, 2006

TABLE OF CONTENTS

List of Appendices:

EB-2005-0520

SETTLEMENT AGREEMENT

This Settlement Agreement ("Agreement") is for the consideration of the Ontario Energy Board ("the Board") in its determination, under Docket No. EB-2005-0520, of Calendar 2007 rates for Union Gas Limited ("Union"). By Procedural Order No. 1 dated February 24, 2006, the Board scheduled a Settlement Conference to commence May 1, 2006. The Settlement Conference was duly convened, in accordance with Procedural Order No. 1, with Mr. Ken Rosenberg as facilitator. The Settlement Conference proceeded until May 12, 2006.

Attached as Appendix A to the Agreement is the Board's Issues List which was issued through Procedural Order No. 3 dated March 22, 2006. The Agreement identifies the issues on the Board's list for which agreement has been reached. The Agreement is supported by the evidence filed in the EB-2005-0520 proceeding.

Each of the issues identified below falls within one of the following three categories:

1. an issue for which there is complete settlement, because Union and all of the other parties who discussed the issue either agree with the settlement or take no position,
2. an issue for which there is partial settlement, agreed to by Union and a majority of parties but one or more parties do not agree with the settlement,
3. an issue for which there is no settlement.

For the purposes of this Agreement, the term "no position" may include both parties who were involved in negotiations on an issue but who ultimately took no position on that issue and parties who were not involved in negotiations on that issue at all.

It is acknowledged and agreed that none of the completely settled provisions of this Agreement is severable. If the Board does not, prior to the commencement of the hearing of the evidence in EB-2005-0520, accept the completely settled provisions of the Agreement in their entirety, there is no Agreement (unless the parties 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 will not withdraw from this Agreement under any circumstances except as provided under Rule 32.05 of the Ontario Energy Board's Rules of Practice and Procedure.

For greater certainty, the parties further acknowledge and agree that these conditions apply to settled issues in respect of which they are shown as taking no position.

It is also acknowledged and agreed that this Agreement is without prejudice to parties re-examining these issues in any other proceeding.

The parties agree that all positions, information, documents, negotiations and discussion of any kind whatsoever which took place or were exchanged during the Settlement Conference 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 on each issue is set out in each section of 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.

The following parties participated in the Settlement Conference:

Canadian Manufacturers & Exporters ("CME")

City of Kitchener ("CCK")

Consumers Council of Canada ("CCC")

Coral Energy Canada Inc. ("Coral")

Enbridge Gas Distribution Inc. ("EGD")

Energy Probe Research Foundation ("Energy Probe")

FONOM & the Cities of Timmins and Greater Sudbury ("FONOM & the Cities")

Industrial Gas Users Association ("IGUA")

London Property Management Association ("LPMA")

Low-Income Energy Network ("LIEN")

Ontario Association of Physical Plant Administrators ("OAPPA")

Ontario Energy Savings L.P. ("OESLP")

School Energy Coalition ("SEC")

Sithe Global Power Goreway ("Sithe")

Superior Energy Management ("SEM")

TransAlta Cogeneration L.P. and TransAlta Energy Corp. ("TransAlta")

TransCanada PipeLines Limited ("TCPL")

Vulnerable Energy Consumers Coalition ("VECC")

Wholesale Gas Services Purchasers Group ("WGSPG")

OVERVIEW

In support of the need for a rate increase, Union identified factors that have an impact on its current and expected business environment, either affecting Union directly, by increasing Union's costs, or indirectly by changing Union's throughput and corresponding revenues from customers. These factors included the impacts of high energy prices, conservation and demand management, foreign exchange, weather, workforce demographics, cost pressures which exceed the general rate of inflation and the investment climate and available investment opportunities. These factors also included the financial and business risks posed by Union's current equity ratio and the impact this will have on Union's ability to raise capital. The rate adjustments that result from this Settlement Agreement will allow the company to make investments to serve new and existing customers, to maintain the integrity of Union's system, including business support processes, and meet all compliance requirements during 2007.

The revenue deficiency reduction for 2007 which the parties have agreed to is approximately \$61.110 million. After excluding incremental DSM budget costs for 2007 of approximately \$9.000 million, Union's revenue deficiency claim for 2007 is \$85.827 million. With this settlement, the revenue deficiency Union will recover in its 2007 rates will be approximately \$24.717 million. (See Appendix E)

The 2007 revenue deficiency of \$24.717 million represents an increase of approximately 2.7% over current approved delivery, storage and transportation rates. (See Exhibit H3, Tab 1, Schedule 1 for delivery, storage and transportation revenue at current rates.) It is the overall revenue deficiency reduction of \$61.110 million and its component parts which constitutes the consideration for the intervenors' acceptance of Union's budgets and forecasts for 2007 as more particularly described below.

In consideration for the overall revenue deficiency reduction of $61.110 million and the total revenue increases component there of $14.000 million described in Sections 2.4 and 2.5, the parties accept that Union's 2007 Contract demand forecasts of volume of 9,276,704 10^3 m^3 and delivery revenue of $115.021 million are reasonable and that the forecast revenue consequences of this forecast are reasonable.

The following parties agree with the settlement of this issue: CME, FONOM & the Cities, CCK, CCC, Energy Probe, IGUA, LPMA, LIEN, SEC, VECC, WGSPG

The following parties take no position on this issue: Coral, EGD, OAPPA, OESLP, Sithe, SEM, TransAlta, TCPL

Evidence References:
1. C1/T2; C1/SS1-SS6/Addendum; C3-C6/T2/S1-S6
2. J1.20, J1.21, J1.22, J1.23, J1.24, J6.18, J13.01, J13.11, J13.12, J14.35, J14.39, J14.40, J14.41, J14.43, J29.11, J30.03, J30.04, J30.05

2.4 IS THE PROPOSED TOTAL 2007 STORAGE AND TRANSPORTATION (S&T) REVENUE FORECAST APPROPRIATE?

(Complete Settlement)

The parties accept Union's 2007 S&T Core services revenue forecast of $121.138 million (C1/SS7 Addendum, line 9(k)). The parties agree that Union's 2007 Short Term Storage Services revenue forecast shall be increased by $12.0 million from $1.794 million as proposed by Union (C1/SS7 Addendum, line 11(k)) to $13.794 million. This increase will result in Union's 2007 Total Transactional Services revenue forecast increasing by $12.0 million from the $60.885 million as proposed by Union (C1/SS7 Addendum, line 17(k)) to $72.885 million. The parties agree that, with this adjustment, Union's 2007 Storage and Transportation (S&T) Revenue forecast is reasonable.

The parties acknowledge that the S&T forecast accepted in this agreement includes revenues associated with providing storage services to ex-franchise customers at market based rates. Further, the parties acknowledge that the appropriateness of charging rates that exceed cost for storage services provided by Union to ex-franchise customers and the appropriateness of the continuation of S&T deferral accounts will be addressed in the Natural Gas Electricity Interface Review proceeding (EB-2005-0551). (The S&T deferral accounts will remain in operation for such revenues unless the EB-2005-0551 proceeding determines otherwise.) Consequently, the outcome of the EB-2005-0551 proceeding may vary the S&T revenue forecast accepted in this agreement.

The following parties agree with the settlement of this issue: FONOM & the Cities, CCK, CCC, EGD, Energy Probe, IGUA, LPMA, LIEN, SEC, TransAlta, VECC, WGSPG

The following parties take no position on this issue: CME, Coral, OAPPA, OESLP, Sithe, SEM, TCPL

Evidence References:
1. C1/T3; D1/T1; C1/SS7/Addendum; C3-C5/T1/S1/Addendum; C3-C5/T1/S2/Addendum; C6/T1/S1-2; C3-C6/T4/S1-4; C5/T4/S1A;
2. J1.25, J1.26, J1.27, J1.28, J1.29, J3.13, J3.14, J3.15, J3.16, J5.02, J6.20, J6.21, J13.01, J13.13, J13.14, J13.15, J14.36, J14.37, J14.39, J14.42, J21.10, J25.01, J29.12, J29.13, J29.14, J29.15

2.5 IS THE PROPOSED TOTAL 2007 OTHER REVENUE FORECAST APPROPRIATE GIVEN THAT IT REPRESENTS A DECREASE FROM THE 2005 ESTIMATE?

(Complete Settlement)

The parties agree that Union's 2007 Other Revenue forecast shall be increased by $2.0 million from the $22.434 million proposed by Union (C1/SS8/line 9(k)) to $24.434 million. This revenue will be attributed to the Mid Market Transactions component of the Other Revenue forecast shown at C1/SS8/line 6(k). The parties agree that, with this adjustment, Union's Other Revenue forecast is reasonable.

TAB 17

Ontario Energy Board | Commission de l'Énergie de l'Ontario

Ontario

EB-2005-0551

NATURAL GAS ELECTRICITY INTERFACE REVIEW

DECISION WITH REASONS

November 7, 2006

7.5 STORAGE AND TRANSPORTATION SERVICE DEFERRAL ACCOUNTS

The deferral accounts at issue in this proceeding are the following:

- Short-Term Storage and Other Balancing Services Account (179-70)
- Long-Term Peak Storage Services Account (179-72)
- Transportation Exchange Services Account (179-69)
- Other S&T Services Account (179-73)
- Other Direct Purchase Services Account (174-74)

On March 15, 2006, the Board notified Union and the intervenors that Union's proposal to eliminate the five deferral accounts, made as part of the rate application EB-2005-0520, had been moved to this proceeding. The relevant evidence from EB-2005-0520 was re-filed in this proceeding.

Union explained that of the five accounts in question, the storage accounts (179-70 and 179-72) are directly related to the storage forbearance issue, while the remaining three transmission accounts (179-69, 179-73 and 174-74) are not directly related to the storage forbearance issue.

Union proposed to eliminate the Short-Term Storage and Other Balancing Services Account (179-70) and Long-Term Peak Storage Services Account (179-72) on the basis that these accounts would no longer be necessary if the Board decides to forbear from regulating ex-franchise storage service sales.

Union also proposed to eliminate the other three transmission-related deferral accounts (179-69, 179-73 and 179-74). Union advanced two reasons for this proposal. First, Union stated that the forecast of S&T revenue should not be treated any differently than the forecast of any other source of revenue. Second, Union submitted that its proposal is consistent with the Board's policy direction, as outlined in its Natural Gas Forum Report, that in an incentive regulation framework there should be no earnings sharing and transactional services revenues should not receive special treatment. Union also expressed concern that there may not be another opportunity or forum to deal with this issue prior to the beginning of the proposed incentive regulation framework.

Most intervenors took the position that the storage related accounts (179-70 and 179-72) should continue if the Board determines that it will not refrain from regulating the prices of ex-franchise storage sales services. However, intervenors also acknowledged that if the Board were to forbear from regulating the prices of ex-franchise storage services, then these accounts would no longer be needed and under those specific circumstances should be eliminated. For example, the Board Hearing Team argued that under forbearance, gas utilities' shareholders will be bearing the risk associated with storage transactions in the ex-franchise market and any premium or shortfalls should accrue to the shareholder.

With respect to the transmission-related deferral accounts (179-69, 179-73 and 179-74), most intervenors were of the view that these accounts should not be eliminated because transmission will remain a regulated service. LPMA/WGSPG supported the objective of reducing the number of variance and deferral accounts but took the position that a comprehensive review of all such accounts should be undertaken as part of the incentive regulation mechanism that is still to be determined. Many intervenors adopted the LPMA/WGSPG position.

The Board Hearing Team supported Union's proposal. It argued that because transactional transportation services are part of the gas utility's monopoly service, these revenues should be treated no differently than any other regulated revenue.

Board Findings

With respect to the storage related accounts (179-70 and 179-72), most intervenors were of the view that the resolution of this issue depends on whether the Board refrains from regulating ex-franchise storage. The Board has determined that it will refrain from regulating rates in this area. However, we have also concluded that there should continue to be a sharing of the premium arising from short-term storage transactions, for both Union and Enbridge, and that there should be a phase-out of the sharing of the premium arising from Union's long-term storage transactions. Accordingly, the Board concludes that the accounts should be maintained for now. As outlined in sections 7.1 and 7.3, we have determined that the gas incentive ratemaking process is the best place in which to determine the precise implementation of these findings.

With respect to the transmission-related accounts, there was general acknowledgement that the issue related to the structure of the incentive regulation framework and not the issue of storage regulation. Union was concerned that this proceeding would be the only opportunity to deal with its proposal before the introduction of incentive regulation. The Board does not agree. On September 11, 2006, the Board issued a letter indicating its intent to establish a consultation process to use in relation to the development of the gas incentive regulation framework. This process is specifically designed to address issues about the framework prior to the commencement of incentive regulation for natural gas utilities. The Board finds that the proposed elimination of these three transmission-related accounts should be considered as part of a comprehensive review that includes all deferral accounts under an incentive regulation mechanism.

The Board therefore concludes that all of the accounts will be maintained and will be reviewed as part of the process for setting the incentive regulation mechanism for natural gas utilities.

EB-2011-0210

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

AND IN THE MATTER OF an application filed by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2013.

CANADIAN MANUFACTURERS & EXPORTERS ("CME") COMPENDIUM OF DOCUMENTS re: Upstream Transportation Cost Reductions

---

TAB 18

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

September 4, 2007

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 19

UNION GAS LIMITED

Undertaking of Mr. Isherwood
To Mr. Thompson

Please provide actual numbers for exchange revenues for the years 2004, 2005, and related to deferral account 179-73, 179-74, and 179-89 for 2004, 2005 and 2006.

Union Gas Limited
Deferral Account Balances
2004-2006

Year	Docket	Balance ($000's)			
		Transportation & Exchange Services 179-69	Other S&T Services 179-73	Other Direct Purchase Services 179-74	Heating Valve 179-89
2004	EB-2005-0211	(7,603)	(413)	(887)	(2,175)
2005	EB-2006-0057	(3,404)	(427)	(749)	(2,709)
2006	EB-2007-0598	(4,004)	(390)	(373)	(2,405)

TAB 20

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 Y FACTOR

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 21

TransCanada
In business to deliver

Important Contract Documents Attached
Immediate Attention Required

Subject: **New FT Service Feature:**
Dawn Authorized Overrun – Must Nominate ("DOS-MN")

Company:
Fax:

Attention:

TransCanada requires 165 TJ of incremental service deliveries to the Dawn area in order to address the capacity short-fall for Short-Haul Firm Transportation ("Short-Haul FT") from Dawn this winter.

In 2003, TransCanada was able to offer increased Short-Haul FT transportation capacity from Dawn, above TransCanada's firm Dawn capacity contracted on Union ("Union M12 TBO"), through the use of its integrated system. Specifically, receipts of gas under Short-Haul FT contracts at Dawn would be offset by deliveries of gas under Long-Haul contracts to the Dawn area. At the same time, Empress receipts of gas under those Long-Haul contracts would be transported through TransCanada's Northern Ontario Line to meet deliveries under Short-Haul FT contracts east of Parkway. Use of the integrated system in this manner enabled TransCanada to meet Shipper demand for increased Short-Haul FT capacity from Dawn at the lowest possible cost..This approach reduced the requirement for additional Union TBO capacity while making use of spare capacity on TransCanada's Northern Ontario Line.

Use of the integrated system in this manner requires that sufficient quantities of Long-Haul gas be nominated to the Dawn area to offset the quantity of gas received under Short-Haul FT contracts at Dawn that is in excess of TransCanada's Union M12 TBO capacity. Due to non-renewals of some Long-Haul FT contracts to Dawn effective November 1, 2008 and considering historical nomination patterns, TransCanada projects that there will be insufficient Long-Haul quantities nominated to the Dawn area on some days of the 2008/09 Winter Season to effect the physical exchange of gas on the integrated system. TransCanada would, therefore, be unable to meet its obligations under Short-Haul FT contracts.

To obtain the required incremental deliveries to Dawn, TransCanada is making available a total of 165 TJ/d of capacity from Empress to the Dawn area ("DOS-MN Capacity"). It is offered as a service enhancement feature for FT, FT-NR, FT-SN and STS shippers ("Firm Shippers") pro rata based on each Firm Shipper's demand charge commitment to the system this winter. Firm Shippers have an option of accepting their pro rata share of DOS-MN Capacity ("DOS-MN

Entitlement"), or not. If they accept their DOS-MN Entitlement they must commit to nominate and flow their full DOS-MN quantity each day. This DOS-MN feature is intended to address the capacity short-fall issue for winter only and will expire as of March 31, 2009.

The first part of the enclosed package details the DOS-MN features in a Q&A format. The second part of the enclosed package contains the DOS-MN Contract & Exhibit "A" and Assignment of Entitlement – DOS-MN form. Please carefully review this package and contact us with any questions:

Analyst - Norma Marchet	**Office: (403) 920-6258 Cell: (403) 831-8361**
Analyst - Minh Nguyen	**Office: (403) 920-5804 Cell: (403) 835-8463**
Manager - Barbara Miles	Office: (403) 920-5780 Cell: (403) 831-9151
Supervisor - Vincent Thebault	Office: (403) 920-5840 Cell: (403) 835-8572

Regards,

Barbara Miles,
Manager, Contracts and Billing

Attachments: STFT Non-Standard Service Contract & Exhibit "A" and Assignment of Entitlement – DOS-MN form

New FT Service Feature:
Dawn Authorized Overrun– Must Nominate ("DOS-MN")

1. What are the details of the DOS-MN feature?

- DOS-MN Entitlement may be accepted, assigned or declined.
- If accepted, the full DOS-MN contract quantity must be nominated, authorized and flowed each day.
- Term: November 15, 2008 - March 31, 2009
- Receipt Point : Empress
- Customer may select one of four Delivery Points: Union SWDA, Enbridge SWDA, Dawn Export or St. Clair
- No Diversion rights
- No Alternate Receipt Point (ARP) rights
- No FT-RAM or short haul FT-RAM linkage
- No Renewal Rights
- Firm Service Priority in the event of curtailment

2. What is the cost?

- The Toll will only be the FT Commodity Toll in effect during the Service Period that may be amended from time to time by the National Energy Board, for the applicable path.
- Pressure Charges at the Delivery Point (if applicable)
- Fuel: In-kind
- GST (if applicable)

3. What are my options and what do I need to do by 12:00 PM (noon) Calgary time on November 10, 2008?

OPTION 1: If I wish to accept my DOS-MN Entitlement?

Execute a DOS-MN Contract and return to TransCanada specifying on the Exhibit A:

- **Select one option in Boxes 1 - 2:**
  Box 1: Accept the stated Minimum Daily Quantity, **or**
  Box 2: Accept the stated Minimum Daily Quantity plus reallocation/assigned entitlement quantities up to a maximum quantity of your choice (not to exceed 165 TJ/day).
- **Select one Delivery Point** (One of Union SWDA, Enbridge SWDA, Dawn Export or St. Clair).
- **Select GST Zero Rate:** Yes or No (Yes only allowed at Dawn Export or St. Clair)
  Note: Selecting Yes for GST Zero Rate instructs TransCanada that the gas is being exported and to set the GST Rate to 0%.

OPTION 2: If I wish to assign my DOS-MN Entitlement to another Shipper(s)?

Only need to complete, execute and return the Assignment of Entitlement - DOS-MN form.

PLEASE NOTE: Assignment of your DOS-MN Entitlement is permanent (cannot be reverted) and Shipper gives up all rights to their DOS-MN Entitlement.

OPTION 3: If I don't want my DOS-MN Entitlement?

You do not need to do anything. Firm Shippers that do not return an executed DOS-MN Contract to TransCanada by 12:00 PM (noon) Calgary time on November 10, 2008 will be deemed to have rejected their DOS-MN Entitlement and such capacity will be reallocated to those Firm Shippers willing to accept additional DOS-MN Capacity on a pro rata basis.

Note: If Shipper accepts an allocation it can subsequently be assigned to a third party on or after November 22, 2008.

4. What is the timeline for DOS-MN?

- **Wednesday November 5th**

TransCanada will provide each Firm Shipper with a Contract, Exhibit "A" stating their DOS-MN Entitlement and an Assignment of Entitlement - DOS-MN form.

- **Monday November 10th**

By 12:00 PM (noon) Calgary time each Firm Shipper must return their executed DOS-MN Contract and Exhibit "A" or Assignment of Entitlement - DOS-MN form, or TransCanada will deem that the Firm Shipper has rejected their DOS-MN Entitlement and the capacity will return to the pool for reallocation.

- **Tuesday November 11th**

TransCanada will determine each Firm Shipper's final allocation of DOS-MN Capacity and return the Exhibit "A" stating the Shipper's final allocation of DOS-MN Capacity and new nomination group number.

- **Friday November 14th**

Shipper Nominations due by Timely Window 11:00 AM Calgary time. Note that Shipper will be required to re-nominate each month.

- **Saturday November 15th**

Flows start 09:00 CCT

5. Where do I send my executed documents?

Fax the executed DOS-MN Contract with a completed Exhibit "A" or the completed and executed Assignment of Entitlement - DOS-MN form to TransCanada:

FAX: (403) 920-2343

6. Who can I call if I have questions?

Analyst - Norma Marchet	**Office: (403) 920-6258 Cell: (403) 831-8361**
Analyst - Minh Nguyen	**Office: (403) 920-5804 Cell: (403) 835-8463**
Manager - Barbara Miles	Office: (403) 920-5780 Cell: (403) 831-9151
Supervisor - Vincent Thebault	Office: (403) 920-5840 Cell: (403) 835-8572

7. What is the allocation methodology used to determine DOS-MN Entitlement?

On November 5, 2008 TransCanada will provide each Firm Shipper with a statement of their share of DOS-MN Entitlement determined as follows:

Firm Shipper's DOS-MN Entitlement = Firm Shipper's Revenue x DOS Allocation Factor

Where:

1. DOS-MN Allocation Factor = 165 TJ/d / Total Firm Shipper Revenue
2. Total Firm Shipper Revenue = sum of all Firm Shipper's Revenue
3. Firm Shipper's Revenue = Σ (Daily Demand Toll * MDQ * Days)
   (i.e., sum of demand charge revenue to be paid by a shipper under all of their firm service contracts this winter)
4. Daily Demand Toll = current FT, FT-SN, FT-NR or STS Monthly Demand Toll x 12 / 365
5. MDQ = Contract Demand specified in each Firm Service Contract
6. Days = the number of days that a Firm Contract is in effect during the DOS-MN term
   (i.e., from November 15, 2008 to March 31, 2009 inclusive)
7. Firm Shipper's DOS-MN Entitlement will be deemed to be zero if the calculated quantity is less than 1 GJ.

For questions concerning the allocation methodology please contact:
Zafir Samoylove Office: (403) 920-6831 Cell: (403) 831-9052

TAB 22

PREFILED EVIDENCE

The purpose of this evidence is to describe proposed changes to Union's regulated transportation, storage and distribution rates effective January 1, 2009 determined in accordance with the approved EB-2007-0606 Settlement Agreement and Addendum (collectively "Settlement").

The approved Settlement sets a multi-year incentive ratemaking ("IR") framework for calendar years 2008 to 2012. The framework defines the price cap formula as PCI = I – X + Z + Y + AU, where PCI is the price cap index, I is the inflation factor, X is the productivity factor, Z represents certain non-routine adjustments, Y represents certain predetermined pass-throughs and AU is a volume adjustment reflecting changes in average gas use in the General Service rate classes. The 2009 rate setting process described below follows the same approach used to set 2008 rates in EB-2007-0606.

This evidence will cover the following topics:

1. 2009 Inflation Factor and Productivity Factor
2. Z factor Adjustments
3. Y Factor Adjustments
4. Average Use Factor
5. Annual Adjustments to General Service Monthly Charges
6. Rate Schedule Changes
7. Customer Bill Impacts
8. Implementation

A description of all supporting schedules referenced below is provided in the Overview of the Working Papers document.

1. 2009 Inflation Factor and Productivity Factor

The 2009 inflation factor is 1.54%. It is calculated as the average of the year over year percentage change in the Gross Domestic Product Implicit Price Index Final Domestic Demand (GDP IPI FDD) for the four quarters ending June 2008. The calculation is provided at Schedule 1, Page 1.

The approved productivity (X) factor for the term of the IR is 1.82%. When the X factor of 1.82% is applied to the inflation factor of 1.54%, the result is a net reduction of 0.28% for 2009. This reduction results in a decrease of $1.923 million to in-franchise rates and a decrease of $0.523 million to regulated ex-franchise rates. The calculation is provided at Schedule 1, Page 2. The allocation to rate classes appears at Schedule 4.

2. Z Factor Adjustments

Treatment of Tax Savings

Consistent with the Settlement, Union's approved 2008 rates included an interim decrease of $8 million to reflect the approximate value of federal and provincial tax changes for 2008, pending the outcome of the Board's decision on the treatment of taxes during the IR term. This $8 million decrease was in addition to the tax savings already reflected in approved 2007 rates. Union also established the 2008 Federal and Provincial Tax Changes Deferral Account (No. 179-119) to capture the variance between the interim adjustment made to 2008 rates and any adjustment resulting from the Board's decision on the treatment of taxes.

On July 31, 2008, the Board issued its EB-2007-0606 Decision on the treatment of tax reductions during the IR term. The Board found that during the IR term (2008 to 2012) 50% of the tax reductions should be treated as a Z factor. The Board also found that 50% of the impact arising from 2007 tax reductions should be subject to Z factor treatment.

On August 28, 2008, Union filed a motion for review and variance of the Board's EB-2007-0606 Decision, dated July 31, 2008. The purpose of the motion was to clarify certain aspects of the Board's decision related to risk management and taxes. The specific clarification sought by Union with respect to taxes was that the Board did not direct Union to share 50% of the tax "savings" associated with new capital additions during the incentive regulation term. Since Union will not be recovering anything in rates related to new capital additions during the IR term it would be unfair and asymmetrical for Union to be required to credit to customers 50% of any tax reductions associated with those new additions. For the purposes of calculating the tax Z factor for 2009, Union has not included tax savings associated with 2008 or 2009 capital additions.

The calculation of the cumulative tax savings to 2009 relative to the tax savings included in 2007 Board approved rates is $7.522 million. The ratepayer portion of the cumulative tax savings is $3.761 million (50% of $7.522 million). As indicated above, approved 2008 rates were reduced by

$8 million to reflect the approximate value of federal and provincial tax changes for 2008 pending the outcome of the Board's decision on the treatment of taxes during the IR term. Accordingly, the net impact on 2009 rates related to taxes is a rate increase of $4.239 million. The calculation of the annual tax rate change impacts and the 2009 rate adjustment can be found at Schedule 15.

Schedule 15 also provides the calculation of the balance in the 2008 Federal and Provincial Tax Changes Deferral Account (No. 179-119). The balance in the deferral account is $4.601 million and will be recovered from ratepayers as part of Union's 2008 deferral account disposition.

International Financial Reporting Standards (Z factor)

Union is proposing a Z factor adjustment effective January 1, 2009 to recover the costs associated with converting from Canadian Generally Accepted Accounting Principles ("Canadian GAAP") to International Financial Reporting Standards ("IFRS").

The conversion to IFRS is the result of the Canadian Accounting Standards Board ("AcSB") requirement that all publicly accountable enterprises adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. As an entity that issues debt in the public market, Union is a publicly accountable enterprise and must comply with the accounting changes required by the AcSB. Further, the Board is of the view that utilities must be IFRS compliant. Union is a participant in the Board's "Consultation for the Transition of Regulatory Accounting to International Financial Reporting Standards". This consultation is centered around generic compliance and Board process (OEB reporting requirements). Given that the purpose of the consultation is not to determine specific utility conversion costs, Union has taken the view that the issue of Union specific costs to convert to the new standards is appropriately dealt with in the 2009 rate setting process.

As indicated above, the conversion to IFRS must be completed in time to allow for reporting of financial statements for fiscal years beginning on or after January 1, 2011. Publicly accountable enterprises will also be required to report prior year financial statements (2010) for comparative purposes under IFRS. As a result, Union must complete the required system and reporting changes by early 2010.

Union has completed the diagnostic, planning and design phases for its IFRS conversion project. Union expects that the requirement to implement IFRS will significantly affect accounting policies and internal control processes and will require changes to Union's financial systems. Union estimates the conversion to IFRS will cost $5.177 million pre-tax during the IR term to complete. Table 1 below provides the projected annual pre-tax costs.

Table 1 – IFRS Conversion Costs ($000's)

		IR Period					
		2008	2009	2010	2011	2012	Total
1	Capital Investment	592	1,334	263	0	0	
	Annual carrying cost						
2	Depreciation	74	315	514	547	473	
3	Interest	12	48	66	48	24	
4	Total	86	363	581	595	497	
5	O&M	882	1,148	929	96	0	
6	Annual cost (pre tax) line 4 + line 5	968	1,511	1,510	691	497	5,177

Z Factor

The approved Settlement sets out the criteria for determining whether an event qualifies for Z factor treatment. The criteria are:

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).

The IFRS conversion project meets the criteria established for treatment as a Z factor. The increased costs are a direct result of the requirement to convert to IFRS. Further, the conversion to

IFRS is mandated by the AcSB for all publicly accountable enterprises such as Union. This change in accounting standards is beyond management control and not a risk which a prudent utility could have mitigated.

The costs associated with changes in accounting standards have been cited on numerous occasions as an example of an event that would be considered as a Z factor. In the Board's RP-1999-0017 (Union's Performance Based Regulation proceeding) Decision pg 260, the Board states:

> *"The Board accepted the use of Z-Factors in certain situations, specifically the Board has found Z Factors appropriate in legislative and regulatory requirements, **changes in generally accepted accounting principles**, property taxes, capital taxes, income taxes and delivery/redelivery costs."* [Emphasis added]

In EB-2007-0606, Exhibit B, Tab 1 (p.40) Union provided examples Z factor events that would be outside management control. Union stated in the table on page 40 of Exhibit B, Tab 1:

> *"Z Factors should capture the change in costs associated with changes in legislation, regulatory requirements and Generally Accepted Accounting Principles."*

This statement was undisputed during the EB-2007-0606 proceeding.

For a cost to qualify for Z factor treatment it must not otherwise be reflected in the price cap index. For Union the inflation factor is calculated using the GDP IPI FDD. The requirement to convert to IFRS is limited to publicly accountable enterprises and conversion must be complete by early in 2010 to allow for IFRS reporting effective January 1, 2011. Corporations carrying on business internationally likely already comply with the new international standards and will not incur conversion costs. Similarily, new entrants will design policies and internal controls to comply with the new standards from the outset and will also incur no conversion costs. Private enterprises are not currently required to convert. Given the nature of this one time occurrence and its limited applicability, Union has no reason to believe, and is aware of no information to suggest, that the cost of converting to IFRS would be reflected in the Canadian GDP IPI FDD.

As indicated above, Union has completed the diagnostic, planning and design phases of the project and has estimated that the total project costs to be $5.177 million pre-tax during the IR term. Union is taking all reasonable measures to contain the costs of converting to IFRS. Union is working with other groups within Spectra Energy to share resources and information to avoid duplicating effort and costs. Union is also using internal resources as much as possible to limit outside consulting costs. Finally, Union has no incentive under the IR framework to do anything other than make every effort to prudently incur costs since the approval of these costs as a Z factor is not guaranteed in any given year.

The final criteria is the cost increase must meet the materiality threshold of $1.5 million pre-tax annually per Z factor event (EB-2007-0606, Exhibit C3/C16/C33.25). For 2009 the pre-tax cost associated with converting to IFRS is $1.511 million, meeting the criteria for treatment as a Z factor.

Accordingly, the IFRS conversion meets all Z factor criteria and is a Board accepted Z factor.

Proposed Recovery

Table 2 below, provides the annual revenue requirement and proposed Z factor adjustment associated with converting to IFRS from 2008 to 2012. Union is proposing to make the Z factor adjustments provided in Table 2 annually over the IR term, starting in 2009. Union is not seeking recovery of the 2008 revenue requirement ($0.868 million). Union is proposing to recover the annual Z factor adjustments because of the one time nature of the conversion to IFRS.

Table 2 – IFRS Conversion Revenue Requirement ($000's)

				IR Period		
		2008	2009	2010	2011	2012
	Revenue requirement					
1	O&M	882	1,148	929	96	
2	Depreciation	74	315	514	547	473
3	Interest	12	48	66	48	24
4	Return	8	32	43	31	15
5	Taxes (flow through)	(108)	(304)	(113)	196	200
6	Total	868	1,239	1,440	919	712
7	Z factor Adjustment			201	(521)	(207)

The revenue requirement associated with the 2009 pre-tax costs of $1.511 million is $1.239 million. The revenue requirement is less than the pre-tax costs as a result of reflecting the tax benefit related to the software costs in the amount proposed to be recovered from customers in 2009 rates. Union is proposing to allocate the annual Z factor adjustment associated with converting to IFRS to rate classes in proportion to General and Administration Expenses included in 2007 approved rates. The allocation to rate classes is provided at Schedule 13.

3. Y Factor Adjustments

The Settlement also provided for a number of Y factors which are not adjusted as part of the price cap formula and are passed through to customers in rates. The 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)

Upstream Gas Costs

Union's current upstream gas costs are as approved in the Board's decision in EB-2008-0281, dated September 18, 2008. Changes in upstream gas costs will continue to be determined using the Board-approved QRAM methodology.

Upstream Transportation Costs

Union's current upstream transportation costs are as approved in the Board's decision in EB-2008-0281, dated September 18, 2008. Changes in upstream transportation costs will continue to be determined using the Board-approved QRAM methodology. Schedule 12 provides the allocation of upstream transportation costs by rate class.

Incremental DSM Costs and Volume Reductions

Consistent with the Board's August 25, 2006 decision in EB-2006-0021 on DSM program spending and cost recovery in rates, Union has increased 2008 DSM program costs of $18.7 million by 10% ($1.87 million). This increase sets total 2009 DSM program costs at $20.57 million. Union has allocated DSM program costs to rate classes in proportion to how DSM costs were included in Union's 2007 rates. This is the same approach used for allocating DSM costs in 2008 approved rates. The detailed allocation to rate classes can be found at Schedule 4.

In addition, the Board's EB-2006-0021 decision approved rate adjustments for volume changes associated with Union's DSM programs. Schedule 11 provides the LRAM volume adjustments by rate class. Schedule 4 shows the price adjustment to applicable rate classes on a revenue neutral basis.

Storage Margin Sharing Changes

In EB-2005-0551 (the NGEIR Decision), Union was directed to phase out the sharing of margins on Union's long term storage transactions over four years, starting in 2008 as follows: 2008 –

25%, 2009 – 50%, 2010 – 75% and thereafter – 100%. By 2011, 100% of the margin from long term storage transactions will be removed from rates

Accordingly, for 2009 Union has reduced the in-franchise ratepayer share of long term storage margins from 75% to 50%.. The resulting increase of $5.351 million to in-franchise rates appears at Schedule 14.

4. Average Use Factor

The average use (AU) factor, for the term of the IR plan, is applicable to General Service rate classes M1, M2, Rate 01 and Rate 10. The AU factor is calculated using the average of the most recent three years' actual weather normalized volume change per General Service rate class.

For Rates M1 and M2 the AU factor is a reduction of 0.3%. For Rate 01 the AU factor is a reduction of 0.7%. For Rate 10, the AU factor is an increase is 1.8%. The derivation of the 2005-2007 AU volume adjustments by General Service rate class appears at Schedule 10. Schedule 4 shows the price adjustment applied to General Service rate classes on a revenue neutral basis.

5. Annual Adjustments to General Service Monthly Charges

Consistent with the Settlement, Union will increase the fixed monthly charge in the M1 and Rate 01 rate classes by $1 per month in each year of the 5 year IR term. In accordance with the

Settlement, the fixed monthly charge in the M1 and Rate 01 rate classes will be $18.00 in 2009. On a revenue neutral basis, the offset to the $1 increase in fixed monthly charges is a decrease in volumetric delivery charges. The calculation of the revenue neutral offset appears at Schedule 4.

6. Rate Schedule Changes

In addition to the rate adjustments noted above, Union is also proposing the following rate schedule changes:

1. The inclusion on in-franchise rate schedules under Delayed Payment of the effective annual interest rate of 19.56% resulting from Union's monthly late payment charge of 1.5%. This change is intended to ensure clarity on in-franchise rate schedules. There is no rate impact as a result of this change.

2. The addition of the Dawn-Tecumseh Sombra Line Extension (Dawn-TSLE) receipt and delivery point to the C1 Rate Schedule to recognize the new interconnect between Union's Dawn Storage facility and Enbridge's Tecumseh Storage operations. There is no impact on any rate class as a result of this change.

7. Customer Bill Impacts

For most residential customers in the Southern Operations area the annual rate increase amounts to $5-6 per year for a customer consuming 2,600 m^3 annually. For most residential customers in the

Northern Operations area the annual rate increase amounts to $8-9 per year for a customer consuming 2,600 m^3 annually. These changes represent an increase of 0.4% to 0.6% of the total annual residential bill. Schedule 8 provides average 2009 unit price changes for all in-franchise rate classes. Schedule 9 provides customer bill impacts for General Service rate classes M1, M2, Rate 01 and Rate 10.

8. Implementation

Union proposes to implement new rates effective January 1, 2009 as described in the Rate Setting Process of the EB-2007-0606 Settlement Agreement at Section 12.1.1. Union therefore requests a final approved rate order by December 15, 2008. This approach allows 2009 rates to be implemented prospectively and aligns with the January 2009 QRAM process.

TAB 23

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 24

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

TABLE OF CONTENTS

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.

EB-2011-0210

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

AND IN THE MATTER OF an application filed by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2013.

CANADIAN MANUFACTURERS & EXPORTERS ("CME") COMPENDIUM OF DOCUMENTS re: Upstream Transportation Cost Reductions

---

TAB 25

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 26

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2008- 0220

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

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas effective January 1, 2009.

BEFORE: Pamela Nowina
Presiding Member and Vice Chair

David Balsillie
Member

Paul Sommerville
Member

DECISION WITH REASONS

INTRODUCTION

Union Gas Distribution Inc. ("Union") filed an Application on September 26, 2008 with the Ontario Energy Board ("Board") under section 36 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, (Sched. B), as amended, for an order of the Board approving or fixing rates for the distribution, transmission and storage of natural gas, effective January 1, 2009.

The Board assigned file number EB-2008-0220 to the Application and issued a Notice of Application dated October 27, 2008.

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

<u>International Financial Reporting Standards</u>

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	$ .263	-	-
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 27

2008 EARNINGS SHARING AND INCENTIVE REGULATION REVIEW

In January of 2008, the Board approved the EB-2007-0606 Settlement Agreement for Union's Incentive Regulation ("IR") framework, effective January 1, 2008. As part of the approved Settlement Agreement, the parties agreed at Section 10.1 that there would 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 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."

At Section 9.1 of the Settlement Agreement parties also made provision for a review of the IR Mechanism at section 9.1 under which;

"...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."

Further, at Section 11 of the Settlement Agreement, Union agreed to provide utility financial information for the most recent historical year in a manner consistent with that provided in Union's 2007 Rate Case (EB-2005-0520).

The benchmark return on equity ("ROE") for 2008 is 8.81%. Union's actual ROE from utility operations in 2008 was 12.49% or 368 basis points above the 2008 benchmark ROE. This results in earnings sharing for 2008 of $15.2 million. Normalizing for weather reduces Union's 2008 ROE from utility operations to 12.11%. For 2008, Union is 330 basis points above the benchmark ROE, triggering the IR review threshold provision at Section 9.1 of the EB-2007-0606, Settlement Agreement.

The purpose of this submission is to:

1. Provide Union's calculation of its 2008 utility earnings for the purposes of earnings sharing and the IR review threshold provision pursuant to Sections 9.1 and 10.1 of Settlement Agreement; and
2. Provide Union's evidence pursuant to section 9.1 of the Settlement Agreement for review of the IR framework. Union's evidence supports the continuation of existing IR framework without amendments to the current parameters or the base upon which rates are set.

Union has also attached, at Appendix A, Union's 2008 Financial Reporting Package pursuant to Section 11 of the Settlement Agreement.

Union's evidence is organized under the following headings:

1. 2008 Utility Results
2. 2008 Earnings Sharing Calculation
3. Need for Review of the IR Mechanism
4. 2009 – 2010 Utility Financial Forecast
5. Summary
6. 2008 Earnings Sharing Allocation and Disposition

2008 UTILITY RESULTS

For the year ended December 31, 2008 Union's actual revenue sufficiency from utility operations is $66.6 million above the 2007 Board approved level. Table below summarizes the results from Union's actual utility operations for 2008.

Table 1
Calculation of Revenue Deficiency/(Sufficiency) from Utility Operations
For the Year Ended December 31, 2008
($millions)

Line No.	Particulars	Board Approved 2007	Actual 2008	Increase/ (decrease)
		(a)	(b)	(c)
1	Gas sales and distribution revenue	1,796.8	1,865.6	
2	Cost of gas	1,134.3	1,178.9	
3	Gas distribution margin	662.5	686.7	24.2
4	Transportation	127.4	165.1	37.7
5	Other revenue	24.4	26.3	1.9
6	Expenses	567.4	568.3	0.9
7	Income taxes	8.7	26.1	17.4
8	Utility income	238.1	283.8	45.7
9	Cost of capital	259.5	257.6	(1.9)
10	Revenue deficiency/(sufficiency) after tax	21.4	(26.2)	(47.6)
11	Provision for income taxes on deficiency/ (sufficiency)	12.1	(13.2)	(25.3)
12	Distribution revenue deficiency/(sufficiency)	33.5	(39.3)	(72.8)
13	Storage premium adjustment	33.5	27.3	(6.2)
14	Total revenue deficiency/(sufficiency)	0.0	(66.6)	(66.6)

The primary drivers of Union's 2008 financial results relative to 2007 Board approved are provided in detail below.

GAS DISTRIBUTION MARGIN

Gas distribution margin for 2008 was $24.2 million over the 2007 Board approved level. This was primarily driven by increases in infranchise contract delivery revenues of $9.9 million, increased general service revenues of $ 9.7 million offset by decreases in other cost of gas items.

2008 Infranchise Contract Delivery Revenue

Infranchise contract delivery revenue growth in 2008 over 2007 Board approved levels was the result of the following:

a. Two new large gas fired power generation plants increased revenues by $3.2 million in 2008 over 2007 Board approved;
b. Favourable weather in 2008, unplanned coal and nuclear power generation outages, restricted electricity transmission access to Eastern Ontario electricity markets and favourable natural gas versus residual oil prices resulted in increased discretionary gas fired power generation at OPG Lennox. For 2008, this resulted in additional infranchise contract revenue of $2.6 million;
c. Increased net production in the large integrated steel market, the greenhouse market and other contract markets resulted in increased infranchise contract revenues in 2008 of $9.2 million. This was offset by rate class migration from contract to general service of $2.1 million. The increased delivery revenue was driven by strong economic conditions both in North American and global markets for the first three quarters of 2008; and

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.

TAB 28

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 29

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 but not 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 excess earnings will be shared 50/50 between Union and its customers. 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%). 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	1,546	(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)

EB-2011-0210

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

AND IN THE MATTER OF an application filed by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2013.

CANADIAN MANUFACTURERS & EXPORTERS ("CME") COMPENDIUM OF DOCUMENTS re: Upstream Transportation Cost Reductions

TAB 30

EB-2009-0101

THE ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Union Gas Ltd. 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.

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Monday, June 8th, 2009,
commencing at 9:32 a.m.

VOLUME 1

BEFORE:

GORDON KAISER	Presiding Member and Vice-Chair
PAUL VLAHOS	Member
PAUL SOMMERVILLE	Member

A P P E A R A N C E S

DONNA CAMPBELL	Board Staff
RICHARD BATTISTA	Board Staff
MICHAEL PENNY MARK KITCHEN MARION REDFORD	Union Gas
ROBERT WARREN	Consumers Council of Canada
PETER THOMPSON	Canadian Manufacturers & Exporters (CM&E)
PETER SCULLY	City of Timmins
DAVID MacINTOSH	Energy Probe Research Foundation
MICHAEL BUONAGURO	Vulnerable Energy Consumers Coalition (VECC)
JAMES GRUENBAUER	City of Kitchener
RANDY AIKEN	London Property Management Association (LPMA)
DWAYNE QUINN	Federation of Rental-Housing Providers of Ontario (FRPO)
IAN MONDROW	Industrial Gas Users Association (IGUA)
JOHN DeVELLIS	School Energy Coalition (SEC)

I N D E X   O F   P R O C E E D I N G S

APPENDED:

Attachment 1   Settlement Agreement, EB-2009-0101

Attachment 2:   Schedule A to Settlement Agreement EB-2007- 0606, Jan. 17, 2008

<u>E X H I B I T S</u>

U N D E R T A K I N G S

Description	Page No.

NO UNDERTAKINGS WERE FILED DURING THIS PROCEEDING come back in 15 minutes.

--- Recess taken at 12:16 p.m.

--- Upon resuming at 12:29 p.m.

DECISION:

MR. KAISER: The Board heard submissions this morning regarding an application Union Gas filed with the Board on April 2nd of this year under section 36 of the Ontario Energy Board Act. That application sought orders to vary rates effective July 1st, 2009, in connection with the sharing of 2008 earnings under the incentive rate mechanism approved by this Board on January 17th, 2008 in EB-2007-0606. That incentive plan covers the period 2008 to 2012. We are now dealing with the first year under that plan, namely the 2008 year.

At the end of the day, what is at issue in this proceeding is two paragraphs in the original agreement. The first is Paragraph 10.1 at page 22 of that agreement. That paragraph states:

> "The parties agree that there will be an earning 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 over the amount calculated annually by application of the Board's ROE formula in any year of the IR plan, then such excess earnings shall be shared 50/50 between Union and its customers."

The other issue concerns paragraph 9.1 of the original settlement agreement. That's at page 21 of the original agreement. That covenant read:

"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 with the Board with appropriate supporting evidence for a review of the price cap mechanism."

The section goes on to outline the procedure regarding that application. This is known as the off-ramp.

On June 4th 2009, the parties in this proceeding filed a new settlement agreement with the Board. The relevant provisions are in paragraph 1 at page 4 of that agreement. Paragraph 1 provides, first of all, that Section 9.1 of the original IR settlement shall be deleted in its entirety. That was the section that provided for the so-called off-ramp

Paragraph 10.1 of the original agreement is also revised in the new agreement. The new agreement provides that:

"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 revenue return on equity is more than 200-basis point but not more than 300 basis points over the amount calculated annually by application of the Boards ROE formula in any year of the IR plan, then such excess earnings shall be shared 50/50 between Union and its customer."

This is followed by a new provision:

"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 percent and Union will be credited 10 percent.)"

A wide range of customer interests were represented in this proceeding. All agree to the settlement except one, which I will come to in a moment.

The evidence before us indicated that under the original settlement plan with the 50/50 split, some $15.2 million would be made available to the customers. That amount has increased by reason of certain adjustments in the calculations as well as the new 90/10 split. The amount is now $34.17 million. Those amounts are set out in Appendix A of the Settlement Agreement which is attached to this decision as Schedule 'A'. The original agreement is attached as Schedule 'B'.

Appendix B of the new Settlement Agreement shows the allocation of the $34.17 million between different customer classes. It has been pointed out that the main beneficiaries are the small-volume general service customers. In the Southern Operations Area, they receive 13.7 million of that 34 million. In the Northern and Eastern Operations Area it's almost 6 million.

The one conclusion no one disputes is that there will be a substantial reduction in rates under the new settlement agreement, all of which is clearly set out in the agreement.

The one objection to the settlement is made by IGUA. IGUA filed a letter on June 5th with the Board. The relevant paragraph of that letter reads as follows:

> "IGUA recognizes that the settlement proposes a greater share for ratepayers of any over-earnings above 300 basis which affords ratepayers some protection. However, IGUA remains concerned that the removal of the trigger mechanism, in effect, provides Union with a 'licence' to continue to over-earn in excess of 300 basis points under the IRM plan without review of the reasons therefore and the reasonableness of the continuing with the plan as set."

As I indicated, IGUA is the only party opposing this settlement Agreement, and it is on that basis.

The Board would note, and this has been argued by counsel, that even if the contractual right of the parties to review the plan disappears when the trigger mechanism disappears, the Board still has inherent jurisdiction to review situations it regards as unfair or unreasonable.

Mr. Thompson referred to Rule 43 of the Board's rules.

Various parties also disputed IGUA's claim that Union will have a 'licence' to continue to over-earn in excess of 300 basis points. The Board agrees. After all, 90 percent of any "over-earnings" go to the customers.

Mr. Penny, in his submissions, referred to the Natural Gas Forum Report this Board issued in 2005. It is useful to remember why we are all here, what the purpose of these settlement agreements is, and in particular what the purpose of IRM is.

Mr. Penny referred at page 25 of his document brief to the message from the Chair, in the introduction to that Report:

> "First, we believe that all stakeholders will benefit from a more predictable and longer term treatment of rates. Utilities will benefit because they can make longer term decisions and customer will benefit through downward pressure on rates. The Board's report identifies the specific components of the incentive regulation plan the Board believes will lead to these results."

The amendment to the original settlement agreement, in the new proposed settlement agreement, meets those goals and the Board's objectives. It will not only reduce the regulatory cost but will allow greater certainty for all parties going forward. We heard that there were a number of disputes regarding the ambiguity of the language in the existing agreement. Two days of settlement discussions on May 25th and 26th were taken up debating those issues. They have largely been resolved through this agreement. The new Agreement is more than a revision of the revenue split. It is a much clearer agreement. That is in the interest of all the parties.

As to the downward pressure on rates, the evidence is set out in Appendix A and B of the agreement. There is a substantial reduction in rates and that, too, is in the interests of the parties.

We recognize Mr. Mondrow's concern on behalf of his client but as mentioned, the Board does have inherent jurisdiction to deal with situations contrary to the public interest. If a clear unfairness arises, the Board has the capacity to deal with it. And, there will continue to be a review of the over-earning amount every year.

For these reasons, the Board approves the Settlement Agreement as drafted. We will ask the applicant to file a rate order giving effect to this decision and allow the parties three days to respond to the draft order. It is in the interest of all parties to ensure that these rate reductions become effective on July 1st as planned. Any questions?

MR. PENNY: No, thank you, Mr. Chairman.

MR. THOMPSON: Mr. Chair, can I just record my client's request for reasonably-incurred costs in connection with this matter, thank you.

MR. KAISER: Yes. Mr. Warren, same?

MR. WARREN: Please, sir.

MR. KAISER: It sounds like Charles Dickens. Anyone else?

MR. WARREN: It is Charles Dickens ...

MR. KAISER: Thank you, gentlemen.

--- Whereupon the conference concluded at 12:40 p.m.

SCHEDULE A

Settlement Agreement, EB-2009-0101

SCHEDULE B

EB-2007-0606 Schedule A to Settlement Agreement dated Jan. 17, 2008

TAB 31

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 fixed level 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 32

VIA E-MAIL & COURIER TO THE BOARD

June 14, 2012

Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4

Attn: Kirsten Walli, Board Secretary

RE: EB-2012-0087 UNION GAS 2011 ESM AND DEFERRAL DISPOSITIONS

The following are the submissions of the Federation of Rental-housing Providers of Ontario in the above proceeding. The Board's Procedural Order No. 1 dated April 19, 2012 in this proceeding ordered that intervenors notify the Board on or before June 15, 2012 if they intend to file intervenor evidence. At this juncture, we respectfully request an additional opportunity for discovery in this proceeding to inform emerging issues. Our respectful request would be for a Technical Conference to be established prior to hearing of these matters.

While some of the dispositions applied for by Union are mechanistic and require little explanation or validation, in our view, there are some significant issues surrounding the use of transportation contract attributes to yield shareholder margins that warrant further examination. The awareness of this issue has grown with ratepayers during our inquiry into cost and revenue allocations in EB-2011-0210. Our submissions in that proceeding will be focused on the 2013 rebasing construct. However, the classification of revenues achieved from transportation cost mitigation in 2011 being channeled to shareholder margins is disconcerting.

Based on information filed in the EB-2011-0210 proceeding, the purpose of TCPL's FT Risk Alleviation Mechanism (RAM) that provides credits to Union for FT Capacity it does not use is to provide a "tool to mitigate unabsorbed demand charges (UDC)". In other words, the FT-RAM feature of Union's TCPL contracts is to enable Union to mitigate the upstream transportation costs it classifies and pays as "gas costs".

The extent to which Union is not filling the pipe that is secured through payment of demand charges thus creating UDC to obtain benefits from FT-RAM credits and then streaming those benefits to its shareholder rather than using them to reduce these demand charges in its gas costs accounts needs to be clarified. As a matter of principle, any gas cost related benefits should be used to reduce gas costs so that Union does not profit from attributes related to its TCPL transportation contracts that it classifies as gas costs.

• 130 Muscovey, Drive • Elmira, ON • N3B 3P7 • drquinn@rogers.com • (519)-500-1092 •

As an example, in response to FRPO IR7.7 Attachment 2, the response provides that 95% of the pathway of Empress to Parkway (Union CDA) was used for optimization to achieve a profit of $11.3 million. From information filed by Union Gas in the TCPL Tolls Hearing (RH-003-2011) on May 16, 2012, Union South held contracts of 71,327 GJ/day from Empress to Union CDA. The annualized cost for this transportation would be over $50 million dollars that would be recovered from Union transportation customers in their rates with no apparent recovery of the benefits of optimization of this transport to these customers. In addition, discovery in the EB-2011-0210 yield significant concerns regarding the level of transportation contracting in Union's North territory.

Having regard to the foregoing, the balances in Union's gas related deferral accounts including the UDC account need to be carefully examined. Therefore, to ensure that the Board has sufficient understanding of these issues, we would respectfully propose that a Technical Conference be provided as an additional opportunity to clarify the record for determination of these issues.

Respectfully Submitted on Behalf of FRPO,

Dwayne Q

Dwayne R. Quinn
Principal
DR QUINN & ASSOCIATES LTD.

c. Interested Parties EB-2012-0087
V. Brescia

TORYS LLP

Suite 3000
79 Wellington St. W.
Box 270, TD Centre
Toronto, Ontario
M5K 1N2 Canada
Tel 416.865.0040
Fax 416.865.7380

www.torys.com

Crawford Smith
Tel 416.865.8209
csmith@torys.com

June 15, 2012

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2012-0087
Union Gas Limited – FRPO Submissions

We are counsel to Union Gas Limited in the above-noted proceeding. We are writing in response to FRPO's letter of yesterday's date.

Pursuant to Procedural Order No. 1 parties were to advise by yesterday whether they intend to file evidence. FRPO's letter does not address this issue. Rather, the letter requests a technical conference to address "issues surrounding the use of transportation contracts". Suffice it to say that Union does not agree with the content of FRPO's letter, or the implication that there is anything novel in Union's application. A technical conference is to clarify the existing record. Here, despite referring to portions of the record, FRPO does not say how or why that record requires clarification.

In the result, there is no basis for a technical conference. Indeed, given the tight regulatory timeframes Union is already operating under – 2013 rates case is scheduled to start on July 10 – Union will be prejudiced if a technical conference is ordered at this late stage.

Yours truly,

Crawford Smith

Tel 416.865.8209
csmith@torys.com

CS/tm

cc: All EB-2012-0087 Intervenors
Michael Millar/Kristi Sebalj, Board Staff

11229-2099 13816882.1

Peter C.P. Thompson, Q.C.
T 613.787.3528
pthompson@blg.com

Borden Ladner Gervais LLP
World Exchange Plaza
100 Queen St, Suite 1100
Ottawa, ON, Canada K1P 1J9
T 613.237.5160
F 613.230.8842
F 613.787.3558 (IP)
blg.com

Borden Ladner Gervais

By electronic filing

June 15, 2012

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

Dear Ms Walli,

Union Gas Limited ("Union")	
2011 Earnings Sharing and Disposition of Deferral Accounts and Other Balances	
Board File No.:	**EB-2012-0087**
Our File No.:	**339583-000137**

We are writing on behalf of Canadian Manufacturers & Exporters ("CME") to support Mr. Quinn's request for a Technical Conference in this proceeding. This letter is further to Mr. DeRose's letter to the Board of June 11, 2012, pertaining to Union's July 1, 2012 QRAM Application in which we reserved our rights with respect to the matters described below.

Mr. Quinn correctly states that we need further evidence from Union to clarify the extent to which FT-RAM credit amounts, that appear in the bills Union receives from TransCanada PipeLines Limited ("TCPL") for upstream transportation services, are being recorded in gas cost-related deferral accounts. These FT-RAM credits stem from the portion of Union's existing FT contracts with TCPL that it does not use in any particular month.

Union classifies its upstream transportation costs as Gas Costs. The deferral account regime that currently exists is supposedly designed to ensure that increases or decreases in items of cost classified as Gas Costs flow through to ratepayers. Notwithstanding the existing deferral account regime, we understand that the FT-RAM credit amounts that Union receives from TCPL are not being flowed through ratepayers, but, instead, are being streamed to Union's shareholder.

Moreover, from information provided by Union in EB-2011-0210, Exhibit JT1.6, it appears that amounts that Union receives from temporarily assigning to a third party its upstream transportation capacity paid for by ratepayers as Gas Costs, in parallel with Union's use of a cheaper way to affectively move its upstream gas supplies to Dawn, are not finding their way into the Gas Costs related deferral accounts. These amounts are also being streamed to Union's shareholder.

We regard these outcomes as incompatible with the existing deferral account regime related to Gas Costs.

Union has the evidence that we seek to introduce with respect to these matters so that the appropriate deferral account balances to be cleared to ratepayers can be determined.

In these circumstances, we agree with Mr. Quinn that, as a precursor to the hearing, the most efficient way to obtain the evidence with respect to these matters is to schedule a Technical Conference to allow parties to obtain the necessary information from Union.

Yours very truly,

Peter C. P. Thompson, Q.C.

PCT\slc

c. Chris Ripley (Union)
Crawford Smith (Torys)
Intervenors EB-2012-0087
Paul Clipsham (CME)

OTT01\5128104\v1

TORYS LLP

Suite 3000
79 Wellington St. W.
Box 270, TD Centre
Toronto, Ontario
M5K 1N2 Canada
Tel 416.865.0040
Fax 416.865.7380

www.torys.com

Crawford Smith
Tel 416.865.8209
csmith@torys.com

June 18, 2012

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2012-0087
Union Gas Limited – CME Submissions

We are counsel to Union Gas Limited in the above-noted matter. We are writing in response to counsel for CME's letter dated June 18, 2012 and further to our letter of the same date.

Like FRPO, CME requests a technical conference in this matter. It does not point to any aspect of Union's evidence in the case which requires clarification, other than a broad assertion that further evidence is required in respect of upstream transportation activities that take advantage of TCPL's FT-RAM program. In addition to the reasons set out in our earlier letter, it is Union's position that a technical conference would serve no useful purpose. Why? Because the Board has already addressed this issue.

Contrary to CME's letter, upstream optimization is a recognized, and accepted feature of Union's incentive regulation mechanism. In EB-2008-0220, the Board considered the issue in relation to TCPL's Dawn Overrun Service (DOS-MN); whether revenues associated with that service should flow to ratepayers or be treated as transactional revenues not subject to deferral but shared with ratepayers pursuant to the existing earnings sharing mechanism. In that case, CME argued that,

> In Ex. 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.[1]

[1] EB-2008-0220, Argument of CME, p. 10

11229-2099 13822592.1

The Board disagreed. It held at pages 8-9:

> Upstream Transportation Changes
>
> Union noted that pursuant to the Settlement Agreement [EB-2007-0606 in which S&T deferral accounts were eliminated] 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 [CME] 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. (Emphasis Added.)

In Union's 2008 earnings sharing proceeding (EB-2009-0101) Union further explained its upstream optimization activities including its use of TCPL's FT-RAM program, as follows (Ex. B1, T1, Sch.4):

> 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.

By Decision and Rate Order dated June 18, 2009 the Board approved an earnings sharing amount available for distribution to ratepayers of $34.461 million (credit). Consistent with Ex. B1, T1, Sch.4, above, this amount reflected revenues associated with TCPL's FT-RAM program. Union's existing application mirrors this treatment.

Should you have any questions or concerns, please do not hesitate to contact me.

Yours truly,

Crawford Smith

Tel 416.865.8209
csmith@torys.com

CS/tm

cc: All EB-2012-0087 Intervenors
Michael Millar, Board Staff

Peter C.P. Thompson, Q.C.
T 613.787.3528
pthompson@blg.com

Borden Ladner Gervais LLP
World Exchange Plaza
100 Queen St, Suite 1100
Ottawa, ON, Canada K1P 1J9
T 613.237.5160
F 613.230.8842
F 613.787.3558 (IP)
blg.com

Borden Ladner Gervais

By electronic filing

June 20, 2012

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

Dear Ms Walli,

Union Gas Limited ("Union")
2011 Earnings Sharing and Disposition of Deferral Accounts and Other Balances

Board File No.:	**EB-2012-0087**
Our File No.:	**339583-000137**

We are writing to respond to counsel for Union's letter to the Board dated June 18, 2012, (the "Union letter") asserting that the issue of Union's diversion of FT-RAM amounts to its shareholder, rather than applying them to reduce the TCPL FT demand charges paid for by ratepayers, is an issue that the Board "has already addressed". We strongly disagree with that assertion. The issue has not been addressed and it should not be considered without a complete record of all relevant facts. For reasons that follow, we urge the Board to reject the attempt by Union to obtain a Board pre-determination of the matter in issue in its favour on the basis of the arguments contained in the Union letter.

Ratepayer representatives have only recently gained an understanding of the factual matters related to the issue. Union's responses to Interrogatories posed by TransCanada PipeLines Limited ("TCPL") and others in the EB-2011-0210 proceeding reveal that FT-RAM credits are not "value" that Union "extracted" from "new services", as asserted in the evidence in the EB-2009-0101 proceeding referenced at pages 2 and 3 of the Union letter. Rather, we have learned that the net FT-RAM revenues that Union is currently streaming to its shareholder stem directly from the TCPL demand charges that ratepayers pay with respect to the FT capacity Union holds on TCPL.

None of this is described in the evidence quoted in the Union letter. The evidence to which Union refers omits any reference to details related to the source and nature of the FT-RAM credits. These details, of which we are now aware, clearly demonstrate that the FT-RAM credit amounts were provided by TCPL to enable FT shippers to mitigate their Unabsorbed Demand Charges ("UDC"). Means of mitigating FT demand charges have been a matter of high priority for shippers on the TCPL Mainline in recent years. This is because the year-over-year tolls have been increasing significantly as a result of the combined effect of increasing Mainline under-utilization and the fact that FT shippers pay all of the fixed costs of the Mainline, regardless of its under-utilization.

Having regard to the source of the FT-RAM credits and their intended purpose, we submit that the amounts should properly be credited to ratepayers through the gas supply related deferral accounts which were never eliminated as a result of the provisions of the EB-2007-0606 Settlement Agreement to which the Board refers in the Decision referenced at pages 1 and 2 of the Union letter. Put another way, the general architecture of the IRM Plan, including its gas supply deferral accounts, and the provisions of the EB-2007-0606 Settlement Agreement require that all mitigation amounts related to items of expense paid for by ratepayers as "gas supply costs" be credited to ratepayers. The principle that applies is that regulated gas utilities in Ontario cannot profit from items of expense classified as "gas supply costs".

The elimination of certain S&T deferral accounts pursuant to the provisions of the EB-2007-0606 Settlement Agreement has no relevance to the issue we seek to have the Board examine. The issue pertaining to the compatibility of Union's actions with the existing gas supply related deferral account regime and the principle that Union cannot profit from items of expense classified as gas costs has never been explicitly considered or addressed by the Board. The issue is of considerable importance because the information at line 5 in Exhibit J.C-4-7-9 Attachment 1 in the EB-2011-0210 proceeding indicates that, to the end of 2010, Union had acted to stream to its shareholders some $31.1M of amounts paid by ratepayers as "gas costs". For 2011, the additional gas costs amount streamed to the shareholder is $22.0M and for 2012, the forecast amount is $14.2M. Using this information, we estimate that the total amount in issue, to the end of 2011, is about $53.1M. We believe that this $53.1M amount is a component of the total over-earnings Union realized in the 5-year period 2007 to 2011 inclusive of about $264.724M, as shown at line 24 of columns (b) to (f) inclusive in Exhibit J.O-4-14-1 Attachment 1 in the EB-2011-0210 proceeding.

We submit that, in situations such as this, where Union takes unilateral action to enrich its shareholder at the expense of its ratepayers, the principle that the Board should apply is that, without explicit prior Board approval, the outcome of such actions is invalid and particularly so when the amounts being streamed to the shareholder are amounts ratepayers have paid to Union as "gas costs". In the EB-2011-0038 proceeding, Union accepted, as a matter of principle, that improper gas supply deferral account balances, in prior years, should be rectified by making the necessary adjustment to the current year's gas supply deferral account balances. That principle applies to the situation we wish the Board to examine.

Neither the question raised in CME's Argument in the EB-2008-0220 proceeding about the Dawn Overrun Service – Must Nominate ("DOS-MN"), nor Union's response to that question in Reply Argument, nor the excerpt in the Board's Decision in that case, nor the excerpt from part of Union's evidence in the EB-2009-0101 proceeding, all of which are cited in the Union letter, can reasonably be construed to support a conclusion that the Board has already addressed Union's actions in streaming to its customers some $67.3M of money paid by ratepayers as gas costs. FT-RAM credits, sourced from FT demand charges paid by Union's ratepayers, were not a factor reflected in the net revenues generated by Union's use of the DOS-MN. The argument in the Union letter is specious.

The Union letter refers to the fact that ratepayers realized an earnings sharing credit in 2008 of $34.461M. and states that this amount "reflects" revenues associated with TCPL's FT-RAM program. The portion of the $34.461M earnings sharing credit attributable to the FT-RAM program is one of the matters that a complete record will clarify. Based on Exhibit J.C-4-7-9 Attachment 1 in the EB-2011-0210 proceeding, we believe that a small portion (about $5M) of Union's 2008 over-earnings of $82.264M was attributable to FT-RAM credit amounts and that 50% of this $5M amount is reflected in the earnings sharing credit of $34.461M.

The point to be emphasized is that the existence of the earnings sharing mechanism in the IRM Plan is not relevant to whether the FT-RAM amounts should properly be applied to reduce Union's upstream transportation costs charged to ratepayers as an item of gas supply costs. If the Board considers this issue in the context of a complete record and eventually agrees that the FT-RAM amounts should have been applied to mitigate these costs, then the Board will need to adjust the amounts to be credited to the appropriate gas supply deferral accounts to eliminate the portion of ratepayers' share of earnings in prior years attributable to FT-RAM credit amounts.

For all of these reasons, we submit that the Board should have a complete record before considering the important question of whether Union is improperly streaming FT-RAM amounts to its shareholder rather than crediting them to ratepayers through the gas supply related deferral accounts.

We reiterate that, in our view, a Technical Conference is the most efficient way of completing the record. If a Technical Conference is not to be held, then intervenors should be allowed to submit further interrogatories to Union. In the alternative, they should be allowed to file, in this proceeding, the interrogatory responses provided by Union in the EB-2011-0210 proceeding that are relevant to the matter in issue so that Union witnesses can be examined, at the hearing, with respect to this information.

Yours very truly,

Peter C. P. Thompson, Q.C.

PCT\slc

c. Chris Ripley (Union)
Crawford Smith (Torys)
Intervenors EB-2012-0087
Paul Clipsham (CME)

OTT01\5132671\v1

TAB 33

EB-2012-0087

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

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. 2
June 27, 2012

Union Gas Limited ("Union") filed an application dated April 13, 2012 with the Ontario Energy Board (the "Board") under section 36 of the Act 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 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 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.

Union filed its interrogatory responses on June 8, 2012. Union filed responses to Board staff interrogatory No. 9 (b) and BOMA interrogatory No. 2 (c) under confidential cover. Union requested that the Board treat these documents as confidential per the Board's *Practice Direction on Confidential Filings*. The Board is of the view that these two documents are properly considered confidential in accordance with the *Practice Direction on Confidential Filings*. Intervenors who would like to review these documents may do so after filing a Declaration and

Undertaking on Confidentiality. Union shall provide the confidential responses to any intervenor that has signed a Declaration and Undertaking on Confidentiality.

By letter dated June 14, 2012, the Federation of Rental-housing Providers of Ontario ("FRPO"), an intervenor in the proceeding, requested that the Board hold a Technical Conference so that intervenors have the opportunity to explore emerging issues such as the use of transportation contract attributes to yield shareholder margins. The Canadian Manufacturers and Exporters ("CME"), also an intervenor in the proceeding, filed a letter on June 15, 2012 supporting FRPO's request.

In response to FRPO's letter, Union filed a letter on June 15, 2012 stating that there is no basis for a Technical Conference and moreover, given the tight regulatory schedules that Union is operating under, Union will be prejudiced if a Technical Conference is ordered by the Board. In response to CME's letter, Union filed a letter dated June 18, 2012 stating that a Technical Conference would serve no useful purpose as the Board has previously addressed the issue raised by FRPO and CME in their respective letters.

The Board is of the view that FRPO and CME have raised issues related to the accounting for upstream transportation services that are relevant to this proceeding and that require additional discovery. The Board has determined that a Technical Conference is the appropriate forum for these issues to be further examined. The Board will therefore establish a Technical Conference in this proceeding. The Board directs FRPO and CME and any other interested intervenors to file a coordinated submission scoping the issue or issues to be addressed at the Technical Conference. Union and any parties that wish to respond will have an opportunity to file a responding submission. The Board will determine the final issues to be addressed at the Technical Conference.

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

THE BOARD ORDERS THAT:

1. FRPO, CME and any other interested intervenors shall, **on or before August 3, 2012**, file with the Board and copy all other parties a single submission outlining the issue or issues that should be addressed at the Technical Conference.

2. Union or any other party may, **on or before August 10, 2012**, file with the Board and copy all other parties a response to the submission filed by FRPO, CME and other parties.

3. A Technical Conference involving Board staff, Intervenors and the Union will be convened on **August 21, 2012**. The Technical Conference will be held at 2300 Yonge Street, Toronto in the Board's hearing room on the 25th floor.

4. A Settlement Conference will be convened at 9:30 a.m. on **August 28, 2012** with the objective of reaching a settlement among the parties on all outstanding issues in this proceeding. The Settlement Conference will be held in the Board's hearing room at 2300 Yonge Street, 25th Floor, Toronto, and may continue until **August 29, 2012** if needed.

5. Any Settlement Proposal arising from the Settlement Conference shall be filed with the Board no later than 4:45 p.m. on **August 31, 2012**.

All filings to the Board must quote file number **EB-2012-0087**, be made through the Board's web portal at www.errr.ontarioenergyboard.ca, 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, June 27, 2012

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

TAB 34

PETER C.P. THOMPSON, Q.C.
T 613.787.3528
pthompson@blg.com

Borden Ladner Gervais LLP
World Exchange Plaza
100 Queen St, Suite 1100
Ottawa, ON, Canada K1P 1J9
T 613.237.5160
F 613.230.8842
blg.com

Borden Ladner Gervais

By electronic filing

August 3, 2012

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

Dear Ms Walli,

Union Gas Limited ("Union")	
2011 Earnings Sharing and Disposition of Deferral Accounts and Other Balances	
Board File No.:	**EB-2012-0087**
Our File No.:	**339583-000137**

The following submission is provided on behalf of Canadian Manufacturers & Exporters ("CME") and the Federation of Rental-Housing Providers of Ontario ("FRPO") pursuant to paragraph 1 of Procedural Order No. 2 in these proceedings dated June 27, 2012.

A. ISSUES RE: UNION'S ACCOUNTING FOR UPSTREAM TRANSPORTATION SERVICES

The foregoing parties submit that the issues related to Union's accounting for Upstream Transportation Services that should be addressed at the Technical Conference in this proceeding scheduled for August 21, 2012, and at the Hearing of the Application, are as follows:

(a) 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?

(b) 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? and

(c) What is the impact on the amount of 2011 earnings to be credited to ratepayers of clearing to ratepayers the foregoing total amounts.

B. BACKGROUND FACTS

In large measure, matters of fact pertaining to each of these issues have been canvassed during the evidentiary portion of the hearing of Union's 2013 Re-basing Application.

1. Union's Inappropriate Activities

A factual issue that is common to the 2013 Re-basing Application and the 2011 Deferral Account Clearance and Earnings Sharing calculation proceeding is whether Union has properly accounted for all amounts that it has received from 2007 onwards to mitigate Upstream Transportation Demand Charges actually incurred.

What has been revealed in evidence in Union's 2013 Re-basing case is that, since 2008, Union has been "optimizing" components of its Gas Supply Plan upon which its rates are based by creating UDC, on a planned basis, and then either concurrently assigning or exchanging its FT transportation contracts for services on the Mainline of TransCanada Pipelines ("TCPL") to:

(i) monetize the FT-RAM credit value of its unused FT contracts;

(ii) obtain cheaper means of delivering its Western Canadian gas supplies to their intended destination; and

(iii) treating the difference between the monetized FT-RAM credits funded by demand charges recovered from ratepayers in rates, and the costs of the cheaper transport as utility earnings, rather than as a reduction to Union's upstream transportation costs.

Union has effectively been converting into profit TCPL FT demand charges paid by ratepayers. In substance, what Union has been doing is analogous to a service provider contracting for and charging his client for the purchase of an executive class transportation ticket to support the provision of services to the client, and then exchanging that ticket for a lower priced economy transportation service in order to treat as "profit" the difference between the amounts paid for executive and economy transportation service.

2. Profits Derived from Union's Inappropriate Activities to December 31, 2011

The magnitude of the demand charge payments made by ratepayers that Union has effectively converted into profits under the auspices of these executive/economy class transportation services activities are disclosed in evidence in Union's 2013 Re-basing case. Exhibit K7.3 in that proceeding shows that, before earnings sharing, the profits realized by Union from these activities to December 31, 2010 were $31.1 million.[1] After taking account of earnings sharing amounts of $14.9 million[2] paid to ratepayers to the end of 2010, the net profits attributable to this approach were $16.2 million[3] to December 31, 2010. A copy of Exhibit K7.3 is attached.

[1] Exhibit K7.3, line 1, columns 1 to 4.
[2] Exhibit K7.3, line 2, columns 2 to 4.
[3] $31.1 million minus $14.9 million

The same exhibit shows that in 2011, the "profits", before earnings sharing, were an amount of \$22.0 million[4]. Because Union's total profits in 2011 exceed the 200 and 300 basis point thresholds above the base return on equity ("ROE") specified in the Settlement Agreement, the portion of these profits attributable to ratepayers is calculated by Union to be \$14.5 million[5]. Put another way, the 2011 earnings sharing amount payable to ratepayers will be reduced by 14.5 million if the Board requires Union to record the \$22.0 million Union characterized as "profits" as gas cost reductions in Union's Gas Supply Deferral Accounts as of December 31, 2011.

3. Expected Profits from 2012

Exhibit J7.11 in Union's 2013 Re-basing case indicates that Union is now expecting to realize \$37.8 million of "profits" from this executive/economy transportation services exchange approach. None of this amount is likely to exceed the 200 basis points band above the base ROE specified in the IRM Settlement Agreement. The \$37.8 million now forecast for 2012 is \$23.6 million more than the \$14.2 million forecast shown in Exhibit K7.3, line 1, column 6. A copy of Exhibit J7.11 is also attached.

4. Total Expected Profits to December 31, 2012

Based on the foregoing, and operating under the auspices of this executive/economy transportation contracting exchange approach, Union will have effectively converted to profits for its shareholder about \$61.4 million[6] of demand charges paid by ratepayers for upstream transportation services on TCPL.

C. GUIDING PRINCIPLES – UNION CANNOT PROFIT FROM ITS UNAUTHORIZED ACTIVITIES

1. A Utility Cannot Profit from its Own Improper Acts

CME, FRPO and others contend that without explicit prior Board approval, this approach to convert a portion of upstream transportation demand charges, paid for by ratepayers, to utility shareholder profit is improper and invalid. A utility such as Union cannot profit from items of expense treated as flow-through items by its regulator. Legal precedents relating to the misuse and/or misappropriation of trust funds by a trustee are, by analogy, applicable to Union's actions in effectively converting to profits demand charges paid by ratepayers. CME and FRPO contend that Union must account to ratepayers for all of the net amounts it has received by virtue of its unauthorized actions of effectively converting to profits a portion of FT demand charges paid by ratepayers.

We are not seeking to unwind the IRM Settlement Agreement as Union contends. The relief that we seek stems from principles embedded in that Agreement, namely that Union cannot profit from reductions in pass-through items of expense.

[4] Exhibit K7.3, line 1, column 5
[5] Exhibit K7.3, line 2, column 5
[6] \$37.8 million plus \$23.6 million

2. The Board Never Authorized Union to Effectively Convert Ratepayer Funded Demand Charges to Profits for its Shareholder

Union justifies its actions on the grounds that "they have already been addressed".[7] Union contends that its actions were authorized by the IRM Settlement Agreement in the EB-2007-0606 proceedings, consented to by Intervenors and approved by the Board. CME and FRPO strongly disagree with this contention. There is no evidence to demonstrate that Intervenors or the Board, expressly or impliedly, authorized Union to convert more than $60 million of FT demand charges paid by ratepayers to profits for Union's shareholder.

The facts on which Union relies, such as the closure of certain Transactional Services ("TS") Deferral Accounts under the auspices of the EB-2007-0606 Settlement Agreement, and its use of the DOS-MN service from TransCanada, do not support Union's contention that its actions were authorized. Conversion of ratepayer funded demand charges to profits was never part of Union's operations under the auspices of the TS Deferral Accounts that were closed as a result of the foregoing Settlement Agreement. At no time did Intervenors or the Board provide Union with an informed consent to convert demand charges to profits.

All issues of fact pertaining to whether Intervenors and the Board authorized Union to effectively convert to profit more than $60 million of FT demand charges will be determined by the Board panel hearing of Union's 2013 Rate Case.

D. RELATIONSHIP BETWEEN ISSUES IN THIS CASE AND UNION'S 2013 RATE CASE

The issues in this case relate to the manner in which Union should account to ratepayers for the profits it has derived from the unauthorized demand charge conversion activities. The conceptual question of whether Union is obliged to account to ratepayers for these profits will be determined in Union's 2013 Rate case.

For the purposes of the 2011 Deferral Account case, we submit that the items of relevance are as follows:

(a) The amount, as of December 31, 2011, that Union received to mitigate Upstream Transportation Demand Charges that is not recorded in Union's Gas Supply Deferral Accounts. We say that this amount is $38.2 million consisting of items described above, namely the $16.2 million amount to December 31, 2010, net of earnings sharing amounts, and the $22.0 million amount received by Union in 2011; and

(b) The impact of 2011 earnings sharing of recording the $38.2 million amount in Union's Gas Supply Deferral Accounts at December 31, 2011. Based on the information provided in the 2013 Re-basing case, we believe that the 2011 earnings sharing amount to be credited to ratepayers should be reduced by $14.0 million.

---

[7] Torys' June 18, 2012 letter to the OEB

A final determination of these two particular issues in the 2011 Deferral Account and Earnings Sharing Calculation proceeding will need to await the Board's determination of issues of fact in Union's 2013 Re-basing proceeding pertaining to the validity of Union's conversion of ratepayer funded upstream transportation demand charges into profits under the auspices of its executive/economy transportation services exchange activities.

E. IMPLICATIONS FOR CLEARANCES OF 2011 DEFERRAL ACCOUNT BALANCES

Until matters pertaining to the validity of Union's actions have been determined, the balance in the 2011 UDC Gas Supply Deferral Account 179-108 to be cleared to ratepayers and the related issue of the final 2011 earnings sharing amount cannot be made. However, the current balances in the UDC and other Gas Supply Deferral Accounts should 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 Re-basing case.

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 Re-basing case.

Undisputed balances in all other 2011 Deferral Accounts can be cleared at this time.

F. CONCLUSION

Based on the foregoing, we expect that the Technical Conference scheduled for August 21, 2012 will be confined to obtaining confirmation on the record in this proceeding of the amounts described herein and any other information not yet in the record pertaining to the issues framed at the outset of this letter.

Yours very truly,

Peter C. P. Thompson, Q.C.

PCT/kt
Encls
c. Chris Ripley (Union)
Crawford Smith (Torys)
Intervenors EB-2012-0087
Paul Clipsham (CME)

OTT01\5207275\v2

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

AND IN THE MATTER OF an application filed by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2013.

CANADIAN MANUFACTURERS & EXPORTERS ("CME") COMPENDIUM OF DOCUMENTS re: Upstream Transportation Cost Reductions

OTT01\5228536\v1

TAB 35

TORYS LLP

Suite 3000
79 Wellington St. W.
Box 270, TD Centre
Toronto, Ontario
M5K 1N2 Canada
Tel 416.865.0040
Fax 416.865.7380

www.torys.com

Alex Smith
Tel 416.865.8142
asmith@torys.com

August 10, 2012

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2012-0087
Union Gas Limited – Response Pursuant to Procedural Order No. 2

This submission by Union Gas Limited ("Union") responds to the August 3, 2012 submission by the Canadian Manufacturers' & Exporters ("CME") and the Federation of Rental Housing Providers of Ontario ("FRPO") (the "CME/FRPO Letter") regarding the issue or issues that should be addressed at the Technical Conference for this proceeding presently scheduled for August 21, 2012. This submission is made pursuant to paragraph 2 of Procedural Order No. 2 in this proceeding dated June 27, 2012.

Two questions are raised by the CME/FRPO Letter:

1) The narrow question as to whether there should be a technical conference and, if so, when and in relation to which issues.

2) The broader question as to how, procedurally, this proceeding should be managed having regard to the extant 2013 rebasing application (EB-2011-0210) (the "2013 Application").

The narrow question. As the CME/FRPO Letter acknowledges, the factual allegations relating to upstream transportation optimization revenue raised in that letter have already been raised by these parties in the 2013 Application. Union strongly believes that the Board should not revisit either the amounts previously cleared pursuant to Final Rate Orders or the terms of the incentive regulation mechanism as, in effect, urged by the CME/FRPO Letter, whether in this proceeding or in the 2013 Application. Union also disagrees with the tone and content of the CME/FRPO Letter and considers it improper. Nevertheless, having regard to the fact that CME and FRPO have raised these issues in the 2013 Application, it is Union's view that the technical conference in this proceeding should be adjourned to a later date. There is no utility in having the technical conference at this time. 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 Application. The CME/FRPO Letter admits as much. Having the matter determined at this time risks inconsistent decisions by the Board in relation to the same issue in two different proceedings and based on the same evidence.

One final observation in relation to this question. In Procedural Order No. 2, the Board asked for an outline of the issue or issues to be addressed at the technical conference. In response, CME and FRPO filed a five-page letter, exclusive of attachments, which largely amounts to argument as to the purported merits of their position. It is respectfully submitted that a letter of this nature is entirely inconsistent with the Board's Order. As outlined above, Union does not agree with the CME/FRPO Letter. A comprehensive response, however, would not be appropriate at this time.

The broader question. If the issues in relation to upstream transportation optimization revenue and their impact should not be determined at this time, the question remains how best to deal with this proceeding going forward. Union respectfully submits 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 on the 2013 Application. Union is not aware, at this time, of any concerns in relation to the other issues, nor did any party request a technical conference in relation thereto. As a result, Union believes that the other issues can be dealt with expeditiously either by way of settlement or brief hearing. There is precedent for this approach. In EB-2010-0039, Union's 2009 Deferral Account and Earnings Sharing Proceeding, the parties were able to reach a settlement in relation to all non-Dawn Gateway related issues and a Final Rate Order was issued by the Board. The Dawn Gateway issues were then adjourned to a later date having regard to the uncertainty that then surrounded the project.

Yours truly,

[original signed by]

Alex Smith

Tel 416.865.8142
asmith@torys.com

cc: All EB-2012-0087 Intervenors
Michael Millar/Kristi Sebalj, Board Staff
Paul Clipsham, (CME)

TAB 36

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 37

Description

RAM is a service feature applicable to the Mainline's Firm Transportation (FT) service, Storage Transportation Service (STS), and Storage Transportation Service — Linked (STS-L). It allows for the mitigation of unutilized demand charges and is intended to give shippers increased confidence in contracting for long-haul FT service on the Mainline.

Under RAM, credits are applied against a Mainline shipper's Interruptible Transportation (IT) service invoice at the end of each month, regardless of the path(s) used for IT service, based on any eligible unutilized demand charges (UDCs) from that shipper's long-haul FT, "linked" short-haul FT, STS and STS-L contracts. A shipper's monthly IT invoice will however be subject to a minimum charge (please see the RAM formulas below for more information).

The RAM credit is a dollar amount and is designed to allow a shipper to transport a quantity of IT equal to the quantity of unutilized FT (for example) if used over the same path, for no additional charge beyond the minimum commodity charge, assuming the IT is bid at the IT floor price. For example, a shipper's eligible FT contract with UDCs that has a daily demand toll of $1.00/GJ would generate a RAM credit of approximately $1.10/GJ towards that shipper's monthly IT invoice.

The RAM service feature does not change the nomination or allocation processes for FT, STS, STS-L or IT service. Shippers still access those services in their usual manner.

Contracts Eligible for RAM Credits

Long-haul FT Contracts

These are FT contracts which have primary receipt points originating in Alberta and Saskatchewan.

Short-haul FT Contracts "linked" to a Long-haul FT Contract at a Common Location

Short-haul FT contracts are eligible for RAM credits as long as the shipper that holds the short-haul contract also holds a long-haul FT contract that has a delivery point at the same location as the receipt point of the shipper's short-haul contract.

STS and STS-L Contracts

For markets downstream of storage:

- STS and STS-L RAM credits will only be generated during the firm Winter Withdrawal period; and only if the STS Balance or STS-L Balance is above zero;
- Injection and withdrawal nominations, except STS overrun, will be considered as usage of the STS and STS-L contracts; and
- The maximum amount of STS or STS-L RAM credits which can be generated each day will be capped by the withdrawal contract demand.

For markets upstream of storage:

- STS and STS-L RAM credits will only be available during the firm Summer Injection period;
- Injection and withdrawal nominations, except STS overrun, will be considered as usage of the STS and STS-L contracts; and
- The maximum amount of STS or STS-L RAM credits which can be generated each day will be capped by the injection contract demand.

Key Points about RAM

RAM credits:

- Are dollar credits, not quantity credits
- Are calculated daily from Unutilized Demand Charges (UDCs)
- Are accumulated in a month and are applied against that shipper's Interruptible Transportation (IT) invoice for that month
- Cannot be carried over to another month
- Are not assignable to third parties
- Are non-refundable
- Are not path specific
- Are not eligible if a contract is terminated or suspended
- Apply to the assignee's account commencing on the date the assignment takes effect, if all or a portion of a qualifying contract is assigned

RAM Formulas & Examples

Note: Formulas are for the applicable primary contract path calculated on a daily basis

Long-haul FT RAM Formula

Long-haul FT RAM credit = (Unutilized Daily Quantity) x [(100% load factor long-haul FT toll x 1.1) – FT long-haul Commodity]

Example:

Assume long-haul FT Contract:
- Contract Demand = 100 GJ/d
- Tolls: Daily Demand = $1.00/GJ, Commodity = $0.05/GJ
- Utilization on a day = 0 GJ

RAM credit for that day =
- (Unutilized Daily Quantity) x [(100% load factor long-haul FT toll x 1.1) – FT long-haul Commodity]
- (100 – 0) x [(($1.00 + $0.05) x 1.1) – $0.05]
- $110.50

RAM Formulas & Examples *continued*

Linked Short-haul FT RAM Formula

Linked Short-haul FT RAM credit = (Short-haul Allocation Factor) x (Unutilized Daily Quantity) x [(100% load factor short-haul FT toll x 1.1) – FT short-haul Commodity]

Where:

Short-haul Allocation Factor = (Sum of all shipper's long-haul contract demand to the common location) ÷ (Sum of all shipper's short-haul contract demand from the common location)

Note: Short-haul Allocation Factor cannot be greater than 1.

Example:

Assume linked long-haul FT Contract:

- Contract Demand = 50 GJ/d
- Tolls: Daily Demand = $1.00/GJ, Commodity = $0.05/GJ
- Utilization on a day = 30 GJ

Assume linked short-haul FT Contract:

- Contract Demand = 100 GJ/d
- Tolls: Daily Demand = $0.60/GJ, Commodity = $0.02/GJ
- Utilization on a day = 40 GJ

Long-haul RAM credit for that day =

- (Unutilized Daily Quantity) x [(100% load factor long-haul FT toll x 1.1) – FT long-haul Commodity]
- (50 – 30) x [(($1.00 + $0.05) x 1.1) – $0.05]
- $22.10

Short-haul RAM credit for that day =

- (Short-haul Allocation Factor) x (Unutilized Daily Quantity) x [(100% load factor short-haul FT toll x 1.1) – FT short-haul Commodity]
- (50/100) x (100 – 40) x [(($0.60 + $0.02) x 1.1) – $0.02]
- $19.86

STS RAM Formula

STS RAM Credit = (STS Unutilized Daily Quantity) x [(100% load factor STS toll x 1.1) – STS Commodity]

STS-L RAM Formula

STS-L RAM Credit = (STS-L Unutilized Daily Quantity) x [(100% load factor STS toll x 1.1) – STS Commodity]

Minimum Monthly IT Invoice = $\sum$ (IT quantity) x (FT Commodity Toll), for each IT path nominated and authorized within the month

IT Floor Price = 1.1 x 100% load factor FT toll for service over the applicable path

Frequently Asked Questions Concerning RAM

1. How does the RAM enhancement work?

RAM takes the form of a credit for your unutilized demand charges under your long-haul FT, linked short-haul FT, STS and STS-L contracts, which is applied to your monthly invoice for Interruptible Transportation (IT) service provided by TransCanada. You access these credits simply by using IT service.

2. Why has RAM been structured as a credit to IT, instead of a separate, nominated RAM service?

A RAM credit mechanism offers a number of important benefits to shippers, including:

a) The credit mechanism can be implemented more quickly and at far less cost.

b) The credit mechanism will be simple for shippers to use. Shippers can nominate IT service as done today. A new type of nominated service would have required new contracts, new nominations groups, additional daily nominations, new priority of service and allocations rules, etc...

c) A credit mechanism offers unparalleled flexibility to capture the value of the services. You can use your credits to purchase IT service on any path on the system, either long-haul or short-haul. A separate nominated RAM service would typically limit the RAM to the primary path of your contract.

Further, you have greater choice on when you use your RAM credits. You can choose to nominate for a steady amount of IT during the month, or you can use your credits by nominating for a large amount of IT on a single day in the month.

3. Will I get RAM credits if my FT diversion or alternate receipt point nomination is not authorized?

Under the RAM feature, FT contract diversion and alternate receipt point nominations that are authorized are considered "usage" of those FT contracts.

If your diversion or alternate receipt point nomination is not authorized, you get to use those unutilized demand charges to purchase IT. That way, you do not lose capacity and dollars if your diversion or alternate receipt point is not authorized.

4. Can I use my credits for Interruptible Backhaul service?

No. The credits can only be used to reduce your invoice for IT service.

5. Will credits be given for FT Delivery Pressure charges?

No. Credits are not available for FT Delivery Pressure Charges. As well, RAM credits cannot be applied against Delivery Pressure Charges on IT service.

6. If I do not use all my credits in one month, can I use the credits in the following month?

No. Credits accumulate and are used within each particular month. Credits that are not used within the month expire and cannot be used in subsequent months.

7. Do I have to sign an IT contract to make use of the credits?

Yes. A single "master" IT contract can give you the ability to nominate for IT service on all paths.

8. In order to use RAM credits, do I need a separate IT contract for each FT, STS or STS-L contract?

You only need a single master IT contract. TransCanada can automatically pool the credits under all of your FT, STS and STS-L contracts and apply the total credit against your IT transportation charges. However, the IT contract must be held by the same legal entity as the FT, STS or STS-L contract. If your contracts are held in different legal names, you will need a separate IT contract for each name.

9. Do I have to use the RAM credits for IT service over the same path as my FT, STS or STS-L contract?

No. Credits can be used for IT over any path on the system. For example, a long-haul FT shipper could use the credits to purchase short-haul IT.

Frequently Asked Questions Concerning RAM *continued*

10. Can my Agent nominate for IT on my behalf to make use of the credits?

Yes. If you have a nominating Agent for your contracts, you can designate that Agent to nominate under your IT contract.

11. How will I know how many credits I've got each day?

Each shipper will be responsible for tracking their credits and IT usage within the month. TransCanada will also provide a daily report via the web to assist shippers in tracking their credits. The Shipper Operational Report called RAM Credits Status Report will provide details on how credits were calculated and then applied to your IT charges. You can track, on a daily basis, the amount of credits available and used during the month. Also, at month end you can use this report to verify against the credits that appear on your IT invoice.

12. Who gets the credits if I assign my FT contract?

The credits are calculated each day and are the "property" of the holder of the contract on each day. If an FT contract is assigned on the 11th day of a month, the original shipper receives the credits for the first 10 days of the month. The assignee receives the credits for the remaining days in the month starting on the 11th.

13. Can I assign my RAM credits to another shipper?

No. The credits can only be applied against the IT transportation charges of the holder of each particular FT, STS or STS-L contract.

14. How will RAM credits be calculated if I am authorized a FT contract shift by TransCanada?

The credit will be calculated based on the FT primary contract path that you are billed on. For contract shifts, you are billed on the "higher of" the original primary contract path or the shifted contract path (subject to certain provisions). The Credits Status Report will indicate which primary contract path (original or shifted) was used in calculating your credit.

15. Why is there a minimum IT charge applied in the RAM calculation?

The minimum IT charge is to ensure recovery of all commodity charges for transportation used. Without the minimum charge, shippers who transported gas would not be contributing to the variable cost of transportation (commodity toll) on the system, which would cause an under-collection of commodity revenues.

For further information about RAM:

The Pipe Line: **403.920.PIPE (7473)**

E-mail: **customer_express@TransCanada.com**

TAB 38

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
450 - 1st Street S.W.
Calgary, Alberta, Canada T2P 5H1

Tel: (403) 920-2046
Fax: (403) 920-2347
Email: murray_sondergard@transcanada.com

January 16, 2009

National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta
T2P 0X8

Filed Electronically

Attention: Ms. Claudine Dutil-Berry, Secretary

Dear Ms. Dutil-Berry:

Re: TransCanada PipeLines Limited ("TransCanada")
Amendments to TransCanada's Canadian Mainline Transportation Tariff

TransCanada hereby files an application with the National Energy Board ("Board") pursuant to Section 60(1)(b) of the *National Energy Board Act* for an order or orders approving certain amendments to TransCanada's Mainline Transportation Tariff's Interruptible Transportation ("IT") Toll Schedule. The proposed amendments were presented to the Tolls Task Force ("TTF") and were unopposed by the TTF in Resolution 04.2009, FT-RAM, STS-RAM and STSL-RAM Permanent Tariff Feature, voted on January 7, 2009.

TTF Resolution 04.2009 describes amendments to the IT Toll Schedule to add the current Risk Alleviation Mechanism ("RAM") for Firm Transportation ("FT") Service, Storage Transportation Service ("STS") and Storage Transportation Linked Service ("STS-L") as permanent features of the Mainline transportation services.

The FT-RAM pilot was originally approved by the Board in a letter dated July 15, 2004 as a feature of FT service for a one year period commencing November 1, 2004 per TTF Resolution 02.2004. The FT-RAM pilot was subsequently extended for a period of one year by the Board in a letter dated September 6, 2005 as per TTF Resolution 20.2005 and again by the Board in a letter dated April 21, 2006 as per TTF Resolution 05.2006. Modifications to apply the FT-RAM pilot to short-haul contracts were made effective April 1, 2006 by Board Order TG-1-2006, and in accordance with the Board's decision in RHW-2-2005.. In a letter dated March 2, 2007, the Board approved an additional two-year extension of the FT-RAM pilot commencing November 1, 2007 as per TTF Resolution 03.2007 and extended the FT-RAM pilot to include Storage Transportation Service (STS-RAM) and Storage Transportation Service Linked (STSL-RAM) for a two-year term commencing November 1, 2007 as per TTF Resolution 02.2007.

During the various RAM pilot periods, the mechanism has been used by a broad spectrum of shippers including producers, producer/marketers, LDCs and end-users TransCanada notes that use of the RAM mechanism does not limit the service entitlements of current FT service.

In support of its application, TransCanada attaches for the Board's information blacklined and clean copies of the IT Toll Schedule and a copy of TTF Resolution 04.2009. TransCanada proposes that these changes become effective November 1, 2009.

Should the Board require additional information, please contact Stella Morin at (403) 920-6844 or stella_morin@transcanada.com.

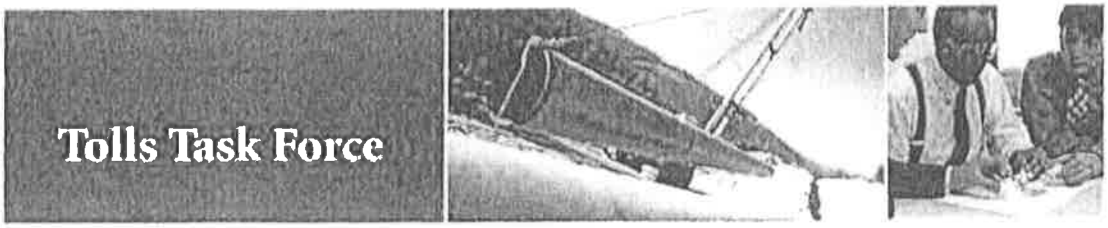
Yours truly,

Original Signed by

Murray Sondergard
Director, Regulatory Services

Attachments

cc: Tolls Task Force (on-line notification)
Mainline Customers (on-line notification)



2008 TOLLS TASK FORCE ISSUE	
Date Accepted As Issue: September 4, 2008	**Resolution:** 04.2009
Date Issue Originated: September 4, 2008	**Sheet Number:** 1 of 3
Issue Originated By:	Shell Energy North America (Canada) Inc.
Individual to Contact: Tomasz Lange	**Telephone Number** (403) 216-3580

ISSUE: FT-RAM, STS-RAM and STSL-RAM Permanent Tariff Feature

RESOLUTION:

The TTF agrees to the addition of the current FT - Risk Alleviation Mechanism (FT-RAM), STS-RAM and STSL-RAM pilots, to the TransCanada tariff as permanent features of the transport services effective November 1, 2009 as per the attached black lined IT Toll Schedule.

BACKGROUND:

On May 6, 2004 the TTF approved, as an unopposed resolution, the initial FT-RAM pilot (Resolution 02.2004) for a one-year period beginning November 1, 2004. The initial pilot program was adopted as a flexibility feature of long-haul FT contracts only. Long-haul FT contracts are those contracts, which have a primary receipt point originating from Empress or Saskatchewan.

On August 3, 2005 the TTF approved, as an unopposed resolution, an extension of the FT-RAM pilot for an additional one-year term commencing November 1, 2005 and ending October 31, 2006 (Resolution 20.2005).

On February 24, 2006 the NEB approved an application by Coral Energy Canada (now Shell Energy North America (Canada) Inc.) for modifications to the FT-RAM pilot effective April 1, 2006 and ending October 31, 2006, to extend FT-RAM credits to short-haul contracts, which when combined with a long-haul contract create a continuous long-haul contract (Board Order TG-1-2006 in RHW-2-2005 proceeding).

The short-haul and long-haul contracts must be held by the same shipper and must share a common location; i.e. the receipt point of the short-haul contract must be the same as the delivery point of the long-haul contract. For example, a Dawn to EDA short-haul contract when combined with a long-haul contract from Empress or Saskatchewan to SWDA if held by the same shipper, effectively results in a long-haul contract to EDA. In keeping with the intent of the FT-RAM Pilot of encouraging firm long-haul contracts, FT-RAM credits will be granted on the full path or both contracts.

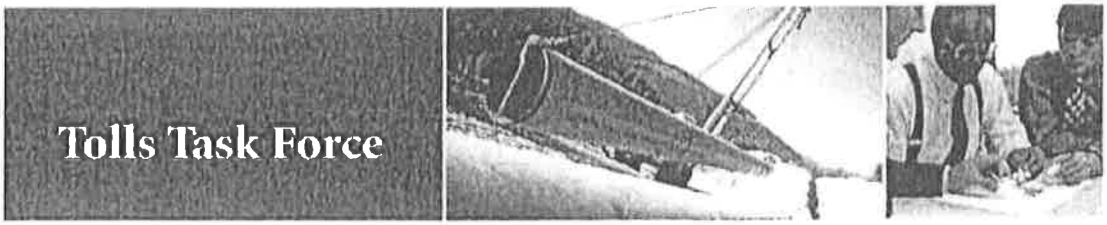
On April 5, 2006 the TTF approved, as an unopposed resolution, an extension of the FT-RAM pilot, as modified by the NEB in the RHW-2-2005 decision, for an additional one-year period commencing November 1, 2006 and ending October 31, 2007 (Resolution 05.2006).

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

Also on February 9, 2007 the TTF approved, as an unopposed resolution, a new RAM pilot for Storage Transportation Service and Storage Transportation Service Linked (STS-RAM and STSL-RAM) for a two-year term commencing November 1, 2007 and ending October 31, 2009 (Resolution 02.2007). On July 4, 2007 the TTF approved, as an unopposed resolution, tariff language for the STS-RAM and STSL-RAM pilot (Resolution 08.2007). STS service was originally designed to work in combination with LDC held long-haul FT service on TransCanada and with market storage. It was designed to allow LDCs to meet seasonal and daily fluctuations in market demand while maintaining their long-haul service at a high load factor. STS shipper must hold long-haul FT. The flow of gas and the capacity rights are virtually identical under STS and STSL. The only difference is that under STS, the long-haul contract is held by the LDC, whereas under STSL, the end-users and marketers hold the long-haul contract.

RAM is a tool to mitigate unabsorbed demand charges and provides greater flexibility in order to give shippers increased confidence in contracting for long-haul FT service on the TransCanada Mainline. The motivation behind RAM is to promote the renewal of and incremental contracting for long-haul FT service. During the various pilot periods, the mechanism has been used by a broad spectrum of shippers including producers, producer/marketers, LDCs and end-users. The mechanism will not limit the service entitlements of current FT service.

VOTING RESULTS:



Unopposed resolution at the January 7, 2009 TTF meeting in Calgary.

TAB 39

1.4 References:

(i) Written Evidence of the MAS, pages 32, line 10-11.

(ii) Written Evidence of the MAS, page 33, lines 20-26 and page 34, lines 1-3.

Preamble: Reference (i) states: "MAS believe that RAM provides a unique tool for Mainline long haul FT shippers to mitigate their risk of unutilized demand charges and differentiates TCPL from other pipelines."

Further, in reference (ii) MAS states: "TCPL reported that $440 million of RAM credits were applied by Mainline shippers in 2010. [reference cited] These applied credits demonstrate the value of RAM to Mainline shippers who make use of the RAM feature. Clearly the value of these RAM credits are material to Mainline shippers who use RAM and far exceeds any potential derived calculation that eliminating RAM *may* increase annual discretionary revenue that would otherwise lower Mainline tolls. TCPL has added only $50 million of discretionary revenue to reflect their recommendation to eliminate RAM, so this appears to be a poor trade-off."

TransCanada requires additional information to better understand how Union extracts value from RAM and the value that Union places on RAM.

Requests:

(a) Please provide a detailed explanation of how Union utilizes the RAM feature in relation to its individual contract profile and gas management strategy.

(b) For the period starting November, 2004, please provide a table showing all assignments of Mainline FT by month for transportation from Union that exceeds 4,000 GJ/D. Please include: assignee, receipt point, delivery point, Toll and volume since November 2004.

(c) For all assignments in (b) above, please provide any costs invoiced either from assignee to Union or from Union to the assignee as a result of the assignments in $/GJ.

(d) For all assignments in (b) above, please provide any other consideration (such as discounted storage, delivered gas, or any other consideration) provided either from assignee to Union or from Union to the assignee as a result of the assignment in $/GJs.

(e) Please provide details on any arrangements Union has entered into with third Parties for purposes of managing Union's transportation contracts and/or transportation requirements on TransCanada for 2012. Please also provide a forecast for any additional arrangements Union plans to enter into for these arrangements.

(f) Based on TransCanada's Mainline Transportation Invoices to Union please provide on a monthly basis, Union's Total Interruptible Transportation charges (before RAM Credits) and the Net Interruptible charges (after RAM Credits) for Mainline service from November 2004 to March 2012.

(g) Please provide the quantities of FT and STS not utilized which account for the RAM dollar figures outlined in (f) above. Please provide the quantities and transportation paths, by month, from November 2004 to March 2012.

(h) For the years 2004 through 2012, please provide a detailed explanation of how the value derived from the assignment of Mainline capacity is credited in whole or in part to Union's rate payers. If any portion of revenue derived through the assignment of Mainline capacity is retained by Union shareholders, please identify the mechanism and dollar amounts.

(i) In each year from 2004 through 2011, what was the total amount received by Union through RAM and what was the share credited to Union's customers.

(j) Please provide a forecast for the period 2012 through 2017 of the total amount expected to be received by Union through RAM and the share of that amount expected to be credited to Union's customers.

(k) Prior to the implementation of RAM, please describe how Union mitigated its unutilized demand charges.

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 the higher value earned as a result of the RAM Program, are returned directly back 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, but at greater costs to the customers.

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 in 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. These arrangements are invoiced as exchange revenue and not "RAM revenue" because Union contracts with customers to provide exchange services and not "RAM services".

The RAM program continues to support the purchase of Empress supply and transportation on TCPL's system. In addition, the RAM program supports liquidity at Empress and a depth of market participants that continues to benefit Union as well as other FT shippers. For example, since 2008, the capacity assignments have been transacted with nearly 20 different shippers, contributing to the activity at Empress and on the TCPL mainline. Additionally, due to the RAM program, Union has been much more active in transacting at more locations on the TCPL system. In 2011, Union transacted transportation and exchange activity on approximately 60 different paths, compared to only 11 paths in 2007.

The impact of Union's use of the RAM program can be seen in Tables 1 and 2. Table 1 reports RAM credits available and used, IT charges, and unutilized capacity data. Table 1 also includes the volume of IT Union has flowed on TCPL since 2007. It is important to note that if the RAM program was discontinued, this same level of IT would not continue to flow on TCPL. Union estimates that Union would likely flow approximately 2 PJs of IT transport annually if the RAM program was eliminated (Table 1, line 7). This means that between 2007 and 2011, approximately 200 PJs of total IT was incremental to TCPL's system as a result of the RAM program.

Table 2 summarizes revenue impacts of the RAM program. "Net Exchange Revenue" includes revenue Union collected from all exchanges, regardless of how the exchange was facilitated; It includes revenue that is unrelated to TCPL or TCPL's RAM program. "Union's Calculated RAM Benefit" is an approximation of the subset of "Net Exchange Revenue" that relates to the use of RAM or TCPL pipe assignments. As noted earlier, Union uses RAM as one of the resources, or in combination with other resources, to generate exchange revenue. Therefore, the benefit of the RAM program is not easily identifiable.

Overall, TCPL, Union and Union's ratepayers have benefitted from the RAM Program. TCPL benefits by offering their FT customers an enhanced value package while still earning the FT revenue. Union and Union's customers benefitted through reduced UDC for system customers and a greater contribution to the exchange revenue over the term of Union's Incentive Rate Mechanism (2008-2012). The elimination of the RAM Program will directly impact Union's ratepayers through increased rates and reduced opportunities.

As indicated in Table 2, as a result of TCPL's proposal to eliminate the RAM Program, Union has not forecast any RAM benefit in 2013 rebasing proceeding. As a result, Union's revenue deficiency and subsequent rate Increase is higher than it would otherwise be.

It has taken Union and other the market participants several few years to gain experience with the RAM program and to fully understand how to realize its full benefit. Likewise, Union developed new processes, procedures, and tools to utilize the program. After such a short tenure, Union does not support the elimination of such a valued program. Instead, Mainline shippers require and value predictability of service, particularly on a pipeline that has suffered such toll volatility.Please refer to attached Table 3 and Table 4. Table 3 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. Table 4 shows TCPL tolls also by month and by zone from November 2007.

Union has not identified assignees as that information is viewed as commercially sensitive.

b) Costs and revenues for third party transactions are included in the "Net Exchange Revenue" and "Net Revenue Attributable to RAM Benefit" reported in Table 2.
c) There was no other consideration provided to assignees as a result of the assignments.

d) Union has not entered into any asset management agreements with its transportation contracts on TCPL.

f)-g) Please refer to Table 1. Union's Total Interruptible Transportation charges (before RAM credits) and Net Interruptible charges (after RAM credits) can be found at lines 4 and 5 respectively. Union has also provided Available RAM Credits and RAM credits Used at lines 1 and 2 respectively. The average total FT and STS capacity unutilized per day underpinning the Available RAM Credits has been provided at line 3.

Please note, data has been provided annually commencing in November, 2007 when Union began to fully use the RAM program. Union has provided the detail necessary to demonstrate how Union's use of the RAM program has grown over time, and the magnitude of its benefit to Union and its ratepayers.

h) Union's current approved rates (2008-2012) include $6.9 million associated with transportation and exchange revenues.

During the term of Union's incentive mechanism, transportation and exchange revenue is one component of Union's regulated earnings and is not subject to any special sharing mechanism beyond that already included in rates.

During the IR term, total regulated earnings in excess of 200 Bps above Union's regulated ROE are shared 50/50 with ratepayers. Any earnings in excess of 300 Bps is shared 90/10 in favour of ratepayers.

On rebasing, Union's forecast transportation and exchange revenue, which would have included any revenue associated with RAM, would have been included in rates to the benefit of Union's ratepayers.

However, as indicated above, Union has not forecast any revenue associated with the RAM program in 2013. This is based on TCPL's Business and Services Restructuring Proposal which includes the elimination of the RAM program.

i) The benefit derived from the program is reflected in Union's Net Exchange revenue, as provided in Table 2. The mechanism by which this revenue was shared with ratepayers is described in h).

j) For 2012, Union has forecasted that the exchange revenue attributable to RAM will be $14.2 million. In their Business and Services Restructuring Proposal, TCPL has proposed the elimination of the RAM program. As a result, Union did not forecast any exchange revenues attributable to RAM past November 1, 2012 for 2013 or beyond. For 2012, the treatment of revenues from all exchanges will be consistent with the revenue treatment outlined in h). The treatment of all exchange revenue in 2013 will be the subject of Union's 2013 rates application.

k) Prior to the implementation of RAM, unutilized capacity due to system supply balancing was released primarily through the use of temporary assignments where possible. The resulting assignment proceeds were passed on to ratepayers to reduce the unutilized demand charges (UDC). Since the implementation of the RAM program, the treatment of unutilized demand has not changed, however it is Union's view that the level of costs recovered has increased with the value of the pipe due to the RAM feature. The benefit of the increased recovery goes directly to Union's ratepayers.

An indication of the incremental value that the RAM program has added to the TCPL FT capacity can be seen in a recent example where Union released a portion of its capacity from Empress to the WDA. Since Empress-WDA is not a traded location, Empress-Emerson is used as a proxy for Empress-WDA value in this example. Normally, one would expect the value of the capacity to simply be the "spread" between the receipt and delivery point. For April, 2012, the average spread for Empress-Emerson capacity was $0.59/GJ, or 76% of tolls. Instead, Union realized a value of 85% of tolls. Union attributes this incremental value to the RAM feature of that capacity.

TABLE 1
RAM Credits & Interruptible Transportation Summary
$Millions*

Line No.		2007	2008	2009	2010	2011	2012 YTD March
1	Available RAM credits	$ 1.1	$ 16.7	$ 14.5	$ 31.8	$ 32.2	$ 9.7
2	RAM credits used	$ 0.7	$ 16.6	$ 14.5	$ 31.7	$ 32.2	$ 9.7
3	Average unutilized capacity (TJ/d)	20.2	68.3	57.2	81.6	61.0	46.5
4	Total IT charges	$ 0.9	$ 18.2	$ 15.9	$ 33.3	$ 35.2	$ 10.1
5	Net IT charges	$ 0.1	$ 1.7	$ 1.4	$ 1.6	$ 3.1	$ 0.9
6	Total IT used (PJ's)	1.9	31.1	47.8	63.4	64.3	18.8
7	Base IT (PJ's)	1.9	1.4	1.3	1.9	1.7	n/a

* Unless otherwise noted

TABLE 2
Net Exchange Revenue & RAM
$Millions

Line No.		2007	2008	2009	2010	2011	2012 Forecast	2013 Forecast
1	Net Exchange Revenue	$ 3.4	$ 11.6	$ 20.5	$ 19.7	$ 31.7	$ 21.1	$ 9.1
2	Net Revenue Attributable to RAM Benefit*	$ 0.4	$ 5.0	$ 14.0	$ 11.7	$ 22.0	$ 14.2	$ -

* Union's approximation of exchange revenue related to the RAM program. This is a subset of Net Exchange Revenue.

Union Response to TCPL 1.4 b)

TABLE 3
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	80,000	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

Union Response to TCPL 1.4 b)

TABLE 4

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	June '12	July '12	Aug '12	Sept '12	Oct '12
13	Empress	Eastern Zone	2.24290	2.24290	2.24290	2.24290	2.24290	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	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	1.13287	1.13287	1.13287	1.13287	1.13287

TAB 40

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 41

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Mr. Shorts

To the extent that Union has FT RAM revenue, please provide capacity assignments or the costs associated with any of the capacity if netted against those revenues?

The capacity assignments included in Attachment 1 of J.C-4-7-10 are all temporary assignments. These assignments include 2 types of transactions – capacity assignments for unabsorbed demand charge (UDC) mitigation and capacity assignments related to FTRAM activities.

In the case where Union has assigned capacity to mitigate UDC, Union does not purchase the supply associated with the pipe capacity, and any revenue earned from the capacity assignment is credited to ratepayers.

In the case where Union has assigned capacity related to FTRAM activities, Union continues to purchase the supply attributable to the assigned capacity and utilizes exchanges or interruptible transportation to deliver the gas supply to Union's franchise (see examples at exhibit JT1-6). There is no change to transportation charges. Any associated revenue from the assignments, less the costs of exchanges or interruptible transportation are reflected in the net revenue from FTRAM. This is included at Exhibit JC-4-7-9, Attachment 2.

Components of Net Exchange Revenue
$Millions

Line No.		2007	2008	2009	2010	2011	2012 Forecast	2013 Forecast
1	Base exchanges	$ 3.0	$ 6.6	$ 6.5	$ 8.0	$ 9.7	$ 6.9	$ 9.1
	RAM Revenue:							
2	Capacity Assignments	0.4	3.1	10.2	10.7	14.4	1.4	-
3	RAM Optimization *	-	0.0	2.8	4.7	9.6	13.7	-
4	Other	-	1.9	1.0	(3.7)	(2.0)	(0.9)	-
5	Subtotal **	$ 0.4	$ 5.0	$ 14.0	$ 11.7	$ 22.0	$ 14.2	-
6	Total Net Exchange Revenue	$ 3.40	$ 11.60	$ 20.50	$ 19.70	$ 31.70	$ 21.1	$ 9.1

* Union's approximation of exchange revenue related to the RAM program. Includes
** Net revenue attributable to RAM benefits.

[Union Gas 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

TAB 42

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 43

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Evers

On a monthly basis, please provide demand cost associated with assigned contracts and proceeds from commercial transactions for this assignment, and show for each month how much went to offset UDC, how much went to reduce cost of transport and how much flowed to S&T revenues.

For the period November, 2009 – March, 2012, there were no capacity assignments of Eastern Zone transportation for purposes of mitigating supply position (UDC). Union purchased all of the planned supply for the Eastern Zone, and the demand charge for the related transportation capacity was charged to ratepayers.

The capacity releases for the Eastern Zone reflected in Exhibit J.C4.7.10 were initiated by S&T. S&T made alternative arrangements to deliver the purchased supply to Union's market and all proceeds from the capacity releases and costs from the alternative arrangements are captured in exchange revenue.

Demand charges and net proceeds by month are in the table below.

		Demand Charge ($/GJ/mo)	$000's Demand Charges	$000's Net Proceeds
Nov-09		$ 33.37571	$ 2,670	$ 749
Dec-09		$ 33.37571	$ 2,670	$ 807
Jan-10		$ 47.77094	$ 3,822	$ 582
Feb-10		$ 47.77094	$ 3,822	$ 452
Mar-10		$ 47.77094	$ 3,822	$ 461
Apr-10		$ 47.77094	$ 4,435	$ 800
May-10		$ 47.77094	$ 4,435	$ 826
Jun-10		$ 47.77094	$ 4,435	$ 804
Jul-10		$ 47.77094	$ 4,435	$ 827
Aug-10		$ 47.77094	$ 4,435	$ 822
Sep-10		$ 47.77094	$ 4,435	$ 806
Oct-10		$ 47.77094	$ 4,435	$ 827
Nov-10		$ 47.77094	$ 2,866	$ 555
Dec-10		$ 47.77094	$ 2,866	$ 377
Jan-11		$ 47.77094	$ 2,866	$ 551
Feb-11		$ 47.77094	$ 2,866	$ 345
Mar-11		$ 47.77094	$ 2,866	$ 428
Apr-11		$ 47.77094	$ 2,866	$ 599
May-11		$ 63.84842	$ 6,180	$ 1,011
Jun-11		$ 63.84842	$ 7,023	$ 1,253
Jul-11		$ 63.84842	$ 7,023	$ 1,295
Aug-11		$ 63.84842	$ 7,023	$ 1,301
Sep-11		$ 63.84842	$ 7,023	$ 1,260
Oct-11		$ 63.84842	$ 7,023	$ 1,290
Nov-11		$ 63.84842	$ 4,776	$ 1,811
Dec-11		$ 63.84842	$ 3,831	$ 1,092
Jan-12		$ 63.84842	$ 3,831	$ 1,171
Feb-12		$ 63.84842	$ 3,831	$ 1,346
Mar-12		$ 63.84842	$ 5,108	$ 2,071

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

AND IN THE MATTER OF an application filed by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2013.

CANADIAN MANUFACTURERS & EXPORTERS ("CME") COMPENDIUM OF DOCUMENTS re: Upstream Transportation Cost Reductions

OTT01\5228536\v1

TAB 44

K7.3

PORTION OF FT-RAM DEMAND CHARGE MITIGATION AMOUNTS NOT CREDITED TO RATEPAYERS – 2007 TO 2012
$Millions

Line No.		(1) 2007	(2) 2008	(3) 2009	(4) 2010	(5) 2011	(6) 2012 Forecast	(7) Totals
1	Net RAM revenue (from line 5, Attachment 2 of Exhibit J.C-4-7-9)	0.4	5.0	14.0	11.7	22.0	14.2	67.3
2	Portion paid to ratepayers through Earnings Sharing (from Exhibit J.E-3-5-1)	0.0	4.5	7.0	3.4	14.5	0.0	29.4
3	Portion paid to shareholder (line 1- line 2)	0.4	0.5	7	8.3	7.5	14.2	37.9
4	IT funded by RAM credits for the benefit of ratepayers – LBA balancing (J3.2)	0.3	0.6	0.1	0.2	0.6	0.3	2.0
5	Released value of pipe to offset UDC (J4.1)(1)(2)	0.0(3)	0.0	1.0	6.2	0.1	2.7	10.0
6	Total value to ratepayer (line 2 + line 4 + line 5)	0.3	5.1	8.5	10.9	15.4	3.1	41.4

(1) This is the total released value obtained for pipe releases as shown in J4.1 adjusted to reflect only TCPL releases as those values were impacted by RAM credits.
(2) While the value directly attributable to the FT RAM program cannot be separated from the total value this has been included to recognize that the FT RAM program has increased the value of assignments of TCPL firm transport.
(3) Set to zero to recognize limited use of RAM credits prior to 2008.

TAB 45

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit A2, Tab 1, page 6

For each year 2007-2012(forecast) please provide the level of overearnings and the allocation of that amount to the ratepayers and the shareholders.

Response:

Excess earnings (pre-tax in $millions)	2007	2008	2009	2010	2011	2012
Shared with customers	-	34.2	7.1	3.4	16.7	-
Retained by Union	26.2	48.1	44.5	40.7	45.8	12.0
Total	26.2	82.3	51.6	44.1	62.5	12.0

TAB 46

UNION GAS LIMITED

Undertaking of Mr. Quinn
To Ms. Evers

Please indicate how much it was funded and what came back as recovery for ratepayers for period November 2009 to March 2012.

All Interruptible Transportation (IT), except the mandatory minimum charge, used to offset Load Balancing Agreement (LBA) fees comes back as recovery for ratepayers since it was funded by RAM credits. For the period January 2007 – March 2012, the amount of IT funded by RAM credits for the benefit of ratepayers was:

	$000's
2007	$320.0
2008	$550.3
2009	$121.4
2010	$224.1
2011	$552.3
2012	$261.6 (1)

(1) Data for YTD March, 2012

TAB 47

UNION GAS LIMITED

Undertaking of Mr. Thompson
To Ms. Evers

For 2007 to 2012, please provide flow through to ratepayers of capacity-release-type transactions, LBA fees transactions, capacity assignment cases not already filed, and other RAM optimization transactions.

---

a) As described at Exhibit J.C.4-7-10, page 2, paragraph 1, where Union releases unutilized pipe to the market due to excess supply to the plan, any value received for the pipe is credited to ratepayers to offset UDC costs. The chart below provides the total UDC costs incurred, the released value of the pipe, and the net UDC costs that were charged to ratepayers.

$000's	2007	2008	2009	2010	2011	2012 (YTD May)
UDC Costs Incurred	$5,202	$12	$3,273	$9,645	$834	$3,814
Released Value	($4,016)	$0	($1,338)	($7,257)	($309)	($2,847)
Net UDC Costs	$1,186	$12	$1,935	$2,387	$525	$967

Releasing the pipe to the market to obtain value is Union's preferred approach. However, as described at Transcript, Day 3, page 10, lines 21-25, in some instances, the pipe may be unutilized for a term that is less than a month or there may not be market value for the pipe.

If the empty pipe is TCPL capacity, when Union leaves the pipe empty, RAM credits are generated and Union's S&T department will act on market opportunities to utilize RAM credits. From 2007 to 2012, there was one month only when RAM credits of $240,000 were generated resulting in revenues of $60,000 which flowed through UDC to ratepayers.

b) As described at Exhibit J.C.4-7-10, page 2, paragraph 2, the benefit to ratepayers for RAM credits used to fund a base minimal level of interruptible transportation to manage LBA fees is provided at Exhibit J.3.2.

c) As described at Exhibit J.C.4-7-10, page 2, paragraphs 3 and 4, S&T revenue generated for optimizing the transportation portfolio by assigning long-haul firm transportation and utilizing the RAM program is provided at Exhibit J.C-4-7-9, Attachment 2.

TAB 48

UNION GAS LIMITED

Undertaking of Mr. Isherwood
To Mr. Thompson

Please provide a forecast for the balance of 2012, assuming FT RAM continues for the balance of the year.

As filed in J6.3, year-to-date June exchange revenue related to RAM is $19.9 million. Union estimates RAM-related activity for the balance of 2012 to be an additional $17.9 million, for an annual total of $37.8 million. This includes $3.6 million of the estimated impact of RAM continuing for November and December as filed in J.C-4-7-9 c).

TAB 49

UNION GAS LIMITED

Undertaking of Mr. Gardiner
To Mr. Aiken

Please produce calculations showing how DOS MN Revenue generation was determined and ratepayers were kept whole in these transactions, and how Dawn reference price was established.

For the winter of 2008-2009, Union used the DOS-MN service to replace planned purchases at Dawn with gas supply purchases at Empress. The reference price at Dawn was established using the market price at which Union would have purchased the gas at Dawn for December, 2008 through to March, 2009. This would have been the Dawn price on the same day the Empress purchase for the same time period was made.

The DOS-MN service was not effective until November 15, 2008. By this time, Union had already completed the planned purchases at Dawn for November supplies.

The DOS-MN service was an example of where Union was able to optimize the overall Gas Supply plan by buying an exchange (in this case, Empress to Dawn).

The following table illustrates how the DOS-MN impact was calculated for December, 2008 through to March, 2009:

	$/GJ	$Millions
Purchase at Dawn	$8.128	$14.2
Purchase at Empress Empress – Dawn Fuel Empress – Dawn Commodity Landed Cost at Dawn	$6.986 $0.260 $0.086 $7.332	 $12.8
Net Benefit	$0.796	$1.40

UNION GAS LIMITED

Undertaking of Mr. Isherwood
To Mr. Thompson

Please provide DOS MN portion of revenue.

DOS-MN revenue included in "Other" is as follows:

2009: $1.1 million

2010: $0.2 million

TAB 50

DESCRIPTION OF EXISTING DEFERRAL ACCOUNTS

GAS COST DEFERRAL ACCOUNTS

TCPL Tolls and Fuel - Northern and Eastern Operations Area (Deferral Account No. 179-100)

This deferral account was established in RP-2003-0063 to record variances in the per unit cost of firm gas purchased each month for the North and the unit cost of gas included in the gas sales rates as approved by the Board. This includes fuel on upstream pipelines, variances in TCPL tolls, the benefit derived from the temporary assignment of TCPL capacity and the costs in excess of amounts recovered from T-Service customers with respect to Union's limited balancing agreement with TCPL.

North Purchase Gas Variance Account (Deferral Account No. 179-105)

This deferral account was established in RP-2003-0063 to record variances in the per unit cost of firm gas purchased each month for the North and the unit cost of gas included in approved gas sales rates.

South Purchase Gas Variance Account (Deferral Account No. 179-106)

This deferral account was established in RP-2003-0063 to record variances in the per-unit cost of gas purchased each month for Union's Southern operations area and the unit cost of gas included in approved gas sales rates.

Spot Gas Variance Account (Deferral Account No. 179-107)

This deferral account was established in RP-2003-0063 to record variances in the per unit cost of spot gas purchased each month and the unit cost of gas included in approved gas sales rates for those volumes purchased in excess of plan.

Unabsorbed Demand Cost ("UDC") Variance Account (Deferral Account No. 179-108)

This deferral account was established in RP-2003-0063 to record the difference between the actual UDC incurred and the amount of UDC included in approved rates.

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

This deferral account was established in RP-2003-0063 to record changes in the value of gas inventory available for sale to sales service customers resulting from changes in Union's weighted average cost of gas as approved by the Board for establishing rates.

STORAGE DEFERRAL ACCOUNTS

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

This deferral account was established to record differences between actual and forecast net revenue from short-term storage and other balancing services. These services include Enbridge LBA, balancing, peak short-term storage, off-peak short-term storage, and loans. As per the Board's EB-2005-0551 Decision 71.1% of the balance in this account is

TAB 51

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 52

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers and Exporters ("CME")

Unabsorbed Demand Cost Account No. 179-108

Reference: Exhibit A, Tab 1, pages 2 to 4

Please provide the following information with respect to the calculation of the Unabsorbed Demand Cost ("UDC") Variance Account credit balance of $4.615M:

a) Is the UDC amount recovered in rates the product of a particular volume of demand per day and a cost per unit of demand per day? If so, then please provide the cost per unit of demand per day associated with the UDC volume of 4.4 PJs in the Northern and Eastern Operations area and 0.2 PJs in the South Operations area that produces costs collected in rates of $6.853M and $0.128M respectively for a total of $6.981M shown in Table 1 of Exhibit A, Tab 1 at page 3.

b) Please explain how 13.207 PJs of actual UDC in the Northern and Eastern Operations area and 1.391 PJs in the Southern Operations area produces UDC costs incurred of $2.160M and $0.227M respectively for each operations area, for a total of $2.387M when the lower volumes of demand being collected in rates produce substantially higher cost recovery amounts in each operations area.

Response:

a) Please see the response at Exhibit B1.1.

The amount also includes an adjustment to correct the UDC deferral account. For the period April 1, 2007 to Dec 31, 2009, the UDC deferral calculation did not account for the changes in TCPL tolls that were included in Union's approved rates during the same period. In the deferral model, Union understated the amount of UDC recovered in approved rates by $1.931 million. As noted above, an adjustment has been made to the 2010 UDC deferral calculation to credit ratepayers an additional $1.931 million.

Please see the Attachment that shows the calculation of the UDC amount recovered in rates in 2010.

b) Unfilled capacity was sold on the secondary market to minimize UDC. Revenues generated from the transportation releases were credited to the UDC deferral account mitigating the UDC that was forecasted in rates.

UNION GAS LIMITED
Calculation of 2010 UDC Collected in Rates

Line No.	Particulars	Actual UDC Unit Rate ($/$10^3m^3$) (a)	Actual Throughput Volumes (10^3m^3) (b)	UDC Collected in Rates ($000's) (c) = (a x b)	Original Deferral Calculation of North UDC Collected in rates: 2007 Board Approved UDC Unit Rate ($/$10^3m^3$) (d)	Original Deferral Calculation of North UDC Collected in rates: Actual Throughput Volumes (10^3m^3) (e) = (b)	Original Deferral Calculation of North UDC Collected in rates: UDC using 2007 Board Approved Rates ($000's) (f) = (d x e)	Variance in UDC from Prior Periods ($000's) (g) = (c - f)	Total 2010 UDC ($000's) (h)
	Jan 1, 2010 - Dec 31, 2010								
1	R01	4.4574	837,802	3,734					
2	R10	3.4066	316,303	1,078					
3	R20	0.9061	122,491	111					
4	Total North			4,922					
5	M1/M2	0.0515	2,467,963	127					
6	M4	0.0515	14,865	1					
7	M10	0.0515	35	0					
8	Total South			128					
	Apr 1, 2009 - Dec 31, 2009								
9	R01	3.1453	471,664	1,484	2.5325	471,664	1,194	289	
10	R10	2.4038	199,792	480	1.9355	199,792	387	94	
11	R20	0.6406	90,563	58	0.5159	90,563	47	11	
12	Total North			2,022			1,628	394	
	Jul 1, 2008 - Mar 31, 2009								
13	R01	3.6775	806,995	2,968	2.5325	806,995	2,044	924	
14	R10	2.8105	301,566	848	1.9355	301,566	584	264	
15	R20	0.7492	109,221	82	0.5159	109,221	56	26	
16	Total North			3,897			2,684	1,213	
	Apr 1, 2008 - Jun 30, 2008								
17	R01	2.9085	136,819	398	2.5325	136,819	346	51	
18	R10	2.2229	62,605	139	1.9355	62,605	121	18	
19	R20	0.5925	39,833	24	0.5159	39,833	21	3	
20	Total North			561			488	73	
	Jul 1, 2007 - Mar 30, 2008								
21	R01	2.7564	771,668	2,127	2.5325	771,668	1,954	173	
22	R10	2.1068	288,736	608	1.9355	288,736	559	49	
23	R20	0.5616	124,805	70	0.5159	124,805	64	6	
24	Total North			2,805			2,577	228	
	Apr 1, 2007 - Jun 30, 2007								
25	R01	2.6564	132,988	353	2.5325	132,988	337	16	
26	R10	2.0302	64,009	130	1.9355	64,009	124	6	
27	R20	0.5412	37,556	20	0.5159	37,556	19	1	
28	Total North			504			480	23	
29	Subtotal - UDC Recovery Adjustment							1,931	
30	Total North 2010 UDC Collected in Rates (Column c, line 4 plus Column g lines 12+16+20+24+28)								6,853
31	Total South 2010 UDC Collected in Rates (Column c, line 8)								128
32	Total 2010 UDC Collected in Rates (line 29 + line 30)								6,981

TAB 53

in relation to the settlement of those rates, the NGEIR decision was rendered? Was it before or after?

MR. TETREAULT: I can't recall myself, Peter. It's before my time in my current capacity.

MR. THOMPSON: That's fine. We will find that out. So what I would like to do is just touch on a few of these interrogatory responses and get some clarification of what's taken place here.

If you could start with CME 1, so this is Exhibit B2.1. In subparagraph (a), you are talking about an adjustment to correct miscalculations in the UDC deferral account; have I got that straight?

MR. TETREAULT: That's correct.

MR. THOMPSON: And it talks about the period April 1, 2007 to December 31, 2009. So can I take it that the error dated back to April 1, 2007?

MR. TETREAULT: Yes.

MR. THOMPSON: All right. And the approach that you took was to correct the error from the date it was first made?

MR. TETREAULT: That's correct.

MR. THOMPSON: So it was made in -- at this point in time, for -- am I right -- for fiscal 2007, fiscal 2008 and fiscal 2009? The 1.931 million is a cumulative correction for that time frame?

MR. TETREAULT: That's correct.

MR. THOMPSON: So that, then, takes me to your B3.53 and some of your responses to Mr. Quinn's written questions

TAB 54

MISCELLANEOUS PROVISIONS

Application of certain provisions

58.38 (1) Sections 76 to 78 and 114 apply in respect of international power lines and of interprovincial power lines in respect of which an order made under section 58.4 is in force as they apply in respect of pipelines.

Application of references

(2) The provisions of this Act referred to in subsection (1) apply in respect of an international power line as if each reference in those provisions to

(*a*) a "company" were a reference to the holder of the permit or certificate issued in respect of the line; and

(*b*) a "pipeline" were a reference to the international or interprovincial power line.

1990, c. 7, s. 23.

Regulations

58.39 The Governor in Council may make regulations for carrying into effect the purposes and provisions of this Part, including regulations

(*a*) prescribing matters in respect of which terms and conditions of permits may be imposed;

(*b*) respecting the information to be furnished in connection with applications for permits;

(*c*) specifying considerations to which the Board shall have regard in deciding whether to recommend to the Minister that an international power line be designated by order of the Governor in Council under section 58.15; and

(*d*) prescribing the form of elections filed under section 58.23.

1990, c. 7, s. 23.

INTERPROVINCIAL POWER LINES

Where certificate required

58.4 (1) The Governor in Council may make orders

(*a*) designating an interprovincial power line as an interprovincial power line that is to be constructed and operated under and in accordance with a certificate issued under section 58.16; or

(*b*) specifying considerations to which the Board shall have regard in deciding whether to issue such a certificate.

Prohibition

(2) No person shall construct or operate any section or part of an interprovincial power line in respect of which an order made under subsection (1) is in force except under and in accordance with a certificate issued under section 58.16.

1990, c. 7, s. 23.

PART IV

TRAFFIC, TOLLS AND TARIFFS

INTERPRETATION

Definition of "tariff"

58.5 In this Part, "tariff" means a schedule of tolls, terms and conditions, classifications, practices or rules and regulations applicable to the provision of a service by a company and includes rules respecting the calculation of tolls.

1990, c. 7, s. 24.

POWERS OF BOARD

Regulation of traffic, etc.

59. The Board may make orders with respect to all matters relating to traffic, tolls or tariffs.

R.S., c. N-6, s. 50.

FILING OF TARIFF

Tolls to be filed

60. (1) A company shall not charge any tolls except tolls that are

(*a*) specified in a tariff that has been filed with the Board and is in effect; or

(*b*) approved by an order of the Board.

Compliance

(2) Where gas or a commodity other than oil transmitted by a company through its pipeline is the property of the company, the company shall file with the Board, on the making thereof, true copies of all the contracts it may make for the sale of the gas or commodity and of any amendments from time to time made thereto, and the true copies so filed are deemed, for the purposes of this Part, to constitute a tariff pursuant to subsection (1).

R.S., 1985, c. N-7, s. 60; 1996, c. 10, s. 241.

Commencement of tariff

61. Where a company files a tariff with the Board and the company proposes to charge a toll referred to in paragraph (*b*) of the definition "toll" in section 2, the Board may establish the day on which the tariff is to come into effect and the company shall not commence to charge the toll before that day.

1977-78, c. 20, s. 41.

JUST AND REASONABLE TOLLS

Tolls to be just and reasonable

62. All tolls shall be just and reasonable, and shall always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate.

R.S., c. N-6, s. 52.

Board determinations

63. The Board may determine, as questions of fact, whether or not traffic is or has been carried under substantially similar circumstances and conditions referred to in section 62, whether in any case a company has or has not complied with the provisions of that section, and whether there has, in any case, been unjust discrimination within the meaning of section 67.

1980-81-82-83, c. 116, s. 17.

Interim tolls

64. Where the Board has made an interim order authorizing a company to charge tolls until a specified time or the happening of a specified event, the Board may, in any subsequent order, direct the company (*a*) to refund, in a manner satisfactory to the Board, such part of the tolls charged by the company under the interim order as is in excess of the tolls determined by the Board to be just and reasonable, together with interest on the amount so refunded; or

(*b*) to recover in its tolls, in a manner satisfactory to the Board, the amount by which the tolls determined by the Board to be just and reasonable exceed the tolls charged by the company under the interim order, together with interest on the amount so recovered.

1980-81-82-83, c. 116, s. 17.

Disallowance of Tariff

Disallowance of tariff

65. The Board may disallow any tariff or any portion thereof that it considers to be contrary to any of the provisions of this Act or to any order of the Board, and may require a company, within a prescribed time, to substitute a tariff satisfactory to the Board in lieu thereof, or may prescribe other tariffs in lieu of the tariff or portion thereof so disallowed.

R.S., c. N-6, s. 53.

Suspension of tariff

66. The Board may suspend any tariff or any portion thereof before or after the tariff goes into effect.

R.S., c. N-6, s. 54.

Discrimination

No unjust discrimination

67. A company shall not make any unjust discrimination in tolls, service or facilities against any person or locality.

R.S., c. N-6, s. 55.

Burden of proof

68. Where it is shown that a company makes any discrimination in tolls, service or facilities against any person or locality, the burden of proving that the discrimination is not unjust lies on the company.

R.S., c. N-6, s. 56.

No rebates, etc.

69. (1) A company or shipper or an officer or an employee, or an agent or a mandatary, of the company or shipper who

(*a*) offers, grants, gives, solicits, accepts or receives a rebate, concession or discrimination, or

(*b*) knowingly is party or privy to a false billing, false classification, false report or other device,

whereby a person obtains transmission of hydrocarbons or any other commodity by a company at a rate less than that named in the tariffs then in force, is guilty of an offence punishable on summary conviction.

Prosecution

(2) No prosecution shall be instituted for an offence under this section without leave of the Board.

R.S., 1985, c. N-7, s. 69; 1996, c. 10, s. 242; 2004, c. 25, s. 153(E).

Contracts Limiting Liabilities

Contracts limiting liability of company

70. (1) Except as provided in this section, no contract, condition or notice made or given by a company impairing, restricting or limiting its liability in respect of the transmission of hydrocarbons or any other commodity relieves the company from its liability, unless that class of contract, condition or notice is included as a term or condition of its tariffs as filed or has been first authorized or approved by order or regulation of the Board.

Board may determine limits

(2) The Board may determine the extent to which the liability of a company may be impaired, restricted or limited as provided in this section.

Terms and conditions

(3) The Board may prescribe the terms and conditions under which hydrocarbons or any other commodity may be transmitted by a company.

R.S., 1985, c. N-7, s. 70; 1996, c. 10, s. 243.

Transmission, etc., of Oil or Gas

Duty of pipeline company

71. (1) Subject to such exemptions, conditions or regulations as the Board may prescribe, a company operating a pipeline for the transmission of oil shall, according to its powers, without delay and with due care and diligence, receive, transport and deliver all oil offered for transmission by means of its pipeline.

Orders for transmission of commodities

(2) The Board may, by order, on such terms and conditions as it may specify in the order, require the following companies to receive, transport and deliver, according to their powers, a commodity offered for transmission by means of a pipeline:

(*a*) a company operating a pipeline for the transmission of gas; and

(*b*) a company that has been issued a certificate under Part III authorizing the transmission of a commodity other than oil.

Extension of facilities

(3) The Board may, if it considers it necessary or desirable to do so in the public interest, require a company operating a pipeline for the transmission of hydrocarbons, or for the transmission of any other commodity authorized by a certificate issued under Part III, to provide adequate and suitable facilities for

(*a*) the receiving, transmission and delivering of the hydrocarbons or other commodity offered for transmission by means of its pipeline,

(*b*) the storage of the hydrocarbons or other commodity, and

(*c*) the junction of its pipeline with other facilities for the transmission of the hydrocarbons or other commodity,

if the Board finds that no undue burden will be placed on the company by requiring the company to do so.

R.S., 1985, c. N-7, s. 71; 1996, c. 10, s. 243.1; 2012, c. 19, s. 89.

Transmission and Sale of Gas

Extension of services of gas pipeline companies

72. (1) Where the Board finds such action necessary or desirable in the public interest, it may direct a company operating a pipeline for the transmission of gas to extend or improve its transmission facilities to provide facilities for the junction of its pipeline with any facilities of, and sell gas to, any person or municipality engaged or legally authorized to engage in the local distribution of gas to the public, and for those purposes to construct branch lines to communities immediately adjacent to its pipeline, if the Board finds that no undue burden will be placed on the company thereby.

Limitation on extension

(2) Subsection (1) does not empower the Board to compel a company to sell gas to additional customers if to do so would impair its ability to render adequate service to its existing customers.

Deemed toll for transmission

(3) Where the gas transmitted by a company through its pipeline is the property of the company, the differential between the cost to the company of the gas at the point where it enters its pipeline and the amount for which the gas is sold by the company shall, for the purposes of this Part, be deemed to be a toll charged by the company to the purchaser for the transmission of that gas.

R.S., c. N-6, ss. 60, 61.

PART V

POWERS OF PIPELINE COMPANIES

General Powers

Powers of company

73. A company may, for the purposes of its undertaking, subject to this Act and to any Special Act applicable to it,

(*a*) enter into and on any Crown land without previous licence therefor, or into or on the land of any person, lying in the intended route of its pipeline, and make surveys, examinations or other necessary arrangements on the land for fixing the site of the pipeline, and set out and ascertain such parts of the land as are necessary and proper for the pipeline;

(*b*) purchase, take and hold of and from any person any land or other property necessary for the construction, maintenance and operation of its pipeline and sell or otherwise dispose of any of its land or property that for any reason has become unnecessary for the purpose of the pipeline;

(*c*) construct, lay, carry or place its pipeline across, on or under the land of any person on the located line of the pipeline;

(*d*) join its pipeline with the transmission facilities of any other person at any point on its route;

(*e*) construct, erect and maintain all necessary and convenient roads, buildings, houses, stations, depots, wharves, docks and other structures, and construct, purchase and acquire machinery and other apparatus necessary for the construction, maintenance and operation of its pipeline;

(*f*) construct, maintain and operate branch lines, and for that purpose exercise all the powers, privileges and authority necessary therefor, in as full and ample a manner as for a pipeline;

(*g*) alter, repair or discontinue the works mentioned in this section, or any of them, and substitute others in their stead;

(*h*) transmit hydrocarbons by pipeline and regulate the time and manner in which hydrocarbons shall be transmitted, and the tolls to be charged therefor; and