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 EX-FRANCHISE REVENUE WITNESS PANEL

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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

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

EB-2005-0520

UNION GAS LIMITED

SETTLEMENT AGREEMENT

May 15, 2006

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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.

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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.

INCENTIVE REGULATION

EXHIBIT LIST

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

Union Gas Limited
Incentive Regulation Proposal
Prefiled Evidence

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

5.0 PROPOSAL PARAMETERS

5.1 BASE RATES

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

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

Items from Previous Board Decisions

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

1. As approved by the Board in the EB-2005-0520 Decision with Reasons dated June 29, 2006 Union will be splitting the M2 rate class into two rate classes (M1 and M2) (see Appendix B for the excerpt from Union's evidence and the Board Decision). The effect of this split will be included in the January 1, 2008 rate order.

2. Union requested pre-approval to change rates effective January 1, 2008 to incorporate incremental capital and O&M costs required to implement the Bill-Ready phase of the GDAR. There was complete settlement of this issue in the Settlement Agreement (see Appendix C for the excerpts from Union's evidence and the Settlement Agreement). As such, Union will adjust 2008 base rates accordingly effective January 1, 2008 and include this adjustment in the 2008 rate order. Should there be any changes to the timing of the implementation of the Bill-Ready phase; Union will address the impact on base rates once a decision is made by the Board.

3. In the EB-2005-0520 and EB-2005-0551 proceedings, Union requested that five S&T deferral accounts (179-70, 179-72, 179-69, 179-73 and 174-74) be eliminated. In EB-2005-0520, Exhibit C1, Tab 3, Union stated that it agreed with the Board's direction that, "in a true IR framework, there should be no earnings sharing, and transactional services revenues should not receive special treatment" (page 24). Union further stated that it, "believes that the elimination of S&T transactional service deferral accounts in 2007 is consistent with and supports the Board's direction to reduce deferral accounts and eliminate earnings sharing mechanisms as part of transitioning

to an IR framework." The Board specified on page 112 of the EB-2005-0551 Decision with Reasons that the proposed elimination of the three transmission-related accounts should be considered as part of a comprehensive review that includes all deferral accounts under an incentive regulation mechanism. Therefore, Union is requesting the elimination of the following three deferral accounts (Transportation Exchange Services Account (179-69), Other S&T Services Account (179-73) and Other Direct Purchase Services Account (174-74)) beginning January 1, 2008. Board staff supported the elimination of the three deferral accounts in the Board Staff paper (page 22). The Long-Term Peak Storage Services Account (179-72) is discussed in Section 5.8.3 below.

4. DSM is discussed in Section 5.8.2

Weather Normalization Method

Union proposes that the 20-year declining trend weather forecasting method be fully implemented effective January 1, 2008 as an adjustment to base rates. This would result in an estimated impact to rates of approximately $7 million.

This adjustment would produce greater symmetry in weather risk (i.e. colder weather being as likely to occur as warmer weather.) Using the current 55% 30-year average and 45% 20-year declining trend blended method ("55/45 blend") represents a substantial risk to the company. The use of the 30-year average has a bias toward exceeding the actual number of heating degree days ("HDDs"). Forecasting the HDDs through use of the

Table 3
Union's Proposed PCIs by Service Group

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

5.8 Y FACTOR

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

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

5.8.1 Cost of Gas and Upstream Transportation

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

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

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

5.8.2 DSM

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

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

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

5.8.4 Other Deferral Accounts

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

5.9 Z FACTOR

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

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.

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

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

EB-2008-0220

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

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

ARGUMENT OF CANADIAN MANUFACTURERS & EXPORTERS ("CME")

December 31, 2008

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

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

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D. Y Factor Adjustments

(a) Upstream Transportation Costs

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

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

(b) Storage Margin Sharing Changes

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

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

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.

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

International Financial Reporting Standards

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

Table 1: IFRS Conversion Costs

(in millions)	2008	2009	2010	2011	2012
Capital Investment	$ .592	$ 1.334	$ .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

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.