unionGas

July 23, 2014

Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, Ontario
M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

RE: EB-2014-0145– Union Gas Limited
2013 Disposition of Deferral Account Balances – Revised Evidence

Dear Ms. Walli,

Further to Union's Application and pre-filed evidence that were filed on May 2, 2014, and as noted in Union's responses to interrogatories, Union identified several required revisions to the evidence. These changes are summarized in the attached table and have been incorporated in the overall evidence package which will be re-filed in RESS. Revisions are noted as "corrected" in the header, and are black lined. Recent interrogatory responses were provided based on these updates and several responses refer to these updates.

If you have any questions with respect to this submission please contact me at (519) 436-5473.

Yours truly,

[original signed by]

Karen Hockin
Manager, Regulatory Initiatives

cc: Crawford Smith, Torys
Myriam Seers, Torys
Mark Kitchen, Union
All Intervenors

P. O. Box 2001, 50 Keil Drive North, Chatham, ON, N7M 5M1 www.uniongas.com
Union Gas Limited

EB-2014-0145 Evidence Updates – July 23, 2014

Evidence Reference	Original Evidence	Corrected Evidence	Date of Corrections
Tab 1 Pages 5-7	Summer price of $4.290/GJ, resulting in summer-winter differential of $2.830/GJ.	Summer price is corrected to $4.676/GJ, resulting in a summer-winter differential of $2.444/GJ. This correction has no impact on the spot gas variance account balance of $1.801 million. The impact of this correction is a reduction in the load balancing costs to be recovered from Union South bundled DP customers from $2.264 million to $1.954 million. This results in a change to the refund of the remaining balance, a credit of $0.153 million to Union South sales service customers. (see Exhibit B.Staff.1b)	July 23, 2014
Tab 2 Page 1	Normalized Utility Results were presented on an after-tax basis, resulting in a normalized revenue sufficiency of $19.3 million.	Union's normalized revenue sufficiency from 2013 utility operations on a pre-tax basis is $14.7 million relative to Board-approved, resulting in a normalized return on equity ("ROE") of 9.73% (unchanged) (see Exhibit B.CME.5).	July 23, 2014
Tab 3 Pages 1-2, 8	Page 8 shows general service bill impacts. For a sales service residential customer in Union South, the charge is $0.44.	General service bill impacts changed as a result of the correction to the summer price as noted in Tab 1. For a sales service residential customer in Union South with annual consumption of 2,200m^3, the charge for the period from October 1, 2014 to March 31, 2015 is $0.64	July 23, 2014
Tab 3 Schedules 1-3		Schedules were impacted by the correction to the summer price as noted in Tab 1.	July 23, 2014
Tab 4 Appendix C, Appendix D (Appendix D to Union's Gas Supply Plan Memorandum)	Appendix D, Line 8, Kirkwall to Niagara Falls Appendix D, column f, Unitized Demand Charge incorrect for lines 2-8 ($1.606/GJ).	Niagara Falls to Kirkwall receipt and delivery points have been updated (Appendix D, Line 8) (see Exhibit B.FRPO_OGVG.28). Unitized demand charge (column f) corrected for lines 2-8. Line 2-7 - $1.541/GJ Line 8 - $0.142/GJ	July 23, 2014

May 2, 2014

Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON
M4P 1E4

Dear Ms. Walli:

Re: EB-2014-0145 - Union Gas Limited - 2013 Disposition of Deferral Account Balances

Enclosed is the application and evidence submitted by Union Gas Limited ("Union") concerning the final disposition and recovery of certain 2013 year-end deferral account balances and a request for approval of a new Deferral Clearing Variance Account (Account No. 179-132). Union is not proposing to dispose of DSM related deferral account balances in this proceeding. Union will prepare additional evidence in support of the DSM related account balances and plans to file that evidence in a separate proceeding in Q3, 2014.

The Application is supported by evidence which is outlined below:

EXHIBIT A

Tab 1	2013 Year-End Deferral Account Balances
Tab 2	2013 Utility Results and Return on Equity
Tab 3	Allocation and Disposition of 2013 Deferral Account Balances
Tab 4	Incremental Transportation Contracting Analysis, Vertical Slice Program and Annual Stakeholder Meeting

Union proposes that the impacts which result from the disposition of 2013 deferral account balances be implemented on October 1, 2014 to align with other rate changes implemented through the Quarterly Rate Adjustment Mechanism.

If you have any questions concerning this application and evidence please contact me at (519) 436-5473.

Yours truly,

[*Original Signed by*]

Karen Hockin
Manager, Regulatory Initiatives

cc Crawford Smith (Torys)
EB-2013-0109 Intervenors

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 clearing certain non-commodity related deferral accounts;

APPLICATION

1. Union Gas Limited ("Union") is a business corporation, incorporated under the laws of Ontario, with its head office in the Municipality of Chatham-Kent.

2. Union conducts an integrated natural gas utility business that combines the operations of selling, distributing, transmitting and storing gas within the meaning of the *Ontario Energy Board Act, 1998* (the "Act").

3. In EB-2011-0210, Union applied to the Ontario Energy Board (the "OEB") for an order approving or fixing just and reasonable rates and other charges for the sale, distribution, storage and transmission of gas by Union effective January 1, 2013. The Board approved Union's request. In doing so, the OEB approved the continuation of certain deferral accounts.

4. Union applies for the:

   a) approval of final balances for all 2013 deferral accounts as listed in Exhibit A, Tab 1, Appendix A, Schedule 1 (with the exception of DSM related deferral accounts noted in evidence) and an order for final disposition of those balances; and,

   b) approval of a new Deferral Clearing Variance Account No. 179-132 effective October 1, 2014.

5. Union also applies to the OEB for such interim order or orders approving interim rates or other charges and accounting orders as may from time to time appear appropriate or necessary.

6. Union further applies to the Board for all necessary orders and directions concerning pre-hearing and hearing procedures for the determination of this application.

7. This application is supported by written evidence. This evidence may be amended from time to time as required by the OEB, or as circumstances may require.

8. The persons affected by this application are the customers resident or located in the municipalities, police villages and First Nations reserves served by Union, together with those to whom Union sells gas, or on whose behalf Union distributes, transmits or stores gas. It is impractical to set out in this application the names and addresses of such persons because they are too numerous.

9. The address of service for Union is:

Union Gas Limited
P.O. Box 2001
50 Keil Drive North
Chatham, Ontario
N7M 5M1
Attention: Karen Hockin
Manager, Regulatory Initiatives

Telephone: (519) 436-5473

Fax: (519) 436-4641

- and -

Torys LLP
Suite 3000, Maritime Life Tower

P.O. Box 270
Toronto-Dominion Centre
Toronto, Ontario
M5K 1N2
Attention: Crawford Smith

Telephone: (416) 865-8209

Fax: (416) 865-7380

DATED: May 2, 2014

UNION GAS LIMITED

[Original signed by]

Karen Hockin
Manager, Regulatory Initiatives

Tab 1

2013 DEFERRAL ACCOUNT BALANCES AND TAX CHANGES

2013 Year-End Deferral Account Balances

Union has classified the deferral accounts approved by the Board for use in 2013 into four groups:

a) Gas Supply accounts;
b) Storage accounts;
c) DSM accounts and
d) Other accounts.

The net balance in the above deferral accounts together with the Federal and Provincial Tax Changes result in a $21.922 million credit to ratepayers. This total includes balances as at December 31, 2013 plus winter 2013/2014 spot gas price variances related to Union South bundled direct purchase ("DP") load balancing, as referenced in Union's April 1, Quarterly Rate Adjustment Mechanism ("QRAM") (EB-2014-0050). Interest has been calculated on account balances according to the Board-approved accounting orders. The applicable short-term interest rate used was 1.47% for the months of January through December as prescribed by the Board in EB-2006-0117.

Exhibit A, Tab 1, Appendix A, Schedule 1 provides a summary of the deferral account balances and tax changes.

GAS SUPPLY DEFERRAL ACCOUNTS

Account No. 179-107 Spot Gas Variance Account

Union is seeking recovery of $1.801 million in the spot gas variance account in this proceeding due to the need to purchase spot gas for Union South bundled direct purchase customers for forecast weather variances relative to the February 28, 2014 inventory checkpoint and forecast March weather and other consumption variances.

Spot gas purchases were also made to manage unaccounted for gas ("UFG") variances for the 2013/2014 winter. Union will seek approval to recover the $4.729 million UFG price related variance in a future QRAM proceeding after the Board's decision in this proceeding.

Background

In Union's April 1, 2014 QRAM (EB-2014-0050), Union indicated that a total of 29.8 PJ of incremental spot gas was purchased at Dawn for the winter period, November 1, 2013 to March 31, 2014. Of the 29.8 PJ of spot gas purchased, Union requested recovery of deferral account balances related to 25.9 PJ of the spot purchases from Union South sales service customers and Union North sales service and bundled DP customers. The difference between the total spot purchase of 29.8 PJ and the spot purchases of 25.9 PJ included in the April 1, 2014 QRAM filing was attributable to three items. The first was Union North Rate 25 consumption variances (0.6 PJ), which Union is not seeking recovery of, the second was Union South bundled DP forecast weather variances relative to the February 28, 2014 inventory checkpoint and forecast March weather and other consumption variances (1.8 PJ) and the third was forecast UFG variances (1.5 PJ).

The Board approved Union's QRAM application, as filed, for recovery of the cost consequences associated with 25.9 PJ of spot purchases. In its EB-2014-0050 Decision, the Board stated:

> *"The Board has examined the record in this application, including the answers to interrogatories, and finds nothing in the record to trigger a more extensive review of the prudence of the actions taken by Union to purchase gas for its customers. Union began to purchase incremental gas supply for its customers early in the winter in response to known and expected future demand variances caused by the colder than normal weather. The Board notes that Union was able to avoid buying gas during the highest price periods due to its frequent monitoring of commodity prices and adoption of a layering approach to its spot gas purchases. The Board also notes that Union proactively purchased the gas necessary to meet its customers' requirements in the forward market, to the extent possible, as opposed to the more expensive intra-month cash market."*

Union deferred the review and recovery of spot gas purchase costs related to Union South bundled DP load balancing and UFG variances to this proceeding because the recovery of these spot gas purchase costs may have required a change to delivery rates not contemplated in the QRAM process.

Spot Purchases on behalf of Union South Bundled Direct Purchase Customers

Union South bundled DP customers have a contractual obligation to meet their defined checkpoint balances at September 30 and February 28, as well as to balance annually at contract renewal. Specifically, the February 28 checkpoint ensures that Union South bundled DP customers do not have a Banked Gas Account ("BGA") balance at the end of February that is less than their contractual checkpoint. It is critical that bundled DP customers meet their contractual checkpoint obligation as their volumes are a significant portion of Union's in-franchise demands and the February 28 checkpoint helps to ensure Union can meet its winter design day requirements.

Notwithstanding Union South bundled DP customers' contractual obligation to meet defined checkpoint balances at February 28, Union retains load balancing obligations for weather variances relative to the February 28 checkpoint (for variances after the establishment of the checkpoint) and March weather and consumption variances. Union's load balancing obligation is required to ensure there is sufficient gas in storage at March 31 to maintain system integrity.

In other words, Union's load balancing obligations, which may require spot gas purchases, remain despite the contractual obligations of Union South bundled DP customers to meet defined checkpoint balances at February 28. As described below, Union was required to purchase 0.8 PJ of spot gas for Union South bundled DP customers to meet its load balancing obligations.

At the time of the April 1, 2014 QRAM filing Union was forecasting spot purchases for

Union South bundled direct purchase load balancing of 1.8 PJ.[1] The spot gas actually purchased for Union South bundled direct purchase customers was 0.8 PJ. The difference between forecast spot purchases and actual spot purchases is attributable to actual activity to the end of March 2014. As described above, the balance in the spot gas variance account for spot gas purchased for Union South bundled DP customers is a debit of $1.801 million. This balance is related to the price variance between actual purchase costs and Union's Ontario Landed Reference Price (i.e. Weighted Average Cost of Gas ("WACOG")). The calculation of the spot gas deferral amounts attributable to Union South bundled DP customers is provided in Table 1 Corrected.

Table 1 – Corrected
Union South Bundled DP Spot Gas Costs

Line No.	**Spot Gas Purchase - 0.8 PJ**	**Average unit price ($/GJ)** **(a)**	**Total Impact ($ million)** **(b)= (a) x 0.8 PJ**
1	Weighted Average Price of Spot purchase	$ 7.120	$ 5.696
2	Ontario Landed Reference Price	$ 4.868	$ 3.895
3	Union South Spot Gas Impact	$ 2.252	$ 1.801
4	Forecast Summer Cost	$ 4.676	
5	Weighted Average Summer-Winter Differential (load balancing costs) (line 1 less line 4)	$ 2.444	$ 1.954
6	Spot Costs (Credit) (line 4 less line 2)	$ (0.192)	$ (0.153)

[1] EB-2014-0050, Tab 1, p.13.

Union South load balancing costs included in the Spot Gas Variance Account reflect spot gas purchases for Union South that would have otherwise been purchased in the following summer, but were required to maintain system integrity and deliverability for Union South customers. The incremental gas purchased by Union and consumed by bundled DP customers in February and March will be returned to Union by DP customers in the summer, prior to their contractual year end. In this circumstance, Union reduces planned summer purchases it would normally have made on behalf of the sales service customers, in order to accept the incremental summer DP deliveries.

Consistent with past practices, load balancing costs are calculated by applying the winter/summer price differential (current winter price versus next summer price) to the incremental volumes purchased. This is consistent with the calculations in Union's May 1, 2003 QRAM (EB-2003-0056) and Union's April 2009 QRAM (EB-2009-0054). The difference between the spot price paid and the forecast summer price (winter/summer differential) is based on the forecast summer price at the time each spot gas purchase was made. The average winter/summer differential for all of the spot gas purchased was $2.444/GJ.

Of the $1.801 million, Union is proposing to recover $1.954 million (calculated as the winter/summer differential of $2.444/GJ multiplied by 0.8 PJ) from Union South bundled DP customers for load balancing costs as part of this proceeding. Union is proposing to recover this $1.954 million from Union South DP customers who were below the planned BGA balance and drove the need for incremental spot purchases based on Union South DP customer's March 31, 2014 DP Status Report . The DP Status report is prepared each month and sent to every Union South Bundled DP contract holder to communicate their current and forecasted direct purchase delivery and consumption activity.

Union is also proposing to refund the remaining balance, a credit of $0.153 million, to Union South sales service customers. The credit attributable to Union South sales service customers is the result of the incremental cost of spot gas of $1.801 million (above the Ontario Landed Reference Price) less $1.954 million to be recovered as load balancing costs from Union South bundled DP customers. The calculation of load balancing costs ensures that bundled DP customers and sales service customers are treated consistently and ensures that sales service customers do not bear the costs associated with more expensive incremental winter purchases.

Unaccounted for Gas Variances (UFG)

At the time of the April 1, 2014 QRAM filing Union was forecasting UFG purchases of 1.5 PJ.[2] The spot gas actually purchased for UFG was 2.1 PJ. The difference between forecast spot purchases and actual spot purchases is attributable to actual activity to the end of March 2014.

[2] EB-2014-0050, Tab 1, p. 14.

As system operator, Union ensures that there is adequate supply available at March 31 to meet design day requirements. As discussed in Union's 2014-2018 IRM evidence (EB-2013-0202, Section 4.7.4), UFG represents the difference between the total gas available from all sources, and the total gas accounted for as delivery, net interchange, and company use. This difference could include leakage or other actual unmeasured losses, discrepancies due to meter inaccuracies, variations of temperature and/or pressure, and other variants, particularly due to measurements being made at different times and at different points on the system.

The total cost of UFG is comprised of two elements: a percentage of throughput volume that determines the UFG volume, and the Board-approved WACOG. Changes to WACOG and the corresponding impact on the total cost of UFG using the Board-approved UFG volume are captured in Union's QRAM.

To the extent that Union has volumetric UFG variances, Union must account for that variance and replace that supply if Union has higher UFG than planned. Union purchased 2.1 PJ of spot gas for delivery in March based on actual UFG variances experienced for the winter from November 1, 2013 to March 31, 2014. If Union did not purchase the incremental supply, there would not be adequate gas in storage to meet customer demands in March and April.

Given the magnitude of the spot gas price variance attributable to UFG, Union deferred the review and recovery of the price related variance to this proceeding as Union wanted to ensure appropriate treatment of these costs, which may have been outside of the scope of the standardized QRAM process approved by the Board in EB-2008-0106. The average price of incremental spot purchased to manage actual UFG variances experienced for the winter from November 1, 2013 to January 31, 2014 was $7.12 Cdn/GJ. The difference between the January 1, 2014 Ontario Landed Reference Price of $4.868 Cdn/GJ and the actual cost of $7.12 Cdn/GJ for the 2.1 PJ of incremental gas purchased, results in a UFG price related variance of $4.729 million.

Subsequent to filing Union's April 1, 2014 QRAM, Union reviewed the historical treatment of UFG price variances. As system operator, Union ensures that there is adequate supply available at March 31 to meet design day requirements. To better understand the impact of price variance related to UFG, Union reviewed UFG activity and associated price variances for 2008-2013.

The variance between the actual cost of gas purchased for company use (compressor fuel and UFG) and the Ontario Landed Reference price used to set rates for planned purchases is recorded in the South purchase gas variance account (SPGVA) and disposed of quarterly through adjustments to gas supply commodity rates. This has resulted in a benefit to Union South sales service customers over the past six years on average of $5.5 million per year. This impact was captured as part of Union's gas cost deferral accounts as part of the standard QRAM process. Table 2 below shows the Ontario Landed Reference Price versus the average cost of gas purchases for years 2008-2013.

Table 2
Price Variance on UFG Volumes in SPGVA Account

	2008	**2009**	**2010**	**2011**	**2012**	**2013**
Average Ontario Landed Reference Price ($ / GJ)	$9.725	$7.398	$6.423	$5.796	$4.975	$5.423
Average Booked Cost Of Gas Purchases ($ / GJ)	$9.435	$4.943	$5.084	$4.686	$3.573	$4.406
Average Price Differential ($ / GJ)	-$0.289	-$2.455	-$1.338	-$1.109	-$1.402	-$1.017
UFG Volumes (PJ)	5.4	7.6	2.5	1.3	2.6	4.3
Total Price Variance on UFG Volumes ($ millions)	-$1.6	-$18.7	-$3.4	-$1.5	-$3.6	-$4.4

Recognizing that delivery rates have not been adjusted in the past for lower costs related to planned purchases, Union determined that it would not be appropriate to isolate the variance related to spot gas purchases for UFG volume. An adjustment to delivery rates for the spot gas purchase cost variance related to UFG is not consistent with the treatment of planned gas purchase cost variances related to UFG. In each year for the above table, the total price variance on UFG volumes was recorded in the SPGVA and benefited Union South sales service customers. Given the above, Union proposes that the cost of $4.729 million associated with price variances related to UFG variances be disposed of to Union South sales service customers consistent with historical practice. Union will include these costs in a future QRAM proceeding after the Board's decision in this proceeding.

Account No. 179-108 Unabsorbed Demand Costs ("UDC")

The balance in the UDC Variance Account is not prospectively recovered or refunded as part of the approved QRAM. It has therefore been included in this submission. The credit balance of $9.947 million in the UDC variance account is the difference between the actual UDC incurred by Union and the amount of UDC collected in rates.

UDC Recovery in Rates

To meet customer demands across Union's franchise area and to meet the targeted (planned) storage inventory levels at October 31, Union's 2013 Board-approved rates included UDC of 8.7 PJ in Union North and 0 PJ in Union South.

In Union North, UDC is part of planned operations due to the requirement to hold sufficient TCPL firm transportation ("FT") capacity and other firm assets (both storage and transportation related) to meet both design day requirements as well as annual demand. Assets required to meet design day demands are greater than what is required to meet average daily demand, and therefore results in planned unutilized pipeline capacity and UDC. In a warmer than normal year, Union may incur UDC in Union South to rebalance supply with lower demands. Union manages its North and South transport portfolios on an integrated basis and will determine the pipeline to leave unutilized, if necessary, based on the least cost option. Consequently, UDC is managed on an integrated basis.

Union collected $9.760 million in rates for UDC and recorded an associated interest credit of $0.084 million. Actual UDC costs are $0.099 million offset by $0.013 million in released capacity value and further offset by a credit of $0.189 million related to a change in contracted capacity on Centra Transmission Holdings and Centra Pipeline Minnesota ("CTHI / CPMI"), resulting in a net credit of $0.103 million (see Table 4). This results in net credit in the UDC variance account of $9.947 million. The UDC costs and the credit related to a change in contracted capacity are described in more detail later in the evidence.

Table 3 below provides the derivation of the UDC variance account balances by operations area.

Table 3
UDC Variance Account by Operational Area

Line No.	Particulars ($000's)	Union North	Union South	Total Franchise Area
1	UDC Collected in Rates	(9,760)	0	(9,760)
2	UDC Costs Incurred (Table 4)	(103)	0	(103)
3	Variance (line 2 - line 1)	(9,863)	0	(9,863)
4	Interest	(84)	0	(84)
5	(Credit) / Debit to Operations Area	(9,947)	0	(9,947)

A description of each item follows:

UDC Collected in Rates

2013 Board-approved rates include $8.905 million associated with planned UDC in Union North and $0.0 million associated with planned UDC in Union South. The total cost of UDC in rates assumes January 1, 2013 TCPL Tolls for the January to September period, and July 1, 2013 TCPL Tolls for the October to December period. Union reflected the July 1, 2013 TCPL in rates in the October 1, 2013 QRAM due to the timing of the National Energy Board (“NEB”) rate order. Please see Schedule 2 for the calculation of $8.905 million of planned UDC in Union North 2013 Board-approved rates.

The working papers filed by Union in connection with the draft rate orders for 2013 rates (EB-2011-0210) and October 1, 2013 QRAM (EB-2013-0316) showed the unit rates associated with the planned UDC recovery for each Union North rate class. In both proceedings the working papers incorrectly reflected UDC costs based on 9.3 PJ of UDC as opposed to UDC costs based on Board-approved UDC of 8.7 PJ. As a result, the working papers overstated UDC costs and the unit rates associated with planned UDC recovery.

In order to calculate the actual UDC costs recovered in rates, Union has updated the previously filed working papers to reflect the correct UDC costs and unit rates for recovery associated with Board-approved UDC of 8.7 PJ. Please see Schedules 3 and 4 for the corrected working papers.

On an actual basis in 2013, Union recovered $9.760 million in Union North and $0.0 million in Union South. The higher than expected recovery is primarily due to higher than forecast demand of 113,137 10^3m^3 in Union North.

UDC Costs Incurred

The costs reflected in the UDC variance account are the total demand charges for unutilized capacity totaling $0.099 million partially offset by revenue generated from transportation releases totaling $0.013 million. Unutilized upstream transportation capacity due to excess supply, is released and sold on the secondary market to minimize

UDC. Revenues generated from the transportation releases are credited to the UDC variance account mitigating the overall UDC impact. In addition to the unutilized capacity, Union has reflected a credit of $0.189 million related to lower contracted capacity on CTHI/CPMI resulting in a net UDC credit of $0.103 million as shown in Table 4 below. The credit associated with contracted capacity on CTHI/CPMI is described in more detail below.

Table 4
UDC Costs Incurred

Line No.	Particulars ($ Millions)	Costs
1	UDC Costs	0.099
2	Released Capacity Value	(0.013)
3	CTHI / CPMI Contracted Capacity Credit	(0.189)
4	Net UDC Costs (Credit)	(0.103)

In 2013, Union's actual UDC was a cost of $0.086 million (0.64 PJ), which was entirely attributable to Union North. The level of UDC experienced in 2013 was less than planned largely due to increased use in the general service market in Union South and Union North and a result of approximately 44,000 bundled direct purchase (DP) customers returning to system supply in Union South. Union provides the default gas supply and manages return to system for bundled DP arrangements. Therefore, when DP customers return to system (either due to the customer or Energy Marketer's initiative), Union manages the resulting default supply function to ensure supply is available for these customers by purchasing additional supplies it otherwise would not have required.

In addition to the UDC incurred, Union has recorded a credit of $0.189 million in the UDC variance account to capture a volume variance related to capacity contracted with CTHI / CPMI. In Union North, Union contracts for capacity on CTHI / CPMI to move gas into Union's Manitoba delivery area (MDA). Union's Manitoba Delivery Area is connected to the TCPL Mainline at the Spruce interconnect in the TCPL Centra MDA by these two pipelines. In Union's 2013 Cost of Service filing (EB-2011-0210), Union reflected the then contracted capacity on CTHI / CPMI of 8,473 GJ/day. Union has since reduced the contracted capacity on these pipelines to 6,330 GJ/day for a reduction of 2,143 GJ/day. The reduction in costs for this contract is $0.189 million in 2013 and this amount has been recorded in the UDC variance account to pass through the benefit of this contract change to Union North sales service and bundled DP customers. The credit was booked in December, 2013 for the 2013 calendar year and will be booked on an ongoing basis each month until such time that Union can reflect the updated volumes in rates.

Interest

Interest associated with UDC amounted to a credit of $0.084 million for Union North and $0 for Union South for a net credit of $0.084 million.

(Credit)/Debit to Operations areas

Consistent with past UDC deferral account dispositions, Union proposes to assign the total credit of $0.103 million to each operations area in proportion to the actual excess supply. The UDC variance account has a net total credit balance of $9.947 million. The balance applicable to customers in Union North is a credit of $9.947 million, while there is no impact to customers in Union South.

Account No. 179-128 Gas Supply Review Consultant Cost

In its 2013 Cost of Service (EB-2011-0210) Decision, the Board directed Union to “file with the Board an expert, independent review of its gas supply plan, its gas supply planning process, and gas supply planning methodology." Further, Union was also directed to establish a deferral account to capture the costs associated with this review. In its Decision, the Board listed 11 elements that should be included in the review.[3] During 2013, Union engaged both Sussex Economic Advisors LLC and Concentric Energy Advisors Inc to perform this review, the results of which were presented to the Board in the 2012 Deferrals Proceeding (EB-2013-0109). Sussex reviewed eight of the elements set out by the Board, and Concentric reviewed three.

Union incurred $0.254 million in consultant costs related to the gas supply review and $0.002 million in associated interest costs. The breakdown of costs by vendor are outlined in Table 5 below. No further costs related to this review are expected.

[3] EB-2011-0210 Decision and Order, pp. 40-41.

Table 5
Gas Supply Costs by Vendor

Line No.	Particulars ($000's)		Amount
1	Sussex		205
2	Concentric		49
3	**Total**	**$**	**254**

Account No. 179-130 Upstream Transportation FT-RAM Optimization

There is no balance in this deferral account. Union will request closure of this account once the disposition of 2012 deferral balances is complete.

Account No. 179-131 Upstream Transportation Optimization

In its EB-2011-0210 Decision, the Board ordered the establishment of a symmetrical variance account to capture the variance in 90% of the net revenues from optimization activities and the amount credited to ratepayers in rates effective January 1, 2013. The balance in this account is to be shared with ratepayers.

In setting rates for 2013, the Board established a forecast of optimization revenue of $14.918 million. Ninety percent of that amount, or $13.426 million, was credited to ratepayers in the Board-approved rates.[4] On an actual basis, consistent with the method approved in its EB-2011-0210 Decision and Rate Order, Union has credited $15.697

[4] EB-2011-0210, Draft Rate Order, Working Papers, Schedule 43.

million in rates to ratepayers during 2013, $2.271 million greater than the Board-approved amount of $13.426 million. As identified in the EB-2011-0210, this difference occurs when Union's actual sales service volumes are greater than the forecast sales service volumes in 2013 rates.[5] Union earned $23.747 million in net revenues from upstream transportation optimization during 2013. Per the approved sharing methodology, 90% of this net revenue, or $21.372 million, is to be credited to customers. As stated above, $15.697 million has already been credited through rates; therefore, $5.675 million ($21.372 million less $15.697 million) is to be further credited to ratepayers through this deferral account disposition. Exhibit A, Tab 1, Appendix A, Schedule 5 provides a summary of the calculation of the amount in this deferral account.

Upstream Transportation Optimization Activities Defined

As previously filed in EB-2013-0109, Exhibit B, Tab 2, Upstream Transportation Optimization activities consist of Upstream Transportation Exchanges and Transportation Assignments. A Transportation Exchange is typically defined as the movement of gas between two locations, where at least one location is not on the Union transmission system. Union "exchanges" gas held by it at one location for gas held by a counterparty at another location.

[5] EB-2011-0210, Decision and Rate Order, p.16.

Transportation Exchanges are further defined by two categories: Base and FT-RAM. Union has transacted Base transportation exchanges since the 1990s. The transportation capacity underlying Base transportation exchanges are temporarily surplus to the gas supply plan, and are not required to meet the market area demands at that time. On non-design days, there is temporarily surplus upstream transportation capacity (capacity in excess of market demands) that can be used to provide exchange services. On these days, Union continues to purchase the gas supply in accordance with the gas supply plan, and delivers that gas to either the market area or to Dawn. Any unutilized upstream transportation capacity is used to provide exchange services as market opportunities exist. For example, during non-peak periods when excess capacity is available, Union may provide an exchange service between Parkway and the Union EDA. The customer would therefore give gas to Union at Parkway and Union would give that gas back to the customer at the Union EDA. Alternatively, during the coldest winter days, the upstream transportation capacity is required to meet in-franchise requirements and there is very limited to no temporarily surplus capacity available for Base transportation exchanges.

The Firm Transportation Risk Alleviation Mechanism (FT-RAM) program was offered by TransCanada PipeLines on a permanent basis from March 2009 to June 2013. The FT-RAM program did not change the Transportation Exchange services that Union provides, however, it did allow Union to monetize the value of some of the temporarily surplus capacities that, without the program, would not have been realized. The FT-

RAM program ended June 30, 2013 and therefore these types of exchanges and assignments also ended at that time. Explicit examples of Union's optimization activities were provided in EB-2013-0109 that also applied to the 2013 activity.

2013 Actual vs. 2013 Board-Approved Variance

Union's 2013 actual Upstream Transportation Optimization revenue is approximately $8.829 million higher than 2013 Board-approved revenue forecast. The increase in revenue is attributable to the following:

1. Weather & Exchange Values: In January to March 2013, Union markets experienced average weather, which resulted in the availability of temporarily surplus upstream transportation capacity to market to S&T customers on many days. In November and December 2013, Union markets experienced colder than normal weather. While colder weather means there is less temporarily surplus capacity available for Transportation Exchanges, on the days that there is temporarily surplus capacity available, it results in more valuable exchange services.

2. TCPL Tolls and Alternatives to Exchange Services: TCPL tolls have a significant influence over the value of exchange services. The cost of TCPL transportation between two locations is a significant contributor to establishing the maximum value for exchange services. The forecast that

supported the 2013 Board-approved rates assumed TCPL tolls would be lower than the actual 2013 TCPL tolls for interruptible and short term firm tolls. Since the TCPL tolls were higher for these services than the assumptions that supported the Board-approved rates Union was able to earn higher values for exchange services.

Treatment of Dawn-Parkway Capacity

As identified in Union's 2012 Deferrals proceeding, when evaluating requests from S&T customers for exchanges, Union considers all resources that may be available to meet this market demand. Three types of resources are typically used to provide transportation exchange services: transportation on Union's system, use of temporarily surplus upstream transportation capacity from the Gas Supply Plan, and on occasion purchased resources.

Union often requires the use of its own transmission system, primarily Dawn to Parkway transportation, to provide transportation exchanges services. Many exchanges include Dawn as a receipt point because it is a Market Hub. The receipt point is the location where an S&T Customer provides gas to Union.

During Union's 2013 Cost of Service proceeding, EB-2011-0210, Union was directed to create a deferral account (No. 179-131) for Upstream Transportation Optimization that includes revenues from optimization of Union's upstream transportation included in the gas supply plan. As a result, Union aligned its contracting practices to be consistent with this decision and contracted with S&T customers separately for use of Union's transmission system using its standard C1 contract. As stated in EB-2013-0109, Union has tracked Dawn to Parkway revenue separately from revenue related to upstream transportation optimization, and as such, these revenues are not included in the Upstream Transportation Optimization deferral account.[6] For example, a customer request for service from Dawn to Union's EDA was negotiated and contracted separately for the C1 service for Dawn to Parkway, and for an exchange from Parkway to the EDA. On any given day, Union may sell Dawn to Parkway C1 capacity to a S&T customer as a standalone transaction, or in combination with an exchange from Parkway to other markets. By selling C1 from Dawn to Parkway, to set up the exchange from Parkway, Union is kept whole in selling Dawn to Parkway capacity to facilitate the exchange versus just a transportation service to Parkway.

Union bears the risk of Short-Term Transportation revenue which includes revenue from transportation on Union's system. The 2013 Board-approved rates include Short-Term Dawn to Parkway system revenues of $8.7 million, of which Union earned $5.1 million in 2013 (including approximately $1.4 million from C1 transportation to Parkway to facilitate downstream exchanges). Even with this revenue, Union earned less revenue on overall C1 transportation services than that embedded in rates.

[6] EB-2013-0109, Application and Evidence, Exhibit B, Tab 4, p. 2

STORAGE DEFERRAL ACCOUNTS

Account No. 179-70 Short-Term Storage and Other Balancing Services

The Short-Term Storage and Other Balancing Services deferral account includes revenues from C1 Off-Peak Storage, Gas Loans, Enbridge LBA, Supplemental Balancing Services, C1 Short-Term Firm Peak Storage, and C1 Firm Short-Term Deliverability. The net revenue for Short-Term Storage and Other Balancing Services is determined by deducting the costs incurred to provide service from the gross revenue.

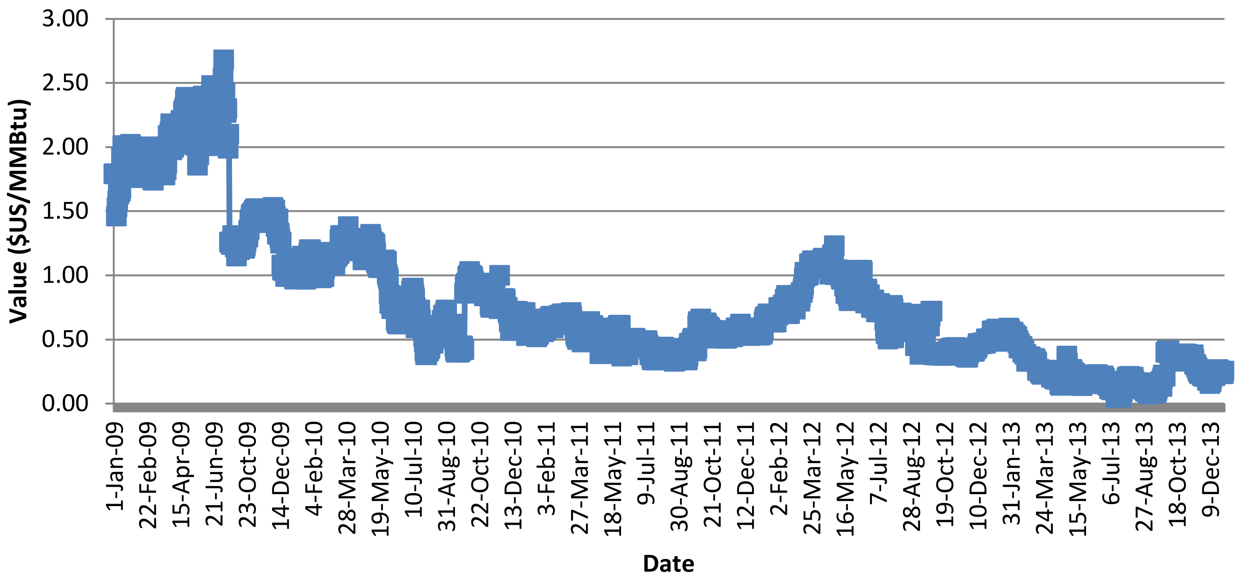
There is a debit balance in the Short-Term Storage and Other Balancing Services deferral account of $1.705 million. The balance is calculated by comparing $2.846 million (90% of the actual 2013 Short-Term Storage and Other Balancing Services net revenue of $3.162 million) to the net revenue included in rates of $4.551 million in the EB-2011-0210 Rate Order, Working Papers, Schedule 9. The details of the balance are found at Exhibit A, Tab 1, Appendix A, Schedule 6.

Actual 2013 revenues from C1 Off Peak Storage, Gas Loans and all other Balancing services were $0.214 million lower than the 2013 Board-approved forecast. The main driver for lower revenues continues to be the higher supply in North America creating less seasonal volatility of natural gas prices.

The C1 Short-Term Firm Peak Storage revenues (utility) were $3.136 million lower than the 2013 Board-approved forecast. The difference between the Board-approved forecast revenue for 2013 and the actual revenue was impacted by a decrease in excess utility storage capacity available for sale and by a lower market value for Short-Term Peak Storage. Actual utility requirements were higher by 2.7 PJ in 2013 which reduced the amount available for sale as C1 Short-Term Peak Storage for 2013/2014 winter (8.6 PJ) compared to the 2013 Board-approved forecast (11.3 PJ). Union's customers received the value of storage directly through the use of the storage space, rather than indirectly, through sales of short-term storage.

The Board-approved forecast implied an annual average value of $0.70/GJ ($7.883 million/11.3 PJ), and the actual average annual C1 Short-Term Peak Storage value in 2013 is $0.54/GJ. The market value for short-term peak storage has declined since the last Board-approved forecast, as shown at Figure 1.

Figure 1
Historical Short -Term Firm Peak Storage Values at Dawn
2009-2013



Non-Utility Balances for 2013/Storage Encroachment Payment

The Board, on page 116 of its EB-2011-0210 Decision, directed Union to file a report similar to that ordered in EB-2011-0038 to monitor the inventory related to non-utility storage operations.

> *"The Board notes that pursuant to EB-2011-0038, Union must disclose to the Board when storage encroachment has occurred. That decision, however, only requires Union to file this information in conjunction with its rebasing applications. The Board therefore directs Union, at the time that the Short-Term Storage Account is to be disposed, to file a report similar to that ordered by the Board in EB-2011-0038."*

Exhibit A, Tab 1, Appendix A, Schedule 7 shows the non-utility balances for October and November of 2013. As discussed in EB-2011-0038, October and November are the two critical months for peak storage.

During the 2013 injection season the non-utility storage balance peaked on October 21 at 89% of available space with a balance of 73.6 PJ compared to available space of 82.3 PJ. Following that date, non-utility customers stayed between 87-89% full until November 12 when they proceeded to withdraw for the majority of the remaining days in November.

As discussed during the 2010 Deferral Proceeding, EB-2011-0038, Union manages its storage balance to the October 31 gas day. At October 31, 2013 the non-utility balance was 87% of available space and stayed below the total non-utility available space for the rest of 2013. Union will continue to update Tab 1, Appendix A, Schedule 7 and file it annually.

During EB-2011-0210, the Board further ordered Union to file a calculation for a storage encroachment payment from Union's non-utility business to Union's utility business, if Union's non-utility business encroached on Union's utility space.

> *"If a storage encroachment has occurred, Union is further directed to file a calculation for the payment by Union's non-utility business to its utility business for storage encroachment. The Board believes that this payment should reflect the market value for the utility space that was subject to the encroachment. The Board notes that this finding only relates to any storage encroachment that occurs after the date of this Decision and will not apply retroactively to previous storage encroachments."*

There was no encroachment of utility space in 2013 and no calculation is required.

Sale of Non-Utility Storage Space

Union prioritizes the sale of its utility storage and allocated short-term peak storage margins as directed by the Board in EB-2011-0210:

> *"Finally, the Board directs Union to file sufficient evidence, at the time the balance in the Short-Term Storage Account is to be disposed, to allow the Board to confirm that Union has appropriately prioritized the sale of its utility storage space and calculated the balance in the account in accordance with this Decision."*

In EB-2011-0210, Union proposed to split margins from short-term peak storage services proportionately between the utility and non-utility customers based on the utility and non-utility share of the total quantity of short-term peak storage sold each calendar year. Short-term peak sales includes any sale of storage space for a term less then 2 years. Based on the Board's Decision in EB-2011-0210, 2013 was the first year Union sold non-utility space short term.

In its EB-2011-0210 Decision, the Board accepted Union's proposed methodology:

> *"On the second issue relating to the Short-Term Storage Account, how the amounts that are to be recorded in the account are to be calculated, the Board accepts Union's proposal. The Board believes that Union's proposal to allocate the total margins received from the sale of all peak short-term storage to ratepayers and shareholders based on the utility and non-utility share of the total quantity of peak short-term storage sold each calendar year is appropriate. Given the uncertainty inherent in the pricing of market-based storage, the Board believes that Union's proposal best ensures that ratepayers and shareholders receive the same proportionate return on all short-term transactions.*
>
> *However, to minimize the opportunity for unintended incentives, the Board directs Union to prioritize the sale of its utility storage capacity ahead of the sale of*

short-term storage services from its non-utility storage operation. The Board finds that whenever utility capacity is available for sale, that capacity is to be used to facilitate short-term storage transactions on a priority basis. Only when utility storage capacity is fully sold can Union sell non-utility storage capacity on a short-term basis."

Union sold a total of 12.7 PJ of short-term peak storage in 2013. Of this amount, 8.6 PJ was excess utility space, calculated by deducting 91.4 PJ of utility requirement (from Union's gas supply plan) from the total 100 PJ of utility storage. The remaining 4.1 PJ of short- term peak storage sold was therefore from non-utility space. A calculation of the allocation of short-term peak storage revenues between utility and non-utility can be found at Exhibit A, Tab 1, Appendix A, Schedule 8.

The short-term peak storage margins were allocated between utility and non-utility based on the share of the total quantity of peak short-term storage sold in 2013 using the methodology outlined in EB-2011-0210, J.DV-1-1-1, Attachment 1. Margins were not to be allocated to the non-utility business unless the total short-term peak storage sold exceeded the excess utility storage. This requires that Union effectively sells excess utility space before any non-utility storage is sold short-term.

The methodology is simple and transparent and inherently gives priority to the sale of utility contracts and a proportionate allocation of margin from the sale of short-term peak storage services.

DSM DEFERRAL ACCOUNTS

Union is not proposing to dispose of any balances in the following accounts in this proceeding:

- Account No.179-75 Lost Revenue Adjustment Mechanism ("LRAM")
- Account No.179-111 Demand Side Management Variance Account ("DSMVA")
- Account No. 179-115 Shared Savings Mechanism ("SSM") Variance Account
    - This account has no balance. In its EB-2013-0109 Decision, the Board found that the SSM deferral account can be closed after the amounts arising from their decision have been disposed of to ratepayers.
- Account No. 179-126 Demand Side Management Incentive Deferral Account ("DSMIDA")

Union will dispose of the DSM balances in a separate proceeding. Given the recent Board Decision in Union's 2012 Deferral Disposition proceeding, Union will prepare additional evidence in support of DSM related account balances. Union plans to file DSM deferral evidence in Q3, 2014.

OTHER DEFERRAL ACCOUNTS

Account No. 179-103 Unbundled Services Unauthorized Storage Overrun

No unauthorized storage overrun charges were incurred by customers electing unbundled service in 2013.

Account No. 179-112 Gas Distribution Access Rule ("GDAR") Costs

The GDAR deferral account records the difference between the actual costs required to implement the appropriate process and system changes to achieve compliance with GDAR and the costs included in rates as approved by the Board. Union incurred $0.468 million in capital costs related to GDAR in 2013.

In the 2012 Deferrals proceeding (EB-2013-0109), Union collected the revenue requirement related to two GDAR Notice of Amendments to a Rule. Union added the costs of an additional Amendment to a Rule in the 2013 revenue requirement calculation for GDAR.

The GDAR capital costs are made up of the costs associated with three separate Notice of Amendments to a Rule (the first two of which were factored into the revenue requirement calculation in 2012 deferrals, and the third is new in this proceeding):

1. On October 14, 2011, the Board issued a Notice of Amendment to a Rule – Residential Customer Service Amendments to the Gas Distribution Access Rule under docket number EB-2010-0280. Union incurred $1.475 million in capital costs in 2011 and 2012 to implement the amendments to GDAR.

2. On September 6, 2012, the Board issued a Notice of Amendment to a Rule – Eligible Low-Income Customer Service Policy Amendments to the GDAR, also under docket number EB-2010-0280. Union incurred $0.278 million in capital costs in 2012 to implement the Low Income Amendments to the GDAR.

3. On March 28, 2013 the Board issued a Notice of Amendment to a Rule – Amendments to the Natural Gas Reporting and Record Keeping Requirements in Relation to Residential and Low Income Customer Service Policies, also under docket number EB-2010-0280. Union incurred $0.468 million in capital costs in 2013 to implement the amendments to GDAR.

The Notice of Amendments are attached at Exhibit A, Tab 1, Appendix B.

1. Residential Customer Service Amendments to the GDAR

On October 14, 2011, the Board issued a Notice of Amendment to a Rule – Residential Customer Service Amendments to the Gas Distribution Access Rule under docket number EB-2010-0280. The amendments to the GDAR require each rate-regulated Gas Distributor to implement and publish a Customer Service Policy that is fair, transparent, and enforceable by the Board. The Board ordered that the amendments to the GDAR come into force on April 1, 2012. Union implemented GDAR amendments effective March 5, 2012

Union incurred $1.475 million in capital costs in 2011 and 2012 to implement the amendments to the GDAR. The capital costs included the costs to modify Union's customer service information system to have the functionality required to implement Union's updated policies and practices. This involved the development of business and system design requirements, programming by the external Customer Service System provider and internal IT staff, testing and implementation. The capital costs also included the salaries and expenses of four temporary additional employees who were added to the Customer Care group in order to implement the amendments to the GDAR by April 1, 2012.

2. Low Income Customer Service Amendments to the GDAR

On September 6, 2012, the Board issued a Notice of Amendment to a Rule – Eligible Low-Income Customer Service Amendments to the GDAR also under docket number EB-2010-0280. The Board ordered that these amendments to the GDAR come into force as of January 1, 2013. Union implemented these GDAR amendments prior to the end of 2012 in order to be able to implement the GDAR requirements on January 1, 2013. Union incurred $0.278 million in capital costs in 2012 to implement the eligible Low-income customer service amendments to the GDAR. Modifications were made to the system to identify low income customers, track payment arrangements, and to waive late payment charges while active payment arrangements are in place.

3. Amendments to the Natural Gas Reporting and Record Keeping Requirements in Relation to Residential and Low Income Customer Service Policies

On March 28, 2013 the Board issued a Notice of Amendment to a Rule – Amendments to the Natural Gas Reporting and Record Keeping Requirements in Relation to Residential and Low Income Customer Service Policies, also under docket number EB-2010-0280. The annual reporting requirements include supplying data (e.g. disconnections, arrears, write-offs, security deposits, billing and payment plans etc.), detailed complaint reporting, enquiries reporting and baseline data for 2011, 2012 and 2013. Union incurred $0.468 million in capital costs in 2013 to implement these reporting requirements. The capital costs included the creation of a reporting tool that would align with the OEB categorization of customer activities.

The capital costs relating to the three Amendments to a Rule discussed above can be found at Table 6 below. The costs include those associated with incremental internal resources and expenses as well as Contractor services. Union Gas' retail CIS system, Banner, is an outsourced solution provided by Vertex Business Services. Vertex is responsible for the sustainment and operation of the system as well as any required infrastructure changes. All system changes are completed by Vertex and charged to Union Gas.

Table 6
GDAR Costs

Line No.	Particulars ($000's)	Residential Customer Service Amendments	Low Income Amendments	Reporting and Record Keeping Requirement Amendments	Total Capital Spend
		(2011, 2012)	(2012)	(2013)	
1	Resources (Salary & Expenses)	345	20	9	374
2	Contractor Services	1130	258	459	1,847
3	**Total Costs**	$1,475	$278	$468	$2,221

Union proposes to replace the capital costs with the annual revenue requirement related to the capital costs as outlined in Table 7 below. Accordingly, the 2013 GDAR deferral account has a debit balance of $0.493 million. The revenue requirement will continue to be included in the respective future deferral disposition proceedings.

Table 7
GDAR Costs by Year

Line No.	Particulars ($000's)	2012	2013	2014	2015	2016	2017	TOTAL
1	Depreciation	219	497	555	555	336	59	2,221
2	Interest	80	82	57	31	10	1	261
3	Return	51	55	38	21	7	1	173
4	Current Tax	(156)	(141)	100	153	90	15	61
5	**TOTAL**	$194	**$493**	$750	$760	$443	$76	$2,716

Account No. 179-117 Carbon Dioxide Offset Credits

This account has no balance. The account was created in accordance with the Board's Decision in the EB-2006-0021 proceeding to record the amounts representing proceeds from the sale of or other dealings in carbon dioxide offset credits earned as a result of Union's DSM activities.

Account No. 179-118 Average Use Per Customer ("AU")

The total AU deferral account for all four general service rate classes, M1, M2, Rate 01 and Rate 10, for the year 2013 has a credit to customers of $11.475 million and interest of $0.060 million. This credit includes a DSM revenue impact of $0.006 million. Overall the Rate M2, 01 and 10 customers receive a credit; the Rate M1 customers have a small payable owing to Union Gas.

The 2013 AU deferral account differs slightly from the previous AU deferral accounting used in the 2008 to 2012 incentive regulation framework. This slight difference relates to the target usage estimates. For the year 2013, the target estimates are equal to the forecast usage estimates for the 2013 test year which were stated in the 2013 Cost of Service evidence. The multiple regression based forecast methodology and the assumptions for each demand driver in the regression analyses set the 2013 forecast usage estimates. The demand drivers include normal weather, residential furnace efficiency indices, total bill amounts, foreign exchange rates, fuel oil prices and the estimated DSM plan usage impacts. The target usage in the previous 2008 to 2012 incentive regulation framework was an estimate generated based upon a chained rate of change obtained from a simple three year averaging calculation.

A credit balance of $11.481 million is the variance resulting from the 2013 forecast usage variance described above. The 2013 actual average use per customer estimates are normalized according to the 2013 weather normal which is based on the Board-approved 50:50 blended weather methodology that incorporates both the 30 year average and 20 year declining trend estimates of annual heating degree-days.

The volume variances and revenue impacts in 2013 attributed to DSM are also calculated and included within the deferral account. The DSM deferral revenue impact is obtained by multiplying the Board-approved average annual number of customers by the DSM usage variance. The DSM usage variance is the actual DSM related impact compared to the DSM forecast estimate. The estimated DSM impact revenue amounts are subtracted from the AU deferral account balances. The DSM impact is subtracted because when the actual DSM usage savings differ from the amount that was planned and included in the forecast estimate, the variance in usage attributed to DSM cannot be claimed by Union in the usage deferral account.

The details of the Average Use per Customer deferral account balance can be found at Exhibit A, Tab 1, Appendix A, Schedule 9.

Account No. 179-120 International Financial Reporting Standards ("IFRS") Conversion Costs

In accordance with the Board-approved Settlement Agreement in EB-2010-0039, Union agreed to remove from the deferral account the capital costs associated with upgrading Union's accounting system in order to report results under IFRS. These capital costs were replaced by the annual revenue requirement related to those capital costs as outlined in Table 8, and are to be included in the respective future deferral account disposition proceedings. Accordingly, the 2013 IFRS Conversion Costs deferral account has a debit balance of $0.505 million.

Table 8
IFRS Conversion Costs by Year

Line No.	Particulars ($ Millions)	2008	2009	2010	2011	2012	2013	2014	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Proposed by Union	1.918	2.071	-	-	-	-	-	3.989
2	Less: Capital expenditures	0.953	0.459						1.412
3	O&M	0.965	1.612	-	-	-	-	-	2.577
4	Revenue requirement	-	-	0.124	0.335	0.538	0.505	0.244	1.747
5	Total	0.965	1.612	0.124	0.335	0.538	**0.505**	0.244	4.324

Account No. 179-123 Conservation Demand Management ("CDM")

In its EB-2010-0055 Decision and Order which granted approval for Union's 2011 DSM plan the Board ordered Union to establish a deferral account to track revenues associated with CDM activities, to be shared 50/50 between Union and ratepayers. The Board approved the accounting order for Union's CDM deferral account in Union's 2011 rates application (EB-2010-0148). The balance in the 2013 CDM deferral account is $0.068 million (50% of total net revenues of $0.136 million).

In 2013 Union Gas delivered four CDM programs on behalf of various electric local distribution companies (LDCs) including:

1) High Performance New Construction Generation 2 (HPNC2),
2) Key Account Management (KAM),
3) Commercial Conservation Account Management (CCAM) and
4) Home Assistance Program (HAP) for Low Income Customers.

HPNC2 is an Ontario Power Authority (OPA) funded program to encourage builders of commercial, industrial, institutional and agricultural facilities to reduce electricity demand and/or consumption by designing and building new buildings or major renovations with higher energy efficient equipment and systems (i.e. lighting, space cooling, ventilation etc.) than required by the building code. Union Gas provides sales and technical support services to Enbridge in their delivery of HPNC2 for designated

LDCs within Union's franchise area. Union contracted with Enbridge to deliver this program until December 31, 2014. Union delivered the HPNC2 program on behalf of 15 electric LDCs in 2013. The revenue shortfall experienced in HPNC2 during 2013 is attributed to fewer total KW savings realized in HPNC program delivery than required to cover the incremental 2013 employee costs.

KAM is an OPA funded CDM program to assist major industrial customers (average monthly peak demand greater than 5MW) develop capital projects that support industrial energy management and electricity efficiency. Union contracted with four electric LDCs, (Hydro One Networks Inc, Veridian Connections, Utilities Kingston and Hydro One Brampton), to deliver the KAM services until December 31, 2014.

The CCAM program supports capital investments in equipment that reduces electrical demand and energy consumption for commercial and industrial electricity customers with average monthly electricity demand of less than 5MW. Union contracted with Hydro One Networks Inc. to deliver the CCAM program in their service area until December 31, 2014.

The Home Assistance Program (HAP) is an OPA funded program to offer free installation of energy efficiency measures to qualifying low income households to reduce electricity and peak demand savings. Union contracted with Halton Hills Hydro and Hydro Burlington to deliver this program in their service area until December 31, 2014.

The Home Assistance Program experienced a slight loss in 2013 as a result of additional marketing expenditure required to help drive program results.

Table 9 below shows the CDM net revenues broken out by program.

Table 9
CDM Net Revenues by Program

Line No.	Particulars ($000's)	HPNC	KAM	CCAM	HAP	Total
1	Revenues	327	607	1,063	347	2,344
2	Costs	430	521	900	357	2,208
3	Net Revenues	(103)	86	163	(10)	**$136**
					50% to ratepayer	$68
					50% to shareholder	$68

Account No. 179-127 Pension Charge on Transition to U.S. GAAP

This account has no balance. In its EB-2011-0025 decision the Board approved the establishment of the Pension Charge on Transition to U.S. GAAP Deferral Account. In its EB-2013-0109 decision the Board approved the disposal of the transition costs. No further costs related to this transition are expected. Union will request closure of this account once the disposition of 2012 deferral balances is complete.

Account No. 179-129 Preparation of Audited Utility Financial Statements

In its EB-2011-0210 Decision, the Board directed Union to prepare and file separate audited financial statements for the portion of its business that is subject to rate

regulation. The Board also ordered Union to collect the costs of preparing the statements in a new Preparation of Audited Utility Financial Statements deferral account.
Union initially retained Ernst & Young to assist in mapping out the plan necessary, the processes required, and a cost estimate to generate a full set of audited utility financial statements. As a result of an increase in the cost estimate to prepare audited utility financial statements, on July 26, 2013 Union filed an addendum in EB-2013-0109 to advise the Board and intervenors of the new estimate. Union's initial timeline was to complete the project as soon as possible after Union released its financial results to the public. In order to meet this timeline Union retained Ernst & Young to assist with the project, and work commenced towards satisfying the Board directive.

In the EB-2013-0109 hearing, on August 1, 2013, the Board, on its own motion, determined that it would initiate a review of the directive. Having regard to the motion, Union suspended all work on the preparation of the audited utility financial statements. In its EB-2013-0109 Decision, the Board found the potential value received from the separate audited financial statements does not justify the expected costs, and therefore the Board relieved Union of the requirement to prepare separate audited financial statements for its regulated business. The Board required Union to record the amount already spent on implementing the Board's directive in the deferral account that was established in the EB-2011-0210 proceeding.

Union incurred $0.541 million in costs relating to this directive and interest of $0.002 million. The breakdown of costs can be found in Table 10 below.

Table 10
Costs of Preparing Audited Utility Financial Statements

Line No.	Particulars ($000's)	$
1	Ernst & Young Project Plan	150
2	Ernst & Young Incremental Support	391
3	**Total**	**541**

OTHER ITEMS

Federal and Provincial Tax Changes

This account has no balance. The account was created in accordance with the Board's decision in EB-2007-0606 to record 50% of the tax increase/decrease subject to sharing under the previous incentive regulation framework.

Account No. 179-132 Deferral Clearing Variance Account

Union is proposing that the Board approve the establishment of a new deferral clearing variance account.

Deferral and variance accounts record the difference between actual and forecast results. The accounts eliminate forecast error, with the intention that actual results be disposed of as directed by the Board. As a matter of principle, neither ratepayers nor Union should be exposed to gains or losses as a result of volume variances associated with the disposition of deferral account balances.

To meet the principle of keeping all parties whole, Union proposes that the Board approve the establishment of this new deferral clearing variance account. In its EB-2013-0109 Decision (Union's 2012 Deferral Account disposition proceeding), the Board rejected Union's proposal to establish the deferral clearing variance account because the deferral account was not contemplated as part of the 2008-2012 IRM framework. Union is requesting this deferral account as part of its 2013 deferral account disposition proceeding to establish the account prior to Union's 2014-2018 IRM framework. Union is requesting this deferral account be approved by the Board effective October 1, 2014. The October 1, 2014 date will align with Union's QRAM filing should Union begin to dispose of the 2013 deferral account balances at that time.

Please see below for the background on the deferral clearing variance account issue and the three alternatives Union considered to minimize or eliminate gains or losses due to volume variances associated with the disposition of deferral account balances.

Background

During the 2008 Deferral Disposition proceeding (EB-2009-0052) the Board had requested Union investigate the possibility of implementing a true-up mechanism to capture any volume variance related to the disposition of deferral accounts. Union determined in response to an interrogatory in the 2009 Deferral Disposition proceeding (EB-2010-0039, Exhibit B2.01) that the average variance of deferral disposition from 2005 through 2007 was approximately $0.025 million per year, which did not represent a material enough amount to warrant a true-up mechanism.

During the 2011 Deferral Disposition proceeding (EB-2012-0087) Union was asked to revisit the need for a true-up mechanism by updating the information supplied in the 2009 Deferral Disposition proceeding to include the years 2008 and 2009. The investigation found that the average impact from 2005 to 2009 of not truing-up the disposition of deferral account balances was approximately $0.003 million per year. Consistent with its response during the 2009 proceeding, Union determined that no true-up mechanism was required. Union did not propose a deferral account to capture the variances resulting from disposition, as the OEB's expectation at the time was for a reduction in the number of deferral accounts unless a material matter needed to be addressed[7].

In 2013, Union determined that due to variances from forecasted volumes, $1.3 million had been refunded to ratepayers in excess of the final deferral balances approved for disposition in EB-2011-0038 (2010 Deferrals Proceeding), and $5.3 million in EB-2012-0087 (2011 Deferrals Proceeding). Major drivers of the variances included a lower volume refund period which resulted in higher unit rates and more volatility, and the uncertainty in the forecast of sales service versus direct purchase volumes.

[7] Natural Gas Regulation in Ontario: A Renewed Policy Framework, p.31

Upon realizing that the variances were material, Union applied for a deferral clearing variance account in EB-2013-0109. The Board found that Union's proposal was not appropriate since this account was not contemplated as part of Union's 2008-2012 IRM Framework. In its Decision the Board stated:

> *"the Board is of the view that the establishment of such an account, at this point in the IRM term, would change the parameters of the original plan significantly and Union has not satisfied the Board that exceptional circumstances have arisen that would justify such a significant change."*

Alternatives

Union considered three alternatives to minimize or eliminate the risk of gains or losses as a result of volume variances associated with the disposition of deferral account balances. These three alternatives are described below. In Union's view, while each alternative is feasible, Union proposes that the Board approve the establishment of a new deferral clearing variance account with a six month disposition period effective October 1, 2014 for the reasons described below.

i.) *Implement a One-time Adjustment for General Service Rate Classes*

Under this alternative, Union would treat general service customers in a manner consistent with contract rate and ex-franchise customers, and dispose of deferral account balances through a one-time adjustment on customers' bills rather than dispose of deferral account balances prospectively over six months. Union used one-time adjustments for deferral disposition to the general service market up until the 2004 deferrals proceeding.

One-time adjustments on customers' bills would eliminate the forecast variance when disposing of deferral account balances, however this alternative would cost approximately $0.500 million to implement, and take approximately eight months to complete the necessary billing system changes. Further, in the past general service customers have expressed concern with one-time billing adjustments due to the magnitude, and out of period nature of the adjustments.

ii.) *Implement a Rolling Price Adjustment*

Under this alternative, Union would continue to dispose of deferral account balances for general service customers prospectively over a period of time, however, Union would adjust the price adjustment each QRAM to account for variances between forecast and actual disposition of deferral account balances. This alternative would result in an update to the price adjustment established for deferral account dispositions as part of the QRAM process, which is intended to be mechanical in nature. Under this alternative, Union would require a twelve month disposition period to ensure the quarterly update to the price adjustment minimizes the variance between forecast and actual disposition of the deferral account balances.

This alternative is consistent with Union's QRAM process, and would minimize forecast variances as a result of disposition of deferral account balances. However, the rolling price adjustment would add administrative burden and complexity to Union's QRAM process, which, per the Board's EB-2008-0106 Decision (QRAM Standardization) is mechanical in nature and reviewed under a tight timeline.

iii.) *Establish a New Deferral Clearing Variance Account.*

Under this alternative, Union would create a new deferral account to capture the variance between forecast and actual volumes on the disposition of deferral accounts. Union would dispose of deferral balances over a period of either six months or 12 months.

This alternative would reduce risk to both ratepayers and Union when disposing of deferral account balances. This alternative is administratively simple and maintains the prospective disposition of deferral account balances to general service customers. Further, there are no incremental costs associated with the establishment of a deferral clearing variance account.

In summary, Union is proposing that the Board approve the establishment of a new deferral clearing variance account in order to minimize or eliminate the gains or losses to ratepayers and Union as a result of volume variances associated with the disposition of deferral account balances. Given the size of the deferral account balances proposed for disposition in this proceeding, variances resulting from forecasted volumes could be material.

Union is requesting this deferral account be approved by the Board effective October 1, 2014. This effective date will align with Union's QRAM filing should Union begin to dispose of the 2013 deferral account balances at that time and will also establish the account prior to Union's 2014-2018 IRM framework.

Appendix A

UNION GAS LIMITED
Deferral Account Balances
Year Ending December 31, 2013

Line No.	Account Number	Account Name	Filed Balance [1] ($000's)
	Gas Supply Accounts:		
1	179-107	Spot Gas Variance Account	1,801
2	179-108	Unabsorbed Demand Costs (UDC) Variance Account	(9,947)
3	179-128	Gas Supply Review Consultant Costs	256
4	179-130	Upstream Transportation FT-RAM Optimization	-
5	179-131	Upstream Transportation Optimization	(5,675)
6	Total Gas Supply Accounts (Lines 1 through 5)		(13,565) [2]
	Storage Accounts:		
7	179-70	Short-Term Storage and Other Balancing Services	1,705
	DSM Accounts:		
8	179-75	Lost Revenue Adjustment Mechanism	-
9	179-111	Demand Side Management Variance Account	-
10	179-115	Shared Savings Mechanism	-
11	179-126	Demand Side Management Incentive	-
12	Total DSM Accounts (Lines 8 through 11)		- [3]
	Other:		
13	179-103	Unbundled Services Unauthorized Storage Overrun	-
14	179-112	Gas Distribution Access Rule (GDAR) Costs	493
15	179-117	Carbon Dioxide Offset Credits	-
16	179-118	Average Use Per Customer	(11,535)
17	179-120	IFRS Conversion Cost	505
18	179-123	Conservation Demand Management	(68)
19	179-127	Pension Charge on Transition to US GAAP	-
20	179-129	Preparation of Audited Utility Financial Statements	543
21	Total Other Accounts (Lines 13 through 20)		(10,062)
22	**Total Deferral Account Balances (Lines 6 + 7 + 12 + 21)**		**(21,922)**

Notes:

[1] Account balances include interest to December 31, 2013.

[2] With the exception of UDC (No. 179-108), Gas Supply Review Consultant Costs (179-128), Upstream Transportation FT-RAM Optimization (179-130), Upstream Transportation Optimization (No. 179-131), and a portion of the Spot Gas Variance Account (No. 179-107), all gas supply-related deferral account balances are disposed of through the QRAM process.

[3] Balances in DSM related deferral accounts will be filed in a separate proceeding.

UNION GAS LIMITED
2013 Forecasted UDC Deferral Amounts with January 1, 2013 and October 1, 2013 Corrected Rates

Line No.	Volumes (10^3m^3)	January	February	March	April	May	June	July	August	September	October	November	December	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Rate 01	169,380	141,550	117,889	70,296	35,926	16,685	16,994	17,540	22,217	48,079	90,980	136,886	884,421
2	Rate 10	50,751	45,986	42,674	28,079	17,491	9,074	9,341	8,841	11,016	22,029	33,390	44,216	322,887
3	Rate 20	13,809	12,142	12,130	10,559	9,416	7,793	6,940	7,201	7,803	10,017	11,177	12,948	121,935
4	Total Union North	233,940	199,678	172,693	108,935	62,833	33,553	33,274	33,582	41,035	80,125	135,546	194,049	1,329,243
	UDC Corrected Rates ($\$/10^3m^3$)													
5	Rate 01	8.2278	8.2278	8.2278	8.2278	8.2278	8.2278	8.2278	8.2278	8.2278	6.7162	6.7162	6.7162	
6	Rate 10	5.9000	5.9000	5.9000	5.9000	5.9000	5.9000	5.9000	5.9000	5.9000	4.8161	4.8161	4.8161	
7	Rate 20	2.1498	2.1498	2.1498	2.1498	2.1498	2.1498	2.1498	2.1498	2.1498	1.7549	1.7549	1.7549	
	UDC Revenue ($)													
8	Rate 01	1,393,623	1,164,647	969,969	578,379	295,594	137,284	139,819	144,315	182,794	322,909	611,040	919,351	6,859,724
9	Rate 10	299,432	271,316	251,777	165,669	103,198	53,537	55,109	52,161	64,993	106,092	160,808	212,947	1,797,040
10	Rate 20	29,686	26,104	26,076	22,700	20,243	16,753	14,920	15,481	16,774	17,579	19,614	22,722	248,653
11	Total Union North	1,722,741	1,462,066	1,247,822	766,749	419,034	207,575	209,848	211,957	264,561	446,580	791,462	1,155,020	8,905,416

UNION GAS LIMITED
2013 UDC Costs in Rates for Deferral Account 179-108
Effective January 1, 2013

Line No.	Rate Class	2013 Forecast (1) (10^3m^3)	UDC ($000's)	UDC Recovered in Rates ($/$10^3m^3$)
		(a)	(b)	(c) = (b) / (a)
	Union North			
1	R01	884,421	7,277	8.2278
2	R10	322,887	1,905	5.9000
3	R20	121,935	262	2.1498
4	R25	-	-	-
5	R100	-	-	-
6	Total Union North		9,444	

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 14, column (a).

UNION GAS LIMITED
2013 UDC Costs in Rates for Deferral Account 179-108
Effective October 1, 2013

Line No.	Rate Class	2013 Forecast (1) (10^3m^3)	UDC ($000's)	UDC Recovered in Rates ($/$10^3m^3$)
		(a)	(b)	(c) = (b) / (a)
	Union North			
1	R01	884,421	5,940	6.7162
2	R10	322,887	1,555	4.8161
3	R20	121,935	214	1.7549
4	R25	-	-	-
5	R100	-	-	-
6	Total Union North		7,709	

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 14, column (a).

UNION GAS LIMITED
Upstream Transportation Optimization Deferral Account (No. 179-131)

Line No.	Particulars ($000's)	2013 Board-Approved (a)	2013 Actual Total (b)
1	Base Exchange Revenue	9,118	15,408
2	FT-RAM Exchange Revenue	5,800	8,338
3	Total Exchange Revenue	14,918	23,747
4	Ratepayer portion	13,426	21,372
5	10% Union Incentive Payment		2,375
6	Less: Gas Supply Optimization Margin Credited to Ratepayers in Rates	13,426	15,697
7	Balance payable to Ratepayers		5,675

UNION GAS LIMITED

Details of Revenues and Costs and Calculation of Balance
in Short-Term Storage Deferral Account (No. 179-70)

Line No.	Particulars ($000's)	Board-Approved 2013	Actual 2013	Variance
		(a)	(b)	(c)
	Revenue			
1	C1 Off-Peak Storage	500	389	
2	Supplemental Balancing Services	2,000	1,481	
3	Gas Loans	-	56	
4	Enbridge LBA	-	360	
5		2,500	2,286	(214)
6	C1 ST Firm Peak Storage	7,883	4,747	(3,136)
7	Total Revenue (1)	10,383	7,033	(3,350)
	Costs			
8	O&M (2)	3,810	2,910	
9	UFG (3)	316	715	
10	Compressor Fuel (4)	1,201	246	
11	Total Costs	5,327	3,871	(1,456)
12	Net Revenue (line 7 - 11)	5,056	3,162	(1,894)
13	Less Shareholder Portion (10%)	505	316	(189)
14	Ratepayer Portion	4,551	2,846	(1,705)
15	Approved in Rates	4,551	4,551	-
16	Balance Receivable from Ratepayers		(1,705)	(1,705)

Notes:
(1) Based on short-term storage services provided.
(2) Revenue requirement based on 11.3 PJ of Board-approved excess in-franchise storage capacity; 2013 actual based on 8.6 PJ.
(3) Based on short-term storage volumes in proportion to total volumes.
(4) Based on short-term storage activity in proportion to total actual storage activity.

Filed: 2014-05-02
EB-2014-0145
Exhibit A
Tab 1
Appendix A
Schedule 7

UNION GAS LIMITED
Southern Operations Area
Summary of Non-Utility Storage Balances

Date	Entitlement (PJs)	Balance (PJs)	% Full (%)	Date	Entitlement (PJs)	Balance (PJs)	% Full (%)
01-Oct-13	82.3	54.8	67%	01-Nov-13	82.3	72.2	88%
02-Oct-13	82.3	55.4	67%	02-Nov-13	82.3	72.4	88%
03-Oct-13	82.3	55.3	67%	03-Nov-13	82.3	72.6	88%
04-Oct-13	82.3	56.2	68%	04-Nov-13	82.3	72.6	88%
05-Oct-13	82.3	57.3	70%	05-Nov-13	82.3	72.4	88%
06-Oct-13	82.3	58.3	71%	06-Nov-13	82.3	72.6	88%
07-Oct-13	82.3	59.4	72%	07-Nov-13	82.3	72.3	88%
08-Oct-13	82.3	60.1	73%	08-Nov-13	82.3	72.1	88%
09-Oct-13	82.3	61.2	74%	09-Nov-13	82.3	72.0	88%
10-Oct-13	82.3	62.3	76%	10-Nov-13	82.3	72.0	87%
11-Oct-13	82.3	63.8	78%	11-Nov-13	82.3	71.9	87%
12-Oct-13	82.3	65.3	79%	12-Nov-13	82.3	71.0	86%
13-Oct-13	82.3	66.7	81%	13-Nov-13	82.3	69.9	85%
14-Oct-13	82.3	68.1	83%	14-Nov-13	82.3	69.1	84%
15-Oct-13	82.3	69.3	84%	15-Nov-13	82.3	68.5	83%
16-Oct-13	82.3	70.3	85%	16-Nov-13	82.3	68.8	84%
17-Oct-13	82.3	70.8	86%	17-Nov-13	82.3	69.1	84%
18-Oct-13	82.3	71.4	87%	18-Nov-13	82.3	69.0	84%
19-Oct-13	82.3	72.1	88%	19-Nov-13	82.3	68.1	83%
20-Oct-13	82.3	72.9	89%	20-Nov-13	82.3	67.1	82%
21-Oct-13	82.3	73.6	89%	21-Nov-13	82.3	66.1	80%
22-Oct-13	82.3	72.9	89%	22-Nov-13	82.3	65.4	79%
23-Oct-13	82.3	72.1	88%	23-Nov-13	82.3	64.2	78%
24-Oct-13	82.3	71.2	86%	24-Nov-13	82.3	62.9	76%
25-Oct-13	82.3	71.2	86%	25-Nov-13	82.3	61.6	75%
26-Oct-13	82.3	71.4	87%	26-Nov-13	82.3	60.0	73%
27-Oct-13	82.3	71.6	87%	27-Nov-13	82.3	58.9	72%
28-Oct-13	82.3	71.7	87%	28-Nov-13	82.3	57.7	70%
29-Oct-13	82.3	71.5	87%	29-Nov-13	82.3	56.5	69%
30-Oct-13	82.3	71.3	87%	30-Nov-13	82.3	55.4	67%
31-Oct-13	82.3	71.7	87%				

UNION GAS LIMITED
Southern Operations Area
Allocation of Short-Term Peak Storage Revenues Between Utility and Non-Utility

Line No.	Particulars	Utility Storage Space (PJs)	Short-Term Peak Storage Sold (PJs)	Revenue from Short-Term Peak Storage ($ millions)
1	Net Revenues from Short-Term Peak Storage			6.9
2	Total Short-Term Peak Storage Sales		12.7	
3	Storage Space reserved for Utility	100.0		
4	Utility Space Requirement	91.4		
5	Excess Utility Storage Space (line 3 - line 4)	8.6		
6	Total Utility Short-Term Peak Storage Sales (line 5)		8.6	
7	Total Non-Utility Short-Term Peak Storage Sales		4.1	
8	Short-Term Peak Storage Net Revenues - Utility (line 6 / line 2 * line 1)			4.7
9	Short-Term Peak Storage Net Revenues - Non-Utility (line 7 / line 2 * line 1)			2.2

Calculation of Balances by Rate Class in Average Use Per Customer Deferral Account (No. 179-118)

Line No.	Particulars (m^3)		Rate 01	Rate 10	Rate M1	Rate M2	Net Account Balance
			(a)	(b)	(c)	(d)	(e)
1	2013 Target Average Use: m^3		2,765	157,381	2,778	143,867	
2	2013 Actual Average Use: m^3		2,900	168,975	2,768	169,422	
3	Actual change in Average Use per customer (line 2 - line 1)		135	11,594	-10	25,556	
4	2013 Board Approved Number of Customers at December		323,287	2,064	1,067,757	6,778	1,399,886
5	Annual Volume Impact ($10^3 m^3$) (line 3 x line 4)	(1)	-43,115	-23,834	10,253	-173,641	-230,336
6	2013 Net Annual Average Delivery Rate ($\$/m^3$)	(2)	$0.091	$0.056	$0.034	$0.038	
7	Average Use Deferral: Annual Amount ($ 000)	(3)	-$3,916	-$1,344	$359	-$6,580	-$11,481
8	DSM Impact ($ 000)	(4)	-$125	$97	-$134	$155	-$6
9	Total Deferral Account Amounts ($ 000) (line 7 - 8)		-$3,792	-$1,441	$493	-$6,736	-$11,475

Notes:

(1) The annual volume is obtained from a monthly calculation of approved customers and the monthly usage variance.

(2) The Net Annual Average Delivery Rate is the average of monthly unit rates that are adjusted by quarterly QRAM adjustments.

(3) Average use deferral amount before DSM impact.

(4) DSM Impact of 2013 Usage.

Appendix B

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

Ontario

NOTICE OF AMENDMENT TO A RULE

RESIDENTIAL CUSTOMER SERVICE AMENDMENTS TO THE GAS DISTRIBUTION ACCESS RULE

BOARD FILE NO: EB-2010-0280

To: All Natural Gas Distributors
All Participants in Consultation Processes EB-2010-0280, EB-2007-0722, EB-2008-0313 and EB-2008-0150
All Other Interested Parties

Date: October 14, 2011

The Ontario Energy Board (the "Board") has today issued amendments to the Gas Distribution Access Rule (the "GDAR") as indicated below, pursuant to section 44(1) of the *Ontario Energy Board Act, 1998* (the "Act").

I. Background

On June 29, 2011, the Board released a Notice of Proposal to Amend a Rule (the "June Notice") in which it proposed a number of amendments to the GDAR (the "Proposed Amendments"). The Proposed Amendments were designed to ensure that rate-regulated natural gas distributors ("Gas Distributors") maintain appropriate standards and practices for certain prescribed areas of customer service for their residential customers, and to ensure that they publish and comply with those standards and practices.

In response to the June Notice, the Board received written comments from six interested parties, consisting of three natural gas utilities and three ratepayer representatives. These comments are available for viewing on the Board's website at www.ontarioenergyboard.ca.

II. Adoption of Proposed Amendments with Revisions

The Board has considered all of the comments received and has determined that no material changes need to be made to the Proposed Amendments. However, in light of the comments received, the Board has decided to make one revision to the Proposed Amendments regarding the coming into force date, which is described further below.

The Board has also made some minor corrections to sections 8.4 and 8.5 of the Proposed Amendments to specify that they apply only to rate-regulated gas distributors, as was the intent.

The residential customer service amendments to the GDAR as adopted by the Board (the "Final Amendments") are set out in Attachment A to this Notice. Attachment B to this Notice sets out, for information purposes only, a comparison version of the Final Amendments relative to the Proposed Amendments.

III. <u>**Summary of Comments in Response to the June Notice and Identification of the Revision Adopted by the Board**</u>

1. Regulatory Approach

As stated in the June Notice, the Board proposed to amend the GDAR by adding a rule requiring each Gas Distributor to develop a "Customer Service Policy" for its residential customers, and to comply with it, post it on its website and provide a copy to anyone requesting it. In the Board's view, this less prescriptive approach will achieve the objectives of fairness and transparency and will ensure that Gas Distributors' customer service-related standards and practices are enforceable by the Board.

Each of the stakeholders expressed general agreement with the less prescriptive approach proposed by the Board. In their submissions, the ratepayer representatives did, however, make some specific requests. Together with the Board's responses, their requests are summarized as follows:

(a) Stakeholder Consultation

Section 8.5.1 of the Proposed Amendments requires a Gas Distributor to give advance notice to its customers of any change to its Customer Service Policy. One of the ratepayer representatives submitted that the Board should encourage the Gas Distributors to include stakeholders in the review and development of their Customer Service Policies. Another of the ratepayer representatives suggested that the Proposed Amendments be modified to include a rule requiring Gas Distributors to consult with stakeholders prior to revising their Customer Service Policies. In the Board's view, Gas Distributors should not be required to enter into further negotiations or consultations with stakeholders prior to implementing, or making revisions to, their Customer Service Policies and, accordingly, no such revision to the Proposed Amendments will be made in this regard.

The Board further notes that it has mechanisms in place to monitor customer complaint trends and that this will enable it, in the future, to identify any potential problem areas with the Gas Distributors' Customer Service Policies and to consider appropriate regulatory action. This type of complaint-driven approach is consistent with the Board's adoption of a generally less prescriptive approach to the regulation of Gas Distributors' customer service rules.

(b) Use of Metrics

One of the ratepayer representatives submitted that the Board should consider requiring Gas Distributors to develop and annually report quantitative and qualitative metrics in the areas (a) through (h) listed under section 8.1.2 of the Proposed Amendments. The Board does not agree to adopt the suggestion at this time. The Board may, in the future, consider whether Gas Distributors should be required to develop and annually report on Customer Service Policy-related metrics to the Board.

(c) Waiver of Compliance

A Customer Service Policy represents the baseline of a Gas Distributor's customer service-related standards and practices, which the Gas Distributor will be required to apply to all of its customers, subject to the exception in section 8.3.1 of the Proposed Amendments. This exception permits a Gas Distributor to waive a provision of its Customer Service Policy in favour of a customer or potential customer. One ratepayer representative suggested that each Gas Distributor be required to develop a guide for the exercise of its discretion to waive a provision of its Customer Service Policy so that all of its customers will have equitable access to such waivers. The ratepayer representative submitted that, unlike the Customer Service Policy, the guide could be more of a "living" document. The Board does not believe a rule to this effect can be practically implemented without defeating the objective of being less prescriptive. In the Board's view, such a requirement could actually reduce the Gas Distributor's ability to provide swift relief to its customers. The Board expects that a Gas Distributor is driven by business and operational realities in the implementation of its Customer Service Policies, which should result in relatively consistent treatments of similar situations.

2. Timing of Amendments

In the June Notice, the Board proposed August 31, 2011 as the coming into force date for the customer service-related amendments to the GDAR and advised that, as of that date, each Gas Distributor must have a compliant Customer Service Policy posted on its website and must conduct its business in accordance with that Customer Service Policy.

The Gas Distributors confirmed that they will amend their customer services policies but asked for more time to do so. The Gas Distributors indicated that they would be required to make significant changes to their current customer service systems, policies and procedures and that further staff training would be needed before the new policies could be implemented. The Gas Distributors advised that they could not meet the proposed August 31, 2011 coming in to force date for posting their revised policies. Instead, they proposed to post their existing policies by September 30, 2011 and work on, and implement, a revised Customer Service Policy over the next 12-month period.

On September 30, 2011, Union and Enbridge each posted their existing customer service policies on their respective websites. Based on their web postings, Union plans to implement the revisions to its customer service polices by March 1, 2012, while Enbridge proposes to do the same by September 30, 2012.

Kitchener Utilities noted that while compliance with the GDAR amendments will be mandatory for the Gas Distributors, Kitchener Utilities has stated that it is prepared to voluntarily comply in a timely fashion with aspects of the proposed amendments to the extent that it can, given its unique situation relative to the larger Gas Distributors.

The Board acknowledges the gas utilities' comments insofar as the work that will be required to revise and implement new Customer Service Policies is not insignificant. The Board, however, does not find it appropriate for customers to wait a full year until they can receive the benefits of their respective Gas Distributor's improved Customer Service Policy. As a result, the Board has revised the Proposed Amendments by amending the final coming in to force date from August 31, 2011 to April 1, 2012. In the Board's view, the new coming in to force date gives Gas Distributors sufficient time to implement their revised Customer Service Policies.

IV. Anticipated Costs and Benefits

The Proposed Amendments to the GDAR will require each rate-regulated Gas Distributor to implement and publish a Customer Service Policy that is fair, transparent, and enforceable by the Board. As stated in the June Notice, the Proposed Amendments will provide greater protection and certainty for residential customers while giving the Gas Distributors an appropriate measure of flexibility to allow them to account for operational considerations. While the Board acknowledges that the Proposed Amendments will cause additional costs for the Gas Distributors, the Board believes that the benefits of the Proposed Amendments outweigh their costs.

V. Cost Awards

The Board will address cost claims for commenting on the June Notice following the conclusion of the entire EB-2010-0280 consultations.

VI. Coming into Force

As indicated above, the Final Amendments to the GDAR as set out in Attachment A to this Notice will come into force on April 1, 2012.

As of today, this Notice, including the Final Amendments to the GDAR as set out in Attachment A, will be available for public inspection on the Board's website at www.ontarioenergyboard.ca and at the office of the Board during normal business hours.

Any questions regarding the Final Amendments to the GDAR as set out in Attachment A should be directed to the Market Operations Hotline at 416-440-7604 or market.operations@ontarioenergyboard.ca. The Board's toll free number is 1-888-632-6273.

DATED at Toronto, October 14, 2011

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Attachment:	Attachment A:	Final Amendments to the Gas Distribution Access Rule: Residential Customer Service Standards
	Attachment B:	Comparison Version Showing the Final Amendments to the Gas Distribution Access Rule Relative to the June 29, 2011 Proposed Amendments (for informational purposes only)

Attachment A

Final Amendments to the Gas Distribution Access Rule:
Residential Customer Service Standards

Note: The text of the proposed amendments is set out in italics below, for ease of identification only.

1. Section 1.2.1 of the Gas Distribution Access Rule is amended by adding the following definition immediately after the definition of "consumer":

   "Customer Service Policy" means the document developed by a rate-regulated gas distributor in accordance with section 8 of this Rule that describes the customer service-related standards and practices applicable to its residential customers;

2. Section 1.4 of the Gas Distribution Access Rule is amended by adding the following immediately after section 1.4.5:

   1.4.6 Section 8 of this Rule, together with the amendment to section 1.2.1 to include the definition of "Customer Service Policy", shall come into force on April 1, 2012.

3. The Gas Distribution Access Rule is amended by adding the following new section immediately after section 7.

8 Customer Service Standards and Practices Applicable to Residential Customers

8.1 General

8.1.1 A rate-regulated gas distributor shall document its customer service-related standards and practices applicable to residential customers in a Customer Service Policy.

8.1.2 A Customer Service Policy shall, at a minimum, include a description of the rate-regulated gas distributor's standards and practices for each of the following customer service-related areas:

(a) bill issuance and payment;
(b) allocation of payments between gas and non-gas charges;
(c) correction of billing errors;
(d) equal payment and equal billing plans;
(e) disconnection for non-payment;
(f) security deposits;

(g) arrears management programs; and
(h) management of customer accounts.

8.2 Policy to be Published

8.2.1 A rate-regulated gas distributor shall file a copy of its Customer Service Policy with the Board, make a copy publicly available for viewing at its head office and on its web site, and provide a copy to each person that requests it.

8.2.2 A rate-regulated gas distributor shall, promptly after the coming into force date of this section, notify its residential customers that it has filed a new or amended Customer Service Policy with the Board and shall provide direction as to where a copy may be viewed and how a copy may be obtained.

8.3 Compliance

8.3.1 Subject to this Rule and other applicable laws, a rate-regulated gas distributor shall comply with its Customer Service Policy but may waive any provision therein in favour of a customer or potential customer.

8.3.2 Commencing in 2013, a rate-regulated gas distributor shall provide, in the form and manner required by the Board, annually by April 30 for the prior calendar year, a statement certifying its compliance with its Customer Service Policy.

8.3.3 A rate-regulated gas distributor shall maintain a compliance monitoring program that enables it to monitor its compliance with its Customer Service Policy and to identify any need for remedial action. A rate-regulated gas distributor shall maintain updated records in a form and manner so as to be able to substantiate its self-certification.

8.3.4 Each statement certifying a rate-regulated gas distributor's compliance with its Customer Service Policy shall be signed by the gas distributor's Chief Executive Officer, Chief Operating Officer, President or person of equivalent position.

8.3.5 A rate-regulated gas distributor shall provide its initial self-certification statement to the Board by April 30, 2013.

8.4 Dispute Resolution

8.4.1 A Customer Service Policy shall describe the rate-regulated gas distributor's process for resolving customer complaints.

8.4.2 If a rate-regulated gas distributor cannot resolve a complaint to the satisfaction of the complainant, the rate-regulated gas distributor shall provide to the complainant contact information for the Ontario Energy Board's Consumer Relations Centre.

8.5 Revisions to a Customer Service Policy

8.5.1 A rate-regulated gas distributor shall provide advance public notice of any revisions to its Customer Service Policy. Notice shall be, at a minimum, provided to each customer by means of a note on or included with the customer's bill. The notice shall include the timeline for implementation of the revisions to the Customer Service Policy.

8.5.2 A rate-regulated gas distributor shall provide the Board with a copy of its revised Customer Service Policy. The revised Customer Service Policy shall be accompanied by a cover letter that indicates the revisions made and their implementation date.

Attachment B

Comparison Version Showing the Final Amendments to the Gas Distribution Access Rule Relative to the June 29, 2011 Proposed Amendments (for informational purposes only)

Note: The text of the proposed amendments is set out in italics below, for ease of identification only.

1. Section 1.2.1 of the Gas Distribution Access Rule is amended by adding the following definition immediately after the definition of "consumer":

   "Customer Service Policy" means the document developed by a rate-regulated gas distributor in accordance with section 8 of this Rule that describes the customer service-related standards and practices applicable to its residential customers;

2. Section 1.4 of the Gas Distribution Access Rule is amended by adding the following immediately after section 1.4.5:

   1.4.6 Section 8 of this Rule, together with the amendment to section 1.2.1 to include the definition of "Customer Service Policy", shall come into force on April 1, 2012. ~~August 31, 2011~~.

3. The Gas Distribution Access Rule is amended by adding the following new section immediately after section 7.

   8 Customer Service Standards and Practices Applicable to Residential Customers

   8.1 General

   8.1.1 A rate-regulated gas distributor shall document its customer service-related standards and practices applicable to residential customers in a Customer Service Policy.

   8.1.2 A Customer Service Policy shall, at a minimum, include a description of the rate-regulated gas distributor's standards and practices for each of the following customer service-related areas:

   (a) bill issuance and payment;
   (b) allocation of payments between gas and non-gas charges;
   (c) correction of billing errors;
   (d) equal payment and equal billing plans;

(e) disconnection for non-payment;
(f) security deposits;
(g) arrears management programs; and
(h) management of customer accounts.

8.2 Policy to be Published

8.2.1 A rate-regulated gas distributor shall file a copy of its Customer Service Policy with the Board, make a copy publicly available for viewing at its head office and on its web site, and provide a copy to each person that requests it.

8.2.2 A rate-regulated gas distributor shall, promptly after the coming into force date of this section, notify its residential customers that it has filed a new or amended Customer Service Policy with the Board and shall provide direction as to where a copy may be viewed and how a copy may be obtained.

8.3 Compliance

8.3.1 Subject to this Rule and other applicable laws, a rate-regulated gas distributor shall comply with its Customer Service Policy but may waive any provision therein in favour of a customer or potential customer.

8.3.2 Commencing in 2013, a rate-regulated gas distributor shall provide, in the form and manner required by the Board, annually by April 30 for the prior calendar year, a statement certifying its compliance with its Customer Service Policy.

8.3.3 A rate-regulated gas distributor shall maintain a compliance monitoring program that enables it to monitor its compliance with its Customer Service Policy and to identify any need for remedial action. A rate-regulated gas distributor shall maintain updated records in a form and manner so as to be able to substantiate its self-certification.

8.3.4 Each statement certifying a rate-regulated gas distributor's compliance with its Customer Service Policy shall be signed by the gas distributor's Chief Executive Officer, Chief Operating Officer, President or person of equivalent position.

8.3.5 A rate-regulated gas distributor shall provide its initial self-certification statement to the Board by April 30, 2013.

8.4 Dispute Resolution

8.4.1 A Customer Service Policy shall describe the rate-regulated gas distributor's process for resolving customer complaints.

8.4.2 If a rate-regulated gas distributor cannot resolve a complaint to the satisfaction of the complainant, the rate-regulated gas distributor shall provide to the complainant contact information for the Ontario Energy Board's Consumer Relations Centre.

8.5 Revisions to a Customer Service Policy

8.5.1 A rate-regulated gas distributor shall provide advance public notice of any revisions to its Customer Service Policy. Notice shall be, at a minimum, provided to each customer by means of a note on or included with the customer's bill. The notice shall include the timeline for implementation of the revisions to the Customer Service Policy.

8.5.2 A rate-regulated gas distributor shall provide the Board with a copy of its revised Customer Service Policy. The revised Customer Service Policy shall be accompanied by a cover letter that indicates the revisions made and their implementation date.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

NOTICE OF AMENDMENT TO A RULE

ELIGIBLE LOW-INCOME CUSTOMER SERVICE POLICY AMENDMENTS TO THE GAS DISTRIBUTION ACCESS RULE

BOARD FILE NO: EB-2010-0280

To: All Natural Gas Distributors
All Participants in Consultation Processes EB-2010-0280, EB-2007-0722, EB-2008-0313 and EB-2008-0150
All Other Interested Parties

Date: September 6, 2012

The Ontario Energy Board has today issued amendments to the Gas Distribution Access Rule (the "GDAR") as indicated below, pursuant to section 44(1) of the *Ontario Energy Board Act, 1998* (the "Act").

I. Background

On July 12, 2012, the Board issued a Notice of Proposal to Amend a Rule (the "July Notice") in which it proposed a number of amendments to the GDAR (the "Proposed Amendments"). The Proposed Amendments were designed to ensure that rate-regulated natural gas distributors develop and maintain appropriate customer service policy standards and practices for their low-income customers, and to ensure that they publish and comply with those policy standards and practices.

In response to the July Notice, the Board received written comments from two gas distributors and a ratepayer group representative. These comments are available for viewing on the Board's website www.ontarioenergyboard.ca under Industry/Regulatory Proceedings/Policy Initiatives and Consultations/GDAR Customer Service Amendments or at the following link:
http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/GDAR+Customer+Service+Amendments#20120730.

II. Summary of Comments in Response to the July Notice

Enbridge Gas Distribution Inc. (“Enbridge”) and Union Gas Limited (“Union”) confirmed that they will maintain appropriate customer service policy standards and practices for their eligible low-income residential customers. Moreover, the utilities made assurances that those policy standards and practices will be published, and that they will comply with those standards and practices as of January 1, 2013.

Enbridge and Union reiterated their earlier submissions that they both intend to track any costs incurred for system and process changes required to implement their customer service policies in their respective GDAR Costs Deferral Account for potential future disposition. The utilities will also be monitoring ongoing operational and potential lost revenue impacts.

The Low-Income Energy Network (“LIEN”) concurred with the Proposed Amendments.

LIEN further stated that the value of the less-prescriptive approach adopted by the Board will be demonstrated in the implementation of the changes the gas distributors have committed to make to their eligible low-income customer service policies, effective January 1, 2013. In support of the Board’s upcoming consultation on customer service monitoring and reporting requirements, LIEN submitted that in order to demonstrate the value of a less-prescriptive approach, the results should be measured over time.

LIEN also noted that the Board intends to later review the posted customer service policies of the rate-regulated gas distributors to assess whether they are consistent with the expectations of the Board. LIEN requested that the Board engage stakeholders in that review process.

III. Adoption of Proposed Amendments

The Board has considered all of the comments received and has determined that no change needs to be made to the Proposed Amendments.

The eligible low-income customer service amendments to the GDAR as adopted by the Board (the “Final Amendments”) are set out in Attachment A to this Notice.

IV. Anticipated Costs and Benefits

As indicated in the July Notice, these amendments to the GDAR will require each rate-regulated gas distributor to document and consistently apply the low-income customer service policies committed to during this consultation. This is expected to provide greater protection and certainty for eligible low-income customers in the areas of security deposits, access to equal billing and payment plans, arrears agreements and under billing adjustments. The approach adopted will also provide gas distributors with an appropriate measure of flexibility to account for each utility's operational considerations, as well as lower overall implementation costs. While proceeding with these amendments may lead to some additional costs for the gas distributors, the Board believes that the benefits to low-income gas customers will be substantial.

V. Updating Customer Service Reporting Requirements

As indicated in its March 1, 2012 letter in this consultation, the Board believes that developing effective customer service monitoring and associated regulatory reporting requirements is important to ensure that the residential and eligible low-income customer service policies in the gas sector are achieving their intended objectives. Given that the gas sector will not be subject to detailed prescriptive customer service rules, it will be useful to monitor customer complaints that may emerge. The Board will initiate a separate consultation process in this area shortly.

VI. Cost Awards

The Board has addressed cost claims for commenting on the July Notice, as well as the earlier Notices in this consultation, in separate correspondence issued today.

Costs in respect of providing any future comments on proposed updated gas sector customer service reporting requirements will be addressed later.

VII. Coming into Force

The Board will adopt January 1, 2013 as the coming into force date for the eligible low-income customer service policy amendments to the GDAR. As of that date, each rate-regulated gas distributor must have an appropriately updated Customer Service Policy posted on its website and must conduct its business in accordance with that Customer Service Policy.

This Notice, including the Final Amendments to the GDAR set out in Attachment A, is available for public inspection on the Board's website at www.ontarioenergyboard.ca under Industry/Regulatory Proceedings/Policy Initiatives and Consultations/GDAR Customer Service Amendments or at the following link:
http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/GDAR+Customer+Service+Amendments#20120730
and at the office of the Board during normal business hours.

Any questions regarding implementation of the Eligible Low-Income Customer Service Policy Amendments to the GDAR set out in Attachment A should be directed to the Market Operations Hotline at 416-440-7604 or market.operations@ontarioenergyboard.ca.

The Board's toll free number is 1-888-632-6273.

DATED at Toronto, September 6, 2012

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Attachment A: Final Eligible Low-Income Customer Service Policy Amendments to the Gas Distribution Rule (September 6, 2012)

Attachment A

Eligible Low-Income Customer Service Policy Amendments to the Gas Distribution Access Rule

September 6, 2012

Note: The text of the amendments is set out in italics below, for ease of identification only.

1. Subsection 1.2.1 of the Gas Distribution Access Rule is amended by modifying the definition of "Customer Service Policy" to read as follows:

   "Customer Service Policy" means the document developed by a rate-regulated gas distributor in accordance with *chapter* 8 of this Rule that describes the customer service-related standards and practices applicable to its residential customers;

   and by adding the following definitions immediately after the definition of "E.B.O. 188 Report":

   "*eligible low-income customer" means a residential customer who:*

   - *has a pre-tax household income at or below the most recent pre-tax Low Income Cut-Off, according to Statistics Canada, plus 15%, taking into account family size and community size, as qualified by a Social Service Agency or Government Agency; or*
   - *has been qualified for Emergency Financial Assistance;*

   "*Emergency Financial Assistance" means any Board-approved emergency financial assistance, or other financial assistance made available by a distributor, to eligible low-income customers;*

   and by adding the following definition immediately after the definition of "Service Transaction Request":

   "Social Service Agency or Government Agency" means:

   - *a social service agency or government agency that partners with a given distributor to assess eligibility for Emergency Financial Assistance; or*
   - *a social service agency or government agency that assesses eligibility for other energy financial assistance or low-income financial assistance programs, and partners with a given distributor to qualify customers for eligibility under chapter 8 of this Rule;*

2. Subsection 1.4.6 of the Gas Distribution Access Rule is amended by replacing the word “Section” at the beginning of the first paragraph with “*Chapter*”.

3. Section 1.4 of the Gas Distribution Access Rule is amended by adding the following new paragraph immediately after subsection 1.4.6.

> *1.4.7 Subsection 8.1.3 and the amendments to subsection 1.2.1 to include the definition of “eligible low-income customer”, “Emergency Financial Assistance” and “Social Service Agency or Government* Agency” *shall come into force on January 1, 2013.*

4. Chapter 8 of the Gas Distribution Access Rule is amended by adding the following new paragraph immediately after subsection 8.1.2.

> *8.1.3 Where a rate-regulated gas distributor has established customer service-related standards and practices specific to eligible low-income customers, the gas distributor shall describe them in its Customer Service Policy in a manner separate and apart from its customer service-related standards and practices applicable to other residential customers.*

5. Subsection 8.5.1 of the Gas Distribution Access Rule is amended by adding the word “*residential*” following the word “each” in the third line.

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Ontario

BY E-MAIL AND WEB POSTING

March 28, 2013

NOTICE OF AMENDMENT TO A RULE

AMENDMENTS TO THE NATURAL GAS REPORTING & RECORD KEEPING REQUIREMENTS IN RELATION TO RESIDENTIAL AND LOW-INCOME CUSTOMER SERVICE POLICIES

BOARD FILE EB-2010-0280

To: All Natural Gas Distributors
All Participants in Consultation Processes EB-2010-0280, EB-2007-0722, EB-2008-0313 and EB-2008-0150
All Other Interested Parties

The Ontario Energy Board is giving notice under section 45 of the *Ontario Energy Board Act, 1998* of amendments to the Natural Gas Reporting and Record Keeping Requirements Rule ("Gas RRR").

1.0 Background

The amendments set out in Attachment A to this Notice require rate-regulated gas distributors to report on the application of the residential and eligible low-income customer service policies that they committed to in the Board's consultation on Customer Service Policies of Natural Gas Distributors (EB-2010-0280).

1.1 Consultation on Customer Service Policies of Natural Gas Distributors

Following consultation with stakeholders, amendments to the Gas Distribution Access Rule ("GDAR") requiring rate-regulated gas distributors to implement and publish updated *residential* customer service policies came into effect on April 1, 2012. Similar amendments to GDAR in relation to customer service policies for *low-income* customers came into effect on January 1, 2013.

In its September 6th, 2012 Notice of Amendment to a Rule: Eligible Low-Income Customer Service Policy Amendments to the Gas Distribution Access Rule, the Board also indicated that "developing effective customer service monitoring and associated regulatory reporting requirements is important to ensure that the residential and eligible low-income customer service policies in the gas sector are achieving their intended objectives."

This Notice sets out the Board's final amendments to the Gas RRR related to the application of customer service policies of rate-regulated natural gas distributors.

1.2 Consultation on Amendments to Gas RRR in Relation to Customer Service Policies of Natural Gas Distributors

The Board's objective for the new Gas RRR requirements is to gather adequate data to monitor and assess the impacts of the customer service policies of gas distributors. When designing the Gas RRR amendments, the Board took into account the less prescriptive customer service regulatory regime adopted for the gas sector.

Board staff solicited comments at the October 18, 2012 meeting of the Low-income Energy Assistance Program (LEAP) Working Group that assisted in the development of the Board's December 13, 2012 Notice of Proposal to Amend a Rule: Customer Service Amendments to the Natural Gas Reporting and Record Keeping Requirements (the "Notice of Proposed Amendments").

In response to the Notice of Proposed Amendments the Board received written comments from Enbridge Gas Distribution Inc. ("Enbridge"), the City of Kitchener, the Low-Income Energy Network ("LIEN"), Natural Resource Gas Limited ("NRG") and Union Gas Limited ("Union"). Stakeholders' submissions are available on the Board's website www.ontarioenergyboard.ca. The Board was greatly assisted by these comments in finalizing the amendments to the Gas RRR.

2.0 Gas RRR Amendments Related to the Residential Customer Service Policies of Natural Gas Distributors

Attachment A to this Notice sets out the Board's new reporting requirements for natural gas distributors in relation to customer service policies for residential, including low-income, customers. These reporting requirements will enable the Board to monitor and assess the impacts of the customer service policies adopted by natural gas distributors.

The Gas RRR requirements build upon the Electricity RRR amendments in relation to customer service rules for residential electricity customers, with adjustments to account for differences between the two sectors.

All the new data to be collected will be filed once a year with the Board, as part of each natural gas distributor's regularly scheduled Gas RRR filing.

3.0 Summary of Stakeholder Comments

3.1 General Comments

LIEN expressed its support for the proposed reporting requirements noting that a less prescriptive approach to customer service policies continues to be appropriate for natural gas distributors provided, among other matters, that appropriate reporting requirements are in place to monitor the effectiveness of the policies.

In their comments Union and Enbridge indicated that, with one exception that will be discussed below, they could readily comply with the proposed reporting requirements. Both noted that the costs of meeting these new reporting requirements are currently unknown but they will be tracked in a variance account until such time as they are reviewed in a rate hearing.

NRG stated that the proposed reporting requirements would be onerous for a company of its size. Arguing that the costs of meeting these requirements would be high (and borne by rate-payers), and that NRG's results would be insignificant in relation to the total data collected, NRG requested that the Board exempt it from these reporting requirements.

The Board notes that the purpose of these reporting requirements is to evaluate the effectiveness of each natural gas distributor's customer service policies and not necessarily to evaluate the sector as a whole. Therefore, it is important for NRG to report this information in order for the Board to assess whether NRG's customer service policies are meeting the intended objectives, regardless of the size of the company in relation to its peers. The Board notes that in previous submissions in this consultation NRG has indicated that it could provide some of the data that will be collected in accordance with the new reporting requirements. The Board has adopted reporting requirements regarding customer service rules for electricity distributors that are very similar to those being adopted for natural gas distributors. Some electricity distributors have similar or more limited internal resources than NRG and yet comply with the reporting requirements regarding customer service rules that the Board adopted. However, NRG may choose to apply for an exemption from specific reporting requirements once it has a more robust estimate of the costs associated with collecting this data.

3.2 Comments on Arrears and Arrears Payment Agreements

LIEN suggested a significant number of additional data points that could be collected in order to provide greater detail about disconnections for non-payment and arrears payment agreements. For example, LIEN proposed that natural gas distributors also report on the number of residential and low income customers that were disconnected once, and that were disconnected more than once, during a year for non-payment where the customer had an arrears payment agreement. LIEN also suggested that it would be helpful to track the number of customers with an arrears payment agreement that also participated in a DSM program as well as the average amount of arrears and the average length of time over which arrears are repaid.

Union and Enbridge provided a joint response to LIEN's submission. They argued that some of the data that LIEN proposed is difficult, and in some cases, impossible to collect. For example, Union and Enbridge indicated that the number of customers with an arrears payment agreement that also participated in a DSM program cannot be determined because these figures are tracked separately and cannot be reconciled. They also argued that other information, such as the average amount of arrears, could be derived or calculated using the data already proposed by the Board.

In addition, Enbridge and Union expressed concerns about the costs relative to the benefits associated with collecting the additional data proposed by LIEN.

Although the Board agrees that the data proposed by LIEN would provide additional insight on the efficacy of natural gas distributors' customer service policies, the Board is also mindful that the costs of collecting this additional information might exceed the benefits. The Board believes that the reporting requirements proposed in its Notice of Proposed Amendments are sufficient to adequately assess the effectiveness of the customer service policies. Therefore, the Board will not make any changes to the proposed Gas RRR amendments related to the areas discussed above.

3.3 Comments on Ongoing Consultation

LIEN recommended that the natural gas distributors be required to consult with stakeholders annually on implementation of their customer service policies with a view to achieving continual improvement. In addition, LIEN proposed the Board undertake a detailed review of customer service policies and associated reporting and recordkeeping requirements at least every 5 years, or consistent with the length of time of the Incentive Regulation framework.

In their joint submission Enbridge and Union noted that it would be useful to collect the data on these policies for a number of years before undertaking an evaluation including consultation with stakeholders.

The Board notes that the LEAP working group meets from time to time, and suggests that these meetings are an appropriate venue for stakeholders to raise issues about the effectiveness of the customer service policies and discuss whether a more detailed review might be needed. As the Board stated in the Notice of Proposed Amendments, the Board intends to revisit its policy on natural gas distributors' customer service policies once several years of results from the annual Gas RRR customer service reporting are available.

3.2 Comments on Proposed Gas RRR Amendments Pertaining to Customer Service-Related Enquiries

In its Notice of Proposed Amendments the Board proposed that the natural gas distributors report the total number of enquiries received from residential customers. In addition, the Board indicated that enquiries from residential customers be reported under similar categories as are used for tracking complaints, but only to the extent possible given the current capabilities of each utility.

Both Union and Enbridge noted that, for the purpose of reporting enquiries, their information technology will currently not allow them to differentiate enquiries from residential and small commercial customers. In addition, upgrades to their Customer Information and Interactive Voice Response systems are necessary in order to report enquiries by the categories proposed and there would be significant costs associated with this.

In light of the potential costs associated with meeting this reporting requirement the Board will require only the total number of enquiries to be reported. Although the term 'residential' is maintained in section 2.1.19 c) of the new Gas RRR, the Board accepts that the total number of enquiries will reflect residential and small commercial customers and notes that this will still provide enough context within which the data about customer complaints can appropriately be analyzed.

3.4 Comments from Non rate-regulated Natural Gas Distributors

The City of Kitchener provided in its comments a list of the data that it could provide. However, some limitations were noted, namely, that the City of Kitchener will not classify customer accounts as "low-income" and further, gas customer accounts are not able to be differentiated from other municipal customer accounts (e.g. water).

Kingston Utilities did not provide any comments in response to the Board Notice of Proposed Amendments.

The Board thanks the City of Kitchener for its efforts in determining the data it could report and encourages both non rate-regulated gas distributors to report any of the data set out in Attachment A that may be feasible.

4.0 Baseline Data

In addition to the data required in accordance with the Gas RRR amendments set out in Attachment A, the Board believes that gathering relevant baseline data will assist in assessing the impacts of the gas customer service policies.

As a result, natural gas distributors must also file available information for 2011, 2012 and for the first six months of 2013 in respect of the various measures that will be tracked under the Gas RRR amendments.

The Notice of Proposed Amendments included a list of the data that each natural gas distributor has indicated that it can provide and the Board expects that, when received, the baseline filings will generally be consistent with these commitments.

5.0 Uses of Data to be Collected

5.1 Annual Performance Monitoring

The information to be reported annually by gas distributors under the proposed Gas RRR amendments, supplemented by gas customer service complaints received directly by the Board, will be used to monitor results each year for gas customers and distributors under the updated residential and eligible low-income customer service policies.

5.2 Assessment of the Impact of the Revised Customer Service Policies

The 2009 Low-Income Energy Assistance Program Report of the Board indicated that it will be important to later evaluate and measure performance so as to better understand “how effective the LEAP program has been in managing low-income energy consumer issues in relation to their use of natural gas and electricity such as disconnections, bad debt expenses, etc.”

As mentioned above, once several years of results from the annual Gas RRR customer service reporting become available, the Board will decide if there is merit in undertaking another detailed review of gas sector customer service policies. Any future assessment could also make recommendations for changes and improvements to the Gas RRR customer service reporting requirements.

6.0 Coming into Force and Initial Filing Date

The new Gas RRR sections 2.1.18 and 2.1.19 will come into force for the rate-regulated natural gas distributors on July 1, 2013. Notwithstanding the foregoing sentence, however, in order to accommodate system upgrades required to collect data under subsection 2.1.19 (b), which requires reporting of complaints by categories, the Board will allow Union to begin collecting this data October 1, 2013. Where feasible, distributors may wish to start collecting the required information earlier.

The Gas RRR provides that the reported data must be filed with the Board four months after the distributor's financial year-end. Currently, Enbridge and Union have a financial year-end of December 31st, while NRG has a September 30th year-end. Therefore the Enbridge and Union filings are due April 30th each year, while NRG's filing is due January 31st.

Enbridge and Union must file their new customer service data for the July to December 2013 period as part of their regular April 2014 RRR filing. NRG must file its new customer service data for the July to September 2013 as part of its regular January 2014 RRR filing. The Board also requires that available baseline data for 2011, 2012 and the first six months of 2013 be filed at these times. The Board will provide a template and directions for the filing of the baseline data in due course.

This Notice and the amendments set out in Attachment A are available for public inspection at the office of the Board during normal business hours and on the Board's website at www.ontarioenergyboard.ca.

Any questions relating to these proposed amendments to the Gas RRR should be directed to Takis Plagiannakos, Manager, Rates, Conservation and Policy Evaluation, Regulatory Policy, at 416-440-7680 or by e-mail at takis.plagiannakos@ontarioenergyboard.ca .

The Board's toll free number is 1-888-632-6273.

DATED at Toronto, March 28, 2013.

Original Signed By

ONTARIO ENERGY BOARD

Kirsten Walli
Board Secretary

Attachment: Attachment A: Amendments to the Natural Gas Reporting and Record Keeping Requirements in Relation to Residential and Low-income Customer Service Policies

Attachment A to March 28, 2013 Notice of Amendment to a Rule

Amendments to the
Natural Gas Reporting & Record Keeping Requirements in Relation to Residential and Low-income Customer Service Policies

EB-2010-0280

Note: The text of the proposed amendments is set out in italics below, for ease of identification only.

Note: Where "year end" is referred to below, financial year end is meant.

1. Section 1.8 of the RRR is amended by adding the following as the new last paragraph in that section:

    - *Sections 2.1.18 and 2.1.19 of this Rule made by the Board on March 28, 2013, come into force on July 1, 2013.*

2. Section 2.1 of the RRR is amended by adding the following subsections:

2.1.18 A utility shall provide in the form and manner required by the Board, annually, by the last day of the fourth month after the financial year end, the following information for the preceding financial calendar year with respect to residential and eligible low-income customers:

a) Number of Customer Accounts

i. number of residential customer accounts at year end; and

ii. number of eligible low-income customer accounts at year end.

b) Disconnections for Non-Payment

i. number of residential customer accounts disconnected for non-payment during the course of the year;

ii. number of residential customer accounts disconnected for non-payment more than once during the course of the year;

iii. number of eligible low-income customer accounts disconnected for non-payment during the course of the year;

iv. number of eligible low-income customer accounts disconnected for non-payment more than once during the course of the year;

v. number of residential customer accounts where the account was disconnected for non-payment in both of the last two years; and

vi. number of eligible low-income accounts where the account was disconnected for non-payment in both of the last two years.

c) Accounts in Arrears

i. number of residential customer accounts in arrears during each month in the year;

ii. number of eligible low-income customer accounts in arrears during each month in the year;

iii. total dollar amount of arrears for residential customer accounts in arrears during each month in the year; and

iv. total dollar amount of arrears for eligible low-income customer accounts in arrears during each month in the year.

d) Aging of Accounts in Arrears

i. number of residential customer accounts in arrears that are, at the end of each month, from 31 to 60 days overdue, from 61 to 90 days overdue, from 91 to 120 days overdue, and greater than 120 days overdue;

ii. total dollar amount of residential customer arrears that are, at the end of each month, from 31 to 60 days overdue, from 61 to 90 days overdue, from 91 to 120 days overdue, and greater than 120 days overdue;

iii. number of eligible low-income customer accounts in arrears that are, at the end of each month, from 31 to 60 days overdue, from 61 to 90 days overdue, from 91 to 120 days overdue, and greater than 120 days overdue; and

iv. total dollar amount of eligible low-income customer arrears that are, at the end of each month, from 31 to 60 days overdue, from 61 to 90 days overdue, from 91 to 120 days overdue, and greater than 120 days overdue.

e) Arrears Payment Agreements

i. number of arrears payment agreements entered into during the course of the year with residential customers;

ii. number of arrears payment agreements entered into during the course of the year with eligible low-income customers;

iii. total amount of monies owing under arrears payment agreements entered into during the course of the year with residential customers;

iv. total amount of monies owing under arrears payment agreements entered into during the course of the year with eligible low-income customers;

v. number of arrears payment agreements with residential customers that were cancelled during the course of the year due to non-payment;

vi. number of arrears payment agreements with eligible low-income customers that were cancelled during the course of the year due to non-payment;

vii. number of arrears payment agreements entered into during the course of the year with residential customers that were: i) up to one month in duration; ii) from one to three months in duration (i) from four to six months in duration; (ii) from seven to nine months in duration; (iii) from nine to twelve months in duration; and (iv) from thirteen or more months in duration;

viii. number of arrears payment agreements entered into during the course of the year with low-income residential customers that were: i) up to one month in duration; ii) from one to three months in duration (i) from four to six months in duration; (ii) from seven to nine months in duration; (iii) from nine to twelve months in duration; and (iv) from thirteen or more months in duration;

f) Write Offs

i. number of residential customer accounts written off in whole or in part during the course of the year;

ii. number of eligible low-income customer accounts written off in whole or in part during the course of the year;

iii. total dollar amount of write offs for residential customer accounts during the course of the year; and

iv. total dollar amount of write offs for eligible low-income customer accounts during the course of the year.

g) Equal Billing and Equal Payment Plans

i. number of residential customer accounts enrolled in an equal billing plan at year end;

ii. number of eligible low-income customer accounts enrolled in an equal billing plan at year end;

iii. number of residential customer accounts enrolled in an equal payment plan at year end; and

iv. number of eligible low-income customer accounts enrolled in an equal payment plan at year end.

h) Security Deposits

i. number of residential customer accounts with a security deposit held at year end;

ii. total dollar amount of security deposits held in respect of residential customers at year end;

iii. number of eligible low-income customer accounts with a security deposit held at year end; and

iv. total dollar amount of security deposits held in respect of eligible low-income customers at year end.

2.1.19 A utility shall provide in the form and manner required by the Board, annually, by the last day of the fourth month after the financial year end, the following information for the preceding financial calendar year with respect to residential and eligible low-income customers:

a) Number of Customer Service-Related Complaints

i. number of customer-service related complaints distributors received during the year from their residential customers; and

ii. number of customer-service related complaints distributors receive during the year from their eligible low-income customers.

b) Type of Customer Service-Related Complaints

A utility shall subdivide the number of customer service-related complaints raised by residential customers under subsection 2.1.19 a) i) above, and by eligible low–income customers under subsection 2.1.19 a) ii) above, into the following topics and sub-topics:

i) Bill Issuance and Payment

- *due date of bill;*
- *date payment received (for customers not on automatic payment plans);*
- *credit balance refund;*
- *payments in respect of Automatic Payment Plans/ Preauthorized Payment Plans; and*
- *other.*

ii) Billing Adjustments

- *under-billing (e.g. about how far go back for under-billing adjustment or about adequacy of time period offered to pay under-billing adjustment); and*
- *over-billing (e.g. about how refund payments are made, such as by cheque, credit to account, etc.).*

iii) Equal Billing & Equal Payment Plans

- *customer could not join the plan;*
- *midseason review (e.g. about whether or not a mid-season review took place);*
- *final true-up (e.g. about time allowed to pay a debit adjustment and whether a refund cheque was issued in the case of a credit adjustment); and*
- *other.*

iv) Disconnection Notices

- *no notice;*
- *notice did not provide adequate information;*
- *notice received too soon prior to disconnection;*
- *deposit not considered before issuing disconnection notice; and*
- *other.*

v) Disconnection and Reconnection Procedures

- *distributor not making one final call before disconnection;*
- *reconnection (e.g. distributor missed reconnection appointment or no show); and*

- *other.*

vi) Suspension of Disconnection Pending Review of Low-Income Eligibility
- *adequacy of period of suspending disconnection pending review of low-income eligibility; and*
- *other.*

vii) Arrears Payment Agreements
- *not making agreement available;*
- *application of late payment charges;*
- *amount of down-payment required before entering agreement;*
- *length of agreement offered;*
- *cancellation and reinstatement (e.g. cancelled after customer missed only one payment, customer not given adequate notice when cancelled or customer was not reinstated when paid in full before cancellation); and*
- *other.*

viii) Security Deposits
- *not offering to allow the customer to pay over 6 months;*
- *unfair amount requested;*
- *not returned;*
- *not waived (e.g. good credit record not accepted); and*
- *other.*

ix) Opening and Closing of Accounts
- *former tenant's charges applied to new tenant;*
- *tenant's charges applied to landlord without consent;*
- *former owner's charges being applied to a new owner; and*
- *other.*

x) Low-Income Customer Eligibility
- *eligibility for low-income customer service policy;*
- *eligibility for low-income customer emergency financial assistance (e.g. LEAP or Winter Warmth); and*
- *other.*

xi) Other Customer Service-Related Topics.

c) Type of Customer Service-Related Enquiries

i. *number of customer service-related enquiries distributors received during the year from their residential customers;*

For the purposes of sections 2.1.18 and 2.1.19 above:

(a) reporting on information regarding residential customers shall cover all residential customers, including eligible low-income customers; and

(b) the following definitions apply:

"account in arrears" means an account that is more than 30 days past the minimum payment period required to pay for the gas and/or non-gas services billed by the utility;

"arrears payment agreement" means a bill repayment arrangement where a customer has entered into extending the payment period beyond the minimum payment period required to pay for the gas and/or non-gas services billed by the utility;

"customer service-related complaint" means a customer service-related enquiry from a residential customer that requires escalation by a customer service employee for further internal review by the utility;

"customer service-related enquiry" means an enquiry from a residential customer pertaining to the utility's customer service policies;

"eligible low-income customer" means an eligible low-income natural gas customer, as defined in section 1.2 of the Gas Distribution Access Rule;

"equal billing plan" means a billing plan where the amount due in each bill is equalized over the course of the billing periods in a year;

"equal payment plan" means an arrangement where a customer has entered into an equal billing plan and the monthly payment is made with an automatic withdrawal from a financial institution;

Tab 2

2013 UTILITY RESULTS AND RETURN ON EQUITY

2013 NORMALIZED UTILITY RESULTS

For the year ended December 31, 2013, Union's normalized revenue sufficiency from utility operations is $14.7 million relative to Board-approved, resulting in a normalized return on equity ("ROE") of 9.73%, which is 80 basis points above the 2013 benchmark ROE. Table 1 Corrected below provides a summary of Union's normalized utility results.

Table 1 - Corrected

Normalized Utility Results
For the Year Ended December 31, 2013

Line No.	Particulars ($ Millions)	Board-Approved 2013	Actual 2013	Increase/ (decrease)
		(a)	(b)	(c) = (b) - (a)
1	Total revenue deficiency/(sufficiency)	-	(32.2)	(32.2)
2	Normalization adjustments:			
3	Weather	-	11.4	11.4
4	Terminated Contract Settlements	-	6.1	6.1
5	Normalized revenue deficiency/(sufficiency)	-	(14.7)	(14.7)
6	Normalized Return on Equity	8.93%	9.73%	0.80%

2013 ACTUAL UTILITY RESULTS

For the year ended December 31, 2013, Union's actual revenue sufficiency from utility operations is $32.2 million relative to Board-approved. Table 2 below provides the results from Union's actual utility operations for 2013.

Table 2

Calculation of Revenue Deficiency/(Sufficiency) from Utility Operations
For the Year Ended December 31, 2013

Line No.	Particulars ($ Millions)	Board Approved 2013	Actual 2013	Increase/ (decrease)
		(a)	(b)	(c) = (b) - (a)
1	Gas sales and distribution revenue	1,448.8	1,605.3	
2	Cost of gas	701.4	830.3	
3	Gas distribution margin	747.4	775.0	27.6
4	Transportation	157.0	160.1	3.1
5	Storage	10.4	8.8	(1.6)
6	Other revenue	20.2	18.0	(2.2)
7	Expenses	643.8	638.7	(5.1)
8	Income taxes	17.1	25.8	8.7
9	Utility income	274.1	297.4	23.3
10	Cost of Capital	272.6	271.7	(0.9)
11	Revenue deficiency / (sufficiency) after tax	(1.5)	(25.7)	(24.2)
12	Provision for income taxes on deficiency / (sufficiency)	(0.5)	(9.2)	(8.7)
13	Distribution revenue deficiency/(sufficiency)	(2.0)	(34.9)	(32.9)
14	Shareholder portion of short-term storage revenue	0.5	0.3	(0.2)
15	Shareholder portion of optimization activity	1.5	2.4	0.9
16	Total revenue deficiency/(sufficiency)	-	(32.2)	(32.2)

The primary drivers of Union's 2013 financial results relative to Board-approved are provided below.

Gas Distribution Margin

The increase in gas distribution margin of $27.6 million relative to Board-approved was mainly driven by an increase in customer usage of natural gas primarily due to colder weather and increased industrial market consumption.

Transportation Revenue

The increase in transportation revenue of $3.1 million relative to Board-approved was mainly driven by a cancellation fee for early termination of an M12 contract, and increased exchange opportunities driven by weather and customer behaviour. These increases were partially offset by lower demand for short-term transportation due to a bottleneck downstream of Parkway.

Expenses

The decrease in expenses of $5.1 million relative to Board-approved was mainly driven by lower operating and maintenance and depreciation expenses. Operating and maintenance expenses were lower primarily due to a decrease in pension costs and other cost savings partially offset by an increase in salaries and wages. Depreciation expense was lower due to the timing of Information Technology related projects going into service partially offset by additions in other asset classes.

Income Taxes

The increase in income taxes relative to Board-approved of $8.7 million is primarily driven by higher utility pre-tax income and a 1% increase in the Ontario statutory income tax rate.

2013 RETURN ON EQUITY

The benchmark return on equity ("ROE") for 2013 was 8.93%. Union's actual ROE from utility operations in 2013 was 10.67% or 174 basis points above the 2013 benchmark ROE.

The calculation of return on equity for 2013 is found at Exhibit A, Tab 2, Appendix B, Schedule 1. To calculate actual utility earnings Union starts in column (a) with Union's total corporate revenues and operating expenses; column (b) removes revenues and costs associated with Union's unregulated storage operations; column (c) makes adjustments that would normally be made under cost of service to arrive at utility income. To arrive at utility earnings for the purposes of calculating actual ROE, income taxes, interest and preferred dividends, and the shareholder portion of net short-term storage revenue and net optimization activity, are deducted. The adjustments are discussed in more detail below.

Unregulated Storage Operations

The revenues and costs for Union's unregulated storage operations are shown at Exhibit A, Tab 2, Appendix B, Schedule 1, column (b). The regulated and unregulated financial information was allocated using the methodology approved in EB-2011-0210.

Adjustments

Union is making the following adjustments to utility earnings (Exhibit A, Tab 2, Appendix B, Schedule 1, column (c)):

A) Demand Side Management Incentive
B) Charitable donations
C) Facility fees, customer deposit interest and foreign exchange on bank balances
D) Other

A) Demand Side Management Incentive

Other revenue includes the revenue recorded from the 2013 Demand Side Management Incentive ("DSMI") of $9.224 million. The DSMI amount is an incentive to the company to encourage it to actively pursue DSM activities. To ensure that the full amount of the DSMI accrues to the company and that the incentive is maintained, the DSMI revenue is removed from the calculation of utility earnings.

B) Charitable Donations

Charitable donation costs incurred by the utility are not allowable as deductions from utility earnings and as a result $2.952 million in costs have been removed.

C) Facility Fees, Customer Deposit Interest and Foreign Exchange on Bank Balances

Facility fees, customer deposit interest and foreign exchange on bank balances are recorded in the company's corporate results as interest expense. Since these items should be included in utility earnings, and are not part of the utility interest calculation they need to be adjusted for. As a result, facility fees and customer deposit interest of $0.383 million have been added to operating expenses and foreign exchange gain on bank balances of $0.374 million has been added to other expenses to arrive at utility earnings.

D) Other

In Union's corporate results, the transportation optimization built into distribution rates was reclassified to transportation revenue as an offset to the actual optimization revenue earned. In order to align with Board-approved presentation, this adjustment of $15.697

million has been shown as a cost of gas reduction.

Union's 2013 corporate results include the reversal of a provision for fuel costs related to 2011 and 2012 FT-RAM activity totaling $1.426 million which has been removed from transportation revenues.

Amounts relating to the Conservation Demand Management (CDM) program of $0.002 million, have been removed from operating and maintenance expenses because of a separate deferral mechanism in place.

Income Taxes

The approach used to calculate income taxes is the same approach used for rate making under cost of service.

Current utility income taxes are calculated using utility income before interest and taxes, less deemed interest costs, permanent and timing differences to arrive at taxable income multiplied by the current tax rates. The calculation can be found at Exhibit A, Tab 2, Appendix A, Schedule 14.

Interest and Preferred Dividends

The calculation of interest and preferred dividends is the same approach used for rate making under cost of service.

Utility interest expense is calculated using actual utility rate base, deemed capital structure, and actual average interest rates. The calculation can be found at Exhibit A, Tab 2, Appendix A, Schedule 4.

Preferred share dividend requirements are based on deemed capital structure and cost of capital. The calculation can be found at Exhibit A, Tab 2, Appendix A, Schedule 4.

Shareholder Portion of Net Short-Term Storage Revenue

The shareholder portion of net short-term storage revenue represents Union's 10% share of the actual net margin generated on the sale of excess utility storage space. The shareholder portion of $0.223 million, net of tax, has been removed from utility earnings.

Shareholder Portion of Net Optimization Activity

The shareholder portion of net optimization activity represents Union's 10% share of the net margin generated on optimization activities. The shareholder portion of $1.746 million, net of tax, has been removed from utility earnings.

Return on Equity (“ROE”)

Actual ROE is determined using utility earnings calculated as described above divided by deemed common equity at 36% of actual utility rate base. The actual 2013 ROE is 10.67% (Exhibit A, Tab 2, Appendix B, Schedule 1, column (d), line 26).

2013 UNREGULATED STORAGE

As directed by the Board in its EB-2011-0210 Decision and Order (p. 79), Union has provided plant continuity schedules related to Union’s unregulated storage business at Exhibit A, Tab 2, Appendix C, Schedules 1-3.

SERVICE QUALITY RESULTS

As set out in Union’s 2014-2018 IRM Settlement Agreement (p. 40), Union has provided the service quality indicator results at Exhibit A, Tab 2, Appendix D, Schedule 1.

UNION GAS LIMITED
Calculation of Revenue Deficiency/(Sufficiency)
Year Ended December 31

Line No.	Particulars ($000s)	Board-Approved 2013 (a)	Actual 2013 (b)
1	Operating revenue	1,636,340	1,792,286
2	Cost of service	1,362,212	1,494,930
3	Utility income	274,128	297,356
4	Requested return	272,639	271,717
5	Revenue deficiency / (sufficiency) after tax	(1,489)	(25,639)
6	Provision for income taxes on deficiency / (sufficiency)	(509)	(9,244)
7	Distribution revenue deficiency / (sufficiency)	$ (1,998)	$ (34,883)
8	Shareholder portion of short-term storage revenue	506	303
9	Shareholder portion of optimization activity	1,492	2,376
10	Total revenue deficiency/ (sufficiency)	-	(32,204)

UNION GAS LIMITED
Statement of Utility Income
Year Ended December 31

Line No.	Particulars ($000s)	Board-Approved 2013	Actual 2013
		(a)	(b)
	Operating Revenues:		
1	Gas sales and distribution	1,448,762	1,605,289
2	Transportation	156,997	160,108
3	Storage	10,383	8,844
4	Other	20,198	18,045
5		1,636,340	1,792,286
	Operating Expenses:		
6	Cost of gas	701,427	830,300
7	Operating and maintenance expenses	383,132	381,038
8	Depreciation	196,091	192,957
9	Other financing	1,179	383
10	Property and capital taxes	63,272	63,845
11		1,345,101	1,468,523
	Other Income (Expense)		
12	Gain/(Loss) on sale of assets	-	64
13	Gain/(Loss) on foreign exchange	-	(655)
14		-	(592)
15	Utility income before income taxes	291,239	323,171
16	Income taxes	17,111	25,815
17	Total utility income	$ 274,128	$ 297,356

UNION GAS LIMITED
Statement of Earnings Before Interest and Taxes
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved Corporate (a)	Unregulated Storage (b)	Adjustments (c)	Utility (d)=(a)-(b)+(c)	2013 Actual Corporate (e)	Unregulated Storage (f)	Adjustments (g)	Utility (h)=(e)-(f)+(g)
	Operating Revenues:								
1	Gas sales and distribution	1,448,762	-	-	1,448,762	1,620,985	-	(15,697) (i)	1,605,289
2	Transportation	156,641	(356)	-	156,997	161,178	(356)	(1,426) (ii)	160,108
3	Storage	96,441	86,059	-	10,383	90,672	81,828	-	8,844
4	Other	24,498	-	(4,300)	20,198	27,268	-	(9,224) (iii)	18,045
5		1,726,343	85,703	(4,300)	1,636,340	1,900,104	81,472	(26,346)	1,792,286
	Operating Expenses:								
6	Cost of gas	701,966	539	-	701,427	848,876	2,879	(15,697) (i)	830,300
7	Operating and maintenance expenses	397,112	12,986	(993)	383,132	397,275	13,283	(2,954) (iv)	381,038
8	Depreciation	205,804	9,713	-	196,091	202,682	9,725	-	192,957
9	Other financing	-	-	1,179	1,179	-	-	383 (v)	383
10	Property and other taxes	64,674	1,402	-	63,272	65,288	1,444	-	63,845
11		1,369,556	24,640	186	1,345,101	1,514,122	27,330	(18,268)	1,468,523
	Other Income (Expense)								
12	Gain/(Loss) on sale of assets	-	-	-	-	(227)	(291)	-	64
13	Other	-	-	-	-	(1,580)	(1,580)	-	-
14	Gain/(Loss) on foreign exchange	-	-	-	-	(1,051)	(22)	374 (vi)	(655)
15		-	-	-	-	(2,858)	(1,893)	374	(592)
16	Earnings Before Interest and Taxes	$ 356,787	$ 61,063	$ (4,486)	$ 291,239	$ 383,124	$ 52,249	$ (7,705)	$ 323,171

Notes:

i) Reclassification of optimization revenue as cost of gas

ii) Reversal of FT RAM fuel cost provision for 2011 and 2012

iii) Demand Side Management Incentive

iv) Charitable donations (2,952)
CDM Program (2)
(2,954)

v) Facility fees and customer deposit interest

vi) Foreign exchange gain on bank balances

UNION GAS LIMITED
Summary of Cost of Capital
Year Ended December 31

		2013 Board-Approved				2013 Actual			
		Utility Capital Structure		Cost Rate	Return	Utility Capital Structure		Cost Rate	Return
Line No.	Particulars	($000s)	(%)	%	($000s)	($000s)	(%)	%	($000s)
1	Long-term debt	2,289,139	61.30%	6.53%	149,481	2,262,097	59.78%	6.51%	147,362
2	Unfunded short-term debt	(1,287)	(0.03%)	1.31%	(17)	56,692	1.50%	1.15%	652
3	Total debt	2,287,852	61.26%		149,464	2,318,789	61.28%		148,014
4	Preference shares	102,248	2.74%	3.05%	3,117	102,879	2.72%	2.00%	2,060
5	Common equity	1,344,432	36.00%	8.93%	120,058	1,362,188	36.00%	8.93%	121,643
6	Total rate base	$ 3,734,532	100.00%		$ 272,639	$ 3,783,855	100.00%		$ 271,717

UNION GAS LIMITED
Total Weather Normalized Throughput Volume by Service type and Rate Class
All Customer Rate Classes
Year Ended December 31

		Board Approved 2013						Actual 2013					
Line No.	Volumes in 10^3m^3	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(a)	(b)	(c)	(d)	(e)	(f)
	General Service												
1	Rate M1 Firm	2,271,443	465,977	185,421	16,702	-	2,939,543	2,533,618	304,157	69,651	15,797	-	2,923,223
2	Rate M2 Firm	378,137	336,728	23,220	237,485	-	975,571	583,062	291,745	11,894	253,205	-	1,139,905
3	Rate 01 Firm	641,423	233,272	-	9,727	-	884,421	789,482	132,305	-	9,443	-	931,231
4	Rate 10 Firm	155,398	82,428	-	85,062	-	322,887	182,314	70,664	-	91,087	3,457	347,521
5	**Total General Service**	**3,446,401**	**1,118,404**	**208,642**	**348,975**	**-**	**5,122,423**	**4,088,476**	**798,871**	**81,545**	**369,532**	**3,457**	**5,341,881**
	Wholesale - Utility	-	-	-	-	-	-	-	-	-	-	-	-
6	Rate M9 Firm	-	-	-	60,750	-	60,750	-	-	-	63,240	-	63,240
7	Rate M10 Firm	48	-	-	141	-	189	284	-	-	-	-	284
8	**Total Wholesale - Utility**	**48**	**-**	**-**	**60,891**	**-**	**60,939**	**284**	**-**	**-**	**63,240**	**-**	**63,524**
	Contract	-	-	-	-	-	-	-	-	-	-	-	-
9	Rate M4	16,855	-	-	387,823	-	404,678	29,890	12,923	-	432,002	-	474,815
10	Rate M7	-	-	-	147,143	-	147,143	10,921	-	-	161,362	-	172,283
11	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-
12	Rate 20 Transportation	13,514	-	-	110,097	506,191	629,802	7,264	-	-	97,110	546,594	650,968
13	Rate 100 Storage	-	-	-	-	-	-	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	1,895,488	1,895,488	-	-	-	-	1,926,579	1,926,579
15	Rate T-1 Storage	-	-	-	-	-	-	-	-	-	-	-	-
16	Rate T-1 Transportation	-	-	-	-	548,986	548,986	-	-	-	-	452,838	452,838
17	Rate T-2 Storage	-	-	-	-	-	-	-	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	4,880,297	4,880,297	-	-	-	-	4,241,475	4,241,475
19	Rate T-3 Storage	-	-	-	-	-	-	-	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	272,712	272,712	-	-	-	-	273,597	273,597
21	Rate M5	14,152	-	-	520,981	-	535,132	25,761	941	-	497,780	-	524,481
22	Rate 25	42,913	-	-	-	116,643	159,555	97,661	-	-	-	117,806	215,467
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total Contract**	**87,433**	**-**	**-**	**1,166,044**	**8,220,317**	**9,473,795**	**171,497**	**13,864**	**-**	**1,188,254**	**7,558,890**	**8,932,505**
25	**Total Throughput Volume**	**3,533,882**	**1,118,404**	**208,642**	**1,575,911**	**8,220,317**	**14,657,156**	**4,260,257**	**812,735**	**81,545**	**1,621,026**	**7,562,347**	**14,337,910**

UNION GAS LIMITED
Throughput Volume by Service type and Rate Class
All Customer Rate Classes
Year Ended December 31

		Board Approved 2013						Actual 2013					
Line No.	Volumes in 10^3m^3	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(a)	(b)	(c)	(d)	(e)	(f)
	General Service												
1	Rate M1 Firm	2,271,443	465,977	185,421	16,702		2,939,543	2,626,749	315,338	72,211	16,377		3,030,675
2	Rate M2 Firm	378,137	336,728	23,220	237,485		975,571	602,017	301,229	12,281	261,437		1,176,964
3	Rate 01 Firm	641,423	233,272		9,727		884,421	830,433	139,168		9,933		979,534
4	Rate 10 Firm	155,398	82,428		85,062		322,887	189,948	73,623		94,901	3,602	362,073
5	**Total General Service**	**3,446,401**	**1,118,404**	**208,642**	**348,975**		**5,122,423**	**4,249,148**	**829,358**	**84,492**	**382,648**	**3,602**	**5,549,247**
	Wholesale - Utility												
6	Rate M9 Firm				60,750		60,750				63,240		63,240
7	Rate M10 Firm	48			141		189	284					284
8	**Total Wholesale - Utility**	**48**	**-**	**-**	**60,891**	**-**	**60,939**	**284**	**-**	**-**	**63,240**	**-**	**63,524**
	Contract												
9	Rate M4	16,855			387,823		404,678	29,890	12,923		432,002		474,815
10	Rate M7				147,143		147,143	10,921			161,362		172,283
11	Rate 20 Storage												
12	Rate 20 Transportation	13,514			110,097	506,191	629,802	7,264			97,110	546,594	650,968
13	Rate 100 Storage												
14	Rate 100 Transportation					1,895,488	1,895,488					1,926,579	1,926,579
15	Rate T-1 Storage												
16	Rate T-1 Transportation					548,986	548,986					452,838	452,838
17	Rate T-2 Storage												
18	Rate T-2 Transportation					4,880,297	4,880,297					4,241,475	4,241,475
19	Rate T-3 Storage												
20	Rate T-3 Transportation					272,712	272,712					273,597	273,597
21	Rate M5	14,152			520,981		535,132	25,761	941		497,780		524,481
22	Rate 25	42,913				116,643	159,555	97,661				117,806	215,467
23	Rate 30												
24	**Total Contract**	**87,433**	**-**	**-**	**1,166,044**	**8,220,317**	**9,473,795**	**171,497**	**13,864**	**-**	**1,188,254**	**7,558,890**	**8,932,505**
25	**Total Throughput Volume**	**3,533,882**	**1,118,404**	**208,642**	**1,575,911**	**8,220,317**	**14,657,156**	**4,420,929**	**843,222**	**84,492**	**1,634,142**	**7,562,492**	**14,545,277**

UNION GAS LIMITED
Weather Normalized Gas Sales Revenue by Service type and Rate Class
All Customer Rate Classes
Year Ended December 31

		Board Approved 2013						Actual 2013					
Line No.	Particulars ($000's)	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(a)	(b)	(c)	(d)	(e)	(f)
	General Service												
1	Rate M1 Firm	693,117	58,944	24,671	889	-	777,621	782,171	37,243	9,813	895	-	830,122
2	Rate M2 Firm	84,792	17,612	2,631	11,466	-	116,501	131,556	15,388	538	12,264	562	160,308
3	Rate 01 Firm	268,545	66,665	-	1,993	-	337,202	329,041	37,556	-	1,958	-	368,554
4	Rate 10 Firm	43,957	13,251	-	12,874	-	70,083	51,782	11,063	-	13,313	235	76,393
5	**Total General Service**	1,090,412	156,472	27,301	27,222	-	1,301,407	1,294,549	101,250	10,351	28,430	797	1,435,377
	Wholesale - Utility												
6	Rate M9 Firm	-	-	-	727	-	727	-	-	-	744	-	744
7	Rate M10 Firm	11	-	-	7	-	18	62	-	-	-	-	62
8	**Total Wholesale - Utility**	11	-	-	734	-	745	62	-	-	744	-	806
	Contract												
9	Rate M4	3,407	-	-	11,786	-	15,193	6,583	597	-	12,306	-	19,485
10	Rate M7	-	-	-	4,127	-	4,127	2,191	-	-	4,109	-	6,299
11	Rate 20 Storage	-	-	-	-	1,057	1,057	-	-	-	-	1,483	1,483
12	Rate 20 Transportation	3,304	-	-	10,277	10,637	24,219	1,634	-	-	8,832	10,304	20,771
13	Rate 100 Storage	-	-	-	-	166	166	-	-	-	-	168	168
14	Rate 100 Transportation	-	-	-	-	15,481	15,481	-	-	-	-	15,656	15,656
15	Rate T-1 Storage	-	-	-	-	1,400	1,400	-	-	-	-	1,412	1,412
16	Rate T-1 Transportation	-	-	-	-	9,241	9,241	-	-	-	-	8,562	8,562
17	Rate T-2 Storage	-	-	-	-	5,976	5,976	-	-	-	-	7,661	7,661
18	Rate T-2 Transportation	-	-	-	-	36,193	36,193	-	-	-	-	38,896	38,896
19	Rate T-3 Storage	-	-	-	-	1,345	1,345	-	-	-	-	1,385	1,385
20	Rate T-3 Transportation	-	-	-	-	3,054	3,054	-	-	-	-	3,072	3,072
21	Rate M5	2,801	-	-	12,913	-	15,713	5,058	32	-	12,335	-	17,424
22	Rate 25	10,172	-	-	-	3,273	13,445	20,777	-	-	-	3,270	24,047
23	Rate 30	-	-	-	-	-	-	-	-	-	-	80	80
24	**Total Contract**	19,684	-	-	39,102	87,824	146,610	36,243	629	-	37,581	91,950	166,402
25	**Subtotal**	1,110,107	156,472	27,301	67,058	87,824	1,448,762	1,330,854	101,878	10,351	66,754	92,746	1,602,585
26	LRAM						-						2,832
27	Average Use						-						(11,481)
28	Tax Rate Change Impact Adjustment						-						-
29	**Total Revenue**						1,448,762						1,593,935

UNION GAS LIMITED
Total Gas Sales Revenue by Service type and Rate Class
All Customer Rate Classes
Year Ended December 31

		Board Approved 2013						Actual 2013					
Line No.	Particulars ($000's)	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(a)	(b)	(c)	(d)	(e)	(f)
	General Service												
1	Rate M1 Firm	693,117	58,944	24,671	889	-	777,621	786,347	37,442	9,865	900	-	834,554
2	Rate M2 Firm	84,792	17,612	2,631	11,466	-	116,501	132,946	15,550	544	12,393	568	162,002
3	Rate 01 Firm	268,545	66,665	-	1,993	-	337,202	332,962	38,003	-	1,981	-	372,946
4	Rate 10 Firm	43,957	13,251	-	12,874	-	70,083	52,348	11,184	-	13,459	238	77,229
5	**Total General Service**	1,090,412	156,472	27,301	27,222	-	1,301,407	1,304,603	102,180	10,409	28,733	805	1,446,730
	Wholesale - Utility												
6	Rate M9 Firm				727		727				744		744
7	Rate M10 Firm	11			7		18	62					62
8	**Total Wholesale - Utility**	11	-	-	734	-	745	62	-	-	744	-	806
	Contract												
9	Rate M4	3,407			11,786		15,193	6,583	597		12,306		19,485
10	Rate M7				4,127		4,127	2,191			4,109		6,299
11	Rate 20 Storage	-	-	-	-	1,057	1,057	-	-	-	-	1,483	1,483
12	Rate 20 Transportation	3,304	-	-	10,277	10,637	24,219	1,634	-	-	8,832	10,304	20,771
13	Rate 100 Storage	-	-	-	-	166	166	-	-	-	-	168	168
14	Rate 100 Transportation	-	-	-	-	15,481	15,481	-	-	-	-	15,656	15,656
15	Rate T-1 Storage	-	-	-	-	1,400	1,400	-	-	-	-	1,412	1,412
16	Rate T-1 Transportation	-	-	-	-	9,241	9,241	-	-	-	-	8,562	8,562
17	Rate T-2 Storage	-	-	-	-	5,976	5,976	-	-	-	-	7,661	7,661
18	Rate T-2 Transportation	-	-	-	-	36,193	36,193	-	-	-	-	38,896	38,896
19	Rate T-3 Storage	-	-	-	-	1,345	1,345	-	-	-	-	1,385	1,385
20	Rate T-3 Transportation	-	-	-	-	3,054	3,054	-	-	-	-	3,072	3,072
21	Rate M5	2,801			12,913		15,713	5,058	32		12,335		17,424
22	Rate 25	10,172				3,273	13,445	20,777				3,270	24,047
23	Rate 30						-					80	80
24	**Total Contract**	19,684	-	-	39,102	87,824	146,610	36,243	629	-	37,581	91,950	166,402
25	**Subtotal**	1,110,107	156,472	27,301	67,058	87,824	1,448,762	1,340,908	102,808	10,409	67,058	92,755	1,613,938
26	LRAM												2,832
27	Average Use												(11,481)
28	Tax Rate Change Impact Adjustment												
29	**Total Revenue**						1,448,762						1,605,289

UNION GAS LIMITED
Delivery Revenue by Service type and Rate Class
All Customer Rate Classes
Year Ended December 31

		Board Approved 2013						Actual 2013					
Line No.	Particulars ($000's)	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(a)	(b)	(c)	(d)	(e)	(f)
	General Service												
1	Rate M1 Firm	303,298	58,944	24,671	889	-	387,801	341,488	37,442	9,865	900	-	389,695
2	Rate M2 Firm	19,898	17,612	2,631	11,466	-	51,607	30,914	15,550	544	12,393	568	59,969
3	Rate 01 Firm	118,812	41,509	-	928	-	161,249	145,099	23,787	-	980	-	169,866
4	Rate 10 Firm	9,524	5,578	-	4,876	-	19,979	11,449	4,778	-	5,129	238	21,594
5	**Total General Service**	451,532	123,643	27,301	18,159	-	620,636	528,950	81,558	10,409	19,402	805	641,124
	Wholesale - Utility												
6	Rate M9 Firm				727		727				744		744
7	Rate M10 Firm	2			7		10	14					14
8	**Total Wholesale - Utility**	2	-	-	734	-	736	14	-	-	744	-	758
	Contract												
9	Rate M4	514			11,786		12,300	1,477	597		12,306		14,379
10	Rate M7				4,127		4,127	396			4,109		4,505
11	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-
12	Rate 20 Transportation	434	-	-	2,425	10,637	13,496	210	-	-	2,063	10,304	12,577
13	Rate 100 Storage	-	-	-	-	-	-	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	15,481	15,481	-	-	-	-	15,656	15,656
15	Rate T-1 Storage	-	-	-	-	1,400	1,400	-	-	-	-	1,412	1,412
16	Rate T-1 Transportation	-	-	-	-	9,241	9,241	-	-	-	-	8,516	8,516
17	Rate T-2 Storage	-	-	-	-	5,976	5,976	-	-	-	-	7,661	7,661
18	Rate T-2 Transportation	-	-	-	-	36,193	36,193	-	-	-	-	38,896	38,896
19	Rate T-3 Storage	-	-	-	-	1,345	1,345	-	-	-	-	1,385	1,385
20	Rate T-3 Transportation	-	-	-	-	3,054	3,054	-	-	-	-	3,072	3,072
21	Rate M5	375			12,913		13,288	688	32		12,335		13,055
22	Rate 25	1,200				3,273	4,473	2,784				3,270	6,054
23	Rate 30						-						-
24	**Total Contract**	2,524	-	-	31,250	86,601	120,375	5,555	629	-	30,812	90,174	127,169
25	**Subtotal**	454,058	123,643	27,301	50,143	86,601	741,747	534,519	82,187	10,409	50,958	90,979	769,051
26	LRAM												2,832
27	Average Use												(11,481)
28	Tax Rate Change Impact Adjustment												
29	**Total Revenue**						741,747						760,402

Filed: 2014-05-02
EB-2014-0145
Exhibit A
Tab 2
Appendix A
Schedule 10

UNION GAS LIMITED
Total Customers by Service Type and Rate Class
All Customer Rate Classes
Year Ended December 31

Line No.	Particulars	Board Apprroved 2013 System Sales (a)	Board Apprroved 2013 ABC-T (b)	Board Apprroved 2013 ABC-Unbundled (c)	Board Apprroved 2013 Bundled-T (d)	Board Apprroved 2013 T-Service (e)	Board Apprroved 2013 Total (f)	Actual 2013 System Sales (a)	Actual 2013 ABC-T (b)	Actual 2013 ABC-Unbundled (c)	Actual 2013 Bundled-T (d)	Actual 2013 T-Service (e)	Actual 2013 Total (f)
	General Service												
1	Rate M1 Firm	837,301	157,165	72,389	902		1,067,757	945,122	92,119	26,110	1,048		1,064,399
2	Rate M2 Firm	3,172	2,594	241	771		6,778	3,942	1,960	59	762		6,723
3	Rate 01 Firm	242,644	80,300		343		323,287	282,559	41,913		585		325,057
4	Rate 10 Firm	930	845		289		2,064	1,217	494		300	5	2,016
5	**Total General Service**	**1,084,047**	**240,904**	**72,630**	**2,305**		**1,399,886**	**1,232,840**	**136,486**	**26,169**	**2,695**	**5**	**1,398,195**
	Wholesale - Utility												
6	Rate M9 Firm				3		3				2		2
7	Rate M10 Firm	1			1		2	2					2
8	**Total Wholesale - Utility**	**1**	**-**	**-**	**4**	**-**	**5**	**2**	**-**	**-**	**2**	**-**	**4**
	Contract												
9	Rate M4	11			104		115	18	5		126		149
10	Rate M7				4		4	1			3		4
11	Rate 20 Storage												
12	Rate 20 Transportation	4			20	39	63	2			18	28	48
13	Rate 100 Storage												
14	Rate 100 Transportation					17	17					14	14
15	Rate T-1 Storage												
16	Rate T-1 Transportation					35	35					38	38
17	Rate T-2 Storage												
18	Rate T-2 Transportation					29	29					22	22
19	Rate T-3 Storage												
20	Rate T-3 Transportation					1	1					1	1
21	Rate M5	5			139		144	11			100		111
22	Rate 25	50				42	92	43				51	94
23	Rate 30												
24	**Total Contract**	**70**	**-**	**-**	**267**	**163**	**500**	**75**	**5**	**-**	**247**	**154**	**481**
25	**Total Number of Customers**	**1,084,118**	**240,904**	**72,630**	**2,576**	**163**	**1,400,391**	**1,232,917**	**136,491**	**26,169**	**2,944**	**159**	**1,398,680**

UNION GAS LIMITED
Revenue from Regulated Storage and Transportation of Gas
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved	2013 Actual
		(a)	(b)
	Revenue from Regulated Storage Services:		
1	C1 Off-Peak Storage	500	389
2	Supplemental Balancing Services	2,000	1,841
3	Gas Loans	-	56
4	C1 Short Term Firm Peak Storage	7,883	4,747
5	Short Term Storage and Balancing Services Deferral	-	1,811
6	**Total Regulated Storage Revenue Net of Deferral**	$ **10,383**	$ **8,844**
	Revenue from Regulated Transportation Services:		
7	M12 Transportation	120,963	125,302
8	M12-X Transportation	13,896	13,895
9	C1 Long Term Transportation	7,039	5,478
10	C1 Short Term Transportation	11,067	9,713
11	Gross Exchange Revenue	14,918	24,524
12	Ratepayer Portion of Exchange Revenue	(13,426)	(21,150)
13	M13 Local Production	424	366
14	M16 Transportation	694	719
15	Other S&T Revenue	1,423	1,260
16	**Total Regulated Transportation Revenue Net of Deferral**	$ **156,997**	$ **160,108**

UNION GAS LIMITED
Other Revenue
Year Ended December 31, 2013

Line No.	Particulars ($000's)	Board-Approved	Actual
1	Delayed payment charges	6,467	6,557
2	Account opening charges	7,000	6,271
3	Billing revenue	3,453	2,465
4	Mid market transactions	2,000	998
5	Other operating revenue	1,278	1,754
6	**Total other revenue**	**20,198**	**18,045**

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved	2013 Actual
		(a)	(b)
1	Salaries/Wages	192,786	201,762
2	Benefits	81,083	76,494
3	Materials	9,958	8,979
4	Employee Training	14,330	13,383
5	Contract Services	66,376	65,931
6	Consulting	8,172	8,497
7	General	18,890	21,932
8	Transportation and Maintenance	9,761	9,176
9	Company Used Gas	2,611	2,530
10	Utility Costs	4,682	4,660
11	Communications	6,380	5,730
12	Demand Side Management Programs	24,031	24,941
13	Advertising	2,386	2,283
14	Insurance	9,056	8,419
15	Donations	788	2,979
16	Financial	1,871	959
17	Lease	4,191	4,125
18	Cost Recovery from Third Parties	(2,549)	(5,600)
19	Computers	6,465	5,638
20	Regulatory Hearing & OEB Cost Assessment	4,300	3,253
21	Outbound Affiliate Services	(13,706)	(12,422)
22	Inbound Affiliate Services	11,888	10,572
23	Bad Debt	6,250	4,811
24	Other	139	-
25	Total	470,139	469,031
26	Indirect Capitalization (OH)	(51,376)	(56,328)
27	Direct Captialization (DCC)	(21,652)	(15,428)
28	Total	397,111	397,275
29	Unregulated Storage	(12,883)	(13,283)
30	Non Utility Earnings Adjustments	(1,096)	(2,954)
31	Total Non Utility Costs	(13,979)	(16,237)
32	Total Net Utility Operating and Maintenance Expense	$ 383,132	$ 381,038

UNION GAS LIMITED
Calculation of Utility Income Taxes
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved	2013 Actual
		(a)	(b)
	Determination of Taxable Income		
1	Utility income before interest and income taxes	291,239	323,171
	Adjustments required to arrive at taxable utility income:		
2	Interest expense	(149,464)	(148,014)
3	Utility permanent differences	4,693	1,538
4		146,468	176,695
	Utility timing differences		
5	Capital Cost Allowance	(185,314)	(181,729)
6	Depreciation	196,091	192,957
7	Depreciation through clearing	2,265	1,730
8	Other	(32,921)	(34,997)
9	Gas Cost Deferrals and Other (current)	-	(40,861)
10		(19,879)	(62,900)
11	Taxable income	126,589	113,795
	Calculation of Utility Income Taxes		
12	Income taxes (line 11 * line 18)	32,280	30,156
13	Deferred tax on Gas Cost Deferrals	-	10,828
14	Deferred tax drawdown	(15,169)	(15,169)
15	Total taxes	17,111	25,815
	Tax Rates		
16	Federal tax	15.00%	15.00%
17	Provincial tax	10.50%	11.50%
18	Total tax rate	25.50%	26.50%

UNION GAS LIMITED
Calculation of Capital Cost Allowance (CCA)
Year Ended December 31

Line No.		Particulars ($000s)	2013 Board-Approved Depreciable UCC Balance (a)	2013 Board-Approved Rate (%) (b)	2013 Board-Approved CCA (c)	2013 Actual Depreciable UCC Balance (d)	2013 Actual Rate (%) (e)	2013 Actual CCA (f)
	Class							
1	1	Buildings, structures and improvements, services, meters, mains	1,259,974	4%	50,399	1,265,050	4%	50,602
2	1	Non-residential building acquired after March 19, 2007	83,527	6%	5,012	83,317	6%	4,999
3	2	Mains acquired before 1988	147,495	6%	8,850	147,500	6%	8,850
4	3	Buildings acquired before 1988	4,279	5%	214	4,280	5%	214
5	6	Other buildings	173	10%	17	170	10%	17
6	7	Compression equipment acquired after February 22, 2005	165,697	15%	24,855	155,767	15%	23,365
7	8	Compression assets, office furniture, equipment	79,640	20%	15,928	71,470	20%	14,294
8	10	Transportation, computer equipment	18,611	30%	5,583	19,683	30%	5,905
9	12	Computer software, small tools	7,701	100%	7,701	10,109	100%	10,109
10	13	Leasehold improvements (1)	332	N/A	113	4,170	N/A	407
11	17	Roads, sidewalk, parking lot or storage areas	946	8%	76	950	8%	76
12	38	Heavy work equipment	6,878	30%	2,063	5,163	30%	1,549
13	41	Storage assets	8,019	25%	2,005	6,192	25%	1,548
14	45	Computers - Hardware acquired after March 22, 2004	246	45%	111	247	45%	111
15	49	Transmission pipeline additions acquired after February 23, 2005	204,628	8%	16,370	205,000	8%	16,400
16	50	Computers hardware acquired after March 18, 2007	22,934	55%	12,614	15,545	55%	8,550
17	51	Distribution pipelines acquired after March 18, 2007	556,733	6%	33,404	578,883	6%	34,733
18	52	Computers hardware acquired after January 27, 2009 and before February 2011	0	100%	-	0	100%	0
19	Total		$ 2,567,813		$ 185,314	$ 2,573,496		$ 181,729

Notes:
(1) The CCA rate depends on the type of the leasehold and the terms of the lease.

UNION GAS LIMITED
Provision for Depreciation,Amortization and Depletion
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved	2013 Actual
1	Total provision for depreciation and amortization before adjustments (per page 3)	-	194,687
2	Adjustments: vehicle depreciation through clearing	-	1,730
3	Provision for depreciation amortization and depletion	$ -	$ 192,957

UNION GAS LIMITED
Provision for Depreciation, Amortization and Depletion
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved Average Plant (1)	Rate (%)	Provision	2013 Actual Average Plant (1)	Rate (%)	Provision
		(a)	(b)	(c)	(d)	(e)	(f)
	Intangible plant:						
1	Franchises and consents				$ 1,288	Amortized	$ 66
2	Intangible plant - Other				6,366	Amortized	122
3		-		-	7,654		188
	Local Storage Plant						
4	Structures and improvements		2.85%	-	3,620	2.85%	103
5	Gas holders - storage		2.54%	-	4,574	2.54%	58
6	Gas holders - equipment		3.54%	-	12,131	3.54%	429
7		-		-	20,326		591
	Storage:						
8	Land rights		2.10%	-	31,984	2.10%	672
9	Structures and improvements		2.50%	-	60,358	2.50%	1,510
10	Wells and lines		2.48%	-	89,315	2.48%	2,216
11	Compressor equipment		2.68%	-	237,014	2.68%	6,358
12	Measuring & regulating equipment		3.11%	-	56,023	3.11%	1,744
13	Other equipment				2,394		517
14		-		-	477,089		13,017
	Transmission:						
15	Land rights		1.76%	-	38,792	1.76%	683
16	Structures and improvements		2.03%	-	52,837	2.03%	1,073
17	Mains		1.98%	-	1,086,116	1.98%	21,505
18	Compressor equipment		3.23%	-	343,424	3.23%	11,093
19	Measuring & regulating equipment		2.60%	-	152,672	2.60%	3,969
20		-		-	1,673,841		38,322
	Distribution - Southern Operations:						
21	Land rights		1.65%	-	5,982	1.65%	99
22	Structures and improvements		2.22%	-	120,529	2.22%	2,702
23	Services - metallic		2.81%	-	112,566	2.81%	3,163
24	Services - plastic		2.51%	-	779,227	2.51%	19,559
25	Regulators		5.00%	-	70,066	5.00%	3,553
26	Regulator and meter installations		2.80%	-	67,962	2.80%	1,875
27	Mains - metallic		2.83%	-	419,865	2.83%	11,882
28	Mains - plastic		2.31%	-	533,219	2.31%	12,317
29	Measuring & regulating equipment		3.66%	-	32,098	3.66%	1,175
30	Meters		3.82%	-	227,155	3.82%	8,677
31	Other equipment			-	-		-
32		-		-	$ 2,368,671		$ 65,002

UNION GAS LIMITED
Provision for Depreciation, Amortization and Depletion
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved Average Plant (1)	Rate (%)	Provision	2013 Actual Average Plant (1)	Rate (%)	Provision
		(a)	(b)	(c)	(d)	(e)	(f)
	Distribution plant - Northern & Eastern Operations:						
1	Land rights		1.71%	-	$ 9,357	1.71%	$ 160
2	Structures & improvements		2.41%	-	62,752	2.41%	1,512
3	Services - metallic		3.22%	-	96,335	3.22%	3,102
4	Services - plastic		2.60%	-	383,396	2.60%	9,968
5	Regulators		5.00%	-	26,169	5.00%	1,337
6	Regulator and meter installations		2.92%	-	30,434	2.92%	872
7	Mains - metallic		3.02%	-	384,302	3.02%	11,606
8	Mains - plastic		2.38%	-	211,238	2.38%	5,027
9	Compressor equipment			-	-	-	-
10	Measuring & regulating equipment		3.77%	-	116,193	3.77%	4,380
11	Meters		4.03%	-	57,142	4.03%	2,303
12	Other distribution equipment			-	-		-
13		-		-	1,377,318		40,268
	General:						
14	Structures and improvements		1.92%		47,733	1.92%	1,283
15	Office furniture and equipment		6.67%	-	11,323	6.67%	747
16	Office equipment - computers		25.00%	-	74,723	25.00%	18,562
17	Transportation equipment		13.27%	-	47,778	13.27%	6,386
18	Heavy work equipment		6.92%	-	14,609	6.92%	1,018
19	Tools and other equipment		6.67%	-	30,492	6.67%	2,010
20	Communications equipment & structures		6.67%	-	14,328	6.67%	920
21	Other equipment			-	-		-
22		-		-	240,986		30,926
23	Regulatory Assets				188,715		6,373
24	Sub-total	-		-	6,354,599		194,687
25	Total provision for depreciation and amortization			-			$ 194,687
26	Depreciation through clearing						1,730
27		-		-	$ 6,354,599		$ 192,957

Notes:
(1) A simple average of the opening and closing plant balances was used to calculate the annual depreciation provision.

UNION GAS LIMITED
Capital Expenditure by Function
Includes IDC and Overheads
Year Ended December 31, 2013

Line No.	Particulars ($000's)	2013 Board-Approved	2013 Actual
		(a)	(b)
1	Storage	11,562	5,742
2	Transmission	113,795	106,647
3	Distribution	131,797	164,946
4	General	37,215	35,167
5	Other	53,333	55,696
6	Total	$ 347,702	$ 368,198
	Less: Parkway West Reliability, and Brantford-Kirkwall/Parkway D Project	80,000	51,966
		$ 267,702	$ 316,232

UNION GAS LIMITED
Statement of Utility Rate Base
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved	2013 Actual
		(a)	(b)
	Gas Utility Plant		
1	Gross plant at cost	6,361,532	6,401,183
2	Less: accumulated depreciation	(2,754,070)	(2,746,177)
3	Net utility plant	3,607,462	3,655,006
	Working Capital and Other Components		
4	Cash working capital	20,007	20,552
5	Gas in storage and line pack gas	163,109	142,677
6	Balancing gas	72,963	68,352
7	ABC receivable (gas in storage)	(44,901)	(30,988)
8	Inventory of stores, spare equipment	29,618	28,636
9	Prepaid and deferred expenses	4,955	5,008
10	Customer deposits	(48,231)	(35,638)
11	Customer interest	(764)	(429)
12	Total working capital and other components	196,757	198,170
13	Total rate base before deduction of accumulated deferred income taxes	3,804,218	3,853,176
14	Accumulated deferred income taxes	(69,686)	(69,321)
15	Total rate base	$ 3,734,532	$ 3,783,855

Appendix B

UNION GAS LIMITED
Return on Equity
Calendar Year Ending December 31, 2013

Line No.	Particulars ($000s)	2013 (a)	Unregulated Storage (b)	Adjustments (c)		2013 Utility (d)=(a)-(b)+(c)
	Operating Revenues					
1	Gas Sales	1,620,985	-	(15,697)	i	1,605,289
2	Transportation	161,178	(356)	(1,426)	ii	160,108
3	Storage	90,672	81,828	-		8,844
4	Other	27,268	-	(9,224)	iii	18,045
5		1,900,104	81,472	(26,346)		1,792,286
	Operating Expenses					
6	Cost of gas	848,876	2,879	(15,697)	i	830,300
7	Operating and maintenance expenses	397,275	13,283	(2,954)	iv	381,038
8	Depreciation	202,682	9,725	-		192,957
9	Other financing	-	-	383	v	383
10	Property and other taxes	65,288	1,444	-		63,845
11		1,514,122	27,330	(18,268)		1,468,523
	Other					
12	Gain / (Loss) on sale of assets	(227)	(291)	-		64
13	Other / Huron Tipperary	(1,580)	(1,580)	-		-
14	Gain / (Loss) on foreign exchange	(1,051)	(22)	374	vi	(655)
15		(2,858)	(1,893)	374		(592)
16	Earnings before interest and taxes	383,124	52,249	(8,705)		323,171
17	Income taxes					25,815
18	Total utility income					297,356
	Less debt and preference share return components					
19	Long-term debt					147,362
20	Unfunded short-term debt					652
21	Preferred dividend requirements					2,060
						150,074
	Less shareholder portions of:					
22	Net short-term storage revenue (after tax)					223
23	Net optimization activity (after tax)					1,746
						1,969
24	Utility earnings					145,313
25	Common equity					1,362,188
26	Return on common equity (line 24 / line 25)					10.67%
27	Benchmark return on common equity					8.93%

Notes:

i Reclassification of optimization revenue as cost of gas

ii Reversal of FT RAM fuel cost provision for 2011 and 2012

iii Demand-side management incentive

iv	Donations	(2,952)
	CDM program	(2)
		(2,954)

v Facility fees and customer deposit interest

vi Foreign exchange gain on bank balances

Appendix C

Filed: 2014-05-02
EB-2014-0145
Exhibit A
Tab 2
Appendix C
Schedule 1

UNION GAS LIMITED
Continuity of Property, Plant and Equipment
Calendar Year Ending December 31, 2013

Line No.	Particulars ($000's)	Balance Dec. 31/12	Additions: Capital Additions	Additions: Transfers	Additions: Net Salvage	Additions: Net Additions	Retirements	Balance Dec. 31/13	Adjustments	Adjusted Balance
		(a)	(b)	(c)	(g)	(h)	(d)	(e)	(f)	(g)
	Unregulated Gas Plant in Service:									
	Underground storage plant:									
1	Land	$ 1,643	365	1		366		2,009		$ 2,009
2	Land rights	21,659	8			8		21,667		21,667
3	Structures and improvements	20,043	120	337		457	(9)	20,491		20,491
4	Wells	86,938	4,836	2		4,838	(4)	91,772		91,772
5	Compressor equipment	147,914	534	(635)		(101)	(289)	147,524		147,524
6	Measuring & regulating equipment	22,408	681	(795)		(114)		22,294		22,294
7	Base pressure gas	22,928				-		22,928		22,928
8	Other equipment	-				-		-		-
9		$ 323,534	6,544	(1,090)	-	5,454	(302)	328,685	-	$ 328,685
	General plant:									
10	Land	$ 17				-		17		$ 17
11	Structures & improvements	1,503	92	-		92	(60)	1,535		1,535
12	Office furniture & equipment	362	26			26	(10)	378		378
13	Office equipment - computers	6,254	695			695	(425)	6,524		6,524
14	Transportation equipment	2,153	231	32		263	(145)	2,271		2,271
15	Heavy work equipment	688	57	(32)		25	(49)	664		664
16	Tools & work equipment	924	113			113	(45)	992		992
17	Communication equipment	435	21	21		42	(39)	438		438
18	Communication structures	21		(21)		(21)		-		-
19	Other general equipment	-				-		-		-
20		$ 12,357	1,235	-	-	1,235	(773)	12,819	-	$ 12,819
21	Total gas plant in service	$ 335,890	7,779	(1,090)	-	6,689	(1,075)	341,504		$ 341,504
22	Gas plant under construction	7,020	3,513			3,513		10,533		10,533
23	Total unregulated property plant and equipment	$ 342,911	11,292	(1,090)	-	10,202	(1,075)	352,037	-	$ 352,037

UNION GAS LIMITED
Continuity of Accumulated Depreciation
Calendar Year Ending December 31, 2013

Line No.	Particulars ($000's)	Balance Dec. 31/12	Transfers	Provisions	Retirements	Net Salvage /(Costs)	Balance Dec. 31/13
		(a)	(b)	(c)	(d)	(e)	(f)
	Unregulated Gas Plant in Service:						
	Underground storage plant:						
1	Land rights	$ 7,111	-	429			$ 7,540
2	Structures & improvements	6,812	158	606	(5)		7,571
3	Wells and lines	23,927	62	1,902	(2)		25,889
4	Compressor equipment	36,323	356	4,013	(235)		40,457
5	Measuring & regulating equipment	9,032	86	507			9,625
6		$ 83,205	662	7,457	(242)	-	$ 91,082
	General plant:						
7	Structures & improvements	638	(239)	54	(60)		393
8	Office furniture & equipment	138	16	32	(10)		176
9	Office equipment - computers	1,721	(8)	1,752	(425)		3,040
10	Transportation equipment	486	199	248	(145)	13	801
11	Heavy work equipment	(65)	138	41	(49)		65
12	Tools and other equipment	478	3	87	(45)		523
13	Communication equipment	225	19	40	(39)		245
14	Communication structures	9	(9)				-
15		$ 3,689	119	2,254	(773)	13	$ 5,243
16	Total unregulated gas plant in service	$ 86,835	781	9,711	(1,015)	13	$ 96,325

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2013

Line No.	Particulars ($000's)	UNREGULATED
1	Total unregulated provision for depreciation and amortization before adjustments (per page 3)	9,711
	Adjustments:	
2	Vehicle depreciation through clearing	(69)
3	Asset Retirement Obligation expense for Unregulated storage wells	83
4	Unregulated provision for depreciation amortization and depletion	**9,725**

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2013

Line No.	Particulars ($000's)	Average Plant (1) (a)	Rate (%) (b)	Total Provision
	Storage:			
1	Land rights	$ 21,663	Allocation	$ 429
2	Structures and improvements	18,587	Allocation	606
3	Wells and lines	86,939	Allocation	1,902
4	Compressor equipment	146,817	Allocation	4,013
5	Measuring & regulating equipment	20,976	Allocation	507
6	Other equipment			
7		$ 294,981		$ 7,457
	General:			
8	Structures & improvements	$ 1,519	Allocation	$ 54
9	Office furniture and equipment	370	Allocation	32
10	Office equipment - computers	6,389	Allocation	1,752
11	Transportation equipment	2,212	Allocation	248
12	Heavy work equipment	676	Allocation	41
13	Tools and other equipment	958	Allocation	87
14	Communications equipment	437	Allocation	40
15	Communications structures	11	Allocation	-
16	Other equipment			
17		$ 12,571		$ 2,254
18	Sub-total	307,552		9,711
19	Total unregulated provision for depreciation and amortization before adjustments			$ 9,711
20	Vehicle depreciation through clearing			(69)
21	Asset Retirement Obligation expense for Unregulated storage wells			83
22	Unregulated provision for depreciation amortization and depletion	307,552		$ **9,725**

Notes:

(1) Average of the opening and closing plant balances (excluding fully depreciated assets) was used to calculate the annual depreciation provision.

Appendix D

Service Quality Indicator Results

G.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM
G.2.1.9.A – TELEPHONE ANSWERING PERFORMANCE
G.2.1.9.A.1 Call Answering Service Level (CASL)
Measurement Calculation: CASL = Number of calls reaching a distributor's general inquiry number answered within 30 seconds divided by the number of calls received by a distributor's general inquiry number (CASL should be rounded to the first decimal number, e.g.74.45% becomes 74.5%)
OEB Approved Standard: Yearly performance shall be 75% with a minimum monthly standard of 40%

Month	Number of Calls Reaching a Distributor's General Inquiry Number Answered Within 30 Seconds (1)	Number of Calls Received by a Distributor's General Inquiry Number (2)	Call Answering Service Level (%) (3 = 1 / 2 * 100)
Jan-13	70,214	81,876	85.8
Feb-13	62,395	80,435	77.6
Mar-13	87,393	113,571	77.0
Apr-13	78,739	100,542	78.3
May-13	72,612	92,715	78.3
Jun-13	88,650	115,576	76.7
Jul-13	68,963	88,009	78.4
Aug-13	89,983	116,157	77.5
Sep-13	74,051	96,789	76.5
Oct-13	71,524	93,327	76.6
Nov-13	87,693	111,443	78.7
Dec-13	54,715	66,766	82.0
Total	906,932	1,157,206	78.4

G.2.1.9.A.2 Abandon Rate (AR)
Measurement Calculation: AR = Number of calls abandoned while waiting for a live agent divided by the total number of calls requesting to speak to a live agent. (AR should be rounded to the first decimal number, e.g. 8.55% becomes 8.6%)
OEB Approved Standard: Performance shall not exceed 10% on a yearly basis

Month	Number of Calls abondoned while waiting for a live agent (1)	Total Number of Calls requesting to speak to a live agent (2)	Abandon Rate (%) (3 = 1 / 2 * 100)
Jan-13	1,431	63,428	2.3
Feb-13	2,323	62,209	3.7
Mar-13	3,728	86,214	4.3
Apr-13	2,041	76,358	2.7
May-13	2,283	71,175	3.2
Jun-13	3,223	89,508	3.6
Jul-13	1,996	68,882	2.9
Aug-13	2,736	90,956	3.0
Sep-13	3,400	76,436	4.4
Oct-13	2,679	74,649	3.6
Nov-13	3,526	88,702	4.0
Dec-13	5,028	52,419	9.6
Total	34,394	900,936	3.8

G.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM

G.2.1.9.B – BILLING PERFORMANCE

G.2.1.9.B - Billing Performance

Measurement Calculation: The billing performance standard is a quality assurance standard. The standard requires gas distributors to have a verifiable quality assurance program in place. No specific metric is attached to this requirement.

OEB Approved Standard: Manual checks must be done to validate data when meter reads fall outside criteria, as set out in the quality assurance program, for excessively high or low usage.

TABLE B

Month	Total Number of Billings (1)	Total Number of Manual Checks Done as (2)	Total Number of Manual Checks Done When Meter Reads Show Excessively High (3)	Brief Explanation for Excessively High Usage (In 100 Words or less) (4)	Total Number of Manual Checks Done When Meter Reads Show Excessively Low (5)	Brief Explanation for Excessively Low Usage (In 100 Words or less) (6)
Jan-13	1,140,563	9,538	4,516	Change in load, previously low estimate/read, previous vacant, seasonal use.	1,674	Vacant, seasonal use (crop dryer), stopped meter, previous high estimate/read.
Feb-13	1,450,566	7,750	3,595		1,801	
Mar-13	1,450,533	10,139	6,604		1,363	
Apr-13	1,449,514	11,590	7,659		1,716	
May-13	1,450,661	13,991	10,594		1,351	
Jun-13	1,453,281	13,855	10,453		1,012	
Jul-13	1,452,311	16,722	13,212		886	
Aug-13	1,453,732	15,638	12,183		912	
Sep-13	1,452,921	14,443	10,488		1,048	
Oct-13	1,463,672	11,611	7,972		1,032	
Nov-13	1,449,458	8,973	4,364		2,381	
Dec-13	1,442,435	6,247	3,505		747	
Total	17,109,647	140,497	95,145		15,923	

G.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM
G.2.1.9.C – METER READING PERFORMANCE
G.2.1.9.C.1 Meter Reading Performance Measurement (MRPM)
Measurement Calculation: MRPM = Number of meters with no read for 4 consecutive months of more divided by the total number of active meters to be read (MRPM should be rounded to the first decimal number, e.g. 0.45% becomes 0.5%)
OEB Approved Standard: Measurement shall not exceed 0.5% on a yearly basis

Month	Number of meters with no read for consecutive 4 months or more (1)	Total number of active meters to be read (2)	Meter reading performance measurement (%) (3 = 1 / 2 * 100)
Jan-13	1,587	1,373,373	0.1
Feb-13	2,379	1,374,720	0.2
Mar-13	4,244	1,375,743	0.3
Apr-13	5,232	1,376,019	0.4
May-13	3,045	1,375,429	0.2
Jun-13	1,545	1,375,408	0.1
Jul-13	1,315	1,375,618	0.1
Aug-13	1,757	1,377,413	0.1
Sep-13	2,221	1,380,031	0.2
Oct-13	1,791	1,384,107	0.1
Nov-13	1,324	1,388,617	0.1
Dec-13	1,309	1,391,614	0.1
Total	27,749	16,548,092	0.2

G.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM

G.2.1.9.D – SERVICE APPOINTMENT RESPONSE TIME

G.2.1.9.D.1 - Appointments Met Within the Designated Time Period

Measurement Calculation: AMWDTP - Number of appointments met within the 4 hour scheduled time/date divided by total number of appointments scheduled in the reporting month.

OEB Approved Standard: The minimum performance standard for this measurement shall be 85% averaged over a year.

	Number of Appointments Met Within the 4-Hour Scheduled Time/Date	Number of Appointments Scheduled in the Reporting Month	Appointments Met Within the Designated Time Period (%)
Month	(1)	(2)	(3 = 1/2*100)
Jan-13	17,454	17,635	99.0%
Feb-13	13,108	13,346	98.2%
Mar-13	16,680	16,818	99.2%
Apr-13	15,559	15,736	98.9%
May-13	14,604	14,926	97.8%
Jun-13	13,592	13,855	98.1%
Jul-13	14,048	14,291	98.3%
Aug-13	14,037	14,382	97.6%
Sep-13	15,363	15,735	97.6%
Oct-13	19,128	19,777	96.7%
Nov-13	17,015	17,588	96.7%
Dec-13	12,013	12,550	95.7%
TOTAL	182,601	186,639	97.8%

G.2.1.9.D.2 - Time to Reschedule a Missed Appointment (TRMA)

Measurement Calculation: TRMA - The distributor must contact the customer to reschedule the work within 2 hours of the end of the original appointment time.

OEB Approved Standard: 100% of affected customers will receive a call offering to reschedule work within 2 hours of the end of the original appointment time.

	Total Number of Customer Appointments Missed	Total Number of Customers Who Did Receive a Call Offering to Reschedule Within 2 Hrs. Of the End of the Original Appointment Time Missed	Brief Explanation of the Reasons Customers did not Receive a Call Within the Time Limit (in 50 words)	Percentage of Customers Who Did Not Receive a Call Within 2 Hrs
Month	(1)	(2)	(3)	(4 = 2/1 *100)
Jan-13	181	181		100.0%
Feb-13	238	238		100.0%
Mar-13	138	138		100.0%
Apr-13	177	177		100.0%
May-13	322	321	Missed recommitment was due to the employee not correctly following procedure. The corrective action was to refresh the employee on the correct procedure.	99.7%
Jun-13	263	263		100.0%
Jul-13	243	242	Missed recommitment was due to very high levels of workload/emergency calls during the timeframe that the customer should be contacted. *	99.6%
Aug-13	345	345		100.0%
Sep-13	372	370	Missed recommitments were due to very high levels of workload/emergency calls during the timeframe that the customer should be contacted. *	99.5%
Oct-13	649	649		100.0%
Nov-13	573	573		100.0%
Dec-13	537	537		100.0%
TOTAL	4038	4034		99.9%

Note:
*The corrective action for each of these missed recommitments was to remind the employee to ask for assistance from teammates if could not call customer to recommit in the required timeframe

G.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM

G.2.1.9.E – GAS EMERGENCY RESPONSE

G.2.1.9.E.1 - Percentage of Emergency Calls Responded Within One Hour (ECRWOH)

Measurement Calculation: ECRWOH - Number of emergency calls responded to within 60 minutes divided by total number of emergency calls in the year.

OEB Approved Standard: The minimum performance standard shall be that 90% of customers have received a response within 60 minutes of their call reaching a live person. The standard shall be calculated on an annual basis.

	Number of Emergency Calls Responded to Within 60 Minutes	Total Number of Emergency Calls Received	Percentage of Emergency Calls Responded within 60 Minutes (%)
Month	(1)	(2)	(3 = 1/2*100)
Jan-13	1,314	1,343	97.8%
Feb-13	997	1,014	98.3%
Mar-13	966	975	99.1%
Apr-13	947	965	98.1%
May-13	1,021	1,039	98.3%
Jun-13	1,038	1,055	98.4%
Jul-13	1,140	1,166	97.8%
Aug-13	1,091	1,117	97.7%
Sep-13	1,202	1,228	97.9%
Oct-13	1,277	1,301	98.2%
Nov-13	1,188	1,216	97.7%
Dec-13	1,199	1,251	95.8%
TOTAL	13,380	13,670	97.9%

G.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM

G.2.1.9.F – CUSTOMER COMPLAINT WRITTEN RESPONSE

G.2.1.9.F.1 Number of Days to provide a written response (NDPAWR)

Measurement Calculation: NDPAWR = Number of complaints requiring response responded to within 10 days divided by the number of number of complaints requiring a written response. (NDPAWR should be rounded to the first decimal number, e.g. 79.45% becomes 79.5%)

OEB Approved Minimum Standard: measurement shall be that 80% of customers have received written reponses in 10 days of the distributor receiving the complaint

Month	Number of complaints requiring a written response responded to within 10 days (1)	Number of complaints requiring a written response (2)	NDPAWR Percentage (%) (3 = 1 / 2 * 100)
Jan-13	25	25	100.0
Feb-13	14	14	100.0
Mar-13	14	14	100.0
Apr-13	21	21	100.0
May-13	10	10	100.0
Jun-13	11	11	100.0
Jul-13	11	11	100.0
Aug-13	6	6	100.0
Sep-13	10	10	100.0
Oct-13	15	15	100.0
Nov-13	0	0	100.0
Dec-13	14	14	100.0
Total	151	151	100.0

G.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM

G.2.1.9.G – RECONNECTION RESPONSE TIME

G.2.1.9.G.1 - Number of Days to Reconnect a Customer (NDTRAC)

Measurement Calculation: NDTRAC - Number of reconnections completed within 2 business days divided by total number of reconnections completed.

OEB Approved Standard: Minimum standard shall be that 85% of customers are reconnected within 2 business days of bringing their accounts into good standing. This will be tracked on a monthly basis

	Number of Reconnections Completed Within 2 Business Days	Total Number of Reconnections Completed	Number of Days to Reconnect a Customer Percentage (%)
Month	(1)	(2)	(3 = 1/2*100)
Jan-13	120	127	94.5%
Feb-13	58	62	93.5%
Mar-13	36	39	92.3%
Apr-13	273	276	98.9%
May-13	482	499	96.6%
Jun-13	362	394	91.9%
Jul-13	513	538	95.4%
Aug-13	814	861	94.5%
Sep-13	901	999	90.2%
Oct-13	1,230	1,389	88.6%
Nov-13	725	811	89.4%
Dec-13	277	289	95.8%
TOTAL	5,791	6,284	92.2%

Tab 3

ALLOCATION AND DISPOSITION OF 2013 DEFERRAL ACCOUNT BALANCES

The purpose of this evidence is to address the allocation and disposition of 2013 deferral account balances identified at Exhibit A, Tab 1, Appendix A, Schedule 1.

The allocation of 2013 deferral account balances to rate classes appears at Exhibit A, Tab 3, Appendix A, Schedule 1 Corrected. Exhibit A, Tab 3, Appendix A, Schedule 2 Corrected provides the unit disposition rates for Union's in-franchise rate classes and summarizes the balances to be disposed of for Union's ex-franchise rate classes. Exhibit A, Tab 3, Appendix A, Schedule 3 Corrected provides the impact of the proposed disposition for general service customers in Union South and Union North.

With the exception of the Spot Gas Variance Account (179-107), the Gas Supply Review Deferral Account (179-128) and the Preparation of Audited Utility Financial Statements Deferral Account (179-129), the allocation of 2013 deferral account balances to rate classes is consistent with the allocation methodologies approved by the Board in EB-2013-0109 (Union's 2012 Deferral Account Disposition proceeding) or in the EB-2011-0210 Decision and Rate Order (2013 rates).

2013 GAS SUPPLY RELATED DEFERRAL ACCOUNTS

The gas supply related deferral accounts include the Spot Gas Variance Account (179-107), the Unabsorbed Demand Cost ("UDC") Variance Account (179-108), the Gas Supply Review

Account (179-128), and the Upstream Transportation Optimization Account (179-131).

SPOT GAS VARIANCE ACCOUNT

Union proposes to allocate the portion of the Spot Gas Variance Account related to Union South bundled direct purchase load balancing costs on a contract specific basis, based on the March 31, 2014 shortfall position. Each direct purchase contract's shortfall position, as a proportion of the total March 31, 2014 shortfall, will be used to determine its allocation of Union South load balancing costs. This approach ensures load balancing costs are recovered solely from the Union South bundled direct purchase customers that caused Union to purchase spot gas for load balancing purposes.

The calculation of the Union South load balancing costs for bundled direct purchase customers also creates a spot gas credit to Union South sales service customers, as shown at Table 1, line 6, column (b) of Exhibit A, Tab 1 Corrected. The allocation of the portion of the Spot Gas Variance Account applicable to Union South sales service customers is based on actual sales service volumes for the period November 1, 2013 to March 31, 2014 by rate class.

UNABSORBED DEMAND COST VARIANCE

Union proposes that the balance in the Unabsorbed Demand Cost ("UDC") Variance Account (179-108) related to Union North be allocated to the firm Rate 01, Rate 10 and Rate 20 sales service and bundled direct purchase customers in proportion to 2013 Board-approved excess of peak day demands over average annual demands. This allocation is consistent with the allocation of UDC in approved 2013 rates.

There is no balance in the UDC Variance Account related to Union South at December 31, 2013.

GAS SUPPLY REVIEW

Union proposes to allocate the balance in the Gas Supply Review Account (179-128) in proportion to 2013 actual Union South sales service and Union North sales service and bundled direct purchase volumes. This approach ensures that the costs of the Gas Supply review are recovered from the customers Union's Gas Supply Plan is designed to serve and who benefitted from the gas supply review. In its EB-2013-0109 Decision, the Board found that Union responded appropriately to the EB-2011-0210 directive to file an independent review of its gas supply plan, and that the evidence filed by Union in regard to its gas supply plan provided the context in which the Board made its findings regarding the treatment of the FT-RAM related revenues.

TRANSPORTATION OPTIMIZATION

Union proposes to allocate the balance in the Upstream Transportation Optimization Account (179-131) between Union North and Union South rate classes based on the upstream transportation contracts used to serve each delivery area. Transportation optimization net revenues generated using upstream transportation long-haul contracts and STS contracts designed to serve Union North (with delivery points of SSMDA, WDA, NDA, NCDA and EDA) have been allocated to Union North. Transportation optimization net revenues generated using upstream transportation long-haul contracts designed to serve Union South (the CDA delivery point) have been allocated to Union South. Specifically, with respect to capacity assignments, the net revenue from each capacity assignment has been attributed to either the Union North or Union South based on the delivery point. With respect to FT-RAM optimization, the total revenue earned from all optimization has been allocated based on the quantity of transportation capacity optimized, either Union North or South.

Union proposes that the portion of the balance related to Union North be allocated to rate classes in proportion to the allocation of 2013 Board-approved TCPL FT transportation demand costs. This approach ensures that transportation optimization margin is allocated to Union North sales service and bundled direct purchase customers consistent with the manner in which this margin is included in approved gas supply transportation rates.

Union proposes that the portion of the balance related to Union South be allocated to sales service customers only. This approach is consistent with the manner in which this margin is included in approved gas supply transportation rates.

2013 NON- GAS SUPPLY RELATED DEFERRAL ACCOUNTS

Non-gas supply related deferral accounts can be divided into two groups: storage-related deferral accounts and other deferral accounts.

STORAGE-RELATED DEFERRAL ACCOUNTS

Union proposes to allocate the balance in the Short-Term Storage and Other Balancing Services Deferral Account (179-70) between Union North and Union South in proportion to the 2013 Board-approved allocation of storage space related costs per the STORAGEXCESS allocator.

Union proposes to allocate the portion of the balance related to Union North to firm Rate 01, Rate 10 and Rate 20 in proportion to the 2013 Board-approved excess of peak day demands over average day demands. This approach is consistent with the 2013 Board-approved allocation of storage demand costs to Union North rate classes.

Union proposes to allocate the portion of the balance related to Union South to Union South rate classes in proportion to the 2013 Board-approved design (peak) day demand.

The proposed disposition is also consistent with the allocation methodology for storage and other balancing services margin approved in Union's 2013 rates.

OTHER DEFERRAL ACCOUNTS

There is no balance in the Unbundled Services Unauthorized Storage Overrun Deferral Account (179-103) at December 31, 2013.

Union proposes to allocate the balance in the Gas Distribution Access Rule ("GDAR") Costs Deferral Account (179-112) in proportion to the Board-approved average number of customers in Rate 01 and Rate M1 in approved 2013 rates.

There is no balance in the Carbon Dioxide Offset Credits Deferral Account (179-117) at December 31, 2013.

Union proposes to allocate the balance in the Average Use Per Customer Account (179-118) to General Service rate classes in proportion to the margin variances by rate class resulting from the difference between the actual rate of decline in use-per-customer and the forecast rate of decline included in approved rates by rate class.

Union proposes to allocate the balance in the IFRS Conversion Costs Account (179-120) to rate classes in proportion to 2013 Board-approved Administrative & General O&M Expense per Exhibit G3, Tab 2, Schedule 2, updated for the EB-2011-0210 Board Decision.

Union proposes to allocate the balance in the Conservation Demand Management ("CDM") Deferral Account (179-123) to rate classes in proportion to the allocation of 2013 DSM costs in approved rates.

There is no balance in the Pension Charge on Transition to US GAAP Account (179-127) at December 31, 2013.

Union proposes to allocate the balance in the Preparation of Audited Utility Financial Statements Account (179-129) to rate classes in proportion to the 2013 Board-approved Administrative & General O&M Expense. This approach is consistent with how similar costs are allocated in Union's 2013 Board-approved cost allocation study.

DISPOSITION OF 2013 DEFERRAL ACCOUNT BALANCES

For General Service Rate M1, Rate M2, Rate 01 and Rate 10 customers Union proposes to dispose of the net 2013 deferral account balances prospectively, over the October 1, 2014 to March 31, 2015 time period. The prospective refund / recovery approach over six months, proposed for Rate M1, Rate M2, Rate 01 and Rate 10 customers, is consistent with how Union disposed of 2012 deferral account and earnings sharing balances in EB-2013-0109.

Union's proposal to dispose of the net 2013 deferral account balances prospectively over six months for general service rate classes is contingent on Board approval of the proposed Deferral Clearing Variance Account.

For in-franchise contract and ex-franchise rate classes, Union is proposing to dispose of the net 2013 delivery-related deferral account balances as a one-time adjustment with October 2014 bills customers receive in November 2014. This approach is consistent with the methodology used for the disposition of 2012 deferral account and earnings sharing balances in EB-2013-0109.

General Service Bill Impacts

General Service bill impacts are presented at Exhibit A, Tab 3, Appendix A, Schedule 3 Corrected. For a sales service residential customer in Union South with annual consumption of 2,200 m^3, the charge for the period October 1, 2014 to March 31, 2015 is $0.64. This $0.64 charge consists of a delivery-related charge of $1.44 (line 13, column (c)) and a commodity-related credit of $0.80 (line 14, column (c)). For a bundled direct purchase residential customer the charge is $1.44.

For a sales service residential customer in Union North with annual consumption of 2,200 m^3, the credit for the period October 1, 2014 to March 31, 2015 is $29.80. This $29.80 credit consists of a delivery-related credit of $7.55 (line 1, column (c)) and a gas transportation-related credit of $22.25 (line 3, column (c)). For a bundled direct purchase residential customer the credit is $29.80.

UNION GAS LIMITED
Allocation of 2013 Deferral Account Balances

			Union North					Union South															
Line No.	Particulars	Acct No.	Rate 01 ($000's)	Rate 10 ($000's)	Rate 20 ($000's)	Rate 100 ($000's)	Rate 25 ($000's)	M1 ($000's)	M2 ($000's)	M4 ($000's)	M5A ($000's)	M7 ($000's)	M9 ($000's)	M10 ($000's)	T1 ($000's)	T2 ($000's)	T3 ($000's)	Bundled DP ($000's)	M12 ($000's)	M13 ($000's)	C1 ($000's)	M16 ($000's)	Total (1) ($000's)
	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
	Gas Supply Related Deferrals:																						
1	Spot Gas Variance Account	179-107	-	-	-	-	-	(124)	(25)	(1)	(1)	(1)	-	(0)	-	-	-		-	-	-	-	(153)
2	Spot Gas Variance Account - Load Balancing for Union South DP	179-107																1,954					1,954
3	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(6,618)	(2,416)	(912)	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-	-	(9,947)
4	Gas Supply Review	179-128	52	19	5	0	5	139	32	2	1	1	0	0									256
5	Transportation Optimization	179-131	(2,980)	(1,025)	(355)	-	(88)	(1,039)	(173)	(8)	(6)	-	-	(0)	-	-	-		-	-	-	-	(5,675)
6	Total Gas Supply Related Deferrals		(9,547)	(3,422)	(1,262)	-	(83)	(1,024)	(166)	(7)	(6)	(1)	-	(0)	-	-	-	1,954	-	-	-	-	(13,565)
	Storage Related Deferrals:																						
7	Short-Term Storage and Other Balancing Services	179-70	255	67	18	1	-	578	194	63	1	23	7	0	53	393	51		-	-	-	-	1,705
	Delivery Related Deferrals:																						
8	Unbundled Services Unauthorized Storage Overrun	179-103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-
9	Gas Distribution Access Rule (GDAR) Costs	179-112	114	-	-	-	-	379	-	-	-	-	-	-	-	-	-		-	-	-	-	493
10	Carbon Dioxide Offset Credits	179-117	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-
11	Average Use Per Customer	179-118	(3,812)	(1,448)	-	-	-	496	(6,771)	-	-	-	-	-	-	-	-		-	-	-	-	(11,535)
12	IFRS Conversion Costs	179-120	102	9	8	7	3	256	24	9	10	3	0	0	7	18	2		48	0	1	0	505
13	Conservation Demand Management	179-123	(8)	(3)	(2)	(4)	-	(22)	(8)	(3)	(6)	(2)	-	-	(4)	(6)	-		-	-	-	-	(68)
14	Pension Charge on Transition to US GAAP	179-127	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-
15	Preparation of Audited Utility Financial Statements	179-129	109	9	8	7	3	275	26	10	11	3	0	0	7	19	2		51	0	1	0	543
16	Total Delivery-Related Deferrals		(3,494)	(1,432)	14	10	6	1,383	(6,730)	15	15	3	1	0	10	32	4	-	99	0	2	0	(10,062)
17	Total 2013 Storage and Delivery Disposition (Line 7 + Line 16)		(3,239)	(1,366)	32	11	6	1,961	(6,535)	78	16	26	8	0	63	425	55	-	99	0	2	0	(8,357)
18	Total 2013 Deferral Account Disposition (Line 6 + Line 17)		(12,786)	(4,788)	(1,231)	11	(77)	937	(6,702)	71	10	25	8	0	63	425	55	1,954	99	0	2	0	(21,922)

Notes:
(1) EB-2014-0145, Exhibit A, Tab 1, Schedule 1.

UNION GAS LIMITED
General Service Unit Rates for Prospective Recovery/(Refund) - Delivery
2013 Deferral Account Disposition

Line No.	Particulars	Rate Class	Deferral Balance for Disposition ($000's) (a)	Forecast Volume (10^3m^3) (1) (b)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3) (c) = (a/b)*100
1	Small Volume General Service	01	(3,239)	743,479	(0.4356)
2	Large Volume General Service	10	(1,366)	247,588	(0.5515)
3	Small Volume General Service	M1	1,961	2,284,824	0.0858
4	Large Volume General Service	M2	(6,535)	883,319	(0.7399)

Notes:
(1) Forecast volume for the period October 1, 2014 to March 31, 2015.

UNION GAS LIMITED
General Service Unit Rates for Prospective Recovery/(Refund) - Gas Supply Transportation
2013 Deferral Account Disposition

Line No.	Particulars	Rate Class	Deferral Balance for Disposition ($000's)	Forecast Volume (10^3m^3) (1)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3)
			(a)	(b)	(c) = (a/b)*100
1	Small Volume General Service	01	(9,547)	743,479	(1.2840)
2	Large Volume General Service	10	(3,422)	246,091	(1.3906)

Notes:
(1) Forecast volume for the period October 1, 2014 to March 31, 2015.

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UNION GAS LIMITED
Unit Rates for Prospective Recovery/(Refund) - Gas Supply Commodity
2013 Deferral Account Disposition

Line No.	Particulars	Rate Class	Deferral Balance for Disposition ($000's)	Forecast Volume (10^3m^3) (1)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3)
			(a)	(b)	(c) = (a/b)*100
1	Small Volume General Service	M1	(1,024)	2,006,670	(0.0475)
2	Large Volume General Service	M2	(166)	494,662	(0.0475)
3	Firm Com/Ind Contract	M4	(7)	18,841	(0.0475)
4	Interruptible Com/Ind Contract	M5	(6)	17,152	(0.0475)
5	Special Large Volume Contract	M7	(1)	-	(0.0475)
6	Small Wholesale	M10	(0)	197	(0.0475)

Notes:
(1) Forecast sales service volumes for the period October 1, 2014 to March 31, 2015.

UNION GAS LIMITED
Contract Unit Rates for One-Time Adjustment - Delivery
2013 Deferral Account Disposition

Line No.	Particulars	Rate Class	Deferral Balance for Disposition ($000's) (a)	2013 Actual Volume (10^3m^3) (b)	Unit Rate ($cents/m^3$) (c) = (a/b)*100
	Union North				
1	Medium Volume Firm Service (1)	20	3	103,259	0.0025
2	Medium Volume Firm Service (2)	20T	11	547,703	0.0021
3	Large Volume High Load Factor (2)	100T	9	1,926,556	0.0005
4	Large Volume Interruptible	25	6	214,641	0.0029
	Union South				
5	Firm Com/Ind Contract	M4	78	475,054	0.0164
6	Interruptible Com/Ind Contract	M5	16	522,676	0.0031
7	Special Large Volume Contract	M7	26	172,399	0.0151
8	Large Wholesale	M9	8	63,052	0.0127
9	Small Wholesale	M10	0	266	0.1467
10	Contract Carriage Service	T1	63	451,964	0.0140
11	Contract Carriage Service	T2	425	4,295,830	0.0099
12	Contract Carriage- Wholesale	T3	55	273,597	0.0200

Notes:
(1) Sales and Bundled-T customers only.
(2) T-service customers only.

UNION GAS LIMITED
Contract Unit Rates for One-Time Adjustment - Gas Supply Transportation and Bundled Storage
2013 Deferral Account Disposition

Line No.	Particulars	Rate Class	Billing Units	Deferral Balance for Disposition ($000's) (a)	2013 Actual Volume/ Demand (b)	Unit Volumetric/ Demand Rate (c) = (a/b)*100
	Gas Supply Transportation (cents/m^3)					
1	Medium Volume Firm Service	20	10^3m^3/d	(1,262)	5,365	(23.5253)
2	Large Volume Interruptible	25	10^3m^3	(83)	96,950	(0.0860)
	Storage ($/GJ)					
3	Bundled-T Storage Service	20T/100T	GJ/d	19	155,904	0.1227

UNION GAS LIMITED
Storage and Transportation Service Amounts for Disposition
2013 Deferral Account Disposition

Line No.	Particulars ($000's) (1)	Rate Class	Deferral Balance for Disposition
			(a)
1	Storage and Transportation	M12	99
2	Local Production	M13	0
3	Short-Term Cross Franchise	C1	2
4	Storage Transportation Service	M16	0

Notes:
(1) Exfranchise M12, M13, M16 and C1 customer specific amounts determined using approved deferral account allocation methodologies.

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UNION GAS LIMITED
General Service Bill Impacts

Line No.	Particulars	Rate Component	Unit Rate for Prospective Recovery/(Refund) (cents/m^3) (1)	Volume (m^3) (2)	Bill Impact ($)
			(a)	(b)	(c) = (a x b) / 100
1	Rate 01	Delivery	(0.4356)	1,733	(7.55)
2		Commodity	-	1,733	-
3		Transportation	(1.2840)	1,733	(22.25)
4			(1.7196)		(29.80)
5	Sales Service				(29.80)
6	Direct Purchase Bundled T				(29.80)
7	Rate 10	Delivery	(0.5515)	66,961	(369.29)
8		Commodity	-	66,961	-
9		Transportation	(1.3906)	66,961	(931.15)
10			(1.9421)		(1,300.44)
11	Sales Service				(1,300.44)
12	Direct Purchase Bundled T				(1,300.44)
13	Rate M1	Delivery	0.0858	1,679	1.44
14		Commodity	(0.0475)	1,679	(0.80)
15			0.0383		0.64
16	Sales Service				0.64
17	Direct Purchase				1.44
18	Rate M2	Delivery	(0.7399)	55,772	(412.66)
19		Commodity	(0.0475)	55,772	(26.49)
20			(0.7874)		(439.15)
21	Sales Service				(439.15)
22	Direct Purchase				(412.66)

Notes:
(1) EB-2014-0145 Exhibit A, Tab 3, Appendix A, Schedule 2 Corrected, Pages 1-3.
(2) Average consumption, per customer, for the period October 1, 2014 to March 31, 2015 .

Tab 4

INCREMENTAL TRANSPORTATION CONTRACTING ANALYSIS, VERTICAL SLICE PROGRAM AND ANNUAL STAKEHOLDER MEETING

The evidence in this tab is organized as follows:

a) Incremental Transportation Contracting Analysis

b) Plan to Suspend Vertical Slice Program

c) Annual Stakeholder Meeting

INCREMENTAL TRANSPORTATION CONTRACTING ANALYSIS

Introduction

Pursuant to Union's EB-2005-0520 Settlement Agreement (p. 13, Subsection 3.1, paragraph 2; and, Appendix B – Incremental Transportation Contracting Analysis), the purpose of this evidence is to provide the analysis used by Union to support its decision to enter into firm transportation capacity on the following contracts:

1. Vector Pipeline (1 year extension)
2. Panhandle Eastern Pipeline (1 year)
3. TransCanada Empress to NDA (22 months)

1. VECTOR PIPELINE (1 YEAR EXTENSION) TRANSPORTATION CONTRACT

Capacity History

As stated in EB-2011-0210, Union Gas holds 80,000 Dth/day (84,405 GJ/day) of capacity on Vector Pipeline LP and Vector Pipeline Limited Partnership (Vector), originally as part of the Alliance/Vector transportation path to transport gas from the Western Canadian Sedimentary Basin ("WCSB") to Union's system at Dawn. This contract on Vector includes extension rights that could be exercised before November 30, 2013 for capacity due to terminate on December 1, 2016.

Renewed Capacity

Union Gas has exercised its right to extend the contracts for a one year period ending November 30, 2017 at the existing $0.2512 US/Dth 100% load factor rate. This capacity will continue to serve sales service customers in Union's Southern Operations Area. Union will have its next opportunity to extend the Vector contract or terminate it on or before November 30, 2014.

Rationale for Transportation Capacity

Union's 2014 - 2018 gas supply plan supports the extension of Vector capacity in order for Union to meet forecasted demand within the Southern sales service customer base. The landed cost of this gas arriving at Dawn is forecast to be competitive with supply flowing on alternative upstream pipelines.

The benefits of this capacity are:

1. The landed cost of gas flowing to Union along this route is competitively priced;

2. The extended term supports Union's objective of structuring a portfolio with a diversity of contract terms and supply basins;
3. Access to the Chicago market hub that receives competing gas supplies from the WCSB, the U.S. Midwest, Marcellus/Utica, Gulf and the expanding Rockies basin which supports Union's objective of diversity of supply basins;
4. Maintains and supports the acquisition of secure supply from a liquid market hub with many gas suppliers accessing multiple gas supply basins;
5. Low unabsorbed demand charge ("UDC") exposure relative to alternative upstream pipeline routes due to the low demand charge on this route;
6. Provides a fixed-rate toll which provides toll certainty on a portion of Union's upstream transportation.
7. Provides Union with both receipt and delivery flexibility within the path.
8. Lands gas at Dawn to support diversity of deliveries and system integrity.
9. The right to renew this capacity is a component of the agreement which ensures secure access to this transportation.

Contract Parameters

- Transportation providers: Vector Pipeline Limited Partnership, Vector Pipeline L.P.
- Service: Firm Transportation
- Term: December 1, 2000 through November 30, 2017
- Volume: 80,000 Dth/day (84,405 GJ/day)

- Rate: $0.2512 US/ Dth at 100% Load Factor (exclusive of fuel)
- Receipt Point: Alliance Pipelines L.P. Interconnect (Joliet)
- Delivery Point: Union (Dawn)

Incremental Contracting Analysis Form

Exhibit A, Tab 4, Appendix A, Schedule 1 shows a comparison of landed costs for the Vector contract relative to the alternatives reviewed by Union at the time the decision was made to acquire the capacity. Schedule 1 is in the format agreed upon in the EB-2005-0520 Settlement Agreement.

2. PANHANDLE EASTERN PIPELINE (1 YEAR) TRANSPORTATION CONTRACT

Capacity History

Union holds 27,000 Dth/day (28,487 GJ/d) of firm transportation on Panhandle Eastern Pipeline (PEPL) from the Panhandle Field Zone to Union's pipeline system at Ojibway through to October 31, 2017. These volumes are then delivered to Parkway by a firm Ojibway-to-Parkway service. There were no changes to these contracts.

In addition to the 27,000 DTh/day (28,487 GJ/d), Union holds a contract for 10,000 Dth/day (10,551 GJ/d) of incremental firm transportation on PEPL (Panhandle Field Zone to Ojibway) beginning November 1, 2012, with a one year term expiring October 31, 2013, at a 100% load factor rate of $0.269 US/DTh.

New Capacity

Union Gas has acquired a new contract for 10,000 Dth/d (10,551 GJ/d) at a 100% load factor rate of $0.2785 US/Dth, with a one year term commencing November 1, 2013 and expiring October 31, 2014. This contract will replace the existing contract for 10,000 Dth/day which is due to expire on October 31, 2013 as noted above. This capacity was acquired on the secondary market through an RFP process and will continue to serve sales service customers in Union's Southern Operations Area.

Rationale for Transportation Capacity

Union's 2014-2018 Gas Supply Plan supports the Panhandle capacity in order for Union to meet forecasted demand within the Southern sales service customer base.

The benefits of this capacity are:

1. The landed cost of gas flowing to Union along this route is competitively priced;
2. The one year term supports Union's objective of structuring a portfolio with a diversity of contract terms and supply basins;
3. Maintains and supports the acquisition of secure supply from the Panhandle Field Zone gas supply basin, maintaining Union's supply diversity;
4. Low UDC exposure relative to alternative upstream pipeline routes due to the low demand charge on this route;
5. Fixed-rate toll which provides toll certainty on a portion of Union's supply;

6. Lands gas at Ojibway to support diversity of deliveries and support system integrity.

Contract Parameters

- Transportation provider: Panhandle Eastern Pipe Line Company, LP
- Service: FT (Firm Transportation Service)
- Term: November 1, 2013 through October 31, 2014
- Volume: 10,000 Dth/day (10,551 GJ/d)
- Rate: $0.2785 US/Dth at 100% Load Factor (exclusive of fuel)
- Receipt Point: Sneed-Parallel Energy (12724)
- Delivery Point: Union Ojibway-Wayne County (UNION)

Incremental Contracting Analysis Form

Exhibit A, Tab 4, Appendix A, Schedule 2 shows a comparison of landed costs for the Panhandle contract relative to the alternatives reviewed by Union at the time the decision to acquire the capacity was made. Schedule 2 is in the format agreed upon in the EB-2005-0520 Settlement Agreement. Note, at the time this analysis was completed, Union approximated the acquired capacity to be $0.36412 US/Dth (100% load factor, exclusive of fuel); on an actual basis Union contracted this capacity for a 100% load factor rate of $0.2785 US/Dth. Therefore, the landed cost of the acquired capacity is actually $0.085 US/Dth lower than shown in the Schedule 2 analysis.

3. TRANSCANADA PIPELINES LIMITED TRANSPORTATION CONTRACTS

Capacity

Effective December 18, 2013, Union entered into a firm long haul transportation contract with TCPL for incremental capacity of 9,000 GJ/d from Empress to Union NDA. This capacity is used to meet the gas supply requirements of Union North customers.

Rationale for Transportation Capacity

The incremental firm transportation capacity of 9000 GJ/d between Empress and Union NDA is required to meet design day demands in Union North. This requirement was determined by utilizing the SENDOUT model within the preparation of the 2013/2014 gas supply plan.

Union acquired this capacity through participating in a TCPL daily open season on August 1, 2013. Union bid for 9,000 GJ/day of capacity to start January 1, 2014, and was awarded the capacity on August 2, 2014. Subsequently, due to changes in TCPL operations and cold weather in the winter of 2013/2014, Union requested to advance the start date of this contract in order to provide Union with improved design day coverage prior to January 1, 2014. TCPL accommodated this and amended the contracts effective date to December 18, 2013.

The benefits of this capacity are:

1. Provides firm transportation capacity to meet the firm design day loads within the Union NDA.
2. Contract is renewable and has an end date that aligns with the gas year.
3. The firm transport purchase is consistent with the gas supply principal of ensuring secure and reliable gas supply to Union's service territory at a reasonable cost.

Contract Parameters

- Transportation provider: TransCanada Pipelines Limited
- Service: (FT) Firm Gas Transportation Service – Renewable
- Term: December 18, 2013 through October 31, 2015
- Volume: 9,000 GJ/day
- Current Rate: $1.3169 Cdn/GJ at 100% load factor (approved Mainline tolls, effective July 1, 2013, exclusive of fuel)
- Primary Receipt Point: Empress
- Delivery Point: Union NDA

Incremental Contracting Analysis Form

The only firm transportation capacity available to the Union NDA is TCPL Empress to Union NDA. Thus, a landed cost comparison is not applicable and has not been included.

PLAN TO SUSPEND VERTICAL SLICE PROGRAM

The purpose of this evidence is to inform the Board and interested parties of Union's plan to suspend the allocation of upstream transportation capacity which currently facilitates the movement to direct purchase in Union's southern delivery area ("Union South") using the vertical slice methodology. Union plans to implement this change through a phased approach, starting in November, 2014, and concluding by November, 2016. Certain contract expiries in Union's upstream transportation capacity portfolio and a continued reduction in the number of customers moving from sales service to direct purchase each year will allow Union to manage any migration absent the vertical slice methodology.

This evidence is organized as follows:

1. Vertical Slice program history and description
2. Drivers for change
3. Plan to suspend Vertical Slice program
4. Impact on obligated deliveries
5. Future considerations

Vertical Slice Program History and Description

In serving sales service customers in Union South, Union holds a diverse portfolio of upstream transportation contracts which transport natural gas from production basins and market hubs to its southern franchise area. When customers exercise their option to move from sales service to direct purchase, Union no longer requires a portion of the upstream transportation contracts to serve those customers. However, due to the term of these upstream transportation contracts and the unpredictable nature of the number of customers migrating to and from direct purchase, it is not always feasible to adjust the upstream transportation portfolio each time a customer migrates to direct purchase.

Since the inception of direct purchase services in 1985, Union has facilitated requests for Union South sales service customers to switch to direct purchase services by allocating upstream transportation capacity previously used to serve them as sales service supplied customers. From 1985 to 2001, Union facilitated the movement of Union South sales service customers to direct purchase primarily through an allocation/assignment of its long-haul Firm Transportation ("FT") capacity on TCPL from Empress Alberta to the Union Central Delivery Area (CDA) at Parkway. Sales service customers at the time requested this transition to direct purchase given the economic benefits of direct purchase (using long-haul TCPL) relative to remaining Union sales service customers.

By November 2001, the Union South sales service transportation portfolio had changed significantly. The remaining amount of TCPL capacity supporting sales service had become much smaller and new upstream capacity on the Alliance and Vector pipelines arriving at Dawn had been introduced. Also by 2001, there was a significant increase in the number of customers moving from sales service to direct purchase each month. Union did not have sufficient TCPL capacity to continue to manage the magnitude of this migration if it continued. In addition, continuing to allocate only TCPL capacity to direct purchase customers would have left the remaining, more expensive, capacity for sales service customers. Union did not view the continued allocation of TCPL capacity alone to be sustainable or equitable.

In RP-1999-0017 and EB-2001-0441, Union made proposals with respect to allocating a pro-rata share (or “vertical slice”) of its upstream transportation portfolio to customers moving from sales service to direct purchase. Union received approval to implement the vertical slice methodology effective November 1, 2001. Since this time, Union South customers migrating from sales service to direct purchase arrangements were allocated a “vertical slice” (a representative portion of upstream transportation capacities used to serve them) of the Union South gas supply upstream transportation portfolio. Implicit with the vertical slice methodology, is the allocation of the corresponding obligated delivery points on Union’s system.

Each year, the vertical slice allocation changes based on the composition of the upstream portfolio. Today, the vertical slice allocation for Union South includes transportation capacity on TCPL, Alliance, Vector, Trunkline and Panhandle transmission systems. The details of the contracts included in the vertical slice allocation, their expiry date, and the corresponding obligated delivery point is shown in Table 1 below:

Table 1
Union South Vertical Slice Components

	Contract Details			Vertical Slice Details	
				New Direct Purchase	Current Direct Purchase
Pipeline	Obligated Delivery	Expiry	Quantity (GJ/d)	% Allocation*	Existing Allocation
Alliance/Vector	Dawn	1-Dec-15/ 1-Dec-17	84,404	27%	10,870
Vector	Dawn	1-Dec-15	85,460	32%	1,257
Panhandle	Parkway	1-Nov-17	28,486	15%	358
Panhandle/Trunkline	Parkway	1-Nov-17	21,101	8%	199
TCPL - Empress to Union CDA	Parkway	1-Nov-16**	67,327	18%	19,292***
Total			286,778	100%	31,976

* Implemented as of November, 2013, rounded.
** All but 11,000 GJ/d expires November 1, 2016.
*** This contract is not vertically sliced but rather allocated to direct purchase customers.

Table 1 also provides the existing capacity allocation (as of March, 2014), and the percent allocation that is “sliced” to customers moving from sales service to direct purchase. For example, if a sales service customer with a DCQ of 1,000 GJ/d moved to direct purchase, the vertical slice allocation they would receive would be 270 GJ/d on Alliance/Vector, 320 GJ/d on Vector, 150 GJ/d on Panhandle, 80 GJ/d on Trunkline and 180 GJ/d on TCPL. For administrative ease, at the choice of customers, movement from sales service to direct purchase with a total contract DCQ less than 300 GJ/d continued to be facilitated through an allocation of upstream capacity on TCPL arriving at the Union CDA/Parkway.

Vertical slice is not applicable to direct purchase in Union’s northern delivery areas (“Union North”) since these customers are served almost exclusively with TCPL capacity. When a Union North sales service customer migrates to bundled direct purchase, they receive an obligation to deliver their DCQ to Union at Empress. Union then transports this supply to the customer's delivery area for their consumption. If the customer migrates to Transportation (T-Service), then the underlying TCPL transportation capacity is assigned to the customer, along with the requirement to deliver their supply to match their consumption in their respective delivery area.

Drivers for Change

There are two significant drivers which have prompted Union's plan to suspend the vertical slice program. First, upcoming upstream transportation contract expiries will allow Union, and therefore direct purchase customers, to turn back their existing vertical slice allocation. Second, a continued and steady reduction in the number of customers moving from sales service to direct purchase will allow Union to manage this migration within the sales service portfolio without requiring an allocation of upstream transportation capacity going forward, provided it remains small and/or predictable.

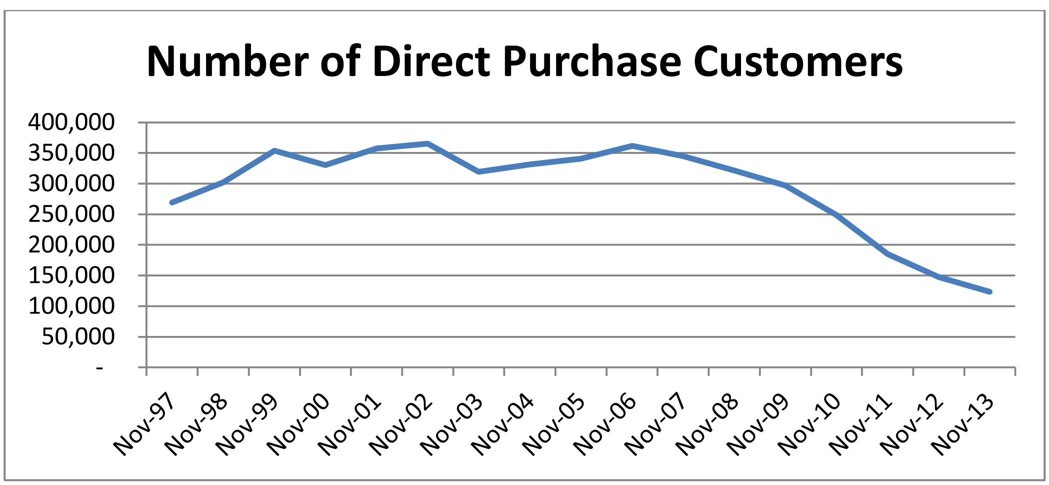
By November, 2016, contracted capacity on two of Union's upstream transportation paths will expire or be reduced:

- Effective December 1, 2015, approximately 84 TJ/d of long-term long-haul Alliance and Vector capacity will expire and will not be renewed.
- Effective November 1, 2016, a significant portion of Union's long-term long-haul TCPL Empress to Union CDA capacity will expire. This capacity is expected to be reduced from 67 TJ/d to 11 TJ/d.

These two paths comprise almost 95% of the vertical slice quantities currently allocated to direct purchase customers, as shown in Table 1 above. Given these contract expiries, Union will be able to offer turnback to direct purchase customers for their existing allocation of these capacities, coincident with the contract expiry date. Once this capacity from the existing vertical slice allocation is removed, then Union will manage capacity relating to sales service customers who migrate to direct purchase going forward. The magnitude of the capacity to be managed will depend upon how many customers are expected to move to direct purchase.

Since 2007, the number of direct purchase customers in the general service market has significantly declined as customers have returned to sales service. The reduction in the number of direct purchase customers is expected to continue to slow down or remain steady for the foreseeable future. Figure 1 below illustrates the movement to/from direct purchase between 1997 and 2006, and the trend to return to sales service since 2007.

Figure 1



The reduced number of customers moving to direct purchase each month has created an environment that will allow Union to manage such movement within the upstream transportation portfolio rather than through the vertical slice capacity allocation.

Plan to Suspend Vertical Slice Program

Given that a large portion of the existing vertical slice quantities can be turned back as a result of upstream transportation contract expiries, and the migration from sales service to direct purchase is expected to be small and manageable going forward, Union is now able to suspend the vertical slice methodology. Instead of allocating a portion (vertical slice) of multiple upstream transportation capacities to customers as sales service customers migrate to direct purchase, Union will adjust the sales service upstream transportation portfolio to accommodate fluctuations of the number of customers moving between sales service and direct purchase. Union will manage migration by adjusting Dawn planned purchases (which can be adjusted on a monthly, seasonal, or annual basis since they are not tied to upstream transportation contracts), and/or through upstream transportation contract expiries.

Union considered the following when determining how to implement the suspension of the vertical slice allocation methodology:

- Union’s gas supply planning principles ensuring secure, reliable service to customers at a prudently incurred cost;

- Existing policies and practises for upstream capacity turnback available to direct purchase customers;
- Removal of contracts from the vertical slice allocation as soon as practical;
- Timing of changes in the upstream transportation capacity portfolio; and
- Magnitude of vertical slice allocations.

Based on these considerations, Union plans on implementing the suspension of the vertical slice allocation methodology in three phases. These phases will occur at November, 2014, December, 2015, and November, 2016 and be implemented as described below:

November 1, 2014: Panhandle and Panhandle/Trunkline capacity

As of November 1, 2014, Union will no longer allocate Panhandle and Panhandle/Trunkline transportation capacity to customers who migrate from sales service to direct purchase. In addition, direct purchase customers who currently hold Panhandle and Panhandle/Trunkline upstream transportation capacity will have the option to turn this capacity back to Union effective November 1, 2014. Their Panhandle and Panhandle/Trunkline capacity allocation will be replaced with an obligation to deliver at Parkway. This is because today Panhandle and Panhandle/Trunkline capacity is ultimately delivered to Parkway through the use of Ojibway to Dawn and Dawn to Parkway transportation. This is required as Union plans and requires this capacity to be delivered at Parkway.

Recognizing that direct purchase customers may have already committed to supply arrangements post-November 1, 2014 using this capacity, they will have the option of retaining their allocation of Panhandle and Panhandle/Trunkline capacity until the implementation of the second phase on December 1, 2015.

While Union's existing Panhandle and Panhandle/Trunkline upstream transportation contracts do not expire until 2017, Union is planning on removing this capacity from the vertical slice methodology effective November, 2014. The reason for this is:

1) Union's experience in recent years has been that the vast majority of customers turn back their existing Panhandle and Panhandle/Trunkline capacity each year and Union has been able to manage this within the remainder of the portfolio.
2) Only a small portion of the Panhandle and Panhandle/Trunkline capacity is "sliced" to sales service customers who migrate to direct purchase in any given year, as shown in Table 1 above.

Since the magnitude of the volume is small, Union can manage these fluctuations within the upstream transportation portfolio until the Panhandle and Panhandle/Trunkline contracts expire in 2017, as well as in the event that these contracts are renewed beyond 2017.

December 1, 2015: Alliance/Vector and Vector

As of December 1, 2015, customers who hold Alliance/Vector and Vector upstream transportation capacity will be required to turn this back to Union. Consistent with recent years' practice, customers will still have the option to turn back existing Vector upstream transportation capacity on November 1, 2014. Any Alliance/Vector and Vector transportation capacity allocation that is turned back (in 2015 for Alliance/Vector and 2014 or 2015 for Vector) will be replaced by a delivery obligation at Dawn.

Given the plan to allow direct purchase customers to turn back existing Alliance/Vector and Vector components effective December 1, 2015, Union will stop allocating these capacities to sales service customers who migrate to direct purchase effective November 1, 2014. This coincides with the implementation of the first phase of the vertical slice suspension, and also minimizes situations where customers would be allocated small slices of capacity for short periods of time.

Union currently holds 3 groups of contracts which comprise the Alliance/Vector and Vector transportation paths:

1) 84 TJ/d of Alliance transportation capacity (December 1, 2015 expiry)
2) 84 TJ/d of Vector transportation capacity (December 1, 2017 expiry)
3) 85 TJ/d of Vector transportation capacity (December 1, 2015 expiry)

Items 1 and 2 comprise the current Alliance/Vector vertical slice capacity, while item 3 is the stand alone Vector vertical slice capacity. Union's plan to remove the Alliance/Vector component from the vertical slice methodology on December 1, 2015 corresponds with expiration date for items 1 and 3. Since the expectation is that future direct purchase migration will continue to be small, Union plans to manage this movement within the sales service portfolio.

November 1, 2016: TCPL Empress to Union CDA

As of November 1, 2016, customers who currently are allocated Empress to Union CDA upstream transportation capacity will be required to turn this back to Union. Their Empress to Union CDA transportation capacity allocation will be replaced by an obligation to deliver at Parkway.

Union's plan to remove this capacity from the vertical slice allocation is driven by Union's planned reduction of the Empress to Union CDA TCPL contracts from approximately 67 TJ/d to 11 TJ/d effective November 1, 2016. Union notes, however, that the turnback of this capacity is dependent upon approval of the Settlement Agreement[1] and planned constructions projects by Union, Enbridge and TCPL.

[1] The Settlement Agreement between TCPL, Union, Enbridge and Gaz Métro, which was filed with the NEB for approval in December, 2013.

Given the plan to allow direct purchase customers to turn back existing Empress to Union CDA capacity effective November 1, 2016, Union will stop allocating these capacities to sales service customers who migrate to direct purchase effective December 1, 2015. This coincides with the implementation of the second phase of the suspension, and also minimizes situations where customers would be allocated small slices of upstream transportation capacity for short periods of time.

The removal of the TCPL Empress to Union CDA contract from upstream transportation capacity allocation to existing and new direct purchase customers is the last step in the suspension the vertical slice program. If the reduction of Union's Empress to Union CDA capacity is delayed as a result of the dependencies noted above, then the final step in the vertical slice suspension will also be delayed. Until Union's contracted transportation capacity can be reduced, direct purchase customers will retain their existing Empress to Union CDA allocation and any sales service customers who migrate to direct purchase will continue to receive an allocation of this capacity.

Table 2 below summarizes the three phases of implementation of vertical slice suspension, its impact on customer turnback of existing allocation of capacity, and when it will impact the allocation of capacity for new direct purchase customers:

Table 2

Impact of Planned Vertical Slice Suspension on Customer Turnback and New Vertical Slice Allocations

	@Nov 1, 2014		@Dec 1, 2015		@Nov 1, 2016	
	Turnback Existing	New Allocations	Turnback Existing	New Allocations	Turnback Existing	New Allocations
Panhandle/Trunkline	Optional	No	Required	No	NOT APPLICABLE	
Panhandle	Optional	No	Required	No	NOT APPLICABLE	
Alliance/Vector	No	No	Required	No	NOT APPLICABLE	
Vector	Optional	No	Required	No	NOT APPLICABLE	
TCPL Empress-UCDA	No	Yes	No	No	Required	No

Legend:

Pre Implementation
Year of Implementation
Post Implementation

Impact on Obligated Deliveries

While direct purchase customers will no longer be required to assume a portion of Union's upstream transportation portfolio once the vertical slice allocation is suspended, they will still be required to meet their obligated deliveries as part of their direct purchase arrangements. This means as the direct purchase customers turn back existing upstream transportation capacity and are not allocated new upstream transportation capacity, they will still be required to make obligated deliveries to Union. The obligated delivery point corresponds to the location that these deliveries are received today using the upstream transportation capacity being removed from the vertical slice, as summarized in Table 3 below:

Table 3
Obligated Delivery Points for Existing Vertical Slice Capacities

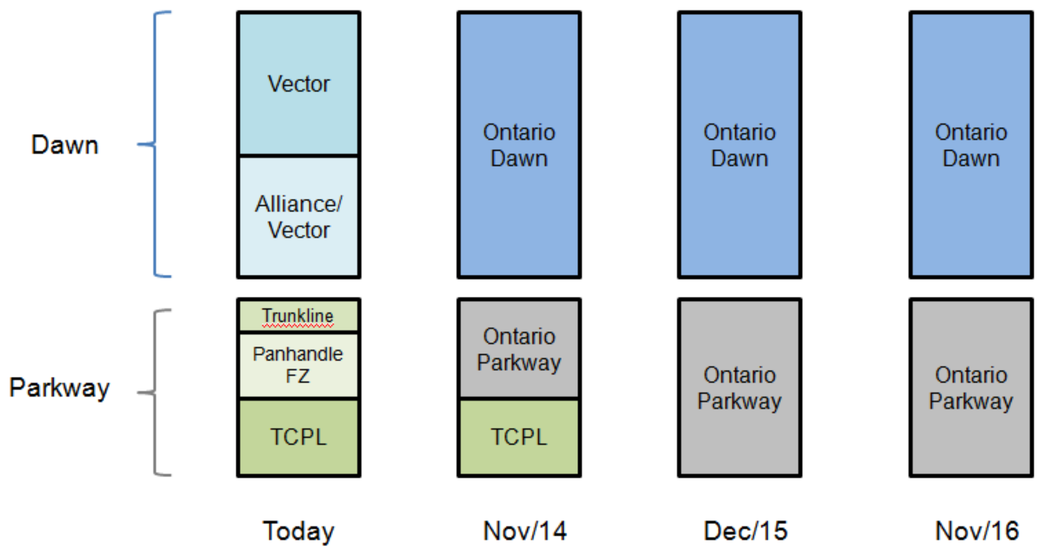
Existing Upstream Transportation Capacity	**Obligated Delivery Point**
Panhandle/Trunkline and Panhandle	Parkway*
Alliance/Vector and Vector	Dawn
TCPL Empress to Union CDA	Parkway

*This capacity is paired with transportation capacity from Ojibway to Dawn and Dawn to Parkway.

Once the vertical slice methodology is suspended, the obligated delivery points for direct purchase load migrating from sales service will be reflective of the underlying allocation between Dawn and Parkway landed supplies in Union’s sales service gas supply portfolio. Consistent with Union’s current practice, this allocation between Dawn and Parkway will be communicated to direct purchase customers annually (late summer) and will be effective on November 1 of each year. If, however, the percentage change in the allocation is less than 5% different than the prior year, allocations will not change and will remain in effect for another year.

The impact of Union’s plan to suspend the vertical slice allocation methodology in the three phases between November, 2014 and November, 2016, and the resulting impact on obligated deliveries for customers migrating from sales service to direct purchase during the transition is depicted in Figure 2 below:

Figure 2
Depiction of Vertical Slice Suspension Implementation



It is important to note that the planned suspension of the vertical slice program applies to direct purchase migration from sales service. It does not impact Union's current policy for new direct purchase load. That is, new direct purchase load located east of Dawn which is served using Union's Dawn-Parkway System will still be obligated at Parkway, and new direct purchase load located west of Dawn will still have the option to be obligated at Dawn.

Union's planned transition does not impact Union's Parkway obligation proposal as filed in Union's 2014 Rates proceeding (EB-2013-0365). Similarly, Union's plan to suspend the vertical slice is not dependent upon the Parkway obligation proposal. The planned transition of the Parkway obligation for existing direct purchase customers that turn back their allocated capacity as part of that proposal will be unaffected by the plan to suspend vertical slice.

Absent any increase in the number of direct purchase customers migrating from sales service, the plan to suspend the vertical slice allocation does not add to the total direct purchase obligation to deliver at Parkway. The direct purchase obligated delivery points remain the same as today with the only difference being that they will not be allocated the associated upstream transportation capacity. For example, there is currently 557 GJ/d of Panhandle and Panhandle/Trunkline capacity allocated to direct purchase customers, as shown in Table 1. Associated with this quantity is an obligation at Parkway. When the Panhandle and Panhandle/Trunkline capacity is turned back in November, 2014 as part of the implementation of the vertical slice suspension, 557 GJ/d will continue to be obligated at Parkway. This obligation remains unchanged by the plan to suspend the vertical slice allocation. The same will hold true for the TCPL Empress to Union CDA capacity, which is also obligated at Parkway.

Union introduced the concept of suspending the vertical slice with customers and intervenors during the annual stakeholder meeting held on April 9, 2014. In addition, Union plans to review the details of the program as described here, as well as any related policy impacts, with customers at upcoming customer meetings and policy group sessions. Preliminary feedback on Union's plan to phase out the vertical slice methodology has been positively received from direct purchase customers.

Future Considerations

Union's plan to suspend the vertical slice allocation methodology is based on customer turnback of existing allocations coincident with the expiration of the underlying upstream transportation contracts in Union's portfolio, and the expectation that the number of sales service customers migrating to direct purchase will remain low and steady, as it has been in recent years.

If migration to direct purchase significantly increases over time, Union will need to maintain the right to re-instate the vertical slice methodology for these customers.

ANNUAL STAKEHOLDER MEETING

In Union's 2014-2018 IRM (EB-2013-0202) Settlement Agreement, parties agreed that Union will hold an annual, funded stakeholder meeting. At the stakeholder meeting Union will review previous year's financial results and other key operating parameters, present and explain market conditions and expected changes/trends, present and review the gas supply plan for the coming year, present new capital projects that meet the capital pass-through criteria and present results of any customer surveys undertaken during the year. Union held the first annual stakeholder meeting on April 9, 2014. The slides from the meeting can be found at Appendix B. The gas supply memorandum can be found at Appendix C.

Appendix A

Schedule 1

2013-2017 Transportation Contracting Analysis

	Route	Point of Supply	Basis Differential $US/mmBtu	Supply Cost $US/mmBtu	Unitized Demand Charge $US/mmBtu	Commodity Charge $US/mmBtu	Fuel Charge $US/mmBtu	100% LF Transportation Inclusive of Fuel $US/mmBtu	Landed Cost $US/mmBtu	Landed Cost $Cdn/G	Point of Delivery
	(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	(I) = E + F + G	(J) = D + I	**(K)**	(L)
(2)	**Trunkline/Panhandle**	Trunkline Field Zone 1A	-0.048	4.7216	0.1923	0.0275	0.1803	0.4000	$5.12	**$5.11**	Ojibway
(2)	**PEPL (2012-2017)**	Panhandle Field Zone	-0.143	4.6266	0.3200	0.0441	0.2230	0.5871	$5.21	**$5.20**	Ojibway
(2)	**TCPL Niagara**	Niagara	0.318	5.0876	0.1427	0.0000	0.0000	0.1427	$5.23	**$5.22**	Kirkwall
*	**Vector (2008-2016)**	Chicago	0.206	4.9751	0.2500	0.0018	0.0478	0.2996	$5.27	**$5.26**	Dawn
(2)	**Panhandle Longhaul (2010-2017)**	Panhandle Field Zone	-0.143	4.6266	0.4251	0.0441	0.2230	0.6922	$5.32	**$5.31**	Ojibway
	Dawn	Dawn	0.647	5.4165	0.0000	0.0000	0.0000	0.0000	$5.42	**$5.41**	Dawn
(2)	**Alliance/Vector (2000-2015)**	CREC	-0.715	4.0543	1.7310	-0.4129	0.2251	1.5432	$5.60	**$5.59**	Dawn
(1)	**TCPL SWDA**	Empress	-0.597	4.1722	1.4228	0.0000	0.0968	1.5196	$5.69	**$5.68**	Dawn
(2)	**TCPL CDA**	Empress	-0.597	4.1722	1.5435	0.0000	0.1135	1.6570	$5.83	**$5.82**	Union CDA

(1) For Reference Only

(2) Existing Union Gas Contract

* indicates path referenced in evidence for this analysis

Assumptions used in Developing Transportation Contracting Analysis:

	Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Dec 2013 - Nov 2014	Dec 2014 - Nov 2015	Dec 2015 - Nov 2016	Dec 2016 - Nov 2017	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
	Henry Hub (NYMEX)	Henry Hub	$3.92	$4.37	$4.84	$5.95	$4.77	
	Trunkline/Panhandle	Trunkline Field Zone 1A	$3.88	$4.33	$4.79	$5.89	$4.72	3.82%
	PEPL (2012-2017)	Panhandle Field Zone	$3.79	$4.25	$4.71	$5.76	$4.63	4.82%
	TCPL Niagara	Niagara	$4.25	$4.68	$5.14	$6.28	$5.09	0.00%
	Vector (2008-2016)	Chicago	$4.13	$4.60	$5.07	$6.11	$4.98	0.96%
	Panhandle Longhaul (2010-2017)	Panhandle Field Zone	$3.79	$4.25	$4.71	$5.76	$4.63	4.82%
	Dawn	Dawn	$4.60	$5.08	$5.52	$6.47	$5.42	0.00%
	Alliance/Vector (2000-2015)	CREC	$3.25	$3.76	$4.14	$5.07	$4.05	5.55%
	TCPL SWDA	Empress	$3.37	$3.87	$4.26	$5.19	$4.17	2.32%
	TCPL CDA	Empress	$3.37	$3.87	$4.26	$5.19	$4.17	2.72%

Sources for Assumptions:

Gas Supply Prices (Col D):	ICF Q3 2013 Base Case		
Fuel Ratios (Col G):	Average ratio over the previous 12 months or Pipeline Forecast		
Transportation Tolls (Cols E & F):	Tolls in effect on Alternative Routes at the time of Union's Analysis		
Foreign Exchange (Col K)	$1 US =	$1.053 CDN	From Bank of Canada Closing Rate September 3, 2013
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	
Union's Analysis Completed:	Sep-13		

Paths included in analysis are those with comparable services available for contracting, as well as relevant benchmarks and currently contracted paths.

Schedule 2
2013-2014 Transportation Contracting Analysis

	Route	Point of Supply	Basis Differential $US/mmBtu	Supply Cost $US/mmBtu	Unitized Demand Charge $US/mmBtu	Commodity Charge $US/mmBtu	Fuel Charge $US/mmBtu	100% LF Transportation Inclusive of Fuel $US/mmBtu	Landed Cost $US/mmBtu	Landed Cost $Cdn/G	Point of Delivery
	(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	(I) = E + F + G	(J) = D + I	**(K)**	(L)
	Dawn	Dawn	0.172	4.0106	0.0000	0.0000	0.0000	0.0000	$4.01	**$3.93**	Dawn
(2)	**TCPL Niagara**	Niagara	0.072	3.9106	0.1453	0.0000	0.0000	0.1453	$4.06	**$3.98**	Kirkwall
*	**Proposed PEPL - (Mkt Quote)**	Panhandle Field Zone	-0.279	3.5598	0.3200	0.0441	0.1716	0.5357	$4.10	**$4.01**	Ojibway
(2)	**PEPL (2012-2017)**	Panhandle Field Zone	-0.279	3.5598	0.3200	0.0441	0.1716	0.5357	$4.10	**$4.01**	Ojibway
	Vector 1 Year (Mkt Quote)	Chicago	0.039	3.8777	0.2000	0.0018	0.0372	0.2390	$4.12	**$4.04**	Dawn
(2)	**Trunkline/Panhandle**	Trunkline Field Zone 1A	-0.051	3.7873	0.1923	0.0275	0.1483	0.3681	$4.16	**$4.07**	Ojibway
(2)	**Vector (2008-2015)**	Chicago	0.039	3.8777	0.2500	0.0018	0.0372	0.2890	$4.17	**$4.08**	Dawn
	ANR-Michcon-Union (Gulf)	ANR South East	-0.077	3.7617	0.2512	0.0161	0.1581	0.4253	$4.19	**$4.10**	Dawn
(2)	**Panhandle Longhaul (2010-2017)**	Panhandle Field Zone	-0.279	3.5598	0.4251	0.0441	0.1716	0.6408	$4.20	**$4.12**	Ojibway
	NGPL - ANR - MICH	NGPL TEX OK EAST	-0.115	3.7235	0.3635	0.0076	0.1590	0.5302	$4.25	**$4.17**	Dawn
	ANR-GLGT-TCPL	ANR South East	-0.077	3.7617	0.4059	0.0223	0.1100	0.5383	$4.30	**$4.21**	Dawn
(1)	**TCPL SWDA**	Empress	-0.545	3.2934	1.4486	0.0000	0.0764	1.5250	$4.82	**$4.72**	Dawn
(2)	**Alliance/Vector (2000-2015)**	CREC	-0.458	3.3808	1.7463	-0.4172	0.1877	1.5169	$4.90	**$4.80**	Dawn
(2)	**TCPL CDA**	Empress	-0.545	3.2934	1.5716	0.0000	0.0896	1.6612	$4.95	**$4.86**	Union CDA

(1) For Reference Only
(2) Existing Union Gas Contract
* indicates path referenced in evidence for this analysis

Sources for Assumptions:

Gas Supply Prices (Col D): ICE Settlement August 19, 2013

Fuel Ratios (Col G): Average ratio over the previous 12 months or Pipeline Forecast

Transportation Tolls (Cols E & F): Tolls in effect on Alternative Routes at the time of Union's Analysis

Foreign Exchange (Col K) $1 US = $1.034 CDN From Bank of Canada Closing Rate August 19, 2013

Energy Conversions (Col K) 1 dth = 1 mmBtu = 1.055056

Union's Analysis Completed: Aug-13

Paths included in analysis are those with comparable services available for contracting, as well as relevant benchmarks and currently contracted paths.

Appendix B

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2014 Annual Stakeholder Meeting

April 9, 2014

Purpose of Meeting

In Section 12.2 of the EB-2013-0202 Settlement Agreement, parties agreed to an annual funded stakeholder meeting where Union would:

- Review previous year's financial results (i.e. earnings, capital spending) and other key operating parameters (i.e. SQI performance) for the most recently completed year;
- Present and explain market conditions and expected changes/trends, and the impact these may have on the regulated operations; Present and review the gas supply plan for the coming year;
- Present new capital projects that meet the capital pass-through criteria as defined in Section 6.6; and,
- Present results of any customer surveys undertaken during the year.

Meeting Agenda

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Opening Comments	**Mark Kitchen** *Director, Regulatory Affairs*
2013 Financial Results	**Pat Elliott** *Controller*
2013/2014 Gas Supply Plan	**Chris Shorts** *Director, Gas Supply*
Facilities Expansions	**Jim Redford** *Director, Business Development and Upstream Regulation*
Community Expansion	**Jeff Okrucky** *Director, Distribution Marketing*
Residential Customer Perceptions of Union Gas	**Jeff Okrucky** *Director, Distribution Marketing*
Hagar LNG and New Union Gas Services	**Tina Hodgson** *Manager, Product Process and Development*

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2013 Financial Results

Pat Elliott

Controller

Agenda

- 2013 Utility Financial Results
- Capital Spend
- Deferral Sharing Accounts
  – Short-Term Storage & Other Balancing Services
  – Transportation Optimization
  – Demand Side Management Activity
- 2014 Trends and Cost Pressures
- Service Quality Requirements and Billing Performance

2013 Utility Financial Results

Particulars ($ millions)	Earnings before interest and taxes	Rate Base	Return on equity
Board approved	291	3,735	8.93%
Increase projected at 3&9 outlook	10		
	301	3,735	9.51%
Weather	11		
Terminated contract settlements	6		
Other	5		
Actual	323	3,784	10.67%
Normalized [1]	306		9.73%

Note 1: normalized for weather and terminated contracts

Capital Spend

Particulars ($000s)	Board Approved	Actual
Storage	11,562	5,742
Transmission	113,795	106,647
Distribution	131,797	164,946
General	37,215	35,167
Other	53,333	55,696
Total	347,702	368,198
Less: Parkway West Reliability, and Brantford-Kirkwall/Parkway D Project	80,000	51,966
	267,702	316,232

Short-Term Storage & Other Balancing Services

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Particulars ($000s)	Board Approved	Actuals	Variance
Net margin (pre-tax)[1]	5,057	3,162	1,895
Less: Shareholder portion (10%)	(506)	(316)	(190)
Ratepayer portion (90%)	4,551	2,846	1,705
Less: Subsidy in rates	(4,551)	(4,551)	-
Deferral balance receivable	**-**	**1,705**	**(1,705)**

[1] Board Approved 11.3 PJ vs. Actual 8.7 PJ

Transportation Optimization

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Particulars ($000s)	Board Approved	Actuals	Variance
Base exchanges	9,118	15,409	6,291
FT-RAM exchanges	5,800	8,338	2,538
Total exchanges revenue (pre-tax)	14,918	23,747	8,829
Less: Shareholder portion (10%)	(1,492)	(2,375)	(883)
Ratepayer portion (90%)	13,426	21,372	7,946
Less: Subsidy in rates	13,426	15,697	2,271
Deferral balance payable	**-**	**5,675**	**5,675**

DSM Activity

Costs	DSM VA ($000s) Board Approved	Actual	Deferral Variance
RA - Residential	3,326	3,372	(46)
RA - C/I	11,419	12,587	(1,168)
Total Resource Acquisition	14,745	15,959	(1,214)
Large Industrial	4,767	4,739	28
Low Income	7,191	8,043	(852)
Market Transformation	1,450	945	505
Portfolio	3,488	3,153	335
Total	**31,641**	**32,839**	**(1,198)**

Scorecard	DSM Incentives ($000s)
Resource Acquisition	5,203
Large Industrial T1/R100	1,638
Low Income	2,729
Market Transformation	550
Total	**10,120**

These results are pre-verification and assume a realization rate of 100%.

2014 Trends & Cost Pressures

- Salary inflation – trends at 3%
- Employer benefit costs
- Increase in line locates
- Sewer safety inspections
- Pipeline integrity (O&M and Capital)
- Facility operating costs (rent, maintenance)
- Electricity rates
- Postage prices
- Foreign exchange sensitivity

Service Quality Requirements and Billing Performance

Service Quality Requirements	Target	Actual
Call Answering Service Level - Annual	75.0%	78.4%
Call Answering Service Level - Monthly	40.0%	>40.0% each month
Abandon Rate	<10%	3.8%
Meter Reading Performance Measurement	<0.5%	0.2%
Appointments Met Within the Designated Time Period	85.0%	97.8%
Time to Reschedule a Missed Appointment	100.0%	99.9%
Percentage of Emergency Calls Responded Within One Hour	90.0%	97.9%
Number of Days to Provide a Written Response	80.0%	100.0%
Number of Days to Reconnect a Customer	85.0%	92.2%

Billing Performance	Actual
Total Number of Billings	17,109,647
Total Number of Manual Checks Done as per QAP	140,497
Total Number of Manual Checks Done when Meter Reads Show Excessively High Usage as per QAP Criteria	95,145
Total Number of Manual Checks Done when Meter Reads Show Excessively Low Usage as per QAP Criteria	15,923

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2013/2014 Gas Supply Plan

Chris Shorts
Director, Gas Supply

2013/2014 Gas Supply Plan Agenda

- Sussex Recommendations Review
- Objectives of the Gas Supply Plan
- Key Inputs and Assumptions
- Key Results and Outcomes
- Future Market Considerations

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Sussex Recommendations

Sussex Recommendations: Design Day Demand Forecasting

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- Increased documentation across departments
  - *Union has prepared a process flow chart. This chart is provided at Appendix A of the memorandum.*
- An annual review process of the prior year's results
  - *In preparing for the upcoming Gas Supply Plan, Union has added an internal kick-off meeting to the annual gas supply planning process*.
- A review/evaluation of whether different data sets should be analyzed
  - *Union has reviewed two methods - Union's Use per Customer Factor and Multiple Winter Average. The two methods result in changes within 1% of each other. Based on the review, Union will continue to evaluate both methods to see if any significant differences result.*
- Use of the coldest observed temperature in Union South for the design day standard
  - *Union has adopted the coldest observed temperature in Union South (43.1 HDD).*

Sussex Recommendations: Gas Supply Plan Documentation

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- Increased documentation of the Gas Supply Plan through a written “Memorandum”, including:
  - the underpinning assumptions
  - how the Gas Supply Plan conforms to the planning principles,
  - A summary of regulatory and market drivers that provides context for stakeholders
- *Union has responded to these recommendations by expanding on information made available internally and to Intervenors through the comprehensive evidence filed in conjunction with the Sussex report in the EB-2013-0109 hearing and through this Gas Supply Plan presentation and accompanying memorandum.*

Sussex Recommendations: Contract Practices

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- Continued use of known information in the contracting decision process, with the addition of scenarios around the base case
  - *Union considers a number of options for paths when contracting, as well as potential toll scenarios, if available or relevant.*
- Documentation of the alternatives analyzed and not analyzed
  - *Union expanded on the documentation of what paths were not analyzed and the reasons as to why the paths were not considered.*
- Review of whether the SENDOUT model could be used to augment the landed cost analysis
  - *Union continues to utilize Sendout to augment the landed cost analysis for Greenfield projects and any significant changes to the Union North portfolio. Union will continue to use Sendout for future portfolio contracting decisions where applicable.*
- Development of a process to review the cost of service, rate level and rate design for St. Clair Pipeline and Bluewater Pipeline
  - *Union has developed a process to review the cost of service, rate level and rate design for St. Clair Pipeline and Bluewater Pipeline.*

Market Conditions during Plan creation

- Emerging Supply Sources
  - Shift from WCSB to Marcellus/Utica supplies
  - Shift from long-haul transportation to short-haul transportation
    - *Improved diversity and security of supply*
    - *Access to liquid supplies at Dawn*
- Stable gas price forecast
- Changing TCPL Tolls
  - Revised TCPL tolls effective July 1, 2013
  - Settlement Agreement negotiations as of September 2013

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Gas Supply Plan Overview

Objectives and Goals of the Gas Supply Plan

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- **Objective**
  - The Gas Supply Plan identifies the efficient combination of upstream transportation, supply purchases, and storage assets required to serve sales service and bundled DP customers' annual, seasonal and design day gas delivery requirements while adhering to the planning principles
- **Goal**
  - Ensure that customers receive secure, diverse gas supply at prudently incurred cost. These principles are:
    - » *Ensure secure and reliable gas supply to Union's service territory;*
    - » *Minimize risk by diversifying contract terms, supply basins and upstream pipelines;*
    - » *Encourage new sources of supply as well as new infrastructure to Union's service territory;*
    - » *Meet planned peak day and seasonal gas delivery requirements;*
    - » *Deliver gas to various receipt points on Union's system to maintain system integrity.*

Key Inputs and Assumptions of the Supply Plan

Union's Gas Supply Plan includes the following key inputs and assumptions:

- Union's in-franchise monthly demand forecast (excludes Transportation Service and Unbundled service);
- The design day demand forecast;
- A monthly commodity price forecast using the same pricing methodology as the Quarterly Rate Adjustment Mechanism ("QRAM") process;
- Upstream transportation tolls in effect at the time the forecast was prepared;
- All upstream transportation contracts held by Union plus existing obligated Ontario deliveries for the bundled DP market;
- Sales service and bundled DP storage requirements;
- Sufficient inventory at February 28 and March 31 to meet the design day requirements for sales service and bundled DP customers;
- No migration between sales service and bundled DP customers for the term of the Gas Supply Plan; and,
- 9.5 PJ of system integrity space.

In-franchise Demand

- Total bundled customer forecast volumes (including U2) has increased by approximately 1.4% in Union's 2013/2014 Gas Supply from what was approved by the Board in 2013
  - The general service forecast has increased by 0.8% in Union South and 2.7% in Union North for a total increase of 2.4 PJ primarily due to higher than expected use in the residential and commercial markets
  - The contract market has increased by 3.2% in Union South and decreased by 6.9% in Union North for a total increase of 0.9 PJ primarily due to the global economic forces and production activity at a number of industrial establishments

General Service In-franchise Demand – Sales Service

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- Total sales service demands have increased by 18.1 PJ.
- In the general service market, sales service demands have increased by 12.1 PJ in Union South and 4.8 PJ in Union North driven by:
  - Estimated customer attachments in 2014 of 13,670 and 6,064 respectively;
  - Union South, Union requires additional supply and transportation capacity to meet increased demand as a result of return to sales service.
    - *Approximately 90,000 direct purchase customers returning to sales service (Union South);*
  - Union North, Union plans for pipe capacity for sales service and bundled direct purchase customers (therefore no impact to Union's contracted capacity in the North as a result of return to system)

Design Day

- The design day is measured in heating degree days ("HDD")
  - The colder the temperature, the higher the HDD.
  - A heating degree day is a temperature 1 degree C below 18 degrees C. Therefore an 18 degree HDD would translate to a temperature of 0 degree C on average for the day.
- Union's franchise is split into Union South and Union North for gas supply planning purposes.
  - Union South is considered one delivery area.
  - Union North is further divided into six delivery areas (EDA, SSMDA, MDA, NDA, WDA and NCDA).
- The main information required to develop the design day demand includes:
  - Weather - the coldest observed degree day for each of the seven delivery areas.
  - Firm Customer Demand - forecast by multiplying the firm use per degree day factor with the coldest observed degree day.
  - Forecast Demand – the winter season growth factor developed by Union's Demand Forecasting Group.
  - Required Assets - assets must be available should that design day occur given Union's role as the supplier of last resort for sales service and bundled DP customers.

Union South Design Day

- The design day weather condition is based on the coldest observed degree day experienced - for Union South is 43.1.
  - There has been no change in the coldest observed degree day experienced from Union's evidence filed in EB-2013-0109.
- The design day requirements of Union's South in-franchise customers are handled differently than in Union North.
  - Union needs to have sufficient volume of gas in storage for the seasonal and firm design day demand requirements and sufficient assets to move the upstream supply out of storage into the transmission pipeline systems.
  - Union needs to have enough assets to move the firm design day demand from the systems supply points to its customers on design day.
  - If the transmission or storage system is not sufficient to meet design day and seasonal requirements, Union will build additional assets or purchase services to meet this shortfall.

Union South Design Day

- For Union South, the Gas Supply Plan focused on upstream supply and transportation to meet Union's annual demand requirements.
  - upstream pipe flows at 100% utilization each day of the year (annual volume requirement is divided by 365 days).
  - when usage is less than the upstream supply, the excess supply is injected into storage.
  - when demands are greater than the upstream supply, gas is withdrawn from storage.

Union South Design Day Demand and Resources (TJ/day)

Demand	
Union South*	2,743
Supply	
Storage at Dawn	1,300
Non-obligated (e.g. Power Plants)	220
TCPL Empress to Union CDA	67
Trunkline	21
Panhandle	39
TCPL Niagara	21
Ontario Parkway	555
Alliance/Vector	84
Vector	85
Ontario Dawn	310
Customer Supplied Fuel	40
Total Supply	2,743

* includes System Sales, Bundled Direct Purchase, T-service, Unbundled

Union North Design Day

Union North design day demand - total firm requirement of the in-franchise sales service and bundled DP customers.

- The design day weather condition is based on the coldest observed degree day experienced in each of the six delivery areas. There has been no change in the coldest observed degree day experienced from Union's evidence filed in EB-2013-0109.

WDA	56.1	Thunder Bay
MDA	54.7	Fort Frances
SSMDA	48.2	Sault Ste Marie
NCDA	49.0	Muskoka / Gravenhurst
NDA	51.9	Sudbury
EDA	47.1	Kingston

- Union North gas supply portfolio ensures sufficient, but not excess, firm transportation services.
- The full suite of assets is only required when a design day occurs so there are days when the pipe is not fully utilized.
- Union North uses a combination of Union storage at Dawn and TCPL STS services to supplement the firm upstream transportation services.

Union North Design Day

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Winter 2013/2014 Northern Firm Demand on Peak Day in GJ's/Day

	Delivery Area						
	MDA	**WDA**	**SSMDA**	**NDA**	**NCDA**	**EDA**	**Total**
Firm Demand							
Bundled Firm Contract Demand	-	4,427	982	1,228	-	10,341	16,978
Non-Industrial Design Day Demand	5,565	75,100	35,298	143,575	37,246	146,487	443,271
T-Service Storage Redelivery Demand	-	-	-	13,806	-	-	13,806
Peak Day Demand for the Region	**5,565**	**79,527**	**36,280**	**158,609**	**37,246**	**156,829**	**474,055**
Firm Supply							
TCPL FT from Empress	4,522	36,580	2,000	49,077	8,796	58,831	159,806
Great Lakes/TCPL FT from Michcon			6,143				6,143
STS Firm Withdrawals from Parkway	-	31,420	-	46,036	28,450	62,998	168,904
Diversion from TCPL 1808 contract	1,043	11,527	-	54,645	-	-	67,215
STS Firm Withdrawals from Dawn	-	-	28,137	-	-	-	28,137
Parkway to EDA FT	-	-	-	-	-	35,000	35,000
Peak Day Supply to the Region	**5,565**	**79,527**	**36,280**	**149,758**	**37,246**	**156,829**	**465,205**
Excess(Shortfall) by delivery area	***()***		***()***	***(8,851)***			***(8,851)***

Union North Design Day

- There was a forecast shortfall of 8,851 GJ/d in Union North on design day.
  - Shortfall was largely due to lower forecast declines in demand across Union North delivery areas (higher demand than 2013 Board-approved forecast), as well as forecast increases in Union North T-service redelivery demands.
  - Union contracted for firm incremental capacity from Empress to Union NDA effective January 1, 2014.
    - » *Union started this contract as of December 18, 2013 due to colder than normal temperatures and operational changes on TCPL.*

Gas Supply Plan
Transportation Portfolio

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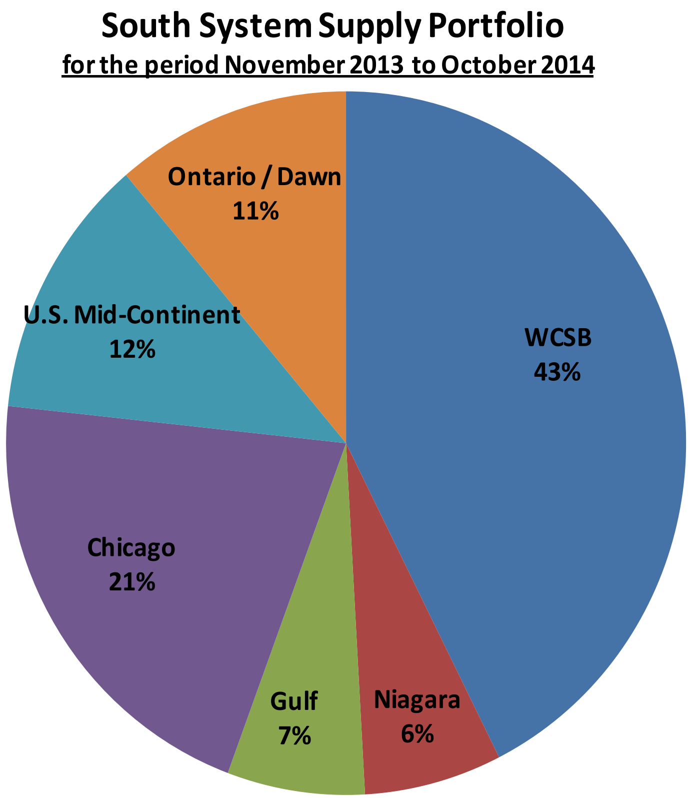
- Union holds a combination of assets to meet forecast annual demand:
  - firm upstream transportation contracts
  - Dawn sourced supply and
  - storage capacity (including STS to move storage volumes to market)
- Firm transportation arrangements provide direct and secure access to a diverse group of supply basins and hubs in North America.
- A key objective of the Gas Supply Plan is the efficient use of the upstream contracted pipeline capacity.
- The contracts in Union's portfolio to serve Union South demands and Union North annual, seasonal and design day demands for the 2013/2014 gas year are provided as Appendices to the memorandum.

Gas Supply Plan
Transportation Portfolio – Union South

- Union holds firm transportation contracts and sources supply at Dawn to meet average annual demand requirements for Union South sales service customers.
- Union utilizes capacity on upstream pipelines to access several supply basins or market hubs for Union system supply portfolio.



Gas Supply Plan
Transportation Portfolio – Union North

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- Union utilizes TransCanada Pipelines (“TCPL”) and Michigan Consolidated Gas Company/Great Lakes Gas Transmission (“MichCon/GLGT”) capacity to meet sales service and bundled DP customer demands.
- The transportation capacity necessary to meet peak day demands on a firm basis exceeds that required to meet the annual demand requirements.
- The Gas Supply Plan reflects the effective management of TCPL and MichCon/GLGT capacity by:
  - *Using TCPL Storage Transportation Service (“STS”) injection to move excess gas to storage;*
  - *Using TCPL STS withdrawals to move gas from storage and to supplement firm transportation capacity; and,*
  - *Using contractual STS pooling rights to group Union’s STS rights serving the various Union North delivery areas.*

Union North Design Day Unutilized Pipe (UDC)

- Union North, the upstream transportation capacity is first sized to meet the winter design day demand requirement
- Gas supply flowing on that capacity is also needed to meet average annual demand requirements
- A portion of Union's contract capacity is planned to be unutilized during the year ("UDC")
- The total forecast UDC is 10.7 PJ in the 2013/2014 Gas Supply Plan
- No UDC is planned for Union South
- If weather is colder than normal and annual consumption is greater, and if it is economical to do so, Union will use this capacity to meet incremental supply requirements in either Union North or Union South subject to TCPL's authorization of downstream diversions.

Union North Transportation Capacity vs Demand	
2013/14 Gas Supply Plan	
	PJ
Total contracted capacity (166 TJ/day x 365)	60.6
Incremental NDA Capacity (9 TJ/day x 304 days) *	2.7
Less:	
Total Annual System Sales Demand	37.1
Total Annual Bundled DP Demand	15.5
UDC	10.7
* Contract in place as of January 1, 2014	

2014 Upstream Transportation Portfolio Changes

- Upstream Transportation Expiring October 31, 2013
  - Vector Pipeline – 10,551 GJ/d (one year term)
  - Panhandle Eastern Pipeline – 10,551 GJ/d (one year term)
  - Union CDA market-based contracts – 64,000 GJ/d (5-month term)
- 2014 Requirements
  - 44,000 GJ/d of supply in addition to what is currently contracted on upstream pipelines, is required as of November 2013
    - » *Upstream Transportation Acquired November 1, 2013*
      - Panhandle Eastern Pipeline – 10,551 GJ/d (re-contracted for a one year term)
      - Dawn delivered supplies make up balance for increased flexibility and diversity of supply
  - Union CDA market-based contracts – 53,000 GJ/d (5-month term)
- Union North Design Day Requirement
  - TCPL Empress to Union NDA 9,000 GJ/d acquired
    - » *Planned term January 1, 2014 to October 31, 2015*
      - Union started this contract as of December 18, 2013 due to colder than normal temperatures and operational changes on TCPL.

In-franchise Storage

- Union operates storage of 166 PJ
  - In-franchise NGEIR allotment is 100 PJ
    - » *This is to meet both existing and future needs*
  - In-franchise space requirement for 2013/2014 is 91.4 PJ.
  - This number is greater than the Board-approved plan by 2.6 PJ.
  - Driven by in-franchise demand growth.

Key Outcomes of 2013/2014 Gas Supply Plan

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- Total volume of supply required for sales service is 155 PJ (versus 137 PJ in 2013) (plus fuel) for November/13 – October/14.
- Sales service demands (November/13-October/14) are growing by 18.1 PJ over the previous forecast. This is mainly due to an increase of 16.9 PJ in the general service market, driven primarily by return to sales service.
- In addition to supply sourced on current contracted transportation capacity, approximately 44,000 GJ/d of supply is required as of November 2013 to balance sales service supply and demands. Transportation capacity has been committed for a portion of this requirement and the remainder will be purchased at Dawn.
- Increase in Union North design day requirement of 8,851 GJ/d for Union North
- In-franchise storage allocation at November 2013 is 91.4 PJ. This represents an increase of approximately 2.6 PJ from the 2013 plan.
- No planned UDC for Union South and 10.7 PJ for Union North .

Summary

- Union establishes a Gas Supply Plan that is right sized to meet firm sales service and bundled customer demands with a diverse, flexible and cost effective portfolio of firm services and assets.
- Union plans and contracts for services and assets to provide an efficient combination of upstream transportation, supply purchases, and storage to serve sales service and bundled DP customers' annual, seasonal and design day gas delivery requirements.
- Union adheres to the gas supply guiding principles to ensure the assets procured on behalf of customers are robust, secure, diverse and reliable to meet firm customer demands.
- As supply and transportation market options change, so does Union's supply mix and how it is transported to Ontario.
- Union continues to proactively evaluate new supply and transportation options for Union North and Union South customers.
- **Unchanged, however, is Union's application of the gas supply planning principles and the requirement to ensure secure, reliable supplies to serve its customers at prudently incurred costs.**

Future Trends

Market Context

- Industry trends
  - Shift from WCSB to Marcellus/Utica supplies
  - Shift from long-haul transportation to short-haul transportation
    - Improved diversity and security of supply
    - Access to liquid supplies at Dawn
  - Stable gas price forecast

- Recent Experience
  - Transportation bottlenecks
  - TCPL discretionary service pricing

- Winter 2013/2014
  - Extreme and sustained cold weather
  - Low storage inventories
  - Changes in TCPL operations
  - Forward market pricing vs. intra-month cash market

Future Trends

- TCPL Settlement Agreement
  - Process underway by TCPL at NEB
- Access to Dawn for Union North
  - Transition of TCPL long-haul transportation to short-haul
- 2016 TCPL Open Season
  - Union bid for sales service/bundled DP and T-Service customers
- TCPL Diversions and Discretionary Services
  - Address operational changes going forward
- Changing TCPL Renewal Notice
  - Revised from 6 months to 2 years

Future Trends

- GLGT Michcon Capacity Replacement with TCPL
  - Union not renewing this path Nov 1, 2014
- Dawn to Parkway Expansions
  - Facilities approved subject to conditions
- Plan to Suspend Vertical Slice
  - Phased approach starting Nov 1, 2014
- Parkway Obligation
  - Changing for both DP and sales service
- Burlington Oakville Project
  - To ensure security of supply and meet growing needs
- Bringing Additional Supplies to Dawn
  - Support diversity and security of supply in the Union North portfolio

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Facilities Expansions

Jim Redford

Director, Business Development and Upstream Regulation

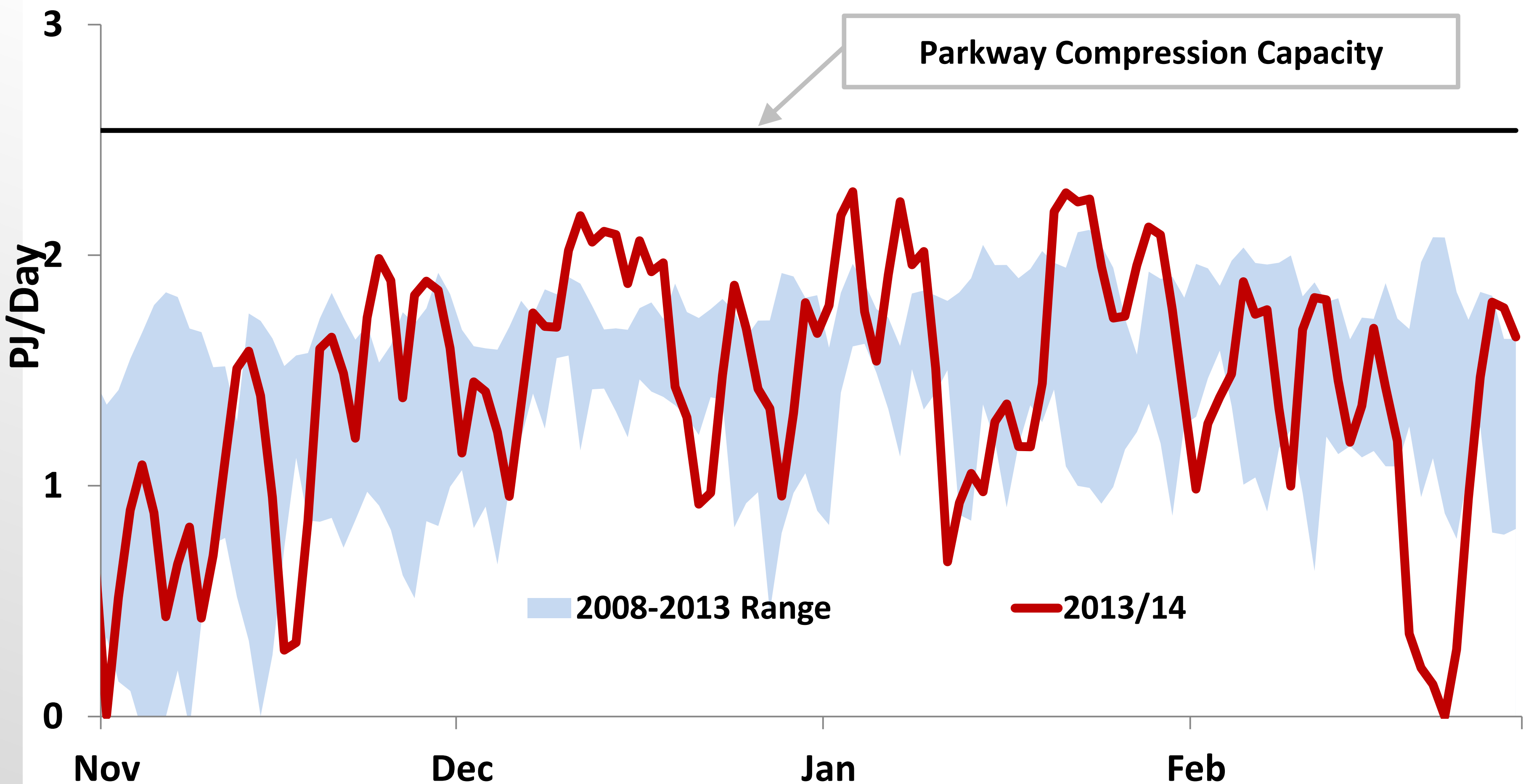
Facilities Expansion Agenda

- Projects Meeting Capital Pass Through Criteria
- Parkway Deliveries
- Update on Approved 2015 Parkway Projects
- 2016 Proposed Dawn to Parkway Expansion
- 2016 Proposed Burlington-Oakville Project

Facilities Expansion
Projects Meeting Capital Pass Through Criteria

- Approved Projects
  - 2015 Parkway Projects
- Proposed Projects
  - 2016 Dawn-Parkway Expansion
  - 2016 Burlington Oakville Pipeline
- All of these projects are expected to be subject to the Capital Cost Pass Through Criteria under the Incentive Regulation Mechanism.

Compressed Parkway Deliveries
New Throughput Heights



Approved Projects
2015 Parkway Projects

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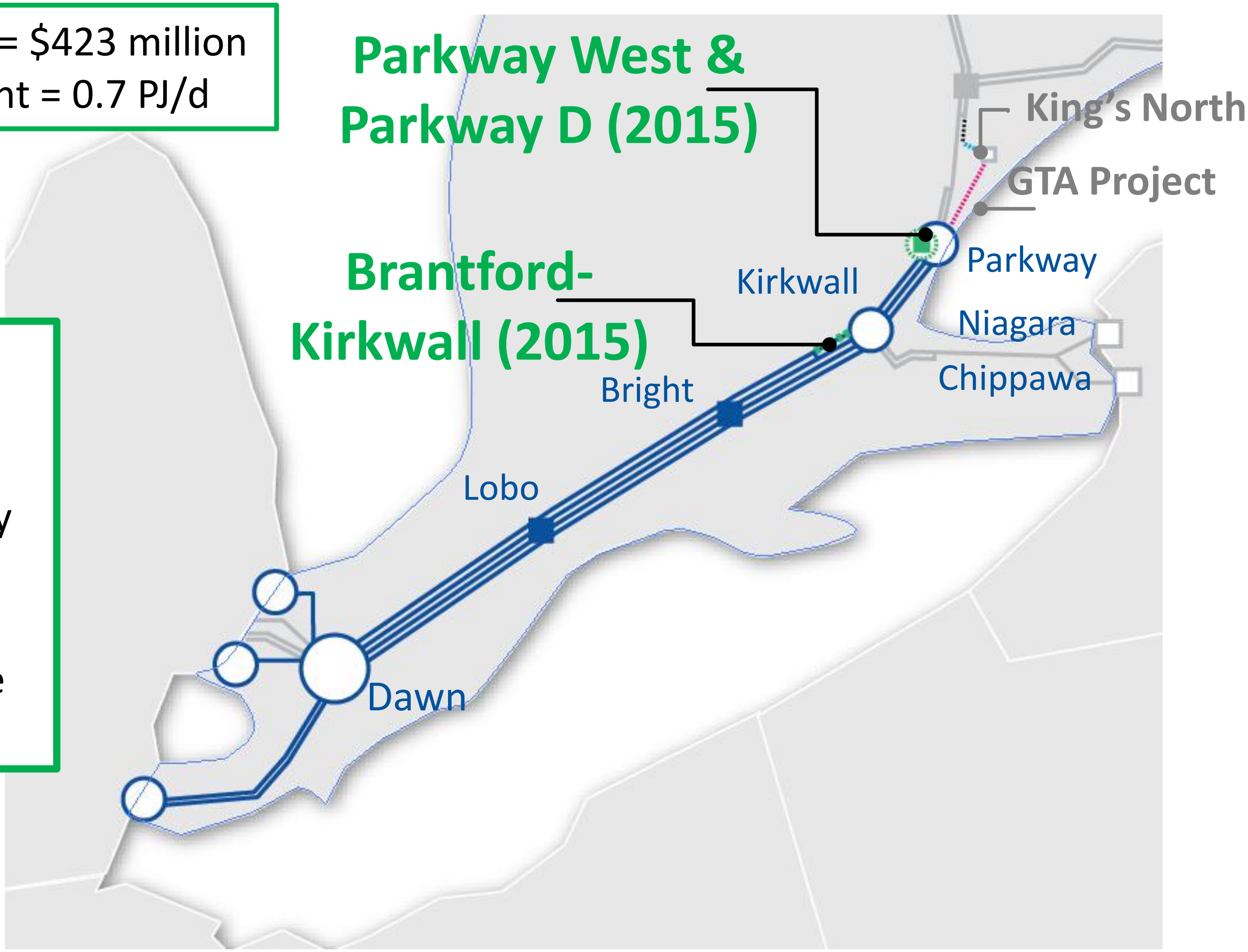
2015 Facility Expansion = $423 million
Customer Commitment = 0.7 PJ/d

- OEB approval received January 30, 2014
- Construction underway at Parkway West
- No change to capital costs or in-service date



2015 Parkway Projects
Parkway West Yard

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2015 Parkway Projects
Parkway West Yard

2015 Parkway Projects
Brantford-Kirkwall Pipeline

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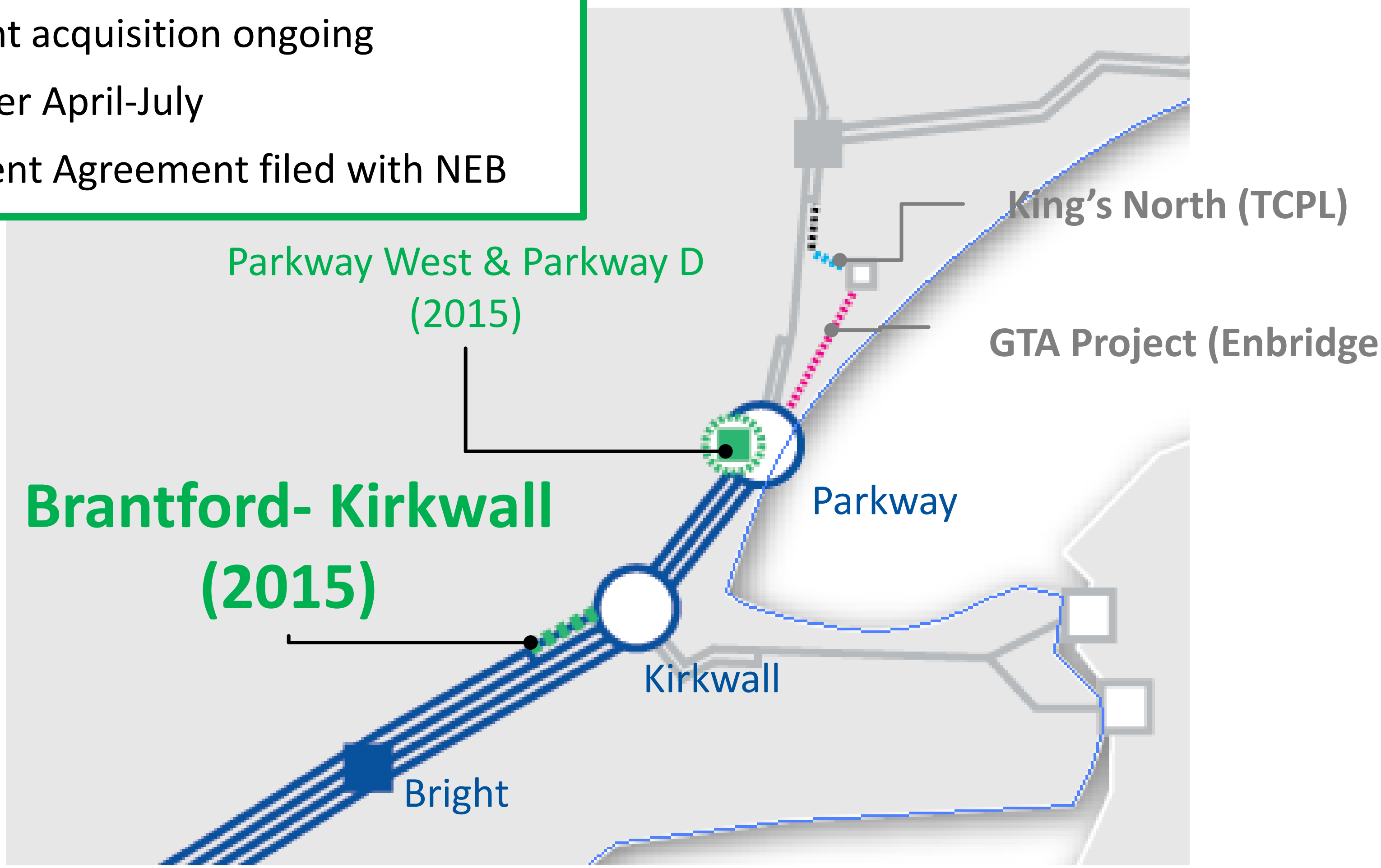
<u>Brantford-Kirkwall</u>

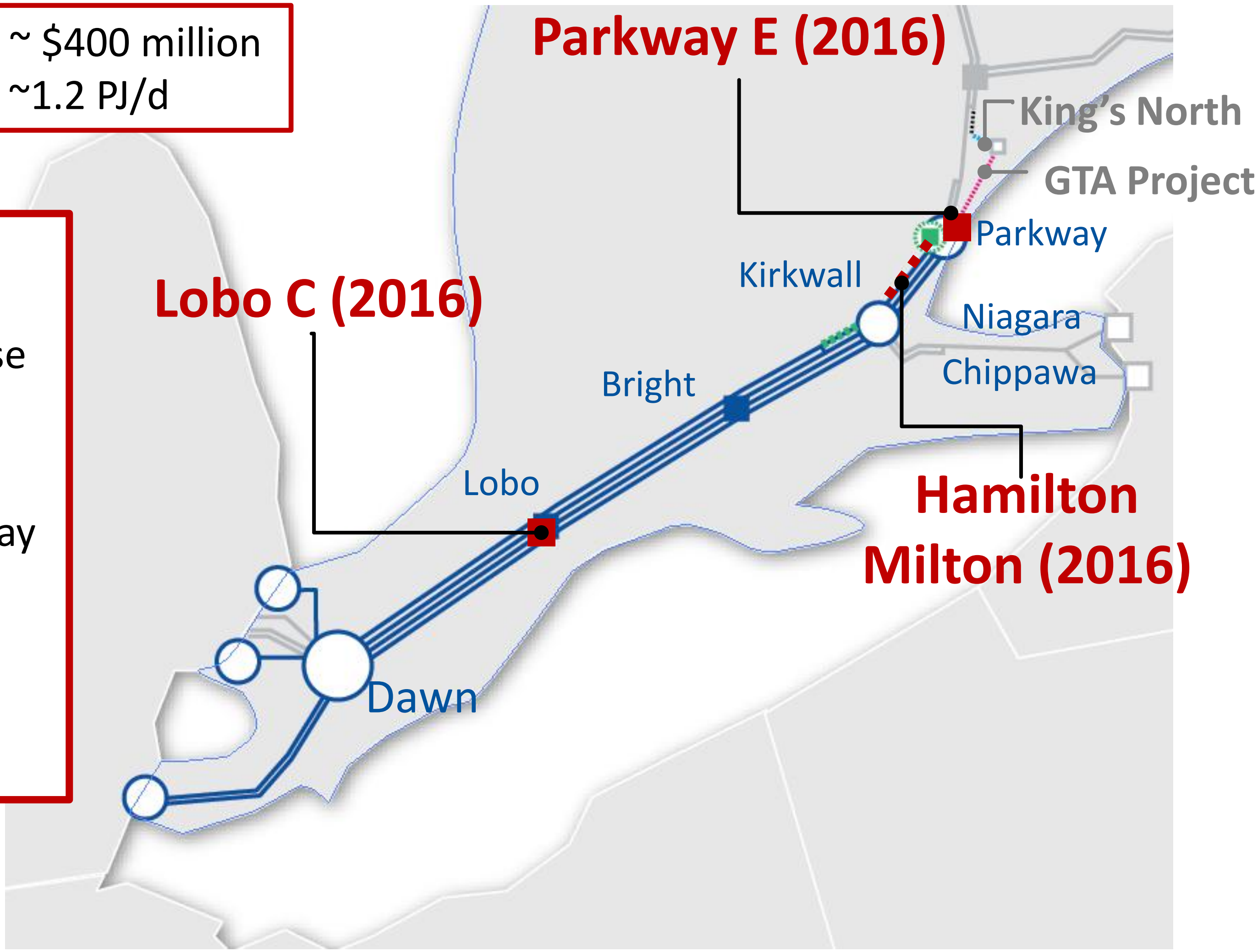
- Easement acquisition ongoing
- Pipe order April-July
- Settlement Agreement filed with NEB



Proposed Projects
2016 Dawn-Parkway Expansion

2016 Facility Expansion ~ $400 million
Customer Interest ~1.2 PJ/d

- Open Season closed
- Large market response
- In the process of executing contracts
- Review facilities in May 2014
- On schedule for regulatory filing in June/July 2014



Dawn-Parkway Summary
Fundamental Changes

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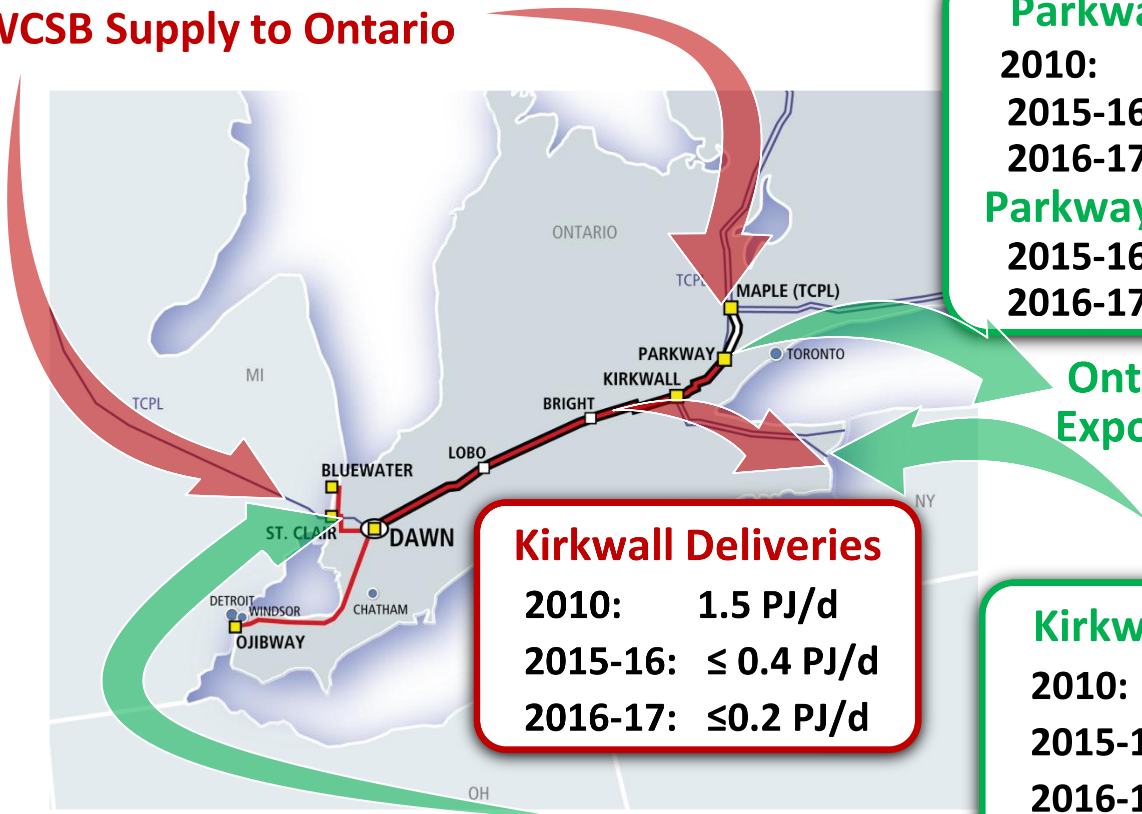
Declining WCSB Supply to Ontario



Parkway Deliveries (Comp.)
2010: 1.9 PJ/d
2015-16: 3.4 PJ/d
2016-17: ≤ 4.6 PJ/d

Parkway Deliveries (Uncomp.)
2015-16: 1.2 PJ/d
2016-17: 1.2 PJ/d

Ontario, Quebec & Exports into US N.E.

Marcellus Supplies to Ontario

Kirkwall Deliveries
2010: 1.5 PJ/d
2015-16: ≤ 0.4 PJ/d
2016-17: ≤0.2 PJ/d

Kirkwall Receipts
2010: ~ 0.0 PJ/d
2015-16: > 0.7 PJ/d
2016-17: ≤1.4 PJ/d

Utica, Marcellus & Midwest Supplies to Ontario

Proposed Projects
2016 Burlington Oakville Pipeline

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Project Drivers

- Increased security of supply
- System positioned to meet future demand
- Annual delivered gas cost decrease for customers

Project Description

- 13km of NPS 20 pipeline from Dawn-Parkway system connecting to existing high pressure system in Oakville
- Estimated capital cost of ≥$100 million
- Replaces third party transportation
- Target November 2016 in-service
- OEB facility application targeting Spring 2014

2016 Burlington Oakville Project
Located in One of Canada's Fastest Growing Areas

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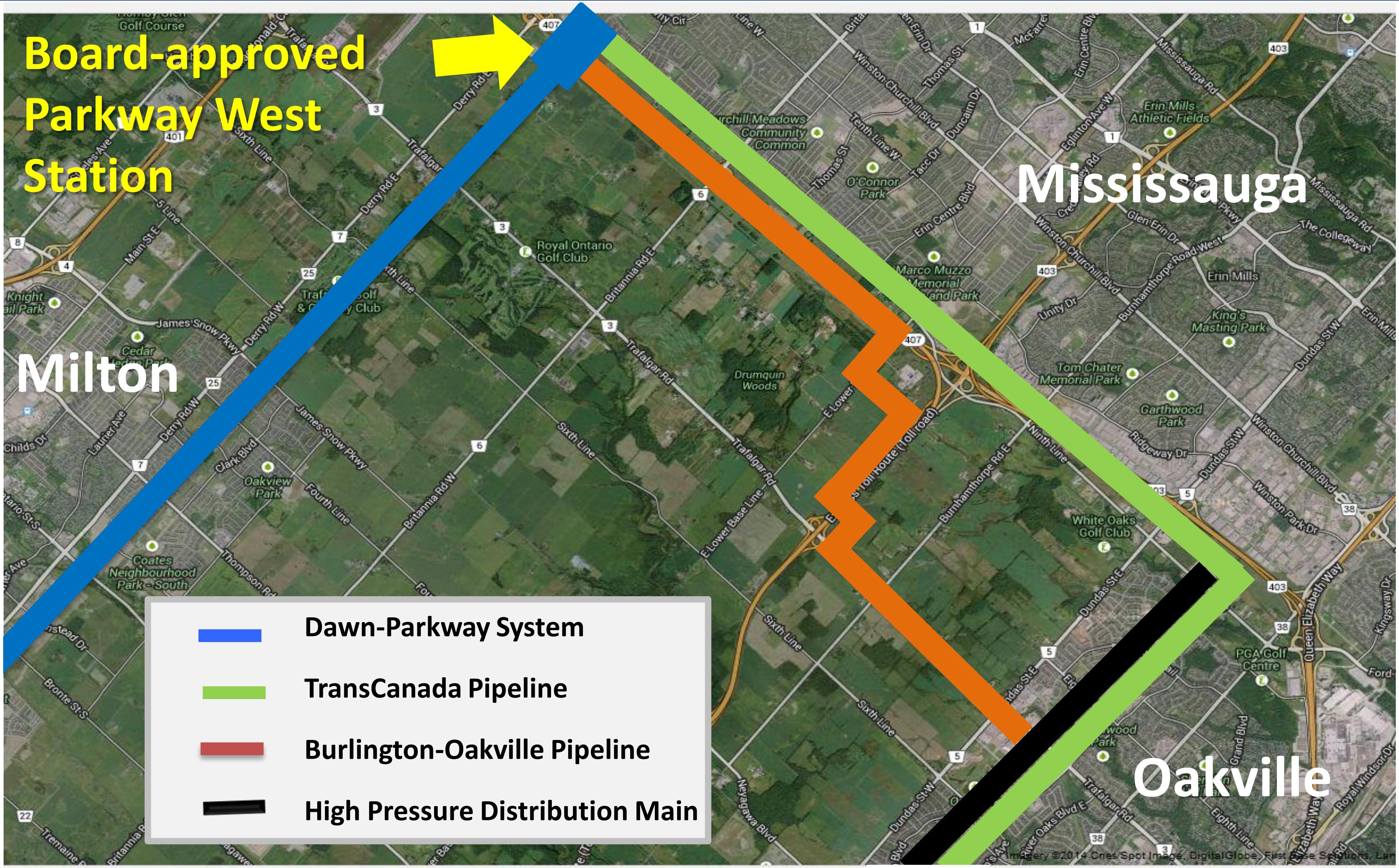

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Community Expansion

Jeff Okrucky

Director, Distribution Marketing

Community Expansion Agenda

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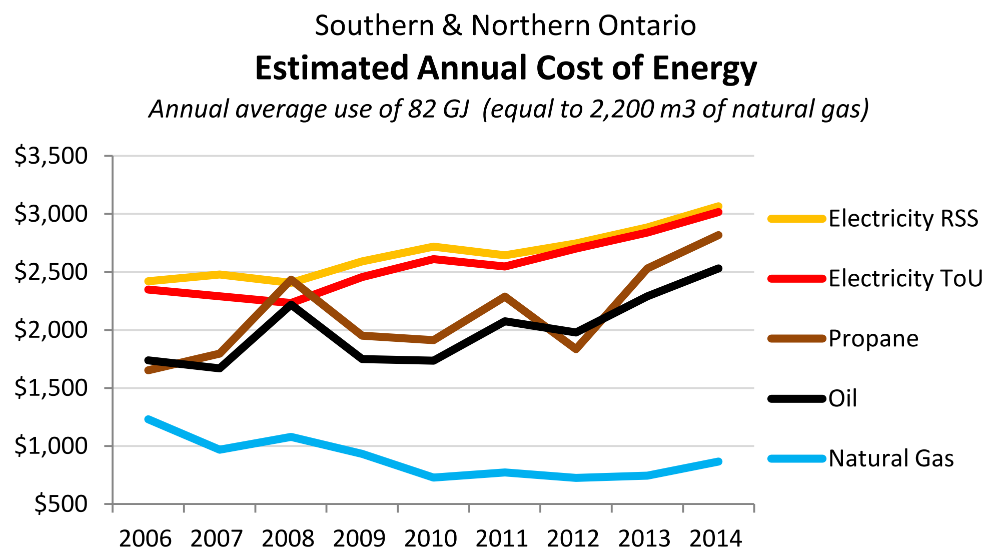
- Background
- Scale and Barriers of Initiative
- Ministry of Energy Discussion
- Next Steps

Background

- Escalation in energy prices for other fuels is creating unprecedented interest in conversion to natural gas
- Detailed discussion with a number of municipalities
- Ontario Federation of Agriculture Provincial budget submission



- December, 2013, Provincial Long Term Energy Plan commitment:
  - "The government will work with gas distributors and municipalities to pursue options to expand natural gas infrastructure to service more communities in rural and northern Ontario."

Scale and Barriers

Potential Scale

- ~20 community projects >500 properties; ~40 with >100 properties
- Natural gas access potential for up to 40,000 customers serving a population of 100,000

Barriers

- Economic Feasibility
  - ~30 km average from existing gas system
- EBO188 Flexibility
  - Very few communities with P.I. > 0.8
  - Prohibitive up-front contributions necessary to get to minimum economic feasibility requirements

Ministry of Energy (MoEn) Discussion: Suggested Principles

- Each of the major participants in an extended gas infrastructure program should contribute towards the cost:
  - Province
  - Municipalities/First Nations
  - Conversion Customers
  - Gas Utility
- Public policy position on "equal access" principle a key consideration
  - If cross subsidization from existing ratepayers contemplated, resulting rate impact should be limited
- Utility partners should not be exposed to additional financial risk related to the incremental capital investment.

MoEn Discussion: Benefits

- Residential customers can save $1,500-$2,500 in annual energy costs; mid sized commercial save in $15,000 range
- Potential local economic stimulus resulting from $40 million per year increase in disposable income for residents
- Removal of an economic development barrier for rural and northern towns and villages
- Construction and HVAC jobs through the conversion period

MoEn Discussion: Enabling Expansion

- Direct Provincial funding
- Regulatory Flexibility:
  - Capital Pass-Through treatment in rate-setting
  - Variance from current guidelines
    - Minimum PI thresholds at Project, Investment Portfolio and Rolling Project Portfolio levels
  - Enable flexibility in means of collecting, and treatment of, conversion customer and/or municipal contributions
    - Temporary “Community Expansion Surcharge” treated as regulated revenue for rate-making purposes

Next Steps

- “Tabletop” quantification of community potential
- Initial exploration of town border supply alternatives
- Firm indication of Provincial Funding support commitment (Provincial Budget)
- Understand required regulatory process

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Residential Customer Perceptions of Union Gas

Jeff Okrucky
Director, Distribution Marketing

Measuring Customer Perceptions

- Union Gas measures customer perceptions of the company and service provided on an ongoing basis:

  ✓ Telephone Interviews are conducted weekly with a random sample of residential customers to achieve a total annual sample of 1200, providing a margin of error of 2.8% at the 95% confidence level.

  ✓ For specific points of touch, such as the customer contacting Union through the call centre or where a Utility Service Representative has performed meter related work at the home, an additional telephone interview process is administered to measure customer satisfaction with the experience.

  ✓ All telephone Interviews are conducted by a third party research supplier, protecting the anonymity of the customer feedback.

Residential Customer Perceptions of Union Gas

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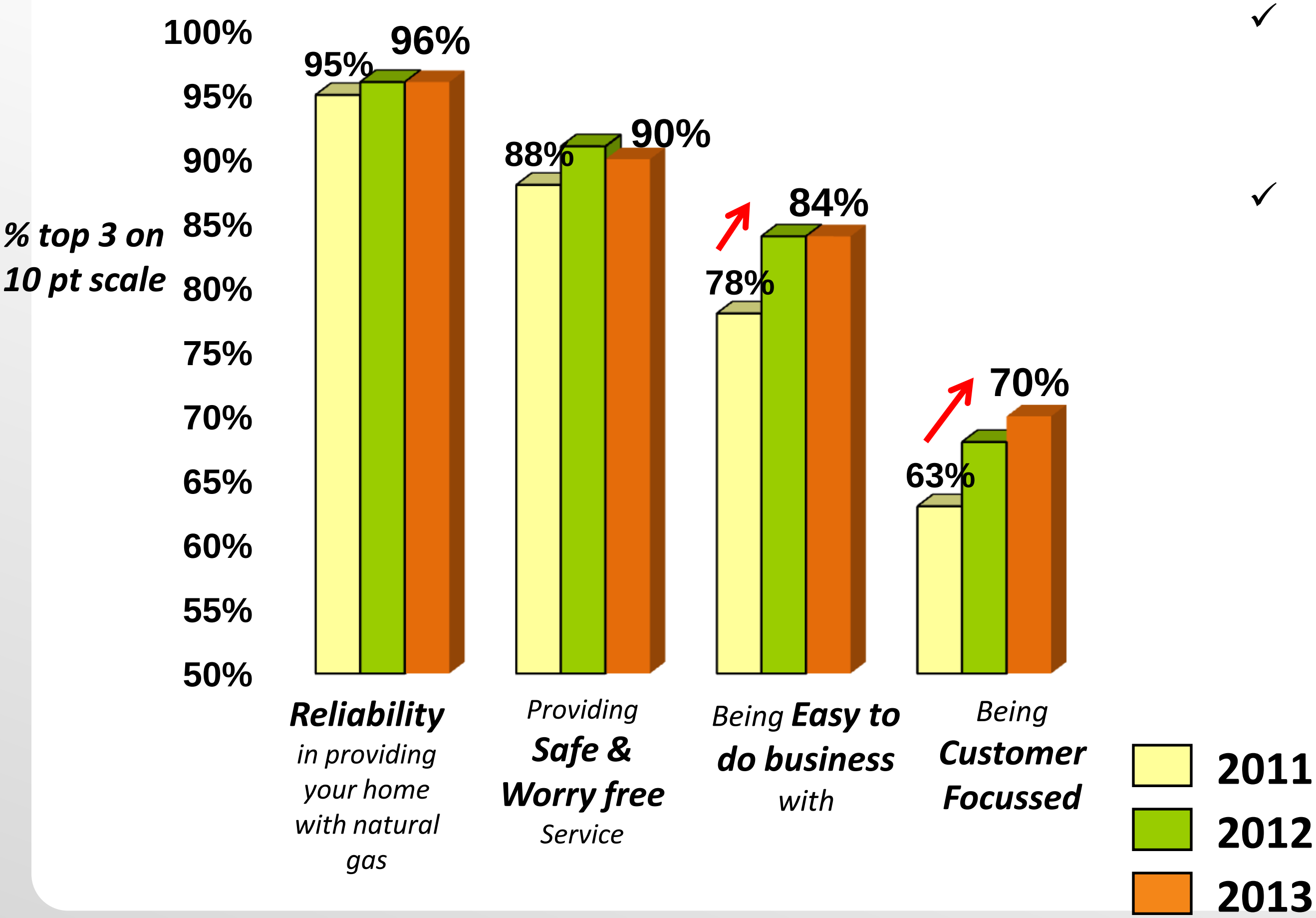
Key Indicators

How would you rate Union Gas for each of the following… where 1 is poor and 10 is excellent?



- ✓ *Red Arrows indicate statistically significant upward change*
- ✓ *Indicators reveal strong positive perceptions on providing safe and reliable service*
- ✓ *Favourable and improving customer experience indicators ("easy to do business" and "customer focus") supported by positive customer experience at points of touch:*
  - *High responsiveness as indicated by 91% first call resolution (call centre)*
  - *92% customer satisfaction (top 3 box score on a 10 point scale) with experience when utility service reps visit homes*

Hagar Liquefied Natural Gas and New Union Gas Service

Tina Hodgson
Manager, Product Process and Development

Hagar Liquefaction (LNG) Service

- Union proposing to offer a regulated interruptible liquefaction (LNG) service at Hagar
- Plan is to provide LNG to wholesale distributors (i.e. trucking company) – LNG to be used as vehicle transportation fuel
- Service requires use of existing liquefaction facilities plus new dispensing facility – no impact to Hagar's system integrity role
- Estimated $8.6 million investment in incremental facilities at Hagar
- Completed a non-binding call for "expressions of interest" to assess market interest
- Service requires a Board-approved rate – developing evidence concurrent with "expression of interest" process
- Timing – plan is to file application end of April 2014 with target in-service date of Q3 2015

New Union Gas Service: North T-service Supply at Dawn

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- A new optional upstream transportation service for T-service customers in Union EDA, NCDA and NDA
- Provides benefits of Dawn supply delivered to Union North
- Requires expansion on Union and TCPL
- Transportation capacity provided at cost of service rates
- 15 customers have signed up for 29 TJ/d for Nov 1, 2016
- In fall of 2014 expect to see a proposal to:
  - Add service option to R10/20/100 rate schedules
  - Update TCPL turnback policy to cover new service
  - Create new deferral account to recover any costs on excess capacity after mitigation

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SE
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NYSE

Recognized by:

Dow Jones Sustainability Indexes
Member 2012/13

CDP
DRIVING SUSTAINABLE ECONOMIES

Appendix C

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2013-14 Gas Supply Plan Memorandum

April 2014

Table of Contents

1. INTRODUCTION

This document is the first overview of the Gas Supply Plan and is a result of the outcome of the Board directive from the EB-2011-0210 Decision for Union to, “file with the Board an expert, independent review of its Gas Supply Plan, its gas supply planning process, and gas supply planning methodology,” (p. 40). Union arranged for an independent review of its gas supply planning process and principles by Sussex Economic Advisors (“Sussex”). The results of that review were incorporated into the EB 2013-0109 (Union’s 2012 Deferrals) application and were tested, reviewed and approved by the Board in its March 27, 2014 Decision. One of the Sussex recommendations was to prepare a memorandum every year including the underpinning assumptions of the Gas Supply Plan and the market context from which it was formed.

1.1 Overview of the Gas Supply Planning Process

The objective of Union’s Gas Supply Plan is to create an efficient supply portfolio that will meet the demands of sales service and bundled direct purchase (“DP”) customers, while meeting the overall gas supply planning principles.

Union’s Gas Supply Plan provides the strategic direction guiding the Company’s long-term resource acquisition process. The Gas Supply Plan does not commit Union to the acquisition of a specific resource type or facility, nor does it preclude Union from pursuing a particular resource. Rather, the Gas Supply Plan identifies the transportation and supply volume requirements to meet annual, seasonal and peak day demand for sales service and bundled DP customers. Union recognizes that the gas supply planning process is dynamic, reflecting changing market forces. Union’s rate setting mechanism and associated gas supply deferral accounts support a direct pass through of gas supply commodity and transportation costs to ratepayers.

1.2 Summary of Union North and Union South

In Ontario, natural gas is a significant and critical energy source relied on for providing heat and hot water to homes and institutions, fuelling manufacturing plants and generating electricity. Approximately 950 PJ of natural gas is consumed annually in Ontario in residential, commercial, industrial and power generation markets. Approximately 70% of homes in Ontario use natural gas for heating and producing hot water. These applications operate on demand, meaning that consumers expect the energy to be readily available to be used when needed.

Home owners in Ontario depend on a reliable supply of natural gas. The natural gas infrastructure supporting Ontario needs to be robust, reflecting the critical role it plays in Ontario, and flexible to allow Ontario to position itself to secure long-term access to economic supply, in light of the changing North American natural gas supply dynamics.

Union serves approximately 1.4 million customers in northern, eastern and southern Ontario through an integrated network of over 67,000 kilometres of natural gas distribution pipelines. Total consumption in Union’s Franchise areas during 2012 was approximately 528 PJ.

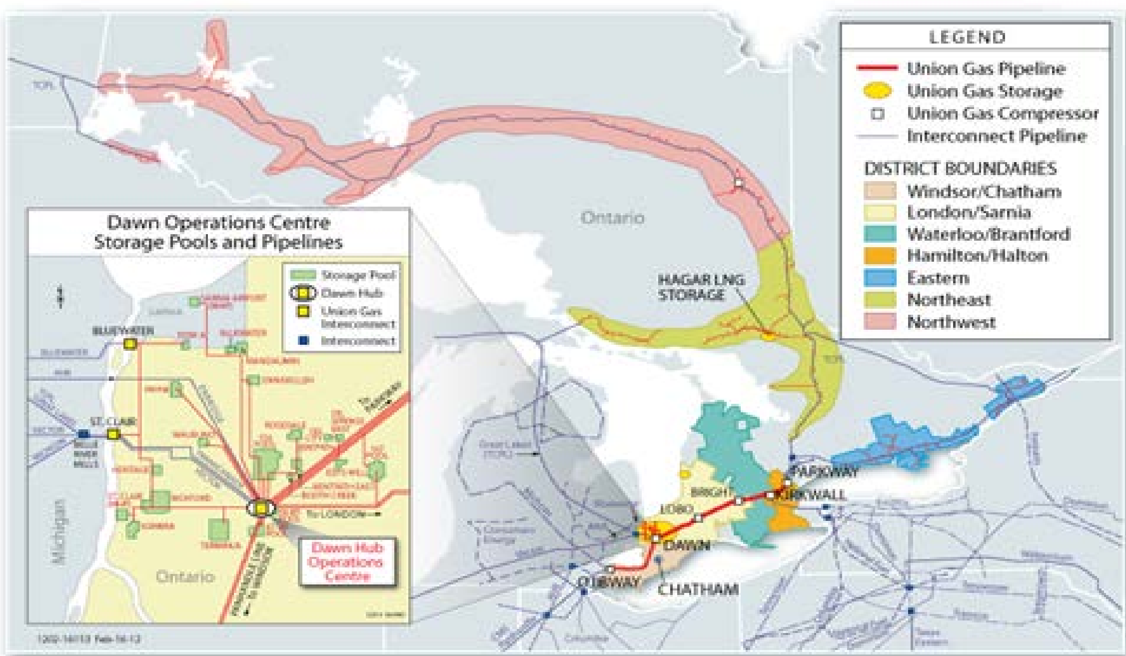
Union operates storage and transmission assets that include 166 PJ of underground natural gas storage at the Dawn Hub and the Dawn-Parkway transmission system. Union’s Dawn-Parkway system is an integral part of the natural gas delivery system for Ontario, Québec and U.S. Northeast residents, businesses, power plants and industry. The Dawn-Parkway system connects these consuming markets to most of North America's major supply basins, the largest area of underground natural gas storage in North America, and the liquid Dawn Hub.

Union's Dawn Hub has been recognized as a key market hub for the province of Ontario and the entire Great Lakes region. The growth of Dawn as an energy hub and the availability of competitively and transparently priced natural gas supplies and services that come with an effective and efficient trading hub have benefitted all Ontarians. Dawn is one of the most physically traded, liquid hubs in North America. The liquidity of Dawn is the result of the combination of access to underground storage, interconnections with upstream pipelines, takeaway capacity to growth markets, a large number of buyers and sellers of natural gas, and price transparency.

Of the 1.4 million customers that Union serves, over 1.2 million are sales service customers that rely on Union to provide their gas supply. These customers are primarily residential and small commercial customers. The remaining customers rely on DP arrangements with marketers and alternate suppliers to meet their gas supply needs. From a volume perspective, sales service customers consumed 136 PJ in 2012, while DP customers consumed 392 PJ.

For gas supply planning purposes, Union is divided into two separate operating areas: Union South and Union North. To serve Union South, Union contracts for transportation capacity on multiple upstream pipelines to access several supply basins or market hubs. These upstream pipelines provide access to supplies in Western Canada, Gulf of Mexico, Chicago, the U.S. mid-continent and the Appalachian shale basins. Union may also serve Union South by purchasing supply at Dawn. Union South includes four Districts, Windsor/Chatham, London/Sarnia, Waterloo/Brantford and Hamilton/Halton shown in Figure 1 below.

Figure 1



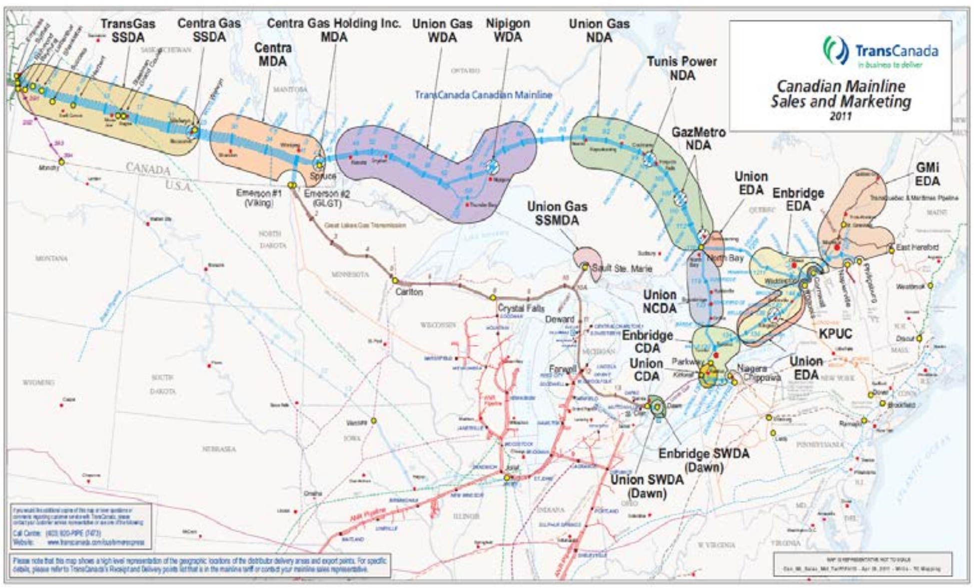
Union North is located throughout Northern and Eastern Ontario, from the Manitoba border in the west, to Cornwall in the east. Union North is depicted by the Eastern, Northeast and Northwest Districts shown in Figure 1 above. Union North is further divided into six delivery areas for gas supply planning purposes. Five of the six delivery areas align with delivery areas on the TransCanada Pipeline Limited ("TCPL") Mainline. From West (Manitoba border) to East (Cornwall) these delivery areas are:

- Manitoba Delivery Area (" MDA")
- Union Western Delivery Area ("Union WDA")
- Union North Delivery Area ("Union NDA")
- Union Sault Ste. Marie Delivery Area (" Union SSMDA")
- Union North Central Delivery Area ("Union NCDA")
- Union East Delivery Area ("Union EDA")

The delivery area that does not align is Union's Manitoba Delivery Area, which is connected to the TCPL Mainline at the Spruce interconnect in the Centra MDA by two additional pipelines (Centra Transmission Holdings and Centra Pipeline Minnesota).

A map of these delivery areas is provided in the Figure 2 below.

Figure 2



Today, all of the customers in Union North are served directly from TCPL interconnects and the vast majority are served almost exclusively from the Western Canadian Sedimentary Basin ("WCSB"). Union uses a portfolio of contracted firm assets including TCPL long-haul firm transportation, TCPL short-haul firm transportation and TCPL firm Storage Transportation Service ("STS") to meet the needs of Union North. In the future, Union anticipates serving a portion of Union North delivery areas with short-haul firm transportation from Dawn replacing long-haul transportation from Empress.

Union provides distribution services to all customers, however customers continue to have the option to either purchase their supply from the utility or arrange supply through a DP arrangement. Union's in-franchise customers fall into four distinct categories.

- Sales service: Union acquires supply and transportation capacity for these customers in Union North and Union South. Sales service demand requirements are included in the Gas Supply Plan.

- Bundled DP: These customers acquire their own supply with Union providing transportation options. Currently Union North bundled DP customers deliver their supply to Union at Empress and Union uses TCPL services to bring the supply to market. In Union South, customers are given a vertical slice (a proportionate amount of the transportation that Union holds in the Union South portfolio) when they first choose the DP option. The DP customers then manage this capacity subject to Union's DP transportation policies. These customers are included in the Gas Supply Plan.
- Unbundled DP: These customers acquire their own supply and transportation from an energy marketer and are not considered within the Gas Supply Plan. This service is available to small residential, commercial and industrial customers.
- Transportation service (or T-Service) DP: These customers acquire their own supply and transportation and are not considered within the Gas Supply Plan. This service is available to large contract commercial and industrial customers.

Union performs the role of system operator and supplier of last resort. As system operator, Union manages many operational factors. These include:

- seasonal balancing requirements for sales service customers;
- weather variances outside of checkpoint balancing for bundled DP customers;
- changes in supply and balancing requirements as customers move between sales service and DP;
- differences between daily receipts from TCPL and the demands of all end users including transportation service customers in the Union North; and,
- unaccounted for gas and compressor fuel variances.

As supplier of last resort, Union is the default supplier to its in-franchise customers (NGF Report, p. 62). A supplier of last resort must ensure it has the assets or can acquire the assets to serve customers that others choose not to serve or fail to serve (e.g. for reason of financial failure), or any customer who chooses to be a sales service customer and have Union provide gas supply services. DP customers can revert back to sales service on short notice. As discussed in Section 6.7 of this report, the 2013/14 Gas Supply Plan assumes that approximately 90,000 bundled DP customers return to sales service supply relative to what was forecast in the 2013 Board-approved forecast in EB-2011-0210.

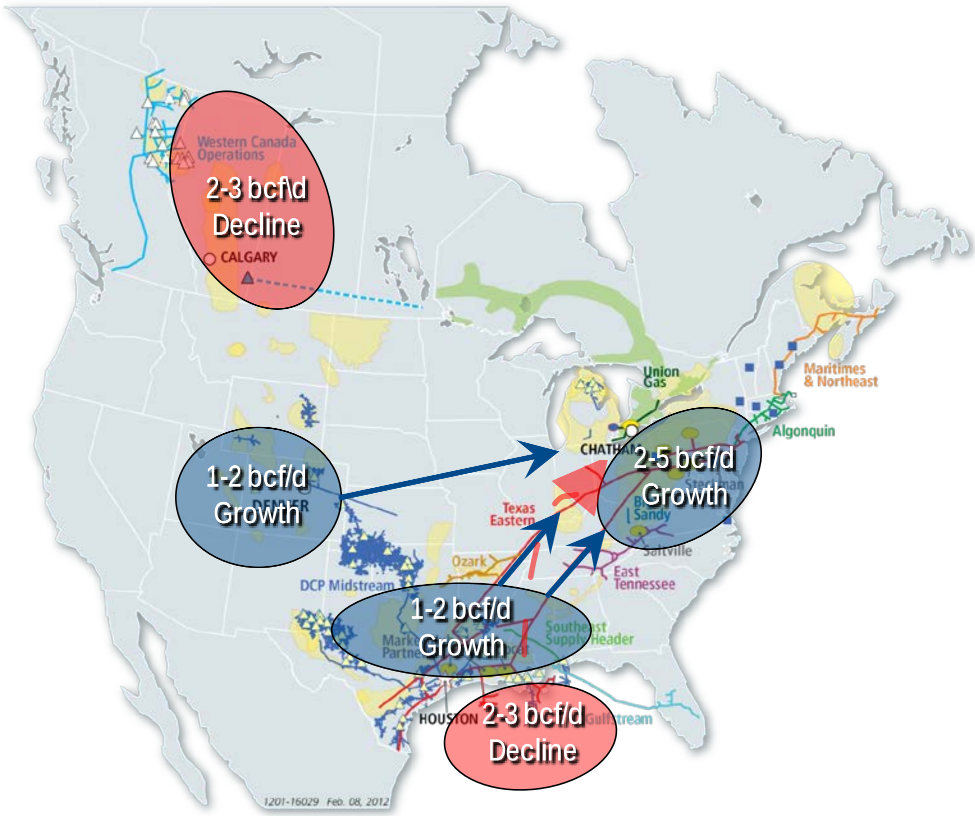
2. MARKET CONTEXT

2.1 Emerging Supply Sources

North American natural gas markets are experiencing dramatic change. Production from mature North American natural gas basins is in decline while new production basins have emerged. While natural gas reserves still exist in mature natural gas basins, the economics of natural gas production favors new emerging production basins such as Marcellus & Utica Shale. This shift in terms of where natural gas is being produced is fundamentally changing how natural gas flows in North America. Figure 3 illustrates projected flow changes in North America.

Figure 3

Gas Supply Basin Trends



Today shale gas comprises over one-third of all natural gas production in the United States. Shale gas as a share of total natural gas production in 2013 was 36% in the United States and 15% in Canada. According to the U.S Energy Information Administration ("EIA") the US Northeast (Marcellus/Utica) production already surpassed 14 Bcf/d, providing approximately 18% of the total US natural gas production. In its "2014 Annual Energy Outlook" the EIA forecasts dry shale gas to constitute 51% of U.S. domestic production in 2035. The Appalachian basin has been one of the most prolific natural gas supply growth areas in North America. This emerging and abundant supply is located within the Great Lakes region in close proximity to Ontario and other eastern North American consuming markets.

The rapid increase in natural gas supply has put downward pressure on North American natural gas prices and volatility. This has impacted market behavior and has driven eastern North American customers to increase the amount of shale gas supply and decrease the amount of supply from traditional supply basins requiring long-haul transportation in their portfolios. For eastern customers that have a choice, these fundamental changes in supply economics will mean that natural gas supply will increasingly be sourced from cost competitive shale gas in closer proximity to the market and less from traditional sources.

Marcellus and Utica shale gas present Ontario consumers, including power, industrial, commercial and residential, with an opportunity to diversify their natural gas supply portfolio and replace declining WCSB supply. Accessing this new supply will be essential to providing diversity of supply and affordable energy prices to fuel Ontario's economic competitiveness.

With new infrastructure, access to these new, proximate and abundant sources of supply can increase reliability and security for the Ontario natural gas supply portfolio.

2.2 Western Canadian Supply

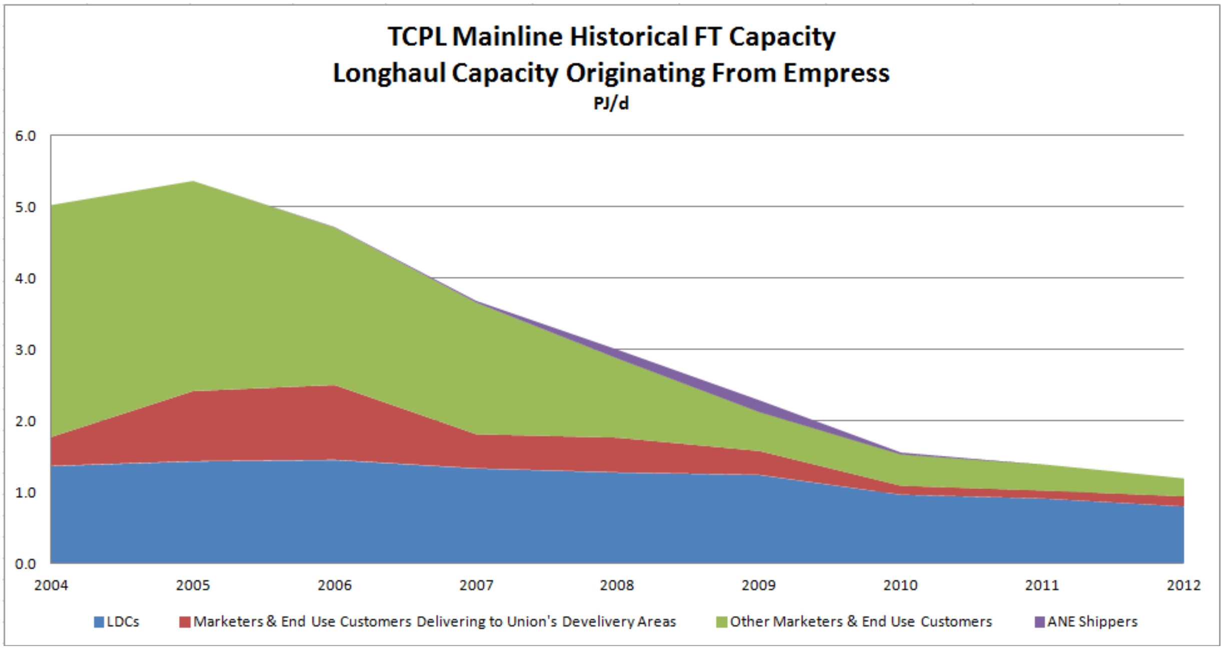
The majority of Ontario's natural gas supply needs for the past five decades were met through the large resources of the Western Canadian Sedimentary Basin ("WCSB"). Natural gas from Alberta was supplied to Ontario on the TCPL mainline either across northern Ontario or through the US via Great Lakes Gas Transmission ("GLGT"). Starting in the 1980's, other pipelines such as the Northern Border Pipeline, the Foothills pipeline and eventually the Vector pipeline (2000), were built to transport WCSB gas to markets east of Alberta, enhancing security of supply and reliability by providing diversity. Over the past ten years, two key trends have been occurring in Alberta: i) Alberta traditional production has matured and is in decline; and ii) domestic use of natural gas in Alberta has increased.

Although shale gas in Alberta and BC is a promising resource with growing production, it is unclear whether these new supplies will be attracted to Eastern markets or to LNG export markets.

Western Canadian natural gas has and continues to be an important source of supply for Ontario. However, as a result of the two trends listed above, there is a declining amount of supply available to flow East to Ontario, leaving the TCPL Mainline and other pipelines connected to the WCSB increasingly challenged. The lower amount of WCSB supply available requires new supply sources to support Ontario's natural gas supply portfolio. To feed Ontario's energy-intensive industry, natural gas-fired generators, businesses and homes, new supply will be required. Union, like other Eastern LDCs, is proactively looking to diversify its supply portfolio with natural gas sourced from other production basins. Beginning in the mid-2000's, there has been a trend in the market away from TCPL long haul from Empress to short-haul back to Dawn.

Figure 4 below shows the long-haul firm transportation contracts held on TCPL by customer category starting in 2004. Between 2005 and 2012, there was a continuous decline in the amount of long-haul firm transportation contracts on TCPL. Marketers and end-use customers have de-contracted the greatest amount of long-haul capacity. The amount of capacity de-contracted by marketers and end-use customers is almost 4 PJ/d over the last eight years.

Figure 4



2.3 Natural gas price signals

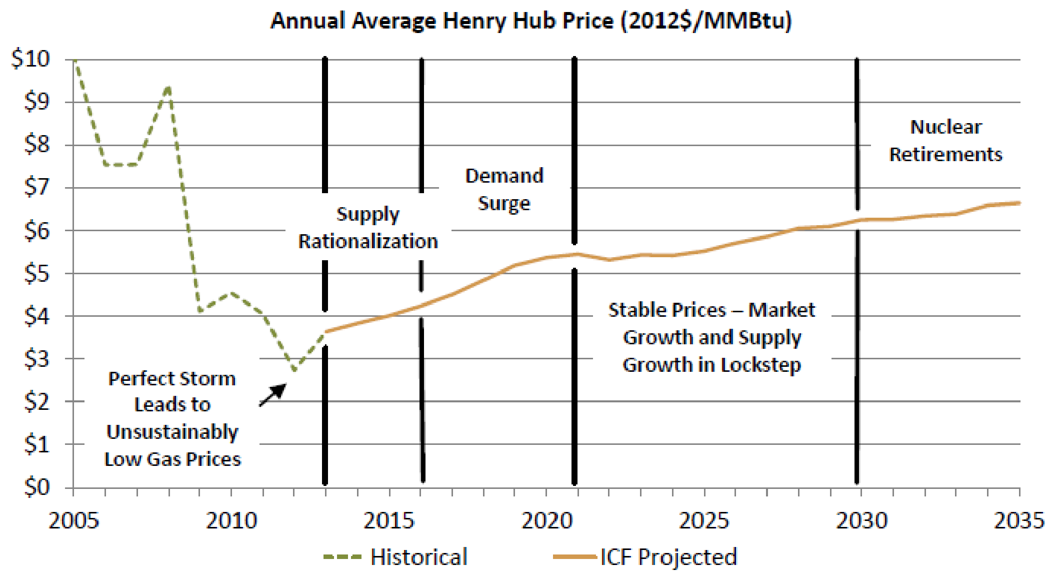
As the emergence of shale production has increased dramatically since 2007, the increase in available supply has put downward pressure on natural gas prices. As shown in the graph below, the price of natural gas dropped from a high of nearly $10 USD/mmbtu in 2005 to current levels under $5 USD/mmbtu.

In the near term, to 2016, prices of natural gas at Henry Hub are expected to continue to hover between $4.00-$5.00 USD/mmbtu. This is predominantly driven by continued productivity in shale plays (particularly in the Marcellus), offset by growth potential in the industrial and power markets. As demand for natural gas rises, the speed with which producers respond will dictate how much and how quickly gas prices respond.

In the long term, between 2020 and 2030, gas prices at Henry Hub are expected to rise up to $6 USD/mmbtu. This price reflects sufficient incentive for producers to continue to develop supply sources, while not so high to reduce market growth. Beyond 2030, prices are projected to continue a gradual increase towards $7 USD/mmbtu, reflecting the increased demand for natural gas from electricity generators and retirement of nuclear facilities.

These projections, provided by ICF International (“ICF”) in January, 2014, are depicted in Figure 5 below.

Figure 5



2.4 Transportation / Pipeline changes

As supply and transportation market options change, so does Union's gas supply mix and how gas is transported to Ontario. Unchanged, however, is Union's application of the gas supply planning principles and the requirement to ensure secure, reliable supplies to serve its customers at prudently incurred costs. When Union considers a new supply basin, a new upstream transportation capacity or existing transportation capacity up for renewal, cost alternatives are considered. The landed cost analysis is completed and filed when a new transportation path is contracted for, in accordance with the Board-approved EB-2005-0520 Settlement Agreement. The analysis for new transportation paths included in Union's 2013/14 Gas Supply Plan are filed as part of Union's 2013 Deferral Disposition Evidence.

Until the 1950's, Union sourced its natural gas supplies through local Ontario production, manufactured gas, and imported U.S. supplies. In the late 1950's, the construction of the TCPL Mainline connected western Canadian supplies to Eastern Canadian consuming markets. By the 1990's, up to 90% of Union's system supply portfolio was sourced from western Canada, and was predominantly transported to Ontario via TCPL. Through the 1990's, Union introduced more supply diversity into the Union South portfolio to increase diversity and take advantage of economic supply options from U.S. locations (i.e. Panhandle, Vector).

Given the changes in flows of gas supply across North America described earlier, and as discussed in EB-2013-0074 and EB-2012-0433, Union is working to increase the level of supply diversity in Union North by replacing a portion of long-haul TCPL transportation from Empress with short-haul deliveries from Dawn to the Union EDA and Union the NDA. This significant change will afford Union North greater access to Dawn and the multiple supply basins Dawn connects to, providing security and diversity of supply. This is discussed in more detail in Section 7.

3. GAS SUPPLY PLANNING OBJECTIVES AND PRINCIPLES

The Gas Supply Plan defines the gas supply requirements and the necessary upstream transportation capacity and assets to meet customers' annual, seasonal and design day gas delivery. Union's Gas Supply portfolio is guided by a set of principles that are designed to ensure customers receive secure, diverse gas supply at a prudently incurred cost and minimal risk. The principles are as follows:

- Ensure secure and reliable gas supply to Union's service territory;
- Minimize risk by diversifying contract terms, supply basins and upstream pipelines;
- Encourage new sources of supply as well as new infrastructure to Union's service territory;
- Meet planned peak day and seasonal gas delivery requirements; and,
- Deliver gas to various receipt points on Union's system to maintain system integrity.

These principles have been presented to and accepted by the Board on a number of occasions. Most recently these principles were presented to the Board in Union's 2013 Rebasing proceeding (EB-2011-0210) and the 2012 Earnings Sharing and Deferral Disposition (EB-2013-0109).

Cost is an important consideration in the Gas Supply Plan; however, Union must balance the benefits of all the attributes of the guiding principles. A description of each guiding principle and how this balance is achieved, is provided below.

3.1 Ensure secure and reliable gas supply to Union's service territory.

Union has an obligation to ensure its firm sales service and bundled DP customers (i.e. residential and commercial customers) have access to secure and reliable gas supply sources. This includes firm upstream transportation contracts to deliver this supply to Union's franchise areas. Union also provides a load balancing function for all sales service and bundled DP customers to manage the seasonal differences between supply and demand. Union's obligation is to provide gas supply and transportation capacity for sales service customers and transportation capacity for bundled DP customers. To meet this obligation Union uses a combination of firm upstream transportation contracts, Dawn sourced supply and storage capacity. Union ensures adequate firm capacity is available on a sustained basis to meet firm design day and annual demands through transportation capacity contractual rights. This includes a combination of long-term transportation contracts with third parties, transportation contracts with guaranteed renewal rights, as well as dedicated Union storage, transmission and distribution assets.

3.2 Minimize risk by diversifying contract terms, supply basins and upstream pipelines.

Union's current upstream transportation portfolio and related supply are diversified with respect to supply basin access, gas supply producers and marketers, contract term and transportation service provider. Union's approach to diversifying the portfolio of firm assets is analogous to a prudent investment portfolio where diversity of funds, risk and term are critical to a successful portfolio.

In Union South, Union utilizes capacity on multiple upstream pipelines to access several supply basins or market hubs. These pipelines provide access to supplies in Western Canada, Gulf of Mexico, Chicago, the U.S. mid-continent and Marcellus through Niagara. The Gas Supply Plan also includes Dawn purchases as part of the Union South supply portfolio. Union purchases gas from suppliers under a North American Energy Standards Board ("NAESB") contract. Union has NAESB contracts with approximately 80 suppliers. The portfolio of suppliers and upstream transportation contracts provides diversity and reduces the exposure to price volatility for Union South customers. It also provides Union the flexibility to manage to its seasonal inventory targets.

Union also manages risk to customers by diversifying the length of the contract terms to provide flexibility in managing the upstream transportation portfolio. In Union South, contract terms range from one to fifteen years. Union holds renewal rights on the majority of these contracts at expiry date. In Union North, approximately 95% of Union's long-haul TCPL firm contracts and STS contracts have completed their primary term and renew on a one-year rolling basis. Union is taking steps to introduce Dawn supplies into the Union North portfolio starting in 2015.

For gas supply purchases, the sales service supply portfolio consists of annual, seasonal, monthly, and in rare cases, daily purchases. In addition, Dawn delivered service in the Union South supply portfolio can be re-sized monthly and annually to manage changes in demand.

3.3 Encourage new sources of supply as well as new infrastructure to Union's service territory.

Union continues to seek new sources of cost-effective supplies to serve its customer base either through accessing new supply sources with existing infrastructure or participating in longer-term projects to encourage the development of new infrastructure to and through Ontario. The development of new supply sources and the related infrastructure often require long-term commitments. In the Board's EB-2010-0300/EB-2010-0333 Decision, the Board recognized the role that regulated utilities play in supporting new infrastructure development:

> *"The Board recognized that the enrolment of regulated utilities for such long term arrangements would be a necessary and desirable element in new infrastructure development…"(p.7).*

Union supports the development required to bring new supply sources to or through Ontario. For example, Union entered into an open season and signed a ten year agreement with TCPL for capacity on the Niagara to Kirkwall path effective November 1, 2012. This path provided Ontario customers with access to supplies from the Marcellus shale basin.

In addition, Union supports the infrastructure required to allow supply sources other than WCSB to flow to Eastern and Northern Ontario. In order for all Ontario natural gas customers to access new emerging supply, new infrastructure at Parkway and between Parkway and Maple on the TCPL Mainline is required. The required infrastructure on Union and Enbridge systems has been approved by the Board (EB-2012-0433/EB-2013-0074/EB-2012-0451). In its Decision, the Board stated:

> *"The project is part of a group of projects, including Enbridge's GTA Segment A pipeline and TransCanada's proposed King's North pipeline that will facilitate greater flows of mid-continent natural gas into Dawn for transportation to downstream markets. The projected benefits of these projects stem from an enhanced diversity of supply, gas costs savings, and enhanced liquidity at Dawn."(p.22).*

This infrastructure will provide additional diversity to Union North starting November 1, 2015.

3.4 Meet planned peak day and seasonal gas delivery requirements.

Inherent in the obligation to meet sales service and bundled DP customers' gas supply needs is the requirement to construct a gas supply portfolio that will meet:

- Design day requirements – to provide service to sales service and bundled DP customers on the day of highest anticipated peak or design day demand in each delivery area.
- Seasonal/annual requirements – to be able to meet the annual requirements of the markets while balancing the summer / winter load changes.

A further description of how Union meets these requirements is provided in Section 6.

3.5 Deliver gas to various receipt points on Union's system to maintain system integrity

The Union South transportation portfolio has delivery points at Dawn, Parkway, Kirkwall, and Ojibway. It is Union's practice to receive gas at multiple points. This practice provides two benefits.

First, it maintains system integrity as Union is not reliant on one receipt point for all of its gas supplies. A system interruption or upset at one receipt point would not cause a complete supply failure to Union's system.

Second, delivery to multiple receipt points allows Union to minimize its pipeline facilities in the area. For example, the delivery of gas at Ojibway enables the Dawn-Ojibway transmission system to be smaller than would otherwise be necessary to meet design day requirements. In this case, if Union delivers gas to Ojibway, Union does not have to ship the equivalent volume from Dawn to Ojibway.

4 SUSSEX GAS SUPPLY RECOMMENDATIONS

In Union's 2013 Rebasing proceeding, EB-2011-0210, the Board approved Union's 2013 Gas Supply Plan as filed. However, the Board ordered Union to "file with the Board an expert, independent review of its Gas Supply Plan, its gas supply planning process, and gas supply planning methodology" (p.40). Sussex was engaged to address the Board's directives that focused on the Gas Supply Plan and design day components. As a result of their review, Sussex provided recommendations which Union accepted and is in the process of implementing as described in more detail below.

4.1 Design Day Demand Forecasting

The Sussex recommendations related to design day demand Forecasting were:

- Increased documentation across departments.
    - *Union has prepared a process flow chart showing the integration across departments and the key steps in preparing the Gas Supply Plan. This chart is provided at Appendix A.*
- An annual review process of the prior year's results;
    - *In preparing for the upcoming Gas Supply Plan, Union has added a kick-off meeting to the annual gas supply process to discuss prior year results and any changes that should be considered for the upcoming period as it relates to the design day methodology and approach.*
- A review/evaluation of whether different data sets should be analyzed as part of the design day demand forecast;
    - *Union has analyzed two methods - Union's Use per Customer Factor and Multiple Winter Average. Both methods smooth the transition of demand from year to year. The two methods result in changes within 1% of each other. Based on the review,*

    - *Union will continue to evaluate both methods to see if any significant differences result.*
- Use of the coldest observed temperature in Union South for the design day standard.
    - *As indicated at EB-2013-0109, Exhibit B, Tab 5, page 7 of 7, Union has adopted the coldest observed temperature in Union South for the design day standard consistent with Union North methodology.*

4.2 Gas Supply Plan

The Sussex recommendations related to the Gas Supply Plan were:

- Increased documentation of the Gas Supply Plan including the underpinning assumptions and how the Gas Supply Plan conforms to the planning principles, circulated via memorandum;
- A summary of regulatory and market drivers that provides context for stakeholders should be included;
    - *Union has responded to these recommendations by expanding on information made available internally and to Intervenors through the comprehensive evidence filed in conjunction with the Sussex report in the EB-2013-0109 hearing and through this Gas Supply Plan Memorandum herein and the corresponding IRM Stakeholder session.*

4.3 Contracting Practices

The Sussex recommendations related to contracting practices were:

- Continued use of known information in the contracting decision process, with the addition of scenarios around the base case
    - *Union continues to utilize current tolls in analyzing contracting options, however, Union has expanded the number of options considered for each path where available, additional paths, as well as potential toll impacts if information is available or relevant, such as TCPL decontracting.*
- Documentation of the alternatives analyzed and not analyzed.
    - *Union expanded on the documentation of what paths were not analyzed and the reasons as to why the paths were not considered.*
- Review of whether the SENDOUT model could be used to augment the landed cost analysis.
    - *Union continues to utilize Sendout to augment the landed cost analysis for Greenfield projects and any significant changes to the Union North portfolio. Union will continue to use Sendout for future portfolio contracting decisions where applicable.*
- Development of a process to review the cost of service, rate level and rate design for St. Clair Pipeline and Bluewater Pipeline.
    - *Union has developed a process, consistent with the Sussex recommendation, to review the cost of service, rate level and rate design for St. Clair Pipeline and Bluewater Pipeline. In addition, Union is reviewing its contracts with St. Clair Pipeline and Bluewater Pipeline to incorporate this process.*

4.4 Ontario Energy Board Findings

On March 27, 2014, the Board released their decision in the EB 2013-0109 application in which the Gas Supply Plan and the Sussex report were discussed. The findings are as follows:

> *"The Board finds that Union responded appropriately to the EB-2011-0210 directive to file an independent review of its gas supply plan. The evidence filed by Union in regard to its gas supply plan provides the context in which the Board made its findings regarding the treatment of the FT-RAM related revenues.*
>
> *The Board notes that no parties have provided any recommended changes to the plan.*
>
> *The Board expects that Union will implement all of the recommendations set out in the Sussex Report.*
>
> *With respect to FRPO's request for further information in relation to UDC mitigation, the Board finds that no additional information is required at this time. At the time that Union's gas supply plan is next reviewed, FRPO can seek information related to UDC mitigation. In regard to FRPO's request for enhancements to the Gas Supply Memorandum, the Board will not require any enhancements at this time. The Board will have an opportunity to review the first filing of that memorandum and determine at that time whether any enhancements are necessary going forward." (p. 8).*

5 GAS SUPPLY PLANNING PROCESS

Union's Gas Supply Plan is a five-year rolling plan that is prepared annually, with the primary focus being the first two years. The annual gas supply planning process is summarized at Appendix A. The Gas Supply Plan is finalized and receives executive approvals in the third quarter each year.

The Gas Supply Plan identifies the efficient combination of upstream transportation, supply purchases, and storage assets required to serve sales service and bundled DP customers' annual, seasonal and design day gas delivery requirements, while adhering to the planning principles described earlier. Once the design day demands are calculated, the planning process continues with a monthly forecast by market of total consumption by each delivery area in Union North and Union South. The Gas Supply Plan is then used to generate a forecast of natural gas supplies, transportation and storage services required by Union's in-franchise sales service and bundled DP customers. The upstream transportation contracts in the Gas Supply Plan, along with storage assets, are managed by Union to provide an integrated service to all sales service and bundled DP customers. The costs for both the supply and the transportation services identified in the Gas Supply Plan are recovered through commodity, transportation and storage charges.

Union's integrated supply planning is a complex process that incorporates demand related items such as customer growth, normalized weather, design day requirements, customer consumption patterns and economic outlooks. Demands are analyzed relative to Union's existing system design and gas supply portfolio (supply and transportation). The firm needs of these customers are analyzed to ensure the appropriate level of firm transportation and storage assets are held to meet design day, seasonal and annual demand. The Gas Supply Plan is appropriately sized and there are no assets in the Gas Supply Plan in excess of those necessary to meet firm customer requirements.

To complete the Gas Supply Plan, Union uses gas supply planning software known as SENDOUT. SENDOUT, supplied by VENTYX, is a widely recognized gas supply planning tool and is used by a number of LDC's in North America. Union has used this software for 26 years and it has been presented in a number of rate applications since 1987.

Union uses SENDOUT to ensure that the assets incorporated in the Gas Supply Plan meet annual, seasonal, and design day demands. SENDOUT determines the amount of capacity, supply and associated costs required to meet customer demands. Union's five-year Gas Supply Plan includes the following key inputs and assumptions:

- The design day demand forecast for each Union North delivery area;
- Union's in-franchise monthly demand forecast based upon customer location, supply arrangement, storage requirement and service type (excludes Transportation Service and Unbundled service);
- A monthly commodity price forecast using the same pricing methodology as the Quarterly Rate Adjustment Mechanism ("QRAM") process;
- Upstream transportation tolls in effect at the time the forecast was prepared;
- All upstream transportation contracts held by Union plus existing obligated Ontario deliveries for the bundled DP market;
- Sales service and bundled DP storage requirements that are cycled completely each year in the Plan with storage full on November 1 and empty by March 31 assuming normal weather;
- Applicable heating value;
- Sufficient inventory at February 28 to meet the design day requirements for sales service and bundled DP customers;
- No migration between sales service and bundled DP customers for the term of the Plan. Any migration is therefore a risk that needs to be managed by Union.
- 9.5 PJ of system integrity space. This storage space is used in a number of ways to maintain the operational integrity of Union's integrated storage, transmission and distribution systems. The Gas Supply Plan has 6.0 PJ of this space filled with system integrity supply while the remaining 3.5 PJ is left empty as contingency space.

The outcome of the annual planning process is a five-year plan that provides a monthly volumetric forecast of supplies (by transportation path) and demands and a monthly forecast of Union's costs to serve its sales service and bundled DP customers. The key inputs and outputs of the Gas Supply Plan are discussed in more detail below.

6 UNION'S 2013/14 GAS SUPPLY PLAN

The Gas Supply Plan defines the gas supply requirements and the necessary upstream transportation capacity and assets to meet customers' annual, seasonal and design day gas delivery. The material changes in the Gas Supply Plan for 2013/14 as compared to 2013 are as follows:

- Sales service demands in the 2013/14 Gas Supply Plan have increased by 18 PJ over the 2013 Gas Supply Plan approved by the Board in EB-2010-0210. This increase is approximately 13 PJ for the South and 5 PJ for the North. The primary drivers of the increase are customers returning to sales service supply from DP and increased use in the residential market driven by a lower rate of decline in the residential market, and higher usage in the commercial market.

- As discussed in more detail in Section 6.7, the increase in demand due to return to sales service impacts the total supply that Union must purchase for both Union North and Union South. For Union North, Union plans for upstream pipeline transportation capacity for sales service and bundled DP customers so there is no impact to Union's contracted capacity in Union North as a result of return to sales service.
- For Union South, Union requires additional supply and transportation capacity to meet increased demand as a result of return to sales service supply. The total increase in sales service demand for general service and contract customers in Union South is approximately 13 PJ. Union received approximately 5 PJ of upstream capacity (vertical sliced pipe capacity) from DP customers when they returned to sales service supply. In addition, Union purchased incremental Dawn supply of approximately 8.0 PJ in addition to what was included in the 2013 Gas Supply Plan in order to meet this incremental demand.
- In addition to supply sourced on upstream transportation capacity currently contracted, the Gas Supply Plan identified approximately 44,000 GJ/d of “uncommitted” supply required as of November, 2013 to balance the increase in sales service demands. Union has contracted for 10,551 GJ/d on Panhandle for one year to replace the prior contract that expired. In addition, Union will purchase approximately 34,000 GJ/d at Dawn. The Dawn sourced supply is approximately 22,000 GJ/d greater than 2013 as indicated above. Union sources a portion of the supply portfolio at Dawn for increased flexibility and diversity of supply.
- In-franchise storage allocation at November 2013 is 91.4 PJ. This represents an increase of approximately 2.5 PJ from the 2012/13 Gas Supply Plan approved by the Board in EB-2011-0210.
- Union requires Parkway to Union CDA transportation to move Dawn supplies across the meter into TCPL’s system. The requirement for the winter of 2013/14 is approximately 53,000 GJ/d and was met with market based contracts. This a slight drop from the level of 64,000 GJ/d in the 2012/2013 plan, reflecting short-term operational conditions.

The key inputs and outputs, as well as the changes, are described in more detail below.

6.1 Design Day

The purpose of the Gas Supply Plan is to determine the appropriate level of assets required to meet firm customer demands for annual, seasonal and design day requirements. To create the Gas Supply Plan, Union must forecast the firm customer demand on the design day as well as annual and seasonal requirements. The main information required to develop the demand includes weather, firm customer demand, forecast demand growth and pipe and / or storage assets which are available.

Weather

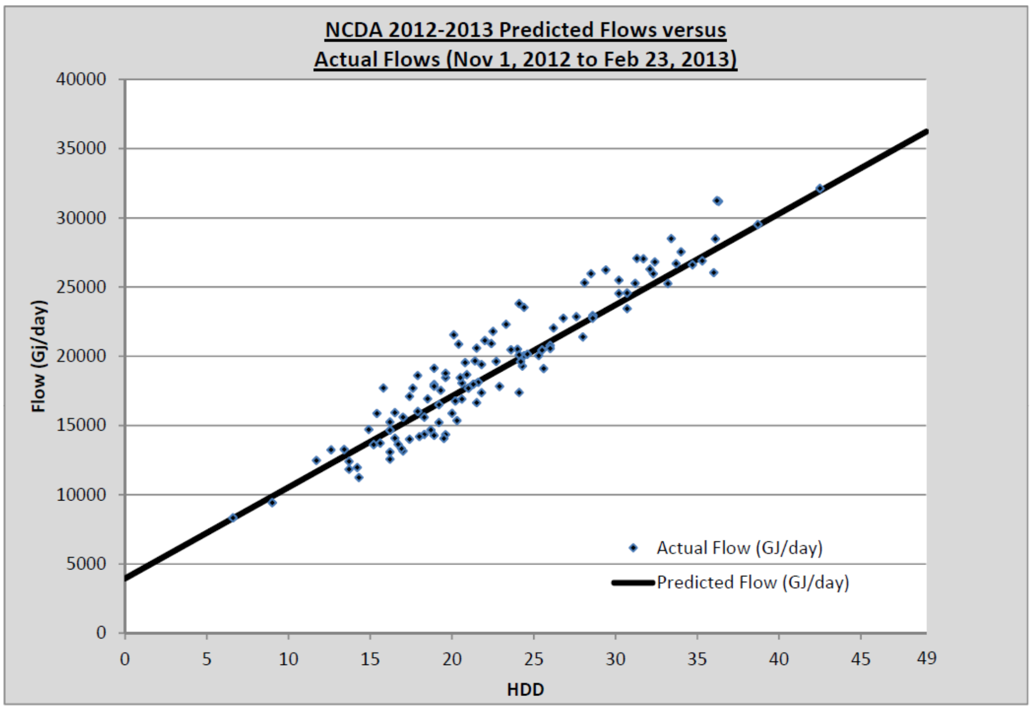
Union ensures assets are available to provide firm service to customers on an extreme cold weather day called the Design Day. The design day is measured in heating degree days (“HDD”). In the gas industry, temperature is translated to HDDs; the colder the temperature, the higher the HDD. A HDD is a temperature 1 degree C below 18 degrees C. Therefore an 18 degree HDD would translate to a temperature of 0 degree C on average for the day. Union uses the coldest observed degree day for Union South and each of the six delivery areas in Union North.

Firm Customer Demand

The firm customer design day demand is forecast by multiplying the firm use per degree day factor with the coldest observed degree day.

Union develops a trend line using the daily firm customer consumption from the prior winter and the associated daily degree day data. Union extrapolates the calculated trend line to the coldest observed degree day resulting in the estimated design day demand for each delivery area. An illustrative example of the degree day data and the trend line calculation for the NCDA is provided in Figure 6 below:

Figure 6



Forecast

The design day demand described above is increased by the winter season growth factor reflected in the demand forecast. This forward looking forecast growth factor is added to the firm customer demand noted above, to provide a total forecasted design day demand for each delivery area.

Required Assets

The design day requirements are met by holding storage and transportation capacity. Design day weather does not occur every year, however, the assets must be available should that design day occur given Union's role as the supplier of last resort for sales service and bundled DP customers.

In order to meet these design day requirements for Union South and Union North, Union uses a combination of contracted upstream transportation capacity, and Union's storage, transmission, and distribution assets. The use of storage assets is more cost effective than contracting for full, all year firm upstream transportation capacity. Since Union's storage and transmission assets reside within its South franchise area, the role of the gas supply portfolio is different on a design day in Union South than in Union North. The North design day demand is a direct input into the Gas

Supply Plan, while Union South design day demand is an input into the storage and transmission design day plan. The differing methodologies are described below.

6.1.1 Union South Design Day

Union South design day demand is the total firm requirement of the in-franchise sales service, bundled, unbundled and transportation service customers in the Union South delivery area. The design day weather condition for the Union South area is based on the coldest observed degree day experienced in the Union South delivery area. The design degree day for Union South is 43.1 measured at the London airport.

For Union South, the Gas Supply Plan is focused on purchasing upstream supply and transportation to meet Union's annual demand requirements. The annual volume requirement is divided by 365 days such that the upstream pipe flows at 100% utilization each day of the year. During times when usage is less than the upstream supply, the excess supply is injected into storage at Dawn. When demands are greater than the upstream supply, gas is withdrawn from storage and transported to Union South in-franchise customers.

The role of meeting the entire design day needs for Union South resides within the gas storage and transmission system plans. The Gas Supply Plan is only a component of this broader exercise and only manages the average day supply needs for Union South sales service customers. To meet the design day requirements of Union's south in-franchise customers, Union must have sufficient volume of gas in storage for the seasonal and firm design day demand requirements (storage plan) and sufficient transportation assets to move the upstream supply and gas out of storage into the transmission pipeline systems and to markets. The transmission system plan requires Union to have enough transmission assets to move the firm design day demand from the systems supply points to its customers on design day. Union's distribution systems are designed to meet peak day requirements. If the transmission or storage assets are not sufficient to meet design day and seasonal requirements Union will build additional assets or purchase services to meet this shortfall.

Design days do not occur every year, however, the assets must be available should the design day occur. The resources available to meet Union's design day in the South are shown below in Figure 7.

Figure 7

Union South Design Day Demand and Resources (TJ/day)

Demand	
Union South*	2,743
Supply	
Storage at Dawn	1,300
Non-obligated (e.g. Power Plants)	220
TCPL Empress to Union CDA	67
Trunkline	21
Panhandle	39
TCPL Niagara	21
Ontario Parkway	555
Alliance/Vector	84
Vector	85
Ontario Dawn	310
Customer Supplied Fuel	40
Total Supply	2,743

* includes System Sales, Bundled Direct Purchase, T-service, Unbundled

6.1.2 Union North Design Day

Union North design day demand is the total firm requirement of the in-franchise sales service and bundled DP customers in each of Union's six Northern delivery areas. Union does not include demand for customers with transportation service and unbundled contracts as these customers are required to provide their own transportation services on TCPL to Union to provide Union sufficient supply to meet their design day requirements.

The design day weather condition is based on the coldest observed degree day experienced in each of the six delivery areas. The design degree day for the Northern Delivery areas is as follows:

WDA	56.1	Thunder Bay
MDA	54.7	Fort Frances
SSMDA	48.2	Saulte Ste Marie
NCDA	49.0	Muskoka / Gravenhurst
NDA	51.9	Sudbury
EDA	47.1	Kingston

For Union North, the firm design day demand is a direct input into the Gas Supply Plan. Union is required to purchase transportation services to move the firm design day demand from either Parkway (in some cases from Dawn) or Empress to the delivery areas where the gas is consumed.

Union's Northern delivery areas are connected to TCPL's Mainline and are physically separated from Union's Dawn storage and transmission pipeline assets. Therefore, Union requires upstream transportation services to connect each of the six northern delivery areas to a supply source (currently almost exclusively at Empress). From Dawn, additional transportation services (primarily STS) are required to move gas from storage to the northern delivery areas.

The Union North gas supply portfolio ensures there is sufficient, but not excess, firm transportation services available to meet the firm design day demand requirements in each delivery area. The full suite of assets is only used in each delivery area when a design or peak day occurs. Since Union is required to contract for transportation services to meet design day demand, there are days when the pipe is not fully utilized. Union uses a portfolio of firm services and assets including TCPL firm transportation, Michcon/GLGT/TCPL transportation capacity, TCPL STS firm and other TCPL services to meet its design day demand requirement.

Design day shortfalls in this Gas Supply Plan were identified in Union North (8,851 GJ for the winter of 2013/14). The design day demands for the 2013/14 Gas Supply Plan are based on a trend line using the daily firm customer consumption from the 2011/12 winter and the associated daily degree day data and the forecast anticipated in the 2013/14 demand forecast. The shortfall identified was largely due to lower forecast declines in demand (higher demand than 2013 Board-approved forecast), as well as forecast increases in Union North T-service redelivery (storage service) demands. Firm TCPL long-haul transportation capacity from Empress to Union NDA has been acquired to address this design day shortfall.

Figure 8 illustrates what services and assets are relied on in the Gas Supply Plan to meet design day demand.

Figure 8

Winter 2013/2014 Northern Firm Design Day Demand in TJ's/Day

	Delivery Area						
	MDA	**WDA**	**SSMDA**	**NDA**	**NCDA**	**EDA**	**Total**
Design Day - Heating Degree Day (HDD)	**54.7**	**51.6**	**48.2**	**51.9**	**49.0**	**47.1**	
Design Day Demand by Delivery Area	***13***	***96***	***119***	***287***	***40***	***262***	***816***
Composed of:							
T-Service Firm Contract Demand	*7*	*16*	*83*	*128*	*3*	*105*	***342***
Union Responsible							
Bundled Firm General Service Demand	6	80	36	145	37	157	**460**
T-Service Storage Redelivery Demand	-	-	-	14	-	-	**14**
Firm Demand - Union Responsible	*6*	*80*	*36*	*159*	*37*	*157*	***474***
Capacity & Supply to meet Firm Demand - Union Responsible							
Upstream Transportation - Capacity							
TCPL L/H from Empress / GLGT/TCPL from Michcon	5	37	8	58	9	59	**175**
Supply - Upstream Transportation							
Union System Sales	4	30	4	47	6	41	**131**
Direct Purchase	1	7	4	11	3	18	**44**
	5	37	8	58	9	59	**175**
Redelivery from Storage							
TCPL STS Withdrawals - contracted	-	31	35	48	14	69	**197**
TCPL STS Withdrawals - pooled in/(out)	-	-	(7)	(2)	15	(6)	**-**
TCPL STS Withdrawals - flowed	-	31	28	46	28	63	**197**
TCPL S/H from Parkway	-	-	-	-	-	35	**35**
	-	31	28	46	28	98	**232**
Supply from Upstream Transport & Storage	***5***	***68***	***36***	***104***	***37***	***157***	***408***
Firm Demand - Union Responsible	***6***	***80***	***36***	***159***	***37***	***157***	***474***
Supply from Upstream Transport & Storage	***5***	***68***	***36***	***104***	***37***	***157***	***408***
Excess/(shortfall) by Delivery Area	***(1)***	***(12)***	***()***	***(54)***			***(67)***
Excess/(shortfall) by delivery area	***(1)***	***(12)***	***()***	***(54)***			***(67)***
Supply from Other Sources							
Diversions - from Union South transport portfolio							
TCPL Empress - Union CDA	1	12	-	54	-	-	**67**
Excess/(shortfall) by Delivery Area	***-***		***-***				***-***

Gas supply flows on the TCPL long-haul firm transportation to meet Union North customers' seasonal and annual average weather normalized demand requirements. As in Union South, the target is to fill Union North in-franchise storage at November 1 and provide sufficient inventory at February 28 to meet the design day withdrawal requirement. Average winter demands are met through a combination of gas flowing on upstream transportation and storage withdrawals.

6.2 Demand forecast

The Gas Supply Plan for 2013/14 is based upon the 2014 weather normalized demand forecast for general service customers and contract rate classes as prepared by Union's demand forecasting team. Total bundled customer forecast volumes, including general service unbundled customers, have increased by approximately 3.36 PJ or 1.4% in Union's 2013/2014 Gas Supply from what was approved by the Board in 2013. Union's sales service demands have increased by 18.1 PJ (Figure 9, lines 1, 6, 10, and 14).

The general service forecast has increased by 0.8% in the south and 2.7% in Union North for a total increase of 2.4 PJ. This is primarily due to higher usage in the residential market and in the commercial market arising from various sources.

The contract market has increased by 3.2% in Union South and decreased by 6.9% in Union North for a total increase of 0.9 PJ primarily due to the global economic forces and production activity at a number of industrial establishments. A comparison of the demand forecast included in the 2013/14 Gas Supply Plan relative to the 2013 Board-approved forecast is provided in Figure 9 below.

Figure 9

Union Bundled Customer Forecast Demand

Line No.	Particulars (TJ)	2013 Board Approved	2013/2014 Gas Supply Plan	Variance	% Change
		(a)	(b)	(c) = (b-a)	(d) = (c/a)
	UNION SOUTH				
1	General Service - sales service	100,022	112,137	12,115	
2	General Service - BT	9,596	10,485	890	
3	General Service - U2	7,876	3,391	(4,485)	
4	General Service - ABCT	30,302	22,959	(7,343)	
5	Subtotal	147,796	148,972	1,176	0.8%
6	Contract - sales service	1,172	2,359	1,186	
7	Contract - BT	42,161	42,354	193	
8	Subtotal	43,333	44,712	1,379	3.2%
9	**Total Union South**	**191,129**	**193,684**	**2,555**	**1.3%**
	UNION NORTH				
10	General Service - sales service	29,889	34,664	4,775	
11	General Service - BT	3,556	3,876	320	
12	General Service - ABCT	11,842	7,987	(3,854)	
13	Subtotal	45,286	46,528	1,241	2.7%
14	Contract - sales service	2,117	2,151	35	
15	Contract - BT	4,130	3,662	(468)	
16	Subtotal	6,246	5,813	(433)	-6.9%
17	**Total Union North**	**51,532**	**52,341**	**808**	**1.6%**
18	Total Union Forecast Demand	**242,661**	**246,024**	**3,363**	**1.4%**

As noted above on lines 1 and 10, sales service demands for the general service market have increased by 12.1 PJ in Union South and 4.8 PJ in Union North driven by estimated customer attachments in 2014 of 13,670 and 6,064 respectively as all growth in the general service forecast is assumed to be sales service. In addition, approximately 90,000 bundled DP customers have returned to sales service supply relative to what was forecast in the Board-approved forecast for 2013 for Union South. A comparison of the number of sales service and DP customers in the 2013/14 Gas Supply Plan relative to the 2013 Board- approved forecast is provided in Figure 10.

Figure 10

Customers by Service Classification - Union South
Total Forecast Number of Customers as at December 31, 2013

	2013 Board Approved Forecast	2013/14 Forecast	Variance	Actual Number of Customers
Sales Service	840,473	928,199	87,726	949,064
Bundled DP	234,062	142,241	(91,821)	122,058
Total	**1,074,535**	**1,070,440**	**(4,095)**	**1,071,122**

For the sales service forecast (the group that Union purchases supply for), the increase in demand due to return to sales service impacts the total supply that Union must purchase for both Union North and Union South. For Union North, Union plans for upstream pipeline transportation capacity for sales service and bundled DP customers so there is no impact to Union's contracted capacity in the north as a result of return to sales service.

For Union South, Union requires additional supply and transportation capacity to meet increased demand as a result of return to sales service supply. The total increase in sales service demand for general service and contract customers in Union South is approximately 13 PJ. Union received approximately 5 PJ of upstream capacity (vertical sliced pipe capacity) from DP customers when they returned to sales service supply. In addition, Union purchased incremental Dawn supply of approximately 8.0 PJ in addition to what was included in the 2013 Gas Supply Plan in order to meet this incremental demand. The gas supply/demand balance for sales service customers for the 2013/2014 Gas Supply Plan is provided at Appendix B.

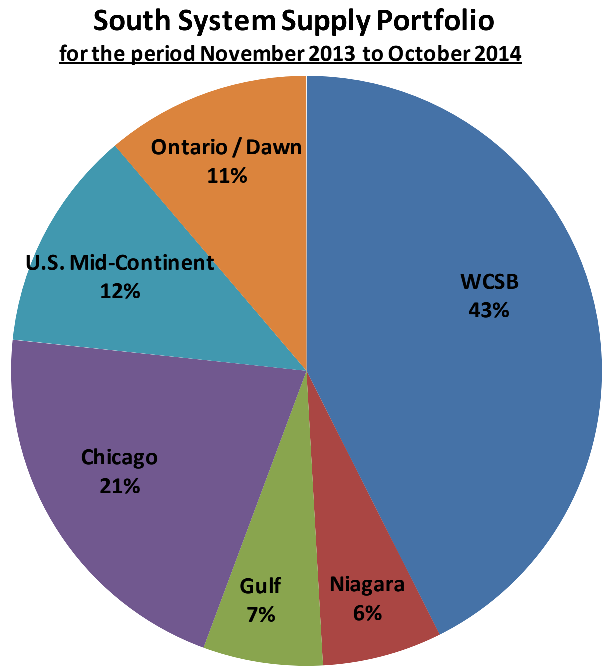
6.3 Transportation Portfolio

Union holds a combination of firm transportation contracts, Dawn sourced supply and storage capacity to meet the full forecasted annual demand. Firm transportation arrangements provide direct and secure access to a diverse group of supply basins and hubs in North America.

i) Union South

For Union South, Union holds firm transportation contracts and sources supply at Dawn to meet average annual demand requirements. Union utilizes capacity on many upstream pipelines to access several supply basins or market hubs. These pipelines provide access to supplies in Western Canada, Gulf of Mexico, Chicago, the U.S. mid-continent and Marcellus through Niagara. The Gas Supply Plan also includes Dawn purchases as part of the Union South supply portfolio. Figure 11 demonstrates the sources of supply underpinned by Union’s transportation portfolio for Union South sales service customers. (A complete list of the upstream transportation contracts is included as Appendix D).

Figure 11



ii) Union North

In Union North, Union's Gas Supply Plan utilizes various services and transportation capacity to meet sales service and bundled DP customer demands and design day including TCPL and Michigan Consolidated Gas Company/Great Lakes Gas Transmission ("MichCon/GLGT") capacity. The transportation capacity necessary to meet peak day demands on a firm basis exceeds that required to meet the annual demand requirements.

A detailed listing of the contracts in place to serve Union North annual, seasonal and design day demands for the 2013/14 gas year are provided in Appendix C.

The Gas Supply Plan reflects the effective management of TCPL and MichCon/GLGT capacity by:

- Using TCPL STS injection and TCPL Dawn Diversions. STS injection is a service that allows Union to move excess volumes from the North to Parkway and ultimately to Dawn storage in the summer;
- Using TCPL STS withdrawals primarily in the winter months to serve weather-driven demands. Gas is withdrawn from Dawn storage throughout the winter and is transported back to Union North via STS withdrawals without the need for contracting additional TCPL FT capacity to that delivery area; and,
- Using contractual STS pooling rights to group all of Union's STS rights serving the various Union North delivery areas. This provides Union with the flexibility to serve the individual delivery areas in Union North with gas service in excess of that delivery area's specific STS rights.

In addition, Union completes the Gas Supply Plan on an integrated basis in order to manage costs for all ratepayers. For example, Union uses the South TCPL Empress to Union CDA contract to serve two purposes. In addition to meeting average day (annual) requirements for

Union South as described above, the Empress to Union CDA contract is also used to meet Union North design day requirements.

6.4 UDC in the Gas Supply Plan

In Union North, the upstream transportation capacity (long-haul, short-haul and STS) is first sized to meet the winter design day demand requirement. The long-haul capacity is also used to deliver, on each day, the average annual volume to each delivery area. The amount of supply transported on the upstream long-haul capacity needed to meet average annual demand requirements is less than the capacity to meet peak day requirements, and therefore, a portion of Union's contract capacity is planned to be unutilized during the year. The difference between total contracted capacity and total demand for both Union North sales service and bundled DP customers results in unutilized capacity or UDC. The total forecast UDC is 10.7 PJ in the 2013/14 Gas Supply Plan. If weather is colder than normal and annual consumption is greater, and if it is economical to do so, Union will use this capacity to meet incremental supply requirements in either Union North or Union South subject to TCPL's authorization of downstream diversions.

Figure 12 shows the total contracted capacity sourcing supply at Empress and Michigan relative to the annual demand and the resulting UDC in the 2013/14 Gas Supply Plan.

Figure 12

Union North Transportation Capacity vs Demand 2013/14 Gas Supply Plan	
	PJ
Total contracted capacity (166 TJ/day x 365)	60.6
Incremental NDA Capacity (9 TJ/day x 304 days) *	2.7
Less:	
Total Annual System Sales Demand	37.1
Total Annual Bundled DP Demand	15.5
UDC	10.7
* Contract in place as of January 1, 2014	

In Union South, capacity on multiple different upstream pipelines is utilized to provide service to meet sales service average and seasonal demands. The Gas Supply Plan reflects the effective management of these capacities as there is no unutilized transportation capacity forecast for the 2013/14 gas year as the Plan forecasts a 100% load factor on all the Union South upstream transportation.

6.5 Changes in Upstream Transportation Portfolio

The Gas Supply Plan assumes that all capacity currently contracted with renewal rights will continue to be available in the future. The plan also excludes the following contracts that have expired:

- Vector Pipeline – 10,551 GJ/d (one year term)
- Panhandle Eastern Pipeline – 10,551 GJ/d (one year term)
- Union CDA market-based contracts – 64,000 GJ/d (5 month term)

Of these contract expiries, only the Vector contract was not replaced with a similar transportation service. This capacity was replaced with purchases at Dawn.

The 2013/14 Gas Supply Plan identified the following requirements:

- Approximately 44,000 GJ/d of supply to balance Union South sales service supply and demands.
- 9,000 GJ/d to meet design day requirements for Union North.
- 53,000 GJ/d from Parkway to Union CDA.

To meet the Union South sales service supply requirements, Union recontracted for 10,551 GJ/d on the Panhandle Eastern Pipeline for an additional one-year term. The remainder of the supply (34,000 GJ/d) will be purchased at Dawn for the 2013/14 gas year. This represents an incremental 22,000 GJ/d of Dawn supply (8 PJ annually) relative to the 2013 forecast. This incremental supply is required due to DP customers returning to sales service as discussed in Section 6.7. Union includes Dawn supplies in the gas supply portfolio to provide additional diversity and flexibility. Dawn delivered supplies provide Union access to a robust and liquid Dawn market hub.

To meet design day requirements in Union North, firm TCPL long-haul transportation capacity from Empress to Union NDA has been acquired.

The total requirement from Parkway to Union CDA identified in the Gas Supply Plan was 69,000 GJ/d, however, the Gas Supply Plan assumes that Union would renew an existing FT contract for 16,000 GJ/d (contract has automatic renewal rights), leaving an outstanding requirement of 53,000 GJ/d. The need for Parkway to Union CDA firm transportation capacity was identified in early 2011 when TCPL indicated that Union would need to contract and pay specifically to transport volumes from Parkway to Union CDA in order to meet consumption requirements. Historically, TCPL had not charged for this service and Union had not had to contract for it. Union described this new requirement in EB-2013-0109 Exhibit J2.6. Union has contracted for 53,000 GJ/d from Parkway to Union CDA in the secondary market with a third party effective November, 2013.

A complete listing of the transportation capacity contracted for Union North and Union South for the 2013/14 gas year is provided at Appendix C and D.

6.6 Cost of Gas

The Gas Supply Plan for the gas year 2013/14 was finalized in the third quarter of 2013. The transportation tolls and gas prices utilized in the development of the Gas Supply Plan are consistent with those used to set the January 1, 2013 Quarterly Rate Adjustment Mechanism (“QRAM”) commodity price. Union then established specific prices for each supply location taking into account the various basis differentials and the foreign exchange rate.

As part of Union’s Incentive Rate Mechanism (“IRM”) Settlement Agreement, Union indicated in Section 4.7.1, that the cost of gas supply, upstream transportation and gas supply balancing would continue to be passed through to customers through the Quarterly Rate Adjustment Mechanism (“QRAM”). Union reflects updated transportation tolls and forecast gas commodity in rates through the QRAM process. Variances in actual gas supply costs and transportation tolls relative to forecast gas supply costs and transportation tolls reflected in rates are captured in Union's gas supply deferral accounts. Union includes the prospective disposition of gas supply-related deferral accounts in the QRAM process.

6.7 Bundled DP Customer Assumptions

The Gas Supply Plan includes all bundled DP demand and contracted Daily Contract Quantities ("DCQ"), and assumes that the number of bundled DP customers remains constant as of January 1, 2013. Union is unable to predict customer migration between sales service and bundled DP. Therefore, for the term of the Gas Supply Plan, customers are assumed to remain with the service they had received effective January 1, 2013.

On an ongoing basis throughout the year, Union continues to monitor the migration between bundled DP and sales service supply. As customers return to sales service supply, Union proactively manages the expected supply requirements by filling any pipe that is returned to Union when the customer returns to sales service supply. In addition, each month, Union purchases incremental supply for demand that is returned without underlying pipe based on forecast activity for the balance of the gas year.

Conversely, for customers that migrate to bundled DP, Union facilitates this movement by displacing planned commodity purchases and allocating upstream transportation capacity, as per the vertical slice allocation methodology approved in the RP-1999-0017 proceeding. As discussed earlier in this memorandum, on a net basis, Union has experienced greater return to sales service supply.

6.8 Storage

Union operates 166 PJ of storage. Consistent with the NGEIR decision, the allotment of storage space to in-franchise customers is 100 PJ. For the 2013/14 supply plan, the in-franchise space requirement is 91.4 PJ. This leaves 8.7 PJ of excess in-franchise space which is available for S&T short term sales. This is an increase of 2.6 PJ in the space required for in-franchise needs when compared to what was approved in the 2013 Gas Supply Plan. The increase in in-franchise storage is due to increased demand for Union's bundled contracts (1.5 PJ increase in storage requirement), and increased storage for Union North and Union South T-service customers (1.0 PJ increase in storage requirement).

The in-franchise space of 91.4 PJ is provided to in-franchise customers to meet the demand requirements of sales service and bundled DP, T1, T3 and Northern T-service customers. The amount available to in-franchise customers is based on the storage allocation methodologies approved by the Board as part of the Natural Gas Storage Allocation Policies Decision (EB-2007-0724/0725).

The storage space available to sales service and bundled DP customers in Union South and Union North is determined using the Board-approved aggregate excess methodology. This method is defined as the calculation of the difference between total winter demand (November 1 through March 31) and the average annual demand for a 151 day period. This method determines the allocation of storage space based on the following formula:

$$\text{Aggregate Excess} = \text{Total Winter Consumption} - [(151/365)*(\text{Total Annual Consumption})]$$

6.9 Conclusion

Union establishes a Gas Supply Plan that is right sized to meet firm sales service and bundled customer demands with a diverse, flexible and cost effective portfolio of firm services and assets. Union's integrated supply planning process incorporates demand related items such as customer growth, normalized weather, design day requirements, customer consumption patterns and economic outlooks. Union plans and contracts for services and assets to provide an efficient combination of upstream transportation, supply purchases, and storage assets to serve sales service and bundled DP customers' annual, seasonal and design day gas delivery requirements. Union adheres to the gas supply guiding principles to ensure the assets procured on behalf of customers are robust, secure, diverse and reliable to meet firm customer demands.

As supply and transportation market options change, so does Union's supply mix and how it is transported to Ontario. Union continues to proactively evaluate new supply and transportation options for Union North and Union South customers. Unchanged, however, is Union's application of the gas supply planning principles and the requirement to ensure secure, reliable supplies to serve its customers at prudently incurred costs.

There are several changes in the North American natural gas industry that may have an impact on Union's gas supply portfolio and plans in the future. These factors and the potential impact are discussed below.

7 FUTURE TRENDS THAT MAY IMPACT THE GAS SUPPLY PLAN

Union monitors the North American natural gas industry and identifies how trends may impact Union's future gas supply portfolio. The market context which Union operates is described above and includes the emergence of shale gas, the reduction in available WCSB supplies flowing eastward, and the trend to move from long-haul transportation to short-haul. In addition to these trends, Union also considers recent industry experience particularly that of the extraordinary winter of 2013/14.

7.1 Winter of 2013/2014

Specifically, this winter, the industry observed the following:

- Sustained, colder than normal weather. The extreme conditions were the coldest experienced in 35 years.
- Lower storage inventories across North America. Union also experienced this as Dawn storage inventory was at all-time low of 9% full by mid-March, 2014.
- Transportation bottlenecks to move supplies to market. This was experienced in gas moving out of Empress, as well as supplies moving to Dawn. The Parkway-Maple bottleneck also continued to restrict movement of supplies downstream of Parkway.

There have also been changes in TCPL contracting, operations, and pricing of discretionary services. TCPL has been successful in selling higher levels of firm services since the implementation of the RH-003-2011 Decision, therefore increasing the utilization of the Mainline. This has resulted in changing operations and flows through the winter period, resulting in less reliability of discretionary services. In addition, TCPL has continued to utilize their flexibility in pricing of discretionary services such as IT and STFT. For example, through the winter period, bid rates for some discretionary services reached a high of 5500% of the firm transportation toll.

These industry developments are factors that will impact Union's future gas supply and transportation portfolio, as discussed in more detail below. These initiatives are primarily longer-term and in many cases, are still in the early stages and were not able to be contemplated in Union's 2014 Gas Supply Plan.

7.2 TCPL Settlement Agreement

Currently, there is a capacity bottleneck between Parkway and Maple which prevents the unrestricted flow of gas from Dawn or Parkway to points east and north. This bottleneck is a critical limiting factor as Union and eastern markets seek to increase the proportion of Dawn purchases and short-haul transportation routes into their portfolio to take advantage of plentiful, economic supply options. Eliminating the bottleneck, including who would add the capacity and at what cost to shippers, was a topic of significant debate in recent years. Several factors, including TCPL implementation of their RH-003-2011 Decision early in 2013 and the suspension of TCPL's planned expansion, resulted in strained relationships and entrenched opposing views between TCPL and Ontario/Quebec LDC's. By summer 2013, there were several contentious and litigious issues outstanding between the parties, resulting in great uncertainty in the marketplace. It was a situation that was not sustainable, not in the best interest of market participants, and ultimately not to the benefit of end-users.

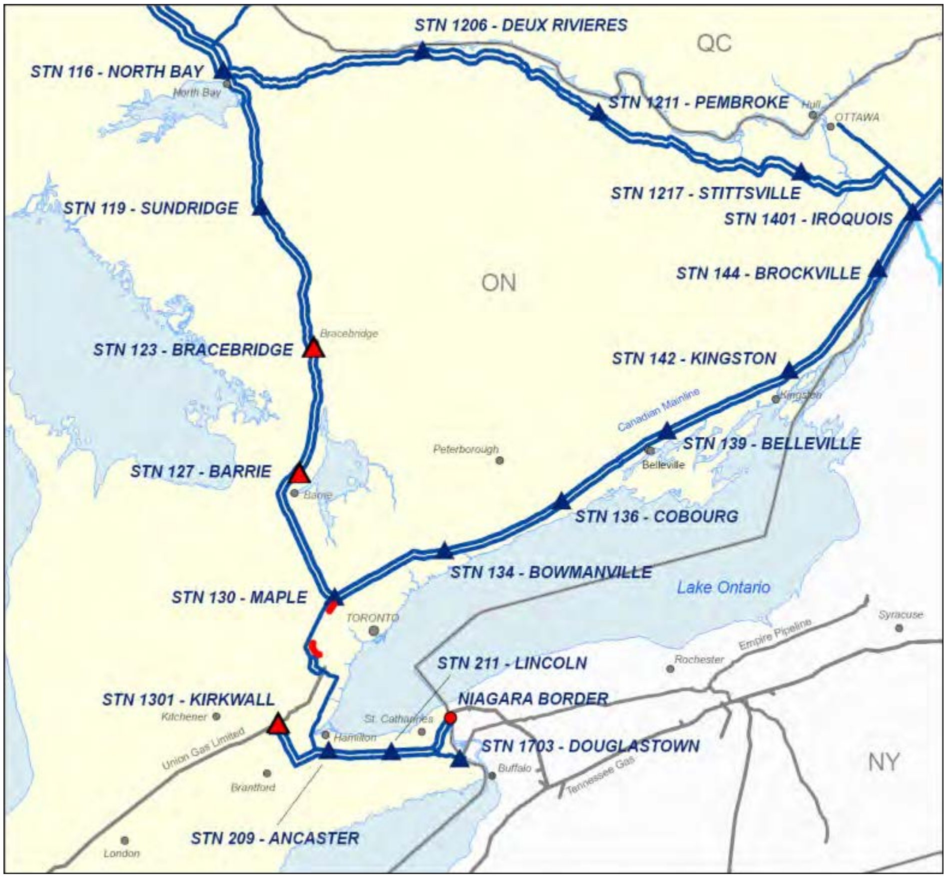
In fall 2013, TCPL, Gaz Métro, Enbridge, and Union negotiated a Settlement Agreement which addressed a number of the outstanding issues between them. Most notably, it provides the following:

- Access to Dawn and Niagara for gas consumers in Ontario and Quebec, resulting in increased diversity and security of supply. This access will be achieved through the completion of pending facilities projects for Union (Parkway Projects), Enbridge (GTA Project), and TCPL (King's North Project), which relieves the bottleneck by providing additional transportation capacity between Dawn and markets north and east. It also provides a framework for TCPL to expand for market-supported short-haul services beyond 2015. This allows market participants, including Union's northern customers, to contract for short-haul transportation from liquid hubs, such as Dawn, located closer to market areas.
- Stable TCPL Mainline tolls. The Settlement provides for stable tolls during the period 2015-2020, while providing a reasonable opportunity for cost recovery for TCPL.
- Resolve outstanding claims. The Settlement Agreement resolved all outstanding disputes which were pending at the time of the negotiation.

The Settlement Agreement was filed by TCPL with the National Energy Board ("NEB") for approval in December, 2013. It is expected that it will be reviewed and decided upon by the NEB in 2014.

Contract demands for Union, Enbridge, and Gaz Métro account for over 50% of the flows on TCPL to the Eastern Ontario Triangle ("EOT"). The EOT is a portion of the TCPL Mainline system which connects North Bay, Parkway/Maple in Mississauga, and Iroquois (before the Ontario/Quebec border). It is shown in the Figure 13 below.

Figure 13



Some TCPL shippers endorse the Settlement Agreement, while some have expressed concerns. These concerns are mainly focused on the increased toll resulting from the Agreement. Union is of the view that the increased tolls are required to support open access to new supplies developing in close proximity to Ontario and Quebec. In addition, if the Settlement is approved by the NEB post 2020, shippers in the EOT will be tolled separately from the other TCPL Mainline segments, better reflecting the true cost of their contracted capacity.

7.3 Access to Dawn for Union North

As described above, the Settlement Agreement results in access to Dawn for shippers downstream of Union's system; for Union, this means customers in the NDA, and the EDA. In order to affect this access, Union entered into the 2015 and 2016 open seasons conducted by TCPL to provide service from Parkway to the EDA and Parkway to the NDA. Union's bids in both open seasons were accepted. Capacity was also reserved in Union's own Dawn-Parkway open seasons for 2015 and 2016 on behalf of sales service and bundled DP customers.

The capacity required in 2015 to serve these contracts includes expansion of Union's Dawn to Parkway system (including the Parkway Projects), the Enbridge GTA project, and TCPL's King's North project. Union's Parkway Projects and the Enbridge GTA project were approved by the Board in January, 2014. Additional Dawn to Parkway capacity will be required for the 2016 volumes of Union and other market participants. In addition, Union expects that additional facilities will be required on the TCPL system in 2016. In tandem with the acquisition of short-haul contract capacity from Dawn, long-haul contract capacity will be de-contracted; said another way, Union is transitioning existing long-haul contracts to short-haul contracts. Quantities being transitioned for the Union EDA and Union NDA are as follows:

Figure 14

TCPL Contract Transitions
GJ/d

	2015	2016
Union EDA	100,000	0
Union NDA	10,000	100,000

For 2015, the Union EDA transition includes the reduction of long-haul Empress to Union EDA transportation of approximately 58 TJ/d and a reduction of STS withdrawals to the EDA of approximately 42 TJ/d. The total reduction of 100 TJ/d is replaced by 75 TJ/d of short-haul Parkway to Union EDA transportation and 25 TJ/d of TCPL's new Enhanced Market Balancing ("EMB") Service. The EMB service, which was introduced as part of the Settlement Agreement, offers Union a short-haul service similar to STS withdrawals. It provides flexibility to manage market fluctuations by including eight nomination windows and is not linked to TCPL-long-haul transportation. The Union NDA transition is a reduction of long-haul Empress to Union NDA transportation of 10,000 GJ/d, replaced by 10,000 GJ/d of Parkway to Union NDA transportation.

For 2016, the only transition of long-haul contracts to short-haul contracts for the sales service/bundled DP portfolio is in the Union NDA. 33,000 GJ/d of Empress to Union NDA transportation is being replaced by 33,000 GJ/d of Parkway to Union NDA transportation.

Also in 2016, Union submitted another bid for 67,000 GJ/d of Parkway to Union NDA. This is to eliminate Union's reliance on upstream diversions on design day to serve Union North, and is described in the next section.

Union also submitted bids for 2016 service on behalf of North T-Service customers electing for Union's North T-Service to Dawn service. These bids were for a total of 29 TJ/d of Dawn service to Union NDA, NCDA, and EDA.

A summary of Union's 2015 and 2016 TCPL bids can be found in Appendix E.

7.4 Reliance on Diversions and Discretionary Services

Given the significant changes to TCPL's system operations and experience from winter 2013/14, Union found TCPL unable to accommodate certain upstream diversions they have previously and consistently accepted. Union is therefore working to replace its reliance of upstream diversions to meet Union North requirements. This has been facilitated through a firm delivery point shift of the Empress to Union CDA contract to northern delivery points in the short term and changes in contracted capacities over the longer term. This includes the elimination of diversions upstream by securing November, 2015 capacity in TCPL existing open seasons for Empress to Union MDA and Union WDA capacity. In addition, Union bid for 67,000 GJ/d of short-haul TCPL Parkway to NDA capacity for November, 2016 capacity, as described above and reflected in Appendix E.

7.5 Changing TCPL Renewal Notice

In summer 2013, TCPL applied to the NEB for a number of changes to their tariff (RH-001-2013). Among the changes contemplated were amendments to the notice period for renewals. In the Decision, the NEB increased the current six month notice period to a two-year notice period. A transition plan was also implemented for shippers with contracts expiring within the two-year window. Per the transition plan, Union elected renewals for 2015 expiries at the end of January, 2014; October, 2016 contract expiries will be elected in October, 2014. Contracts will roll forward on a one-year basis, while maintaining the two-year notice requirement. This is consistent with Union's own contracting practice.

7.6 GLGT Michcon Capacity Replacement

In November, 2011, Union contracted for 6 TJ/d of capacity on GLGT, MichCon, and TCPL to provide US sourced supply from Michigan to the Union SSMDA. This provided an economic alternative to introduce some diversity into the Union North portfolio. The economics were based on a discounted transportation rate that was briefly offered by GLGT. Union understands that this discounted capacity will be unavailable upon the expiration of the current arrangement (November 1, 2014). As well GLGT is in the process of gaining regulatory approval for a substantial increase in their transportation rates.

As a result of these factors, Union has elected not to renew the GLGT/MichCon/TCPL path, and instead serve the Union SSMDA using long-haul TCPL transportation from Empress. This change will be implemented November, 2014.

7.7 Dawn to Parkway Expansion

As described above, eastern markets, including Union, are seeking to source more supplies from Dawn. This growth at Dawn will need to be supported by increased capacity on the Dawn to Parkway System, as well as east of Parkway (as described above). In order to identify and serve this requirement, Union held an open season in May, 2012 to solicit customer interest in this path commencing November, 2015. This expansion is part of the Parkway Projects that were approved by the Board in January, 2015 as part of EB-2012-0433 and EB-2013-0074.

Union held a second open season in December 2013/January 2014 for incremental interest on the Dawn to Parkway System commencing November, 2016. Union is in the process of executing contracts for this capacity and, subject to the market commitment, will result in Union bringing forth a facilities application to the Board later this year.

On behalf of the Union sales service and bundled DP customers, Union has reserved incremental Dawn to Parkway capacity in both the 2015 and 2016 open seasons; the amount of capacity reserved was approximately 70 TJ/d and 140 TJ/d respectively. These capacities, in combination with the incremental TCPL capacity from Parkway to Union EDA and Union NDA, will allow Union's northern customers to shift supplies previously sourced from the WCSB to Dawn.

7.8 Plan to Suspend Vertical Slice

Since 2001, Union South customers migrating from sales service to DP arrangements are allocated a "vertical slice" (a representative portion of upstream transportation capacities) of Union's gas supply portfolio. Today, this vertical slice includes transportation capacity on TCPL, Alliance, Vector, Trunkline and Panhandle transmission systems. Union plans to implement the suspension of vertical slice of upstream transportation capacity in phases. There will be three phases to the implementation starting in November, 2014 and concluding by November, 2016. Union's plan, and the implementation of that plan, is dependent upon the result of the Parkway Obligation proposal.

There are two significant drivers which have prompted Union's plan to suspend the vertical slice program. First, upcoming contract expiries will allow bundled DP customers to turnback their existing vertical slice allocation. By November, 2016, approximately 95% of the capacity which comprises the existing vertical slice allocation is expected to expire. This will facilitate the turnback of this capacity by bundled DP customers. Due to the small quantity of the remaining capacity in the existing vertical slice allocation, Union plans to facilitate its turnback as part of the suspension plan as well.

The second factor driving the suspension of vertical slice is the expectation that there will be small, manageable quantities of migration to DP. A steady reduction in the number of new bundled DP customers means that Union's sales service portfolio can manage this migration going forward, provided it remains small and/or predictable. Since 2007, there has been a steady decline in the number of bundled DP customers. Today, only 119,700 customers are DP compared to 364,000 in 2001.

Given that a large portion of the existing vertical slice can be turned back in coordination with contract expiries, and new DP quantities are expected to be small and manageable going forward, Union is now able to offer a suspension of the vertical slice methodology. Instead of allocating a portion of multiple upstream capacities to customers as they migrate from DP, Union would utilize flexibility within the sales service upstream transportation portfolio to accommodate fluctuations between sales service and DP.

Union notes, however, if migration to DP significantly increases over time, Union would reserve the right to revert back to the vertical slice methodology to serve these customers.

7.9 Parkway Obligation

DP customers in Union South are obligated to deliver gas to Union at receipt points upstream or on Union's system, including the interconnect with TCPL at Parkway. With the exception of unbundled customers, this delivery obligation is required every day of the year unless otherwise agreed to by Union. A portion of Union's deliveries on behalf of sales service customers is also delivered at Parkway. These delivery points have been determined through a historical allocation of Union's upstream transportation contracts.

As part of its 2014 Rates application (EB-2013-0365), Union proposed to transition the Parkway delivery obligation to Dawn using temporarily available Dawn-Parkway capacity, shortfall capacity, and expected Dawn-Kirkwall turnback capacity from customers. Union is working with customers to transition the obligations at Parkway to Dawn starting in April 2014.

The location and quantity of DP obligated deliveries and the upstream transportation contracts that the sales service and certain bundled DP customers utilize are all inputs into the gas supply planning process. As these change over time, the Gas Supply Plan would also have to change. Union's proposal to shift the Parkway Obligation to Dawn for Union's DP customers also contemplates transportation of those deliveries at Dawn, to Parkway. As a result, there is minimal impact to the Gas Supply Plan.

As of January 1, 2014, approximately 98 TJ/d of supply is delivered to Parkway on behalf of sales service customers. By November, 2016, the Parkway deliveries are expected to decrease to 11 TJ/d, facilitated by the expiration of underlying contracts in the upstream transportation portfolio for sales service customers. These contracts include long-haul and short-haul TCPL capacity in the gas supply portfolio that currently delivers sales service gas at Parkway for Union South customers.

7.10 Burlington-Oakville Project

On the TCPL system, Union CDA is a TCPL delivery area that is located at the eastern end of Union's Dawn-Parkway System. It is located entirely within in the Union South operating area and is comprised of four city gate stations: Bronte, Burlington, Hamilton Gate, and Nanticoke. TCPL supplies a portion of this area while the Union transmission and distribution system supplies the remainder. Today, Burlington, Oakville, and surrounding areas are served from Union's Dawn-Parkway system, deliveries from TCPL's Domestic line, and third-party contracts Union has secured to the Union CDA within the upstream transportation portfolio.

The drivers for the project are increased security of supply, annual delivered gas cost decreases, and providing infrastructure to support future demand growth.

The method of serving the market today is not sustainable. The availability of Union CDA capacity is limited, as are market-based options. In addition, market-based contracts do not typically offer renewal rights, which compromises the reliability and security of supply. In addition, the existing capacity into the Union CDA will not be sufficient to serve market growth in the Milton, Burlington, and Oakville areas.

The Burlington-Oakville project will involve Union constructing approximately 13 km of NPS 20 pipeline from the Dawn-Parkway System to the existing high pressure system in Oakville. The estimated cost of capital is approximately $100 million, and the in-service date is planned to be November 1, 2016. As a result of this project, Union will no longer require certain TCPL and market-based contracts it currently requires to serve the Union CDA. The facilities application for this project is expected to be filed with the Board in the second quarter of 2014.

The Settlement Agreement described above also provides clarity on how the Union CDA gate stations will be served, based on the capabilities of the TCPL system. TCPL also recognizes the Burlington Oakville project and the resulting impact on TCPL delivery points. Coincident with the implementation of the Burlington Oakville project, Union recognized the need to contract and pay for TCPL services to transport volumes from Kirkwall to the amended Union CDA. As such, Union will contract with TCPL to provide service from Kirkwall to Hamilton and Nanticoke (collectively referred to as the Amended Union CDA in the Settlement Agreement) Gate Stations. Union was awarded this capacity (135,000 GJ/d) in TCPL's 2016 open season. This capacity is reflected in Appendix E.

7.11 Bringing Additional Supplies to Dawn

Union has and continues to acquire supply sources which support diversity and security of supply for Ontario. Additional supply coming into Dawn, particularly from Marcellus/Utica shale production regions are required and are an economic and secure alternative to supply traditionally sourced from the WCSB and transported to Ontario via TCPL or Alliance/Vector. Union will be looking for alternatives which will deliver gas to Dawn to provide sustainable, reliable, and economic supplies for markets in both the Union South and Union North delivery areas.

8 APPENDICES

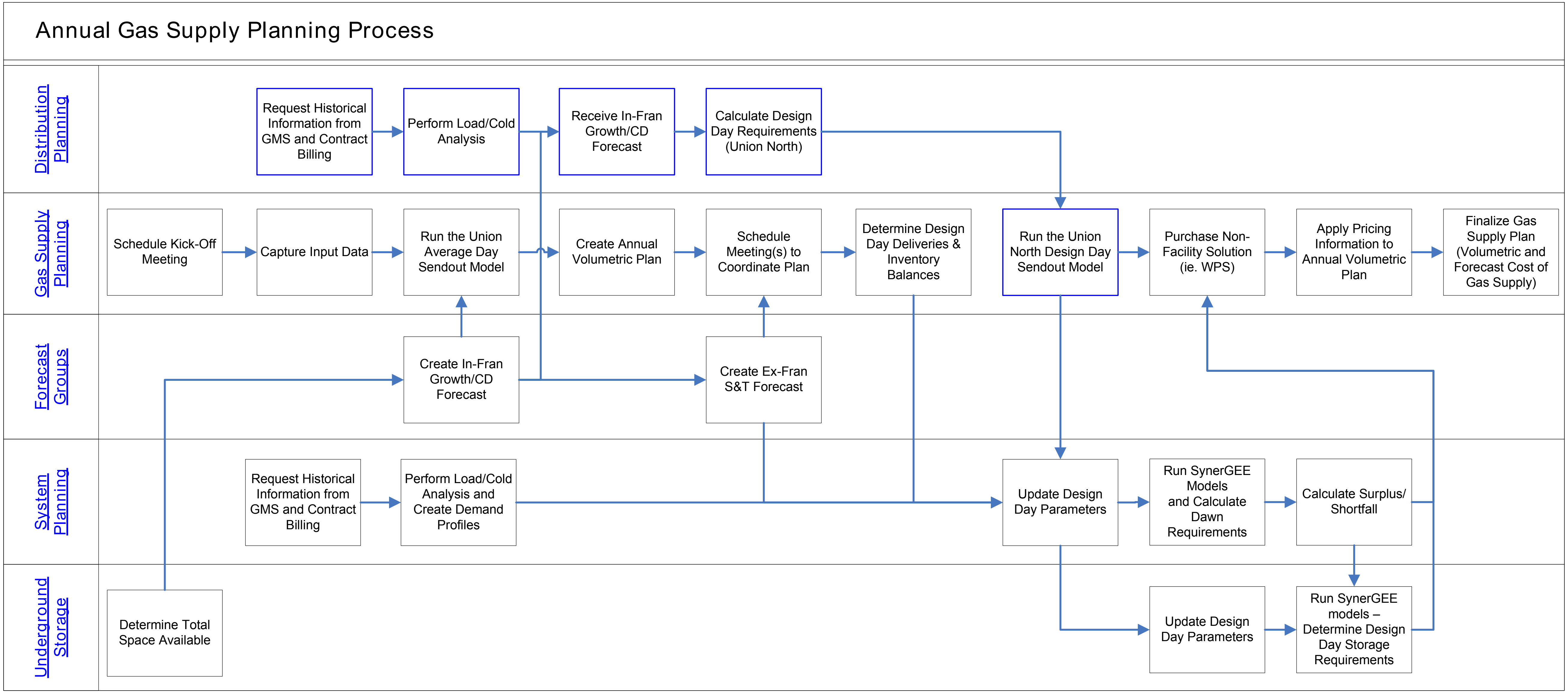
Appendix A - Gas Supply Planning Process

Appendix B - Sales service Gas Supply Demand Balance

Appendix C - Union North Detailed List of Transportation Contracts

Appendix D - Union South Detailed List of Transportation Contracts

Appendix E - Summary of Union’s 2015 and 2016 TCPL New Capacity Open Season Bids


Annual Gas Supply Planning Process
Distribution Planning
Gas Supply Planning
Forecast Groups
System Planning
Underground Storage
Request Historical Information from GMS and Contract Billing
Perform Load/Cold Analysis
Receive In-Fran Growth/CD Forecast
Calculate Design Day Requirements (Union North)
Schedule Kick-Off Meeting
Capture Input Data
Run the Union Average Day Sendout Model
Create Annual Volumetric Plan
Schedule Meeting(s) to Coordinate Plan
Determine Design Day Deliveries & Inventory Balances
Run the Union North Design Day Sendout Model
Purchase Non-Facility Solution (ie. WPS)
Apply Pricing Information to Annual Volumetric Plan
Finalize Gas Supply Plan (Volumetric and Forecast Cost of Gas Supply)
Create In-Fran Growth/CD Forecast
Create Ex-Fran S&T Forecast
Request Historical Information from GMS and Contract Billing
Perform Load/Cold Analysis and Create Demand Profiles
Update Design Day Parameters
Run SynerGEE Models and Calculate Dawn Requirements
Calculate Surplus/ Shortfall
Determine Total Space Available
Update Design Day Parameters
Run SynerGEE models – Determine Design Day Storage Requirements

Appendix B
Union Gas Limited - Sales Service Supply Demand Balance - November 2013 to October 2014
(TJ)

	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Total
South													
Demands													
Sales Service	11,333	17,412	20,292	17,706	15,456	9,060	4,862	2,793	2,910	2,912	3,162	6,599	**114,495**
South Co. Use, UFG, Comp. Fuel	644	958	1,345	1,338	1,165	702	472	406	487	531	540	632	**9,220**
Less: Customer Supplied Fuel	(615)	(677)	(932)	(752)	(596)	(411)	(274)	(269)	(332)	(268)	(240)	(437)	**(5,802)**
Total Demands	11,362	17,693	20,705	18,291	16,026	9,351	5,059	2,930	3,064	3,175	3,462	6,794	**117,913**
Supplies													
TCPL Empress-Union CDA	1,448	1,496	1,496	1,351	1,496	1,448	1,496	1,448	1,496	1,496	1,448	1,496	**17,612**
Alliance/Vector	2,155	2,227	2,227	2,012	2,227	2,155	2,227	2,155	2,227	2,227	2,155	2,227	**26,223**
Vector	2,549	2,634	2,634	2,379	2,634	2,549	2,634	2,549	2,634	2,634	2,549	2,634	**31,011**
TCPL Niagara-Kirkwall	633	654	654	591	654	633	654	633	654	654	633	654	**7,702**
Trunkline	633	654	654	591	654	633	654	633	654	654	633	654	**7,702**
Panhandle	1,171	1,210	1,210	1,093	1,210	1,171	1,210	1,171	1,210	1,210	1,171	1,210	**14,249**
Local Production	79	82	82	74	82	79	82	79	82	82	79	82	**967**
Dawn	1,012	1,177	1,019	913	1,276	1,136	1,020	792	732	847	1,190	1,105	**12,218**
Total Supplies	9,680	10,134	9,977	9,004	10,233	9,804	9,977	9,460	9,689	9,804	9,858	10,062	**117,684**
Change in Inventory - wd/(inj)	1,682	7,558	10,729	9,288	5,792	(453)	(4,918)	(6,530)	(6,625)	(6,629)	(6,397)	(3,268)	**229**
Total Supplies + Inventory Change	11,362	17,693	20,705	18,291	16,026	9,351	5,059	2,930	3,064	3,175	3,462	6,794	**117,913**
North													
Demands													
Sales Service													
Union NCDA	307	462	581	461	404	245	135	69	69	67	75	173	**3,048**
Union EDA	1,080	1,525	1,947	1,544	1,383	845	473	260	260	255	287	607	**10,467**
Union MDA	42	65	80	64	56	34	18	9	9	9	10	24	**418**
Union NDA	1,329	2,000	2,370	1,861	1,691	1,009	534	277	297	272	312	725	**12,678**
Union SSMDA	313	454	546	514	456	235	129	65	65	64	72	176	**3,087**
Union WDA	707	1,066	1,275	1,043	912	561	367	229	173	147	235	401	**7,117**
North Comp Fuel	30	30	9	5	3	14	30	30	30	30	30	30	**272**
	3,808	5,602	6,808	5,493	4,905	2,944	1,686	938	902	845	1,020	2,136	**37,088**
Supplies													
TCPL Empress-Union NCDA	169	173	173	157	-	167	173	167	173	173	167	173	**1,862**
TCPL Empress-Union EDA	1,240	1,278	1,275	1,154	-	1,232	1,274	1,232	1,274	1,274	1,232	1,274	**13,738**
TCPL Empress-Union MDA	44	72	92	72	62	34	13	2	2	2	3	21	**419**
TCPL Empress-Union NDA	1,081	1,116	1,117	1,008	-	1,076	1,112	1,077	1,112	1,112	525	1,112	**11,450**
TCPL Empress-Union SSMDA	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Michcon/GLGT/TCPL-Union SSMDA	184	190	190	172	190	95	98	45	30	38	67	-	**1,301**
TCPL Empress-Union WDA	901	930	930	840	377	900	930	900	574	128	229	458	**8,098**
Total Supplies	3,619	3,761	3,777	3,403	629	3,505	3,600	3,423	3,165	2,727	2,224	3,038	**36,869**
Change in Inventory - wd/(inj)	190	1,841	3,031	2,090	4,276	(561)	(1,913)	(2,485)	(2,263)	(1,882)	(1,204)	(902)	**219**
Total Supplies + Inventory Change	3,808	5,602	6,808	5,493	4,905	2,944	1,686	938	902	845	1,020	2,136	**37,088**
Total Demands													
South	11,362	17,693	20,705	18,291	16,026	9,351	5,059	2,930	3,064	3,175	3,462	6,794	**117,913**
North	3,808	5,602	6,808	5,493	4,905	2,944	1,686	938	902	845	1,020	2,136	**37,088**
	15,171	**23,294**	**27,513**	**23,785**	**20,931**	**12,295**	**6,746**	**3,868**	**3,966**	**4,020**	**4,482**	**8,930**	**155,001**
Total Supplies													
South	9,680	10,134	9,977	9,004	10,233	9,804	9,977	9,460	9,689	9,804	9,858	10,062	**117,684**
North	3,619	3,761	3,777	3,403	629	3,505	3,600	3,423	3,165	2,727	2,224	3,038	**36,869**
	13,299	13,895	13,754	12,407	10,862	13,309	13,577	12,883	12,854	12,531	12,082	13,100	**154,552**
Change in Inventory - wd/(inj)													
South	1,682	7,558	10,729	9,288	5,792	(453)	(4,918)	(6,530)	(6,625)	(6,629)	(6,397)	(3,268)	**229**
North	190	1,841	3,031	2,090	4,276	(561)	(1,913)	(2,485)	(2,263)	(1,882)	(1,204)	(902)	**219**
	1,872	9,399	13,759	11,378	10,068	(1,015)	(6,831)	(9,015)	(8,887)	(8,511)	(7,600)	(4,170)	**448**
Total Supplies + Inventory Change	**15,171**	**23,294**	**27,513**	**23,785**	**20,931**	**12,295**	**6,746**	**3,868**	**3,966**	**4,020**	**4,482**	**8,930**	**155,001**

2013/14 Gas Supply Plan Memorandum
Appendix C

UNION GAS LIMITED

Summary of Upstream Transportation Contracts - as at November 1, 2013
Northern and Eastern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date	Unitized Demand Charge ($Cdn/GJ)	Commodity Charge ($Cdn/GJ)	100% LF Toll ($Cdn/GJ)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h=f+g)
	TransCanada Pipeline								
1	Empress to Union NCDA FT	Empress	Union NCDA	1,545	GJ	31-Oct-2014	1.495		1.495
2	Empress to Union EDA FT	Empress	Union EDA	8,675	GJ	31-Oct-2014	1.650		1.650
3	Empress to Union NDA FT	Empress	Union NDA	64,715	GJ	31-Oct-2015	1.317		1.317
4	Empress to Union WDA FT	Empress	Union WDA	39,880	GJ	31-Oct-2015	0.856		0.856
5	Empress to Union SSMDA FT	Empress	Union SSMDA	2,700	GJ	31-Oct-2015	1.194		1.194
6	Empress to Union EDA FT	Empress	Union EDA	50,426	GJ	31-Oct-2015	1.650		1.650
7	Empress to Union NCDA FT	Empress	Union NCDA	9,211	GJ	31-Oct-2015	1.495		1.495
8	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	31-Oct-2015	0.598		0.598
9	Parkway to Union EDA FT	Parkway	Union EDA	30,000	GJ	31-Oct-2016	0.250		0.250
10	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	31-Oct-2017	0.250		0.250
11	Parkway to Union CDA FT	Parkway	Union CDA	16,000	GJ	31-Oct-2014	0.101		0.101
12	TCPL FT - Total			232,674	GJ				
	Other								
13	Parkway to Union CDA - Exchange	Parkway	Union CDA	8,000	GJ	31-Mar-2014	0.780		0.780
14	Dawn to CDA - Exchange	Parkway	Union CDA	45,000	GJ	31-Mar-2014	0.780		0.780
15	Total - Other			53,000	GJ				
	TransCanada Storage Transportation Service Firm Withdrawal								
16	NCDA	Parkway	Union NCDA	13,704	GJ	31-Oct-2015			
17	WDA	Parkway	Union WDA	31,420	GJ	31-Oct-2015			
18	SSMDA	Dawn	Union SSMDA	35,022	GJ	31-Oct-2015			
19	NDA	Parkway	Union NDA	48,375	GJ	31-Oct-2015			
20	EDA	Parkway	Union EDA	68,520	GJ	31-Oct-2015	0.250		0.250
21	TCPL Firm STS Withdrawal - Total			197,041	GJ				
	TransCanada Storage Transportation Service Firm Injection								
22	NCDA	Union NCDA	Parkway	0	GJ	31-Oct-2015			0.000
23	WDA	Union WDA	Parkway	3,150	GJ	31-Oct-2015	0.840		0.840
24	SSMDA	Union SSMDA	Parkway	0	GJ	31-Oct-2015			
25	EDA	Union EDA	Parkway	47,571	GJ	31-Oct-2015			
26	NDA	Union NDA	Parkway	49,100	GJ	31-Oct-2015	0.358		0.358
27	TCPL Firm STS Injection - Total			99,821	GJ				
	Michigan Consolidated Gas Company (MichCon)/Great Lakes Gas Transmission (GLGT)/TransCanada Pipeline (TCPL)								
28	TCPL to Union SSMDA	S.S. Marie	Union SSMDA	6,143	GJ	31-Oct-2014	0.091		0.091
29	GLGT to TCPL	Belle River Mills	S.S. Marie	5,829	DTH	31-Oct-2014	0.080	0.009	0.089
30	MichCon to GLGT	MichCon Generic	Belle River Mills	5,829	DTH	31-Oct-2014	0.004		0.004
31	MichCon/GLGT/TCPL FT - Total			6,143	GJ		0.175	0.009	0.184
	Centra Transmission Holdings Inc.								
32	Centra Transmission Holdings Inc.	Spruce	Union MDA	169.95	10^3m^3	31-Oct-2014	0.221		0.221
33	Centra Pipelines Minnesota Inc.	Sprague	Baudette	6,000	MCF	31-Oct-2014	0.058		0.058
34	CTHI FT - Total			6,414	GJ		0.279		0.279

Exchange Rate 1 US =	1.0614	CAD
Conversion Factor	1.055056	
Heat Content	38.07	

UNION GAS LIMITED

Summary of Upstream Transportation Contracts - as at November 1, 2013
Southern Operations Areas

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date	Unitized Demand Charge ($Cdn/GJ)	Commodity Charge ($Cdn/GJ)	100% LF Toll ($Cdn/GJ)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h=f+g)
	TransCanada Pipeline								
1	Dawn to Union CDA FT	Dawn	Union CDA	60,000	GJ	31-Oct-2014	0.204		0.204
2	Empress to Union CDA FT	Empress	Union CDA	3,699	GJ	31-Oct-2015	1.541		1.541
3	Empress to Union CDA FT	Empress	Union CDA	1,004	GJ	31-Oct-2014	1.541		1.541
4	Empress to Union CDA FT	Empress	Union CDA	40,000	GJ	31-Oct-2014	1.541		1.541
5	Empress to Union CDA FT	Empress	Union CDA	1,979	GJ	31-Oct-2015	1.541		1.541
6	Empress to Union CDA FT	Empress	Union CDA	12,500	GJ	31-Dec-2015	1.541		1.541
7	Empress to Union CDA FT	Empress	Union CDA	8,145	GJ	31-Dec-2015	1.541		1.541
8	Niagara Falls to Kirkwall	Niagara Falls	Kirkwall	21,101	GJ	31-Oct-2022	0.142		0.142
9	TCPL FT - Total			148,428	GJ				
	Alliance Pipelines/Vector Pipelines								
10	Alliance	Northern Alberta	Cdn/US Interconnect	2,266.2	103M3	30-Nov-2015	0.861		0.861
11	Alliance (L.P.)	Cdn/US Interconnect	Vector	80,000	MCF	30-Nov-2015	0.621		0.621
12	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	80,000	DTH	30-Nov-2017	0.232	0.001	0.233
13	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,405	GJ	30-Nov-2017	0.019		0.019
14	Alliance/Vector - Total			84,405	GJ		1.732	0.001	1.734
	Panhandle Eastern Pipe Line Field Zone								
15	PEPL FT	Panhandle Field Zone	Ojibway (Union)	25,000	DTH	31-Oct-2017	0.428	0.044	0.471
16	PEPL FT	Panhandle Field Zone	Ojibway (Union)	2,000	DTH	31-Oct-2017	0.322	0.044	0.366
17	PEPL FT	Panhandle Field Zone	Ojibway (Union)	10,000	DTH	31-Oct-2014	0.236	0.044	0.280
18	PEPL - Total			39,307	GJ				
	Trunkline Gas Company/Panhandle Eastern Pipe Line								
19	Trunkline FT	East Louisiana	Bourbon	20,467	DTH	31-Oct-2017	0.116	0.014	0.130
20	PEPL EFT	Bourbon	Ojibway (Union)	20,000	DTH	31-Oct-2017	0.075	0.012	0.087
21	TGC/PEPL FT - Total			21,101	GJ		0.191	0.026	0.217
	Vector Pipelines								
22	Vector (L.P.) FT1	Chicago	Cdn/US Interconnect	81,000	DTH	30-Nov-2015			
23	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	85,460	GJ	30-Nov-2015			
24	Vector - Total			85,460	GJ		0.252	0.001	0.253
	Other:								
25	St.Clair Pipelines L.P. (St.Clair Pipeline)	St. Clair/Intl Border	St. Clair/Intl Border	214,000	GJ	31-Oct-2023			
26	St.Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Intl Border	Bluewater/Intl Border	127,000	GJ	31-Oct-2023			

Exchange Rate 1 US =	1.0614	CAD
Conversion Factor	1.055056	
Heat Content	38.07	

2013/14 Gas Supply Plan Memorandum
Appendix E

Summary of Union 's 2015 and 2016 TCPL New Capacity Open Season Bids

TCPL New Capacity Open Season for November 1, 2015

Service	Path	GJ/d	Purpose
Short-Haul Transportation	Parkway - Union EDA	75,000	Transition of existing long-haul transportation from Empress (58 TJ/d) and STS service (42 TJ/d) to Union EDA
Enhanced Market Balancing	Union EDA	25,000	
TOTAL Union EDA		**100,000**	

Short-Haul Transportation	Parkway - Union NDA	10,000	Transition of existing long-haul transportation from Empress to Union NDA
TOTAL Union NDA		**10,000**	

Total Bids - Union	**110,000**

TCPL New Capacity Open Season for November 1, 2016

Service	Path	GJ/d	Purpose
Short-Haul Transportation	Parkway - Union NDA	33,000	Transition of existing long-haul transportation from Empress to Union NDA
Short-Haul Transportation	Parkway - Union NDA	67,000	Replace upstream diversions to serve Union North on design day
TOTAL Union NDA		**100,000**	

Short-Haul Transportation	Kirkwall - Amended Union CDA	135,000	Service to Hamilton and Nanticoke gate stations
TOTAL Kirkwall - Amended Union CDA		**135,000**	

Short-Haul Transportation	Parkway - Union NDA, NCDA and EDA	29,115	Bid on behalf of Union North T-Service customers for Union's T-Service to Dawn Service
TOTAL T-Service		**29,115**	

Total Bids - Union and T-Service	**264,115**