uniongas
A Spectra Energy Company

May 5, 2016

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

Dear Ms. Walli:

Re: EB-2016-0118 – Union Gas Limited ("Union") – 2015 Disposition of Deferral Account Balances and 2015 Utility Earnings - CORRECTION

Please find attached Union's corrected evidence for the above noted proceeding.

Union corrected Tab 2, page 1 and Table 1 of its 2015 Deferrals Disposition and Utility Earnings evidence to correct Union's actual revenue sufficiency from utility operations as per Tab 2, Appendix A, Schedule 1.

If you have any questions concerning this correction, please contact me at (519) 436-5476.

Yours truly,

[Signed by Emily Pavli on behalf of]

Chris Ripley
Manager, Regulatory Applications

c.c.: EB-2015-0116 Intervenors
Crawford Smith (Torys)

April 19, 2016

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

Dear Ms. Walli:

Re: EB-2016-0118 - Union Gas Limited - 2015 Disposition of Deferral Account Balances and 2015 Utility Earnings

Enclosed is the application and evidence submitted by Union Gas Limited ("Union") concerning the final disposition and recovery of certain 2015 deferral account balances and earnings sharing amount.

Union is not proposing to dispose of DSM related deferral account balances in this proceeding. Union will file its DSM deferral account evidence following the completion of the 2015 audit of program results.

The Application is supported by evidence which is outlined below:

EXHIBIT A

Tab 1	2015 Deferral Account Balances
Tab 2	2015 Utility Results and Earnings Sharing
Tab 3	Allocation and Disposition of 2015 Deferral Account Balances and 2015 Earnings Sharing Amount
Tab 4	Incremental Transportation Contracting Analysis and Annual Stakeholder Meeting
Tab 5	April 13, 2016 Stakeholder Presentation

Union proposes that the impacts which result from the disposition of 2015 deferral account balances be implemented on October 1, 2016 to align with other rate changes implemented through the QRAM.

If you have any questions concerning this application and evidence please contact me at (519) 436-5476.

Yours truly,

[*Original Signed by*]

Chris Ripley
Manager, Regulatory Applications

c.c.: Crawford Smith (Torys)
EB-2015-0116 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 and sharing utility earnings pursuant to a Board-approved earnings sharing mechanism;

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-2014-0271, Union applied to the Ontario Energy Board (the "Board") 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, 2015. The Board approved Union's request. In doing so, the Board approved the continuation of certain deferral accounts.

4. The approved Incentive Regulation Mechanism ("IRM") provides for sharing if in any calendar year, Union's actual utility return on equity ("ROE") is more than 100 basis points over the 2013 Board-approved ROE of 8.93%.

5. Excess earnings between 100 basis points and 200 basis points would be shared 50/50 between Union and its customers. If, in any calendar year, Union's actual ROE is more than 200 basis points over the 2013 Board-approved ROE of 8.93%, then such earnings in excess of 200 basis points would be shared 90/10 between customers and Union.

6. Union's 2015 actual utility earnings did not exceed this threshold therefore there is no earnings sharing.

7. Union applies for the:

    a) approval of final balances for all 2015 deferral accounts as listed in Exhibit A, Tab 1, Appendix A, Schedule 1 and an order for final disposition of those balances.

8. Union also applies to the Board 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.

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

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

11. 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.

12. The address of service for Union is:

Union Gas Limited
P.O. Box 2001
50 Keil Drive North
Chatham, Ontario
N7M 5M1
Attention: Chris Ripley
Manager, Regulatory Applications

Telephone: (519) 436-5476

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: April 19, 2016

UNION GAS LIMITED

[Original signed by]

Chris Ripley
Manager, Regulatory Applications

2015 DEFERRAL ACCOUNT BALANCES

2015 Year-End Deferral Account Balances

Union has classified the deferral accounts approved by the Ontario Energy Board (the "Board") for use in 2015 into three groups:

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

The net balance in the above deferral accounts results in a $23.145 million debit from ratepayers. This total includes balances as at December 31, 2015. 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 March and 1.10% for the months April through December as prescribed by the Board in EB-2006-0117.

Tab 1, Appendix A, Schedule 1 provides a summary of the deferral account balances.

GAS SUPPLY DEFERRAL ACCOUNTS

Account No. 179-107 Spot Gas Variance Account

There is no balance in this deferral account. The account was created in accordance with the Board's Decision in the EB-2003-0063 proceeding to record the difference between the unit cost of spot gas purchased each month and the unit cost of gas included in the gas sales rates as approved by the Board on the spot volumes purchased in excess of planned purchases.

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 Quarterly Rate Adjustment Mechanism ("QRAM"). It has therefore been included in this submission. The debit balance of $0.388 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 2015 Board-approved rates included planned unutilized pipeline capacity of 6.3 PJ in Union North and 0 PJ in Union South. The UDC volumes included in rates is based on the Gas Supply Plan as filed in

Union's 2013 Cost of Service proceeding (EB-2011-0210), updated for the Normalized Average Consumption ("NAC") adjustment in 2014.

In Union North, UDC is part of planned operations due to the requirement to hold sufficient TransCanada Pipeline Limited ("TransCanada") firm transportation ("FT") capacity and other firm assets (both storage and transportation related) to meet design day needs. 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 also incur UDC in Union South, as well as additional UDC in Union North, to rebalance supply with lower demands. Union manages its Union North and Union South transportation 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 $5.629 million in rates for UDC during 2015 and recorded an associated interest credit of $0.010 million. Actual UDC costs in 2015 were $9.905 million offset by $3.260 million in released capacity value and further offset by a credit of $0.618 million related to a change in contracted capacity on Centra Transmission Holdings and Centra Pipeline Minnesota ("CTHI / CPMI"), resulting in a net cost of $6.027 million (please see Table 2).

The variance between the amounts collected in rates and the actual UDC costs, including an interest credit of $0.010 million, results in a net debit in the UDC Variance Account of $0.388 million (please see Table 1). The UDC costs and the credit related to a change in contracted capacity are described in more detail later in this evidence.

Table 1 provides the derivation of the UDC Variance Account balances by operations area.

Table 1
UDC Variance Account by Operational Area

Line No.	Particulars ($000's)	Union North	Union South	Total Franchise Area
1	UDC Collected in Rates	(5,629)	-	(5,629)
2	Net UDC Costs Incurred (Table 2)	4,582	1,445	6,027
3	Variance (line 2 - line 1)	(1,047)	1,445	398
4	Interest	(10)	-	(10)
5	(Credit) / Debit to Operations Area	(1,057)	1,445	388

A description of each item follows:

UDC Collected in Rates

2015 Board-approved rates include $5.580 million of UDC associated with planned unutilized pipeline capacity in Union North and $0 associated with planned unutilized pipeline capacity in Union South. The total cost of UDC in rates assumes TransCanada final tolls effective July 1, 2015 including the TransCanada abandonment surcharge. On an actual basis in 2015, Union recovered $5.629 million in Union North (due to higher throughput than forecast) and $0 in Union South.

UDC Costs Incurred

In 2015, the planned unutilized pipeline capacity reflected in the Gas Supply Plan was 12.1 PJ[1]. The actual unutilized capacity in 2015 was 13.4 PJ.

As indicated on Tab 1, page 7 of Union's April 2015 QRAM filing (EB-2015-0035), Union filled planned winter UDC and purchased 20.2 PJ of incremental spot gas to meet actual and forecast demands for the winter 2014/15. Due to changes in late season weather, the spot gas supply requirement was 13.2 PJ. The 7.0 PJ of spot gas purchased, but not ultimately required to cover the winter needs, reduced what would have otherwise been purchased for sales service customers in the summer of 2015.

Consequently, Union reduced purchases in the summer of 2015 by 7.0 PJ. In addition, planned unutilized pipeline capacity in the summer of 2015 was 6.5 PJ offset by supply requirements that were greater than forecast by 0.1 PJ resulting in total unutilized pipeline capacity of 13.4 PJ.

[1] EB-2015-0010, Exhibit A, Tab 5, 2014-2015 Gas Supply Plan Memorandum, Section 5.4.

The costs reflected in the UDC Variance Account are the total demand charges for unutilized pipeline capacity totaling $9.905 million offset, in part, by revenue generated from pipeline transportation releases totaling $3.260 million. Unutilized upstream transportation capacity due to supply that is ultimately not required, 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 as shown in Table 2.

Table 2
Net UDC Costs Incurred

Line No.	Particulars ($000's)	Costs
1	UDC Costs Incurred	9,905
2	Released Capacity Revenue	(3,260)
3	CTHI / CPMI Contracted Capacity Credit	(618)
4	Net UDC Costs (Credit)/Debit	6,027

In addition, consistent with the approach in 2013 and 2014 deferrals, Union has reflected a credit of $0.618 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 MDA is connected to the TransCanada Mainline at the Spruce interconnect in the TransCanada Centra MDA by CTHI / CPMI. In Union's 2013 Cost of Service filing (EB-2011-0210), Union reflected the then contracted capacity on CTHI / CPMI of 8,473 GJ/d. Union has since reduced the contracted capacity on these pipelines to 5,572 GJ/d for a reduction of 2,143 GJ/d effective November 1, 2012 and a further reduction of 758 GJ/d effective November 1, 2014. The reduction in costs for this contract is $0.618 million in 2015 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 Direct Purchase ("DP") customers. The credit will be booked on an ongoing basis each month until such time that Union can reflect the updated volumes in Union's 2017 Rates application.

Interest

Interest associated with UDC amounted to a credit of $0.010 million for Union North and $0 for Union South for a net credit of $0.010 million.

(Credit)/Debit to Operations areas

The UDC Variance Account has a net total debit balance of $0.388 million. The balance of $0.388 million is allocated to Union North and Union South in proportion to the actual excess supply and costs incurred for UDC for each respective area. The balance applicable to sales service and bundled DP customers in Union North is a credit of $1.057 million, and a debit of $1.445 million applicable to sales service customers in Union South.

Account No. 179-128 Gas Supply Review Consultant Cost

There is no balance in this deferral account. Union will request closure of this account as part of its 2017 Rates application.

Account No. 179-131 Upstream Transportation Optimization

The Upstream Transportation Optimization Deferral Account was approved by the Board in its EB-2011-0210 Decision to capture the variance between 90% of the net revenues from optimization activities and the amount refunded to ratepayers in rates. The balance in this deferral account is a debit of $8.600 million.

In setting rates for 2015, the Board approved a forecast of optimization revenue of $14.918 million[2]. 90% of that amount, or $13.426 million, was credited to ratepayers in the Board-approved 2015 rates.[3] On an actual basis, consistent with the method approved in its EB-2011-0210 Decision and Rate Order, Union credited $15.565 million in rates to ratepayers during 2015, $2.139 million greater than the Board-approved amount of $13.426 million. The credit is due to Union's actual sales service volumes exceeding the forecast sales service volumes in rates.[4]

Union earned $7.739 million in net revenues from upstream transportation optimization during 2015. Per the Board-approved sharing methodology, 90% of this net revenue, or

[2] EB-2014-0271, Draft Rate Order, Working Papers, Schedule 14, p. 1.
[3] EB-2014-0271, Draft Rate Order, Working Papers, Schedule 14, p. 1.
[4] EB-2011-0210, Decision and Rate Order, p. 16.

$6.965 million, is to be credited to customers. As stated above, $15.565 million has already been credited through rates; therefore, $8.600 million ($6.965 million less $15.565 million) is to be collected from ratepayers through this deferral account disposition.

Tab 1, Appendix A, Schedule 2 provides a summary of the calculation of the amount in this deferral account. Union's 2015 actual Upstream Transportation Optimization revenue is lower than 2013 Board-approved revenue primarily because of the elimination of the TransCanada FT-RAM program.

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 and C1 Short-Term Firm Peak Storage. 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 $0.508 million. The balance is calculated by comparing $4.043 million (90% of the actual 2015 Short-Term Storage and Other Balancing Services net revenue of

$4.492 million) to the net revenue included in rates of $4.551 million in the EB-2011-0210 Rate Order. The details of the balance are found at Tab 1, Appendix A, Schedule 3.

Actual 2015 revenues from C1 Off Peak Storage, Gas Loans and all other Balancing services of $1.924 million were $0.576 million lower than the 2013 Board-approved forecast of $2.500 million.

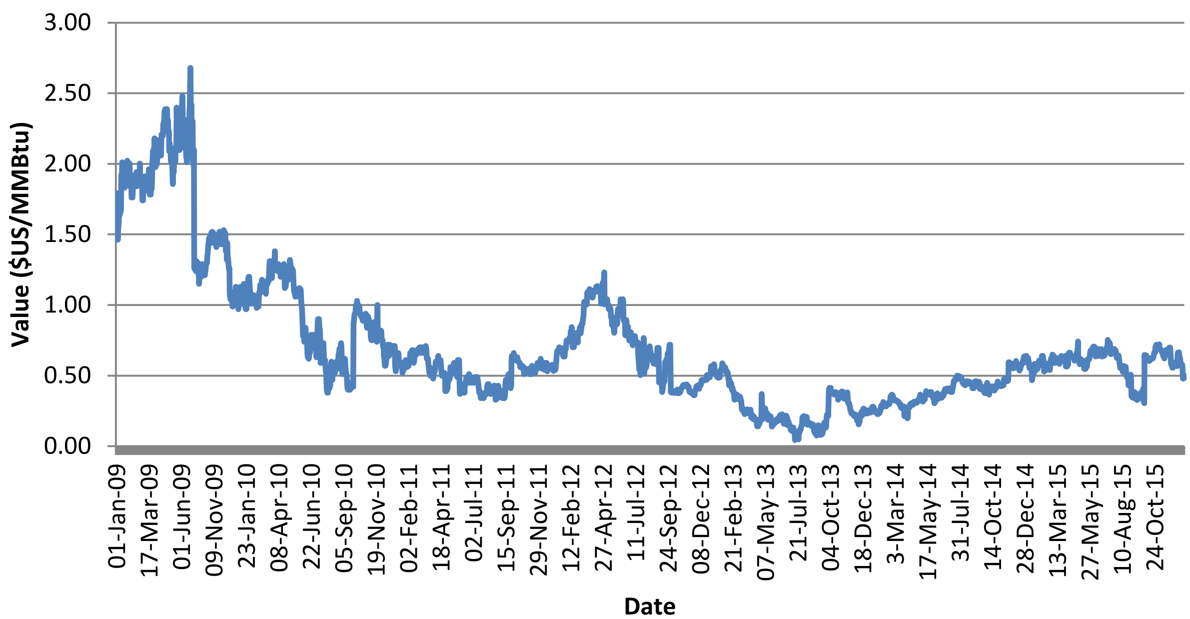
The C1 Short-Term Firm Peak Storage revenues (Utility) of $4.935 million were $2.948 million lower than the 2013 Board-approved forecast of $7.883 million. The difference between the Board-approved forecast revenue for 2013 and the actual revenue in 2015 was due to a decrease in excess utility storage capacity available for sale. Actual utility requirements were higher in 2015 which reduced the amount available for sale as C1 Short-Term Firm Peak Storage for 2015/2016 winter (5.0 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 the sale of short-term storage.

The increase in the actual utility storage requirement of 1.4 PJ in 2015 (resulting in a decrease in the C1 Short-Term Peak Storage available for sale from 6.4 PJ in 2014 to 5.0 PJ in 2015) is a result of increases in consumption in both the general service and the contract markets. The general service market required 0.2 PJ of additional storage in

2015 over the Board-approved amount due to growth in the number of customers. The contract market required 1.2 PJ of additional storage over the Board-approved amount due to increased production activity by industrial customers. The storage requirement for the general service market was calculated using the Board-approved aggregate excess methodology and the storage requirement for the contract market was calculated using either the Board-approved aggregate excess methodology or the 15 X obligated Daily Contracted Quantity ("DCQ") storage methodology.

The 2013 Board-approved forecast implied an annual average value for C1 Short-Term Firm Peak Storage of \$0.70/GJ (\$7.883 million/11.3 PJ), and the actual average annual C1 Short-Term Firm Peak Storage value in 2015 was \$0.99/GJ (\$4.935 million/5.0 PJ) please see Figure 1 for Short-Term Peak Storage values in US dollars.

Figure 1
Historical Short -Term Firm Peak Storage Values at Dawn 2009-2015



Non-Utility Storage Balances for 2015

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

Tab 1, Appendix A, Schedule 4 shows the non-utility inventory balances for October and November of 2015.

During the 2015 injection season, the non-utility storage balance peaked on November 19, 2015 at 97% of available space with a balance of 84.5 PJ compared to available space of 86.8 PJ. At October 31, 2015 (the date to which Union manages its storage balance), the non-utility balance was 91% of available space. Due to warmer than normal weather, customers injected into storage throughout November. The balance stayed below the total non-utility available space of 100% for the rest of 2015.

In 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. There was no encroachment of utility space in 2015 and therefore no calculation applies.

Sale of Non-Utility Storage Space

Union prioritizes the sale of its utility storage ahead of the sale of its short-term non-utility storage and allocates short-term peak storage margins between utility and non-utility as directed by the Board in EB-2011-0210, Decision and Order, pp. 116-117. Margins from short-term peak storage services are proportionately split 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 include any sale of storage space for a term of less than two years.

In 2015, Union sold a total of 5.0 PJ of short-term peak storage. The total 5.0 PJ was excess utility space, calculated by deducting 95.0 PJ of in-franchise utility requirement (as per Union's Gas Supply Plan) from the total 100 PJ of in-franchise utility storage. There was no sale of short-term peak storage from non-utility space.

Total revenue from the sale of C1 Short-Term Peak Storage (Utility) in 2015 was $4.935 million.

Details of the above sales are reflected in Tab 1, Appendix A, Schedule 5.

Other Deferral Accounts

Account No. 179-103 Unbundled Services Unauthorized Storage Overrun

There is no balance in this deferral account. The account was created in accordance with the Board's Decision in the RP-1999-0017 proceeding to record any unauthorized storage overrun charges incurred by customers electing unbundled service.

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.

The GDAR capital costs are made up of the costs associated with three separate Notice of Amendments to a Rule:

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 capital costs relating to the three Amendments to a Rule discussed above can be found at Table 3. The costs include those associated with incremental internal resources and expenses as well as Contractor services. Union's retail CIS system, Banner, is an outsourced solution provided by Vertex Business Services ("Vertex"). 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.

Table 3
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	1,130	258	459	1,847
3	Total Costs	$1,475	$278	$468	$2,221

Consistent with Union's 2013 and 2014 Deferrals Disposition proceedings (EB-2014-0145 and EB-2015-0010), Union replaced the capital costs with the annual revenue requirement related to the capital costs as outlined in Table 4. Accordingly, the 2015 GDAR Deferral Account has a debit balance of $0.760 million. The revenue requirement will continue to be included in the respective future deferral disposition proceedings.

Table 4
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

There is no balance in this deferral account. 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 Demand Side Management ("DSM") activities.

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

There is no balance in this deferral account. The account was created in accordance with the Board's Decision in the EB-2010-0039 proceeding to remove from the deferral account the capital costs associated with upgrading Union's accounting system in order to report results under IFRS.

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 2015 CDM Deferral Account is a credit of $0.213 million, which includes 50% of total net revenues of $0.422 million, plus interest of $0.002 million.

In 2015 Union delivered three 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"); and,
3) Commercial Conservation Account Management ("CCAM").

HPNC2 is an Independent Electricity System Operator ("IESO") -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 contracted with Hydro One Networks Inc. to deliver HPNC2 in 2015.

KAM is an IESO-funded CDM program meant to assist major industrial customers (average monthly peak demand greater than 5MW) in developing capital projects that support industrial energy management and electricity efficiency. Union contracted with Hydro One Networks Inc. to deliver the KAM services in 2015.

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 in 2015.

Table 5 shows the CDM net revenues for 2015 by program.

Table 5
2015 CDM Net Revenues by Program

Line No.	Particulars ($000's)	HPNC2	KAM	CCAM	Total
1	Revenues	242	708	1,182	2,132
2	Costs	164	592	954	1,710
3	Net Revenues	78	116	228	**$422**
4				50% to ratepayer	$211
5				50% to shareholder	$211

Account No. 179-132 Deferral Clearing Variance Account

The Deferral Clearing Variance Deferral Account was approved by the Board in its EB-2014-0145 Decision. The purpose of the account is to capture the differences between the forecast volumes and the actual volumes associated with the disposition of deferral account balances. The deferral account is intended to eliminate the gains or losses to ratepayers and Union as a result of volume variances associated with the disposition of deferral account balances.

The deferral account has a debit balance of $3.141 million plus interest of $0.013 million. This balance represents an over-refund of $2.317 million compared to the Board-approved deferral account balances in Union’s 2013 Deferral Account Disposition (EB-2014-0145) and an under-recovery of $0.824 million for the Board-approved deferral account balances in Union’s 2013 Demand Side Management (“DSM”) Deferral Account Disposition proceeding (EB-2014-0273). Details are reflected in Tab 1, Appendix A, Schedule 7.

Union’s 2013 Deferral Account Disposition (EB-2014-0145)

In its EB-2014-0145 Decision, the Board approved the prospective disposition to rate classes of the total balances in the Board-approved deferral accounts through a temporary rate adjustment from January 1, 2015 and June 30, 2015. The total amount approved for prospective refund to rate classes was a credit of $19.979 million. Please see Tab 1, Appendix A, Schedule 7, page 2, column (e), based on the forecasted volumes as noted in column (a).

Actual volumes for the period January 1, 2015 to June 30, 2015 averaged approximately 14% higher than forecast due to colder weather in the first three months of 2015. As a result of the actual volumes being greater than the forecasted volumes, Union refunded $22.296 million, or $2.317 million to ratepayers in excess of the deferral account balances approved for prospective disposition in EB-2014-0145. Please see Tab 1, Appendix A, Schedule 7, page 2, column (f) for the actual disposition of deferral accounts and column (g) for the variance between forecast and actual disposition.

Union's 2013 DSM Deferral Account Disposition (EB-2014-0273)

In its EB-2014-0273 Decision, the Board approved the prospective disposition of Union's 2013 DSM deferral account balances to general service rate classes. Union was directed to dispose of the deferral account balances to general service rate classes through a temporary rate adjustment beginning with its next QRAM application. Accordingly, the amount to be collected from ratepayers was processed as part of Union's July 1, 2015 QRAM Application (EB-2015-0187).

As described at EB-2015-0187, Appendix E, p. 3, the prospective disposition of the 2013 DSM deferral account balances to general service rate classes was based on forecast volumes from July 1, 2015 to December 31, 2015. The total balance to be recovered from general service rate classes was $5.522 million. Please see Tab 1, Appendix A, Schedule 7, page 3, column (e), based on the forecasted volumes as noted in column (a).

Actual volumes for the period July 1, 2015 to December 31, 2015 averaged approximately 15% lower than forecast due to warmer weather in the last two months of 2015. As a result of the actual volumes being lower than the forecast volumes, Union only recovered $4.698 million, or $0.824 million less than the amount approved for disposition in EB-2014-0273. Please see Tab 1, Appendix A, Schedule 7, page 3, column

(f) for the actual disposition of deferral accounts and column (g) for the variance between forecast and actual disposition.

Account No. 179-133 Normalized Average Consumption ("NAC")

The purpose of the NAC Deferral Account is to record the variance in delivery revenue, storage revenue and costs resulting from the difference between the target NAC included in Board-approved rates and the actual NAC for general service rate classes Rate M1, Rate M2, Rate 01 and Rate 10. As described in Union's 2014 Deferral Account Disposition proceeding (EB-2015-0010), including the revenue from storage rates in the NAC Deferral Account requires Union to include storage-related costs associated with the difference in target and actual NAC.

For 2015, the balance in the NAC Deferral Account is a debit from ratepayers of $10.499 million plus interest of $0.047 million for a total of $10.546 million.

The NAC Deferral Account follows the same methodology agreed to by parties in Union's 2014-2018 Incentive Regulation ("IR") Settlement Agreement (EB-2013-0202) and subsequently modified in Union's 2015 Rates proceeding (EB-2014-0271).

Target and Actual NAC

The 2015 target NAC for each rate class was approved by the Board in Union's 2015 Rates proceeding (EB-2014-0271). The 2013 actual NAC, weather normalized using the 2015 weather normal, was used to determine the 2015 target NAC. Setting the 2015 target NAC based on the 2013 actual NAC recognizes that over the two-year span to the current year, any saved volumes and associated lost revenues due to DSM activities will be captured by the variance between the target and actual consumption. This is due to the inclusion of the DSM saved volumes within the actual reported consumption.

The 2015 actual NAC for each rate class is weather normalized using the 2015 weather normal, which is based on the Board-approved 50:50 blended weather methodology, incorporating both the 30-year average and 20-year declining trend estimates of annual heating degree-days.

Table 6 provides the 2015 target and 2015 actual NAC by rate class.

Table 6
2015 Target and Actual NAC (m^3/customer)

Line No.		Rate 01	Rate 10	Rate M1	Rate M2
		(a)	(b)	(c)	(d)
1	2015 Target NAC	2,901	169,025	2,761	169,121
2	2015 Actual NAC	2,799	162,078	2,676	163,129
3	Change in NAC (Target - Actual NAC)	102	6,947	85	5,992

Delivery and Storage Revenues

The deferral account balance is calculated by multiplying the variance between the weather normalized target NAC and the weather normalized actual NAC by the 2013 Board-approved number of customers and the 2015 Board-approved delivery and storage rates for each general service rate class. A credit balance in the NAC Deferral Account reflects that the actual NAC is greater than the target NAC, while a debit balance in the NAC Deferral Account reflects that the actual NAC is less than the target NAC.

Table 7 provides the NAC Deferral Account balances by rate class.

Table 7
2015 NAC Deferral Account

Line No.	Particulars ($000s)	Rate 01	Rate 10	Rate M1	Rate M2	All Rates
		(a)	(b)	(c)	(d)	(e)
1	Delivery Revenue Balances	2,819	747	3,211	1,353	8,130
2	Storage Revenue Balances	1,270	397	669	262	2,598
3	Storage Cost Balances	166	(122)	797	(1,070)	(229)
4	Interest	21	4	22	-	47
5	Total NAC Deferral Balance	4,276	1,026	4,699	545	10,546

Storage Costs

The storage costs recognize that variances between the 2015 target NAC and the 2013 Board-approved NAC volumes change the storage requirements for each general service rate class. As Union’s Board-approved storage rates during the IR term are not updated to reflect changes in storage requirements due to NAC variances, Union must capture the

NAC-related change in storage costs in the NAC Deferral Account as per the Board's Decision in Union's 2013 Deferrals Disposition proceeding (EB-2014-0145), p. 9, *"starting in 2014, the NAC Deferral Account, which replaces the Average Use Per Customer Deferral Account, will include storage related revenues and costs for general service rate classes."*

To determine the change in storage requirements for each general service rate class due to NAC variances, Union calculated the NAC volume variance between its 2015/2016 Gas Supply Plan and the 2013 Board-approved volumes multiplied by the 2013 Board-approved number of customers.

Using the Board-approved aggregate excess methodology, Union then calculated the change in storage requirements for each of the general service rate classes due to variances in NAC. The storage requirements for general service rate classes effective November 1, 2015 are determined using the 2015/2016 Gas Supply Plan volumes which represent the April 1, 2015 to March 31, 2016 period. These general service rate class storage requirements are then used in the calculation of the total in-franchise utility storage space requirement at November 1, 2015. The difference between the total in-franchise utility storage requirement and the total 100 PJ of utility storage represents the excess utility storage capacity available for sale ("excess utility space") at November 1, 2015.

For Rate M1, the NAC volume variance between the 2015/2016 Gas Supply Plan and the 2013 Board-approved volumes was a decrease of 1.89 PJ. The majority of the NAC volume decrease occurred in the summer months, which increased the Rate M1 storage requirement by 1.12 PJ. This resulted in increased storage costs of $0.797 million (please see Table 7, line 3, column c).

For Rate M2, the NAC volume variance between the 2015/2016 Gas Supply Plan and the 2013 Board-approved volumes was an increase of 7.54 PJ. The majority of the NAC volume variance increase occurred in the summer months, which decreased the Rate M2 storage requirement by 1.50 PJ and resulted in decreased storage costs of $1.070 million (please see Table 7, line 3, column d).

For Rate 01, the NAC volume variance between the 2015/2016 Gas Supply Plan and the 2013 Board-approved volumes was an increase of 1.67 PJ. The NAC volume variance increase was slightly higher in the winter months than the summer, which increased the Rate 01 storage requirement by 0.20 PJ and increased storage costs by $0.166 million (please see Table 7, line 3, column a).

For Rate 10, the NAC volume variance between the 2015/2016 Gas Supply Plan and the 2013 Board-approved volumes was an increase of 1.48 PJ. The majority of the NAC volume variance increase occurred in the summer months, which decreased the Rate 10 storage requirement by 0.15 PJ and resulted in decreased storage costs of $0.122 million (please see Table 7, line 3, column b).

Overall, the NAC volume variance between the 2015/2016 Gas Supply Plan and the 2013 Board-approved volumes resulted in a decrease in general service storage requirements of 0.33 PJ (0.38 PJ in Union South offset by 0.05 PJ in Union North). Accordingly, Union has included a storage cost credit of $0.229 million, related to the volume variance, in the NAC Deferral Account. Please see Table 8 for a summary of the change in general service storage requirements due to NAC volume variances by rate class.

Table 8
Change in General Service Storage Requirements from 2013 Board-approved
(Based on weather normalized NAC)

(PJ)			
Rate M1	1.12	Rate 01	0.20
Rate M2	(1.50)	Rate 10	(0.15)
Total South	(0.38)	Total North	0.05

The reduction in storage activity has decreased storage deliverability costs, the commodity-related costs at Dawn and storage inventory carrying costs.

The 0.33 PJ reduction in general service storage requirements due to NAC volume variances forms part of the 5.0 PJ of excess utility space available for sale for winter

2015/2016. The revenue from the sale of the 5.0 PJ of excess utility space is recorded in the Short-Term Storage and Other Balancing Deferral Account (Account No. 179-70).

Deferral Account Impacts

The detailed calculation of the NAC Deferral Account balance can be found at Tab 1, Appendix A, Schedule 6.

For Rate M1, actual NAC is less than target NAC by 85 m^3/customer (please see Table 6). This results in a delivery and storage revenue charge of $3.880 million ($3.211 million and $0.669 million respectively) (please see Table 7, line 1 and 2). In addition, the NAC volume variance increases the Rate M1 storage requirement by 1.12 PJ. Accordingly, Union must recover an additional $0.797 million (Table 7, Line 3) to recognize the increase in Rate M1 storage requirements.

For Rate M2, actual NAC is less than target NAC by 5,992 m^3/customer (please see Table 6). This results in a delivery and storage revenue charge of $1.615 million ($1.353 million and $0.262 million respectively) (please see Table 7, line 1 and 2). In addition, the NAC volume variance decreases the Rate M2 storage requirement by 1.50 PJ. Accordingly, Union must refund $1.070 million (Table 7, Line 3) to recognize the decrease in Rate M2 storage requirements.

For Rate 01, actual NAC is less than target NAC by 102 m^3/customer (please see Table 6). This results in a delivery and storage revenue charge of $4.089 million ($2.819 million and $1.270 million respectively) (please see Table 7, line 1 and 2). In addition, the NAC volume variance increased the Rate 01 storage requirement by 0.20 PJ. Accordingly, Union must recover an additional $0.166 million (Table 7, Line 3) to recognize the increase in Rate 01 storage requirements.

For Rate 10, actual NAC is less than target NAC by 6,947 m^3/customer (please see Table 6). This results in a delivery and storage revenue charge of $1.144 million ($0.747 million and $0.397 million respectively) (please see Table 7, line 1 and 2). In addition, the NAC volume variance decreases the Rate 10 storage requirement by 0.15 PJ. Accordingly, Union must refund $0.122 million (Table 7, Line 3) to recognize the decrease in Rate 10 storage requirements.

Account No. 179-134 Tax Variance Deferral Account

The establishment of the Tax Variance Deferral Account was approved through the EB-2013-0202 Settlement Agreement. The purpose of this account is to record 50% of the variance in costs resulting from the difference between the actual tax rates and the approved tax rates included in rates as approved by the Board. For 2015, there is no impact related to income tax, however, a credit balance of $0.060 million is included in the deferral account related to Harmonized Sales Tax ("HST") changes as discussed below.

On July 1, 2010, HST came into effect in Ontario, combining provincial and federal taxes. On July 1, 2015, the input tax credit ("ITC") recapture for compressor fuel costs, and certain Operations and Maintenance ("O&M") and capital costs, was reduced as follows:

- 100% for the period from July 1, 2010 to June 30, 2015;
- 75% for the period from July 1, 2015 to June 30, 2016;
- 50% for the period from July 1, 2016 to June 30, 2017;
- 25% for the period from July 1, 2017 to June 30, 2018; and,
- 0% on or after July 1, 2018.

As this constitutes a change in tax rates, Union is proposing to include 50% of the annual incremental savings in the Tax Variance Deferral Account until Union's next rebasing since Union's HST Deferral Account used for the 2010 implementation of HST is closed. The annual balance is expected to grow until rebasing in proportion to the timeline of tax changes above.

To calculate the 2015 Tax Variance Deferral Account balance related to HST changes, Union reviewed its transactions from July 1 to December 31, 2015 for:

a) Capital and O&M purchases that are subject to the ITC recapture reduction including specified Meals and Entertainment costs, specified Road Vehicles and related Fuel costs, specified Energy costs, and specified Telecommunications costs; and,

b) Compressor Fuel costs.

For 2015, the Tax Variance Deferral Account is a credit balance of $0.060 million. The calculation of the balance is provided in Table 9.

Table 9
50% of 2015 Net Savings from the Impact of HST Changes
to be Shared with Ratepayers

Line No.		Particulars ($000's)
1	Capital Savings	0.001
2	O&M Savings	0.059
3	Compressor Fuel Savings	0.000
4	Tax Variance Deferral Account Balance	$0.060

Account No. 179-135 Unaccounted for Gas ("UFG") Volume Deferral

There is no balance in this account. The establishment of the UFG Volume Deferral Account was approved through the EB-2013-0202 Settlement Agreement. The purpose of this account is to capture the difference between Union's actual UFG costs and Board-approved UFG costs included in Union's rates, related to UFG volumes variances as a percentage of throughput volumes (please see Table 10, line 6). The amount of the UFG volume deferral account to be cleared to customers is subject to a symmetrical dead-band of $5 million, with amounts within such dead-band being to Union's account only. For 2015, Union's actual UFG expense had a UFG percent volume variance of $3.6 million lower (favourable) than Board-approved. There is no balance in the UFG Volume Deferral Account for 2015 because this year-end variance is within the $5 million threshold.

Table 10
2015 UFG Variances from Board-approved

Line No.	Particulars ($ Millions)	2015 Actual (a)	Board-approved (b)	Variance (c) = (b – a)
1	Gross UFG Expense	10.5	14.7	4.2
2	Less: UFG Allocation to Non-Utility	(1.4)	(1.3)	0.1
3	Net UFG Utility Expense	9.1	13.4	4.3
	Variance Analysis			
4	Price Variance (1)			0.4
5	Throughput Variance			0.2
6	UFG % Volume Variance (2)			3.6
7	Non-Utility Allocation Variance			0.1
8	Total UFG Variance			4.3

(1) Reference Price included in Board-approved was $210.506 / 10^3m^3
2015 Actual Reference Prices by quarter were $218.866, $194.138, $198.417 and $198.147 / 10^3m^3.

(2) Board-approved UFG percent is 0.219% versus actual UFG percent of 0.17% for 2015. This is subject to Deferral Account when greater than +/- $5 million.

Account No. 179-136 Parkway West Project Costs

In its EB-2012-0433 Decision, the Board approved the establishment of the Parkway West Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Parkway West Project and the revenue requirement included in rates.

The deferral account has a total credit balance of $0.334 million. This balance consists of a $0.319 million credit, which represents the difference between the $6.373 million included in 2015 Rates (EB-2014-0271) and the calculation of the actual revenue requirement for 2015 of $6.054 million as shown in Table 11. The remaining $0.015 million credit represents a true-up to the 2014 revenue requirement of a $0.751 million credit included in the 2014 Deferral Disposition (EB-2015-0010) and the recalculated actual 2014 revenue requirement of a $0.766 million credit to adjust the long-term debt rate from the estimate of 4.0% to the actual of 3.82%.

2015 Deferral Balance

Table 11
2015 Parkway West Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2015 Board-approved (a)	2015 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	144,652	131,930	(12,722)
2	Average Investment	102,133	103,750	1,617
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses	739	294	(445)
4	Depreciation Expense (1)	3,026	3,071	45
5	Property Taxes	290	135	(155)
6	Total Operating Expenses	4,055	3,500	(555)
7	Required Return (2)	5,898	5,872	(26)
8	Total Operating Expense and Return	9,953	9,372	(581)
	Income Taxes:			
9	Income Taxes - Equity Return (3)	1,182	1,203	21
10	Income Taxes - Utility Timing Differences (4)	(4,762)	(4,521)	241
11	Total Income Taxes	(3,580)	(3,318)	262
12	Total Revenue Requirement	6,373	6,054	(319)

Notes:

(1) Depreciation expense at 2013 Board-approved depreciation rates.

(2) The required return assumes a capital structure of 64% long-term debt at 3.82% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2015 required return calculation is as follows:

$103.750 million * 64% * 3.82% = $2.537 million plus

$103.750 million * 36% * 8.93% = $3.335 million for a total of $5.872 million.

(3) Taxes related to the equity component of the return at a tax rate of 26.5%.

(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

Capital Expenditures

The actual capital expenditures on 2015 in-service assets were $12.722 million less than the 2015 Board-approved as shown in Table 12.

Table 12
Parkway West Capital Expenditures

Line No.	Particulars ($000's)	2015 Board-approved (a)	2015 Actuals (b)	Difference (c) = (b - a)
1	Land & Easement	-	-	-
2	Station Infrastructure	27,220	29,761	2,541
3	Pipeline Replacement	569	20	(549)
4	Dawn-Parkway Valve Nest	-	3,908	3,908
5	Station Header	18,909	11,453	(7,456)
6	Enbridge Measurement	718	379	(339)
7	Interconnect/TransCanada	17,666	13,788	(3,878)
8	LCU Compressor	79,570	72,621	(6,949)
9	Total Capital Expenditures	144,652	131,930	(12,722)

Station infrastructure costs were $2.541 million higher than the costs included in the 2015 Board-approved rates due to a delay in placing the administration building into service until 2015, originally estimated for 2014. Increased labour costs were also realized due to permitting and site plan approval delays.

The NPS 26 and NPS 34 pipeline replacement costs were $0.549 million lower than the costs included in the 2015 Board-approved rates due to site restoration being completed in 2014.

Dawn-Parkway valve nest costs were $3.908 million higher than the costs included in the 2015 Board-approved rates due to delay in placing the connection of the 48" pipeline into service in 2015 originally estimated for 2014.

The station headers costs were $7.456 million lower than the costs included in the 2015 Board-approved rates. This was associated with a portion of the station header put into service in 2014 which was necessary to service the Enbridge measurement facilities. Increase in material and labour costs were offset by contingencies.

Interconnect/TransCanada measurement station costs were $3.878 million lower than the costs included in the 2015 Board-approved rates. This was a result of the project scope changing from an NPS 42" interconnect pipeline between the Parkway West site and the Parkway East TransCanada measurement site to a new measurement station at the Parkway West site. Higher material costs were offset by lower labour costs and contingencies.

The Loss of Critical Unit ("LCU") Compressor costs were $6.949 million lower than the costs included in the 2015 Board-approved rates. Design of this compressor station was not yet complete at the time of the project estimate. The main contract labour and design costs increased compared to the estimate however these were more than offset by lower costs for permitting, site supervision and contingencies. Interest during construction was lower due to rate reduction and timing of spend.

Average Investment

The average investment has increased by $1.617 million over the costs included in the 2015 Board-approved rates due to in-service timing and capital expenditure differences.

As noted in Union's 2014 Deferral Disposition proceeding (EB-2015-0010), capital expenditures for the Parkway West Project were $6.951 million higher in 2014 than the Board-approved capital expenditures. This has the effect of raising the opening balance in 2015 for purposes of calculating the average investment.

This is offset by the reduced capital spend in 2015 and the fact that the monthly timing differences from the original estimate were lower in 2015 as certain compressor and pipeline components were put into service in November 2015 rather than the original October 2015 estimate.

Operating Expenses

Operating and maintenance expenses were $0.445 million lower than the costs included in the 2015 Board-approved rates. The decrease is due to the timing of staff additions compared to the costs in rates and the inclusion of maintenance costs in 2015 rates that were not incurred in 2015 for the project.

The increase in depreciation expense of $0.045 million relates to a full year's depreciation expense on assets put into service in 2014 in excess of those included in 2014 rates (2014 Actual - $80.9 million; 2014 rates - $73.9 million) offset by lower depreciation expense on lower actual capital expenditures in 2015 than included in 2015 rates.

The $0.155 million property tax decrease relates to the assessed value of the Parkway West land. The estimate of $0.290 million in the 2015 Board-approved rates was based on an assumption that the land would have a commercial assessed value and a commercial tax rate. The Municipal Property Tax Assessment Corporation did not reassess the land in 2015 and actual property taxes for 2015 were based on a farmland assessed value and a residential tax rate. It is expected that the reassessment will occur in 2016.

Required Return

The decrease in the required return of $0.026 million is the result of a decrease in the long-term debt rate used in the calculation offset by an increase in the average investment. The Board-approved required return calculation was derived using a capital structure of 64% long-term debt at 4%, and 36% equity at the Board-approved rate of return of 8.93%. The 2015 actual required return calculation was derived using a capital structure of 64% long-term debt at 3.82% and 36% equity at the Board-approved rate of return of 8.93%.

When Union prepared the Parkway West Project application (EB-2012-0433) the long-term debt rate used was 4.0%. In 2015, when the project was brought into service, Union issued debt which reduced the average long-term debt rate to 3.82%. This rate will be used to calculate the debt portion of the utility required return through to and including 2018.

Income Taxes

Union's actual tax rate for 2015 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $0.021 million "Income Taxes-Equity Return" increase relates to an increase in the tax impact of the equity component of the required return resulting from an increase in average investment.

The $0.241 million "Income Taxes-Timing Differences" increase relates to a lower Capital Cost Allowance deduction due to lower actual capital expenditures than included in 2015 Board-approved rates.

Account No. 179-137 Brantford-Kirkwall/Parkway D Project Costs

In its EB-2013-0074 Decision, the Board approved the establishment of the Brantford-Kirkwall/Parkway D Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Brantford-Kirkwall/Parkway D Project and the revenue requirement included in rates.

The deferral account has a debit balance of $0.579 million, which represents the difference between the $0.077 million credit included in 2015 rates (EB-2014-0271) and the calculation of the actual revenue requirement for 2015 of a $0.502 million as shown in Table 13.

Table 13
2015 Brantford-Kirkwall/Parkway D Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2015 Board-approved (a)	2015 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	200,069	188,042	(12,027)
2	Average Investment	23,533	24,171	638
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses (1)	107	-	(107)
4	Depreciation Expense (2)	2,622	2,364	(258)
5	Property Taxes (3)	142	157	15
6	Total Operating Expenses	2,871	2,521	(350)
7	Required Return (4)	1,359	1,368	9
8	Total Operating Expense and Return	4,230	3,889	(341)
	Income Taxes:			
9	Income Taxes - Equity Return (5)	272	280	8
10	Income Taxes - Utility Timing Differences (6)	(4,580)	(3,667)	912
11	Total Income Taxes	(4,307)	(3,387)	920
12	Total Revenue Requirement (7)	(77)	502	579

Notes:

(1) O&M expenses include $0.012 million for pipeline related O&M and $0.630 million of annual Compressor maintenance. Parkway

(2) Depreciation expense at 2013 Board-approved depreciation rates.

(3) Property taxes include $0.187 million for compression and $0.665 million for pipeline and building taxes.

(4) The 2015 required return assumes a capital structure of 64% long-term debt at 3.82% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2015 required return calculation is as follows:

$24.2 million * 64% * 3.82% = $0.591 million plus

$24.2 million * 36% * 8.93% = $0.777 million for a total of $1.368 million.

(5) Taxes related to the equity component of the return at a tax rate of 26.5%.

(6) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

(7) As per EB-2013-0074 Schedule 10-1 Line 9.

Capital Expenditures

The actual capital expenditures on 2015 in-service assets decreased by $12.027 million compared to the 2015 Board-approved as shown in Table 14.

Table 14
Brantford-Kirkwall Pipeline/Parkway D Compressor Capital Expenditures

Line No.	Particulars ($000's)	2015 Board-approved (a)	2015 Actuals (b)	Difference (c) = (b - a)
Brantford-Kirkwall Pipeline				
1	Land Rights	8,634	9,077	443
2	Pipelines	83,921	91,141	7,220
Parkway D Compressor				
3	Structures	3,502	3,170	(332)
4	Compressor Equipment	104,012	84,654	(19,358)
5	Total Capital Expenditures	200,069	188,042	(12,027)

Land rights costs were $0.443 million higher than the costs included in the 2015 Board-approved rates due to the estimate being based on preliminary estimates compared to the actual negotiations with landowners.

Pipelines costs were $7.220 million higher than the costs in the 2015 Board-approved rates. Contract labour cost in the estimate was based on a quote from the contractor. The actual contract amount was higher and more rock was encountered than originally estimated. The increase was offset by lower costs for materials and contingencies.

Additionally, interest during construction was lower due to rate reduction and timing of spend.

Structures costs were $0.332 million lower than the costs included in the 2015 Board-approved rates. The original estimate included an auxiliary building for Parkway Plant D and the Parkway West project included an auxiliary building for the Parkway West LCU Plant. Both plants share one auxiliary building with the full amount charged to the Parkway West LCU Plant.

The compressor equipment costs were $19.358 million lower than the costs included in the 2015 Board-approved rates. The design of the Parkway Plant D was not yet complete at the time of the estimate, and actual costs for labour and material were lower than estimated. Permitting and land development costs originally included in the Parkway Plant D estimate were charged to the Parkway West LCU project. Lower labour costs were also realized due to contingencies included in the estimate that were not required. Interest during construction was lower due to rate reduction and timing of spend.

Average Investment

The average investment has increased by $0.638 million over the costs included in 2015 Board-approved rates due to in-service timing, even though capital expenditures for 2015 were below the Board-approved amount.

Compressor and measurement equipment were put into service in September 2015 rather than the original November 2015 estimate. These early in-service expenditures are partially offset by the decreased capital expenditures seen in November and December 2015, as explained above.

Operating Expenses

There were no operating and maintenance expenses associated with the Brantford-Kirkwall/Parkway D project in 2015.

The $0.258 million depreciation expense decrease relates to the decrease in in-service capital expenditures of $12.027 million in 2015.

Required Return

The $0.009 million required return increase relates to an increase in the average rate base investment in 2015 from $23.533 million to $24.171 million. The Board-approved required return calculation was derived using a capital structure of 64% long-term debt at 4% and 36% equity at the Board-approved rate of return of 8.93%. The 2015 actual required return calculation was derived using a capital structure of 64% long-term debt at 3.82%, and 36% equity at the Board-approved rate of return of 8.93%.

When Union prepared the Brantford-Kirkwall/Parkway D application (EB-2013-0074) the long-term debt rate used was 4.0%. In 2015, when the project was brought into service, Union issued debt which reduced the average long-term debt rate to 3.82%. This rate will be used to calculate the debt portion of the utility required return through to and including 2018.

Income Tax

Union's actual tax rate for 2015 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $0.912 million "Income Taxes-Utility Timing Difference" decrease relates primarily to a lower actual Capital Cost Allowance versus the 2015 Board-approved amount due to the lower capital expenditures in 2015 versus Board-approved.

Account No. 179-138 Parkway Obligation Rate Variance

There is no balance is this deferral account. In the EB-2013-0365 Settlement Agreement, Union and intervenors agreed to permanently shift the Union South DP Parkway Delivery Obligation ("PDO") to Dawn over time. As part of the Settlement, Union agreed to record rate variances associated with the timing differences between the effective date of the PDO changes and the inclusion of the cost impacts in approved rates (January 1 of the following year) in the Parkway Obligation Rate Variance Deferral Account. Per Union's

2016 Rates proceeding (EB-2015-0116), there was no additional PDO shift during 2015. Accordingly, there are no timing differences to account for in this deferral account.

Account No. 179-139 Energy East Pipeline Consultation Costs

The Energy East Pipeline Consultation Costs account was created in accordance with the Board's Decision in EB-2014-0271 to record Union's consultation costs related to the Energy East Pipeline allocated by the Board. The balance in this deferral account is a debit of $0.137 million related to invoices received from the Board in relation to costs incurred for the Energy East Pipeline Consultations.

Account No. 179-141 Unaccounted for Gas ("UFG") Price Variance Account

Consistent with the Board's Decision in Union's EB-2015-0010 proceeding, the UFG Price Variance Account will capture the variance between the average monthly price of Union's purchases and the applicable Board-approved reference price, applied to Union's actual UFG volumes. For 2015, the balance in the UFG Price Variance Account is a credit to ratepayers of $0.581 million plus interest of $0.004 million for a total credit of $0.585 million.

During 2015, Union purchased 12,887 10^3m^3 of gas supply related to actual UFG volumes on behalf of ratepayers who do not provide UFG in kind through customer supplied fuel, as shown in Table 15.

The actual average weighted cost of the Union South gas portfolio in 2015 was $159/$10^3m^3$. Relative to Board-approved reference prices included in rates, the weighted average variance is $45.08/$10^3m^3$. Please see to Union's QRAM application EB-2015-0340 (at Tab 1, Schedule 3, p. 4) and EB-2016-0040 (at Tab 1, Schedule 3, p. 4) for detailed costs by month. Accordingly, the UFG Price Variance Account has a credit balance of $0.581 million, as shown in Table 15.

Table 15
Calculation of 2015 UFG Price Deferral

Line No.		UFG Volumes (10^3m^3)
1	Planned UFG (1)	54.407
2	UFG collected through T1, T2, T3 and ex-franchise CSF	41.520
3	UFG Volumes - Utility Ratepayer (2)	12.887
		Deferral Calculation
4	UFG Volumes - Utility Ratepayer (2)	12.887
5	Price Variance (3)	$ 45.08
		$ 0.581

(1) Converted using the following heat values (38.29 Jan-Mar) (38.55 Apr - Dec).
(2) UFG Volumes represent gas supply related to actual UFG volumes on behalf of utility ratepayers who do not provide UFG in kind as part of customer supplied fuel.
(3) Price variance represents weighted average cost, relative to Board-approved reference prices.

Account No. 179-142 Lobo C Compressor/Hamilton-Milton Pipeline Project Costs

In its EB-2014-0261 Decision, the Board approved the establishment of the Lobo C Compressor/Hamilton-Milton Pipeline Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Lobo C Compressor/Hamilton-Milton Pipeline Project and the revenue requirement included in rates.

The deferral account has a credit balance of $0.334 million plus interest of $0.001 million for a total credit of $0.335 million. There was no revenue requirement included in

Union's 2015 rates (EB-2014-0271) and the balance represents the calculation of the actual revenue requirement for 2015 of a $0.334 million credit as shown in Table 16.

Table 16
2015 Lobo C Compressor/Hamilton-Milton Pipeline Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2015 Board-approved (a)	2015 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	-	14,058	14,058
2	Average Investment	-	2,259	2,259
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses (1)	-	-	-
4	Depreciation Expense (2)	-	176	176
5	Property Taxes (3)	-	-	-
6	Total Operating Expenses	-	176	176
7	Required Return (4)	-	136	136
8	Total Operating Expense and Return	-	312	312
	Income Taxes:			
9	Income Taxes - Equity Return (5)	-	26	26
10	Income Taxes - Utility Timing Differences (6)	-	(672)	(672)
11	Total Income Taxes	-	(646)	(646)
12	Total Revenue Requirement	-	(334)	(334)

Notes:
(1) Expenses include salaries and wages, employee-related expenses, fleet costs, materials and operating expenses.
(2) Depreciation expense at 2013 Board-approved depreciation rates.
(3) Property taxes in 2018 include $0.380 million for the Lobo C compressor and facilities and $0.792 million for the Hamilton-Milton pipeline.
(4) The 2015 required return assumes a capital structure of 64% long-term debt at 4.40% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2015 required return calculation is as follows:
$2.3 million * 64% * 4.40% = $0.064 million plus
$2.3 million * 36% * 8.93% = $0.072 million for a total of $0.136 million.
(5) Taxes related to the equity component of the return at a tax rate of 26.5%.
(6) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.
(7) Project revenue assumes an estimated M12 Dawn-Parkway rate of $2.560 GJ/mo and an M12 Kirkwall-Parkway rate of $0.450 GJ/mo. No revenue forecasted for 2015.

Capital Expenditures

The actual capital expenditures on 2015 in-service assets increased by $14.058 million compared to the 2015 Board-approved as shown in Table 17.

Table 17
Lobo C Compressor/Hamilton-Milton Pipeline Capital Expenditures

Line No.	Particulars ($000's)	2015 Board-approved (a)	2015 Actuals (b)	Difference (c) = (b - a)
	Lobo C Compressor			
1	Land	-	-	-
2	Structures	-	614	614
3	Pipelines	-	7,577	7,577
4	Compressor Equipment	-	5,867	5,867
	Hamilton-Milton Pipeline			
5	Land	-	-	-
6	Land Rights	-	-	-
7	Pipelines	-	-	-
8	Total Capital Expenditures	-	14,058	14,058

Per Union’s Dawn Parkway 2016 Expansion Project proceeding (EB-2014-0261) there were no Lobo Compressor Plant costs included in the 2015 Board-approved rates. In order to meet construction schedules and have the plant available for the 2016/17 operating season, piping and auxiliary facilities were placed in service by November 2015.

Average Investment

The average investment of $2.259 million is based on the in-service timing of the capital expenditures. The 2015 capital expenditures were split evenly between October 2015 and November 2015.

Operating Expenses

There were no operating and maintenance expenses associated with the Lobo C Compressor/Hamilton-Milton Pipeline project in 2015.

The $0.176 million depreciation expense increase relates to capital expenditures placed in service in 2015.

There were no property taxes associated with the project in 2015.

Required Return

The $0.136 million required return increase relates to the average rate base investment in 2015 being $2.259 million greater than expected. The 2015 actual required return calculation was derived using a capital structure of 64% long-term debt at 4.4%, and 36% common equity at the Board-approved return of 8.93%. The required return calculation is consistent with that filed and approved in the Lobo C Compressor/Hamilton-Milton Pipeline Project (EB-2014-0261, Exhibit A, Tab 10, Schedule 1).

Income Taxes

Union's actual tax rate for 2015 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $0.672 million in "Income Taxes – Utility Timing Differences" relates to the Capital Cost Allowance (less depreciation booked) on the capital expenditures and a deduction for interest during construction incurred in 2015.

UNION GAS LIMITED
Deferral Account Balances
Year Ending December 31, 2015

Line No.	Account Number	Account Name	Filed Balance [1] ($000's)
	Gas Supply Accounts:		
1	179-107	Spot Gas Variance Account	-
2	179-108	Unabsorbed Demand Costs (UDC) Variance Account	388
3	179-128	Gas Supply Review Consultant Costs	-
4	179-131	Upstream Transportation Optimization	8,600
5	179-132	Deferral Clearing Variance Account - Supply	172 [3]
6	179-132	Deferral Clearing Variance Account - Transport	1,665 [3]
7		Total Gas Supply Accounts (Lines 1 through 6)	10,825 [2]
	Storage Accounts:		
8	179-70	Short-Term Storage and Other Balancing Services	508
	Other:		
9	179-103	Unbundled Services Unauthorized Storage Overrun	-
10	179-112	Gas Distribution Access Rule (GDAR) Costs	760
11	179-117	Carbon Dioxide Offset Credits	-
12	179-120	IFRS Conversion Cost	-
13	179-123	Conservation Demand Management (CDM)	(213)
14	179-132	Deferral Clearing Variance Account	1,317 [3]
15	179-133	Normalized Average Consumption	10,546
16	179-134	Tax Variance	(60)
17	179-135	Unaccounted for Gas (UFG) Volume Variance Account	-
18	179-136	Parkway West Project Costs	(334)
19	179-137	Brantford-Kirkwall/Parkway D Project Costs	579
20	179-138	Parkway Obligation Rate Variance	-
21	179-139	Energy East Pipeline Consultation Costs	137
22	179-141	Unaccounted for Gas (UFG) Price Variance Account	(585)
23	179-142	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	(335)
24		Total Other Accounts (Lines 9 through 23)	11,812
25		**Total Deferral Account Balances (Lines 7 + 8 + 24)**	**23,145**

Notes:

1 Account balances include interest to December 31, 2015.

2 With the exception of UDC (No. 179-108), Gas Supply Review Consultant Costs (No. 179-128), Upstream Transportation Optimization (No. 179-131), Deferral Clearing Variance Account (No. 179-132) related to Supply and Transport, 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 Deferral Clearing Variance Account (No. 179-132) total balance of $3,154 ($172 + $1,665 + $1,317)

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

Line No.	Particulars ($000's)	2013 Board-approved	2015 Actual Total
		(a)	(c)
1	Base Exchange Revenue	9,118	7,739
2	FT RAM Exchange Revenue	5,800	-
3	Total Exchange Revenue	14,918	7,739
4	Exchange Revenue Subject to Deferral		7,739
5	Ratepayer portion - 90%	13,426	6,965
6	10% Union Incentive Payment		774
7	Less: Gas Supply Optimization Margin in Rates	13,426	15,565
8	Deferral balance payable to/(collectable from) ratepayers		(8,600)

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 2014	Actual 2015
		(a)	(b)	(c)
	Revenue			
1	C1 Off-Peak Storage	500	241	603
2	Supplemental Balancing Services	2,000	752	1,001
3	Gas Loans		54	38
4	Enbridge LBA		237	282
5		2,500	1,283	1,924
6	C1 ST Firm Peak Storage	7,883	3,235	4,935
7	Total Revenue (1)	10,383	4,518	6,859
	Costs			
8	O&M (2)	3,810	2,161	1,684
9	UFG (3)	316	500	278
10	Compressor Fuel (4)	1,201	428	405
11	Total Costs	5,327	3,089	2,367
12	Net Revenue (line 6 - 10)	5,056	1,429	4,492
13	Less Shareholder Portion (10%)	505	143	449
14	Ratepayer Portion	4,551	1,286	4,043
15	Approved in Rates	4,551	4,551	4,551
16	Deferral balance payable to/(collectable from) ratepayers	-	(3,265)	(508)

Notes:
(1) Based on short-term storage services provided.
(2) Revenue Requirement on11.3 PJ's of Board-approved excess in-franchise storage capacity.
(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.

UNION GAS LIMITED
Summary of Non-Utility Storage Balances

Date	Entitlement (PJ)	Balance (PJ)	% Full (%)
01-Oct-15	86.8	69.7	80%
02-Oct-15	86.8	70.7	81%
03-Oct-15	86.8	71.4	82%
04-Oct-15	86.8	72.1	83%
05-Oct-15	86.8	72.5	83%
06-Oct-15	86.8	73.3	84%
07-Oct-15	86.8	74.2	85%
08-Oct-15	86.8	74.5	86%
09-Oct-15	86.8	74.9	86%
10-Oct-15	86.8	75.6	87%
11-Oct-15	86.8	76.5	88%
12-Oct-15	86.8	77.5	89%
13-Oct-15	86.8	78.0	90%
14-Oct-15	86.8	78.0	90%
15-Oct-15	86.8	78.3	90%
16-Oct-15	86.8	78.3	90%
17-Oct-15	86.8	78.2	90%
18-Oct-15	86.8	77.9	90%
19-Oct-15	86.8	78.0	90%
20-Oct-15	86.8	78.2	90%
21-Oct-15	86.8	78.2	90%
22-Oct-15	86.8	78.4	90%
23-Oct-15	86.8	78.5	90%
24-Oct-15	86.8	79.1	91%
25-Oct-15	86.8	79.4	91%
26-Oct-15	86.8	79.2	91%
27-Oct-15	86.8	79.1	91%
28-Oct-15	86.8	79.1	91%
29-Oct-15	86.8	79.1	91%
30-Oct-15	86.8	78.9	91%
31-Oct-15	86.8	79.1	91%

Date	Entitlement (PJ)	Balance (PJ)	% Full (%)
01-Nov-15	86.8	79.9	92%
02-Nov-15	86.8	80.6	93%
03-Nov-15	86.8	81.4	94%
04-Nov-15	86.8	81.6	94%
05-Nov-15	86.8	82.4	95%
06-Nov-15	86.8	83.4	96%
07-Nov-15	86.8	83.6	96%
08-Nov-15	86.8	83.7	96%
09-Nov-15	86.8	83.7	96%
10-Nov-15	86.8	83.6	96%
11-Nov-15	86.8	83.7	96%
12-Nov-15	86.8	83.7	96%
13-Nov-15	86.8	83.5	96%
14-Nov-15	86.8	83.5	96%
15-Nov-15	86.8	83.8	97%
16-Nov-15	86.8	84.0	97%
17-Nov-15	86.8	84.0	97%
18-Nov-15	86.8	84.3	97%
19-Nov-15	86.8	84.5	97%
20-Nov-15	86.8	84.5	97%
21-Nov-15	86.8	84.4	97%
22-Nov-15	86.8	84.1	97%
23-Nov-15	86.8	83.6	96%
24-Nov-15	86.8	83.4	96%
25-Nov-15	86.8	83.8	96%
26-Nov-15	86.8	84.1	97%
27-Nov-15	86.8	84.5	97%
28-Nov-15	86.8	84.5	97%
29-Nov-15	86.8	84.4	97%
30-Nov-15	86.8	84.2	97%

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

Line No.	Particulars	Utility Storage Space (PJ)	Short-Term Peak Storage Sold (PJ)	Revenue from Short-Term Peak Storage ($ millions)
1	Net Revenues from Short-Term Peak Storage			4.935
2	Total Short-Term Peak Storage Sales		5.000	
3	Storage Space reserved for Utility	100.000		
4	Utility Space Requirement	95.000		
5	Excess Utility Storage Space (line 3 - line 4)	5.000		
6	Total Utility Short-Term Peak Storage Sales (line 5)		5.000	
7	Total Non-Utility Short Term Peak Storage Sales		0.000	
8	Short-Term Peak Storage Net Revenues - Utility (line 6 / line 2 * line 1)			4.935
9	Short-Term Peak Storage Net Revenues - Non-Utility (line 7 / line 2 * line 1)			0.000

UNION GAS LIMITED
Calculation of Balances by Rate Class in the NAC Deferral Account (No. 179-133)

Line No.	Particulars (m^3)		Rate 01 (a)	Rate 10 (b)	Rate M1 (c)	Rate M2 (d)	Net Account Balance (e)
1	2015 Target NAC: m³		2,901	169,025	2,761	169,121	
2	2015 Actual NAC: m³		2,799	162,078	2,676	163,129	
3	Actual change in NAC (line 1 - line 2)		102	6,947	85	5,992	
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 (10^3m^3) (line 3 x line 4)	(1)	32,608	14,271	90,243	40,709	177,831
6	2015 Net Annual Average Delivery Rate ($/m^3)	(2)	$0.086	$0.053	$0.035	$0.033	
7	2015 Net Annual Storage Rate ($/m^3)	(3)	$0.039	$0.027	$0.007	$0.006	
8	Delivery Rate Annual Balance Amount ($ 000)	(4)	$2,819	$747	$3,211	$1,353	$8,130
9	Storage Rate Annual Balance Amount ($ 000) (line 5 x line 7)	(4)	$1,270	$397	$669	$262	$2,598
10	Storage Cost Annual Balance Amount ($ 000)		$166	($122)	$797	($1,070)	($229)
11	Interest ($ 000)	(5)	$21	$4	$22	-	$47
12	Total Deferral Account Amounts ($ 000) (line 8+9+10+11)		$4,276	$1,026	$4,699	$545	$10,546

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 rate adjustments.
(3) The Storage Rates are constant each month throughout the year.
(4) The annual revenue is obtained from a monthly calculation of volumes (line 5) and the monthly unit delivery and storage rates (line 6 and 7).
(5) Interest is calculated on the monthly opening balance in the deferral account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED
179-132 Deferral Variance Account
2013 Deferral Disposition (EB-2014-0145) and 2013 DSM Deferral Disposition (EB-2014-0273)
2015 Deferral Account Dispositions

		2015				
Line No.	Particulars ($000's)	2013 Deferral Disposition EB-2014-0145 ($000)	2013 DSM Deferral Disposition EB-2014-0273 ($000)	Total ($000)	Interest ($000)	Total Variance With Interest ($000)
		(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) + (d)
1	Total General Service for Prospective Recovery (Refund) - Delivery	488	824	1,312	5	1,317
2	Total General Service for Prospective Recovery (Refund) - Gas Supply Transportation	1,658		1,658	7	1,665
3	Total Prospective Recovery (Refund) - Gas Supply Commodity	171		171	1	172
4	Total Deferral Account Amounts	2,317	824	3,141	13	3,154

UNION GAS LIMITED
179-132 Deferral Variance Account
2013 Deferral Disposition (EB-2014-0145)
Disposition Period - January 1, 2015 to June 30, 2015

Line No.	Particulars	Rate Class	2015 Forecast Volume (10^3m^3) (1)	Actual Volume (10^3m^3)	Volume Variance (10^3m^3)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3) (2)	Forecast ($000)	Actual ($000)	Variance ($000)
			(a)	(b)	(c) = (a) - (b)	(d)	(e) = (a) * (d)/100	(f) = (b) * (d)/100	(g) = (e) - (f)
	General Service for Prospective Recovery(Refund) - Delivery								
1	Small Volume General Service	01	581,408	655,515	(74,107)	(0.4725)	(2,747)	(3,098)	351
2	Large Volume General Service	10	197,190	221,754	(24,563)	(0.6162)	(1,215)	(1,366)	151
3	Small Volume General Service	M1	1,804,382	2,090,079	(285,697)	0.2353	4,245	4,917	(672)
4	Large Volume General Service	M2	690,822	768,162	(77,339)	(0.8512)	(5,880)	(6,538)	658
5	Total General Service for Prospective Recovery (Refund) - Delivery		3,273,803	3,735,509	(461,706)		(5,597)	(6,085)	488
	General Service for Prospective Recovery(Refund) - Gas Supply Transportation								
6	Small Volume General Service	01	581,408	655,515	(74,107)	(1.6633)	(9,671)	(10,903)	1,232
7	Large Volume General Service	10	196,161	220,293	(24,132)	(1.7674)	(3,467)	(3,893)	426
8	Total General Service for Prospective Recovery (Refund) - Gas Supply Transportati		777,569	875,808	(98,239)		(13,138)	(14,796)	1,658
	Prospective Recovery/(Refund) - Gas Supply Commodity								
9	Small Volume General Service	M1	1,584,241	1,861,951	(277,710)	(0.0623)	(1,058)	(1,159)	101
10	Large Volume General Service	M2	384,751	375,545	9,206	(0.0623)	(172)	(234)	62
11	Firm Com/Ind Contract	M4	17,104	18,211	(1,107)	(0.0623)	(7)	(11)	4
12	Interruptible Com/Ind Contract	M5	12,654	4,957	7,697	(0.0623)	(6)	(3)	(3)
13	Special Large Volume Contract	M7	-	12,081	(12,081)	(0.0623)	(1)	(8)	7
14	Small Wholesale	M10	147	238	(91)	(0.0623)	(0)	(0)	0
15	Total Prospective Recovery (Refund) - Gas Supply Commodity		1,998,897	2,272,982	(274,086)		(1,244)	(1,415)	171
16	Total						(19,979)	(22,296)	2,317

Over Refund to Rate Payers

Notes:
(1) Forecast volume for the period January 1, 2015 to June 30, 2015 (see EB-2014-0145, Rate Order, Appendix D, pp. 1-3).
(2) See EB-2014-0145, Rate Order, Appendix D, pp. 1-3.

UNION GAS LIMITED
179-132 Deferral Variance Account
2013 DSM Deferral Disposition (EB-2014-0273)
Disposition Period - July 1, 2015 to December 31, 2015

			2015						
Line No.	Particulars	Rate Class	Forecast Volume (10^3m^3) (1)	Actual Volume (10^3m^3)	Volume Variance (10^3m^3)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3)	Forecast ($000)	Actual ($000)	Variance ($000)
			(a)	(b)	(c) = (a) - (b)	(d)	(e) = (a) * (d)/100	(f) = (b) * (d)/100	(g) = (e) - (f)
	General Service for Prospective Recovery(Refund) - Delivery								
1	Small Volume General Service	01	359,409	302,438	56,971	(0.0488)	(175)	(147)	(28)
2	Large Volume General Service	10	144,390	130,717	13,673	0.3189	460	417	43
3	Small Volume General Service	M1	1,103,164	913,033	190,130	0.2968	3,274	2,709	565
4	Large Volume General Service	M2	508,675	445,533	63,142	0.3859	1,963	1,719	244
5	Total General Service for Prospective Recovery (Refund) - Delivery		2,115,637	1,791,721	323,916		5,522	4,698	824
6	Total						5,522	4,698	824

Under Collection from Rate Payer

Notes:
(1) Forecast volume for the period July 1, 2015 to December 31, 2015 (See EB-2015-0187, Appendix E, p. 1).

2015 UTILITY RESULTS AND EARNINGS SHARING

2015 UTILITY RESULTS

For the year ended December 31, 2015 Union's actual revenue sufficiency from utility operations is $19.9 million which is $14.4 million lower than the 2014 revenue sufficiency of $34.3 million. Table 1 provides the results from Union's actual utility operations for 2015.

Table 1
Calculation of Revenue Deficiency/(Sufficiency) from Utility Operations
For the Year Ended December 31, 2015

Line No.	Particulars ($ Millions)	Board-approved 2013	Actual 2014	Actual 2015	Increase/ (decrease) 2015 vs. 2014
		(a)	(b)	(c)	(d) = (c) - (b)
1	Gas sales and distribution revenue	1,448.8	1,761.5	1,659.2	
2	Cost of gas	701.4	958.5	856.8	
3	Gas distribution margin	747.4	803.0	802.4	(0.6)
4	Transportation	157.0	151.4	156.2	4.8
5	Storage	10.4	7.8	7.4	(0.4)
6	Other revenue	20.2	14.9	19.9	5.0
7	Expenses	643.8	646.3	662.3	16.0
8	Income taxes	17.1	24.0	15.7	(8.3)
9	Utility income	274.1	306.8	307.9	1.1
10	Cost of Capital	272.6	280.9	292.4	11.5
11	Revenue deficiency / (sufficiency) after tax	(1.5)	(25.9)	(15.5)	10.4
12	Provision for income taxes on deficiency / (sufficiency)	(0.5)	(9.3)	(5.6)	3.7
13	Distribution revenue deficiency/(sufficiency)	(2.0)	(35.2)	(21.1)	14.1
14	Shareholder portion of short-term storage revenue	0.5	0.1	0.4	0.3
15	Shareholder portion of optimization activity	1.5	0.8	0.8	(0.0)
16	Total revenue deficiency/(sufficiency)	-	(34.3)	(19.9)	14.4

The primary drivers of Union's 2015 financial results relative to 2014 are provided below.

Gas Distribution Margin

The decrease in gas distribution margin of $0.6 million relative to 2014 was mainly driven by a decrease in customer usage of natural gas due to warmer weather, partially offset by growth in the number of customers being serviced by Union (and related natural gas usage) and lower UFG expense.

Transportation Revenue

The increase in transportation revenue of $4.8 million relative to 2014 was mainly driven by increased M12 rates due to capital pass-through projects being included in rates, partially offset by decreased C1 short-term transportation. The decrease in C1 short-term transportation was a result of incremental market opportunities in the first quarter of 2014 from higher gas prices at Dawn due to extreme weather.

Other Revenue

The increase in other revenue of $5 million relative to 2014 was mainly driven by the Board's Decision in Union's 2012 Deferrals Account Disposition proceeding (EB-2013-0109) disallowing Union's proposal to establish a new Deferral Clearing Variance Account to capture differences between deferral balances approved for disposition and amounts prospectively refunded to or recovered from customers. The Board's Decision disallowing the new deferral account was reflected in Union's actual 2014 Other Revenue. Subsequently, in Union's 2013 Deferral Account Disposition proceeding (EB-

2014-0145), the Board approved a new Deferral Clearing Variance Account to capture the differences between the forecast and actual volumes associated with the disposition of deferral account balances. Union's actual 2015 Other Revenue reflects the recovery of deferral account balances previously over-refunded or under-recovered.

Expenses

The increase in expenses of $16.0 million relative to 2014 was mainly driven by higher depreciation expense due to new projects placed into service.

Income Taxes

The decrease in income taxes relative to 2014 of $8.3 million is primarily driven by lower utility income before income taxes, and utility timing differences due to higher capital cost allowance.

2015 EARNINGS SHARING

The benchmark return on equity ("ROE") for 2015 was 8.93%. Union's actual ROE from utility operations in 2015 was 9.89% or 96 basis points above the 2015 benchmark ROE.

The calculation of ROE for 2015 is found at 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 non-utility 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 earnings sharing, 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.

Non-Utility Storage Operations

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

Adjustments

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

A) Demand Side Management ("DSM") Incentive
B) Charitable Donations
C) Facility Fees, Customer Deposit Interest and Foreign Exchange on Bank Balances
D) Other

A) DSM Incentive

Other revenue includes the revenue recorded for the DSM Incentive of $5.917 million. The DSM Incentive amount is an incentive to the company to encourage it to actively pursue DSM activities. To ensure that the full amount of the DSM Incentive accrues to the company and that the incentive is maintained, the DSM Incentive revenue is removed from the earnings sharing calculation.

B) Charitable Donations

Charitable donation costs incurred by the utility are not allowable as deductions from utility earnings and as a result $1.666 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. As a result, facility fees and customer deposit interest of $0.820 million have been added to operating expenses and foreign exchange gain on bank balances of $1.154 million has been included in 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 $15.565 million has been shown as a cost of gas reduction.

Amounts relating to the Conservation Demand Management ("CDM") program of $0.351 million have been removed from operating and maintenance expenses because of a separate deferral sharing 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, and permanent and timing differences to arrive at taxable income multiplied by the current tax rates. The calculation can be found at 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 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 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 $0.330 million, net of tax, has been removed from the earnings sharing calculation.

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 $0.569 million, net of tax, has been removed from the earnings sharing calculation

Return on Equity

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 2015 ROE is 9.89%

(Please see Tab 2, Appendix B, Schedule 1, column (d), line 28).

Earnings Subject to Sharing

The actual ROE is compared to the benchmark ROE. If the difference between the actual ROE and the benchmark ROE is greater than 100 basis points but less than 200 basis points, the excess earnings are shared 50/50 between Union and its ratepayers. If the difference between the actual ROE and the benchmark ROE exceeds 200 basis points, the excess over 200 basis points is shared 90/10 to the benefit of the ratepayers. For 2015, the difference is 96 basis points or no earnings sharing for the year (please see Tab 2, Appendix B, Schedule 1, column (d), line 35).

2015 NON-UTILITY STORAGE

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

SERVICE QUALITY RESULTS

As set out in Union's 2014-2018 IR Mechanism Settlement Agreement (p. 40), Union has provided the service quality indicator results at 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	Actual 2014	Actual 2015
		(a)	(b)	(c)
1	Operating revenue	1,636,340	1,935,529	1,842,717
2	Cost of service	1,362,212	1,628,716	1,534,839
3	Utility income	274,128	306,813	307,878
4	Requested return	272,639	280,898	292,359
5	Revenue deficiency / (sufficiency) after tax	(1,489)	(25,915)	(15,519)
6	Provision for income taxes on deficiency / (sufficiency)	(509)	(9,344)	(5,595)
7	Distribution revenue deficiency / (sufficiency)	(1,998)	(35,259)	(21,114)
8	Shareholder portion of short-term storage revenue	506	143	449
9	Shareholder portion of optimization activity	1,492	792	774
10	Total revenue deficiency/ (sufficiency)	$ -	$ (34,324)	$ (19,891)

UNION GAS LIMITED
Statement of Utility Income
Year Ended December 31

Line No.	Particulars ($000s)	Board-approved 2013 (a)	Actual 2014 (b)	Actual 2015 (c)
	Operating Revenues:			
1	Gas sales and distribution	1,448,762	1,761,499	1,659,203
2	Transportation	156,997	151,373	156,244
3	Storage	10,383	7,783	7,368
4	Other	20,198	14,874	19,902
5		1,636,340	1,935,529	1,842,717
	Operating Expenses:			
6	Cost of gas	701,427	958,517	856,842
7	Operating and maintenance expenses	383,132	379,760	382,984
8	Depreciation	196,091	200,368	212,219
9	Other financing	1,179	689	820
10	Property and capital taxes	63,272	64,324	65,848
11		1,345,101	1,603,658	1,518,713
	Other Income (Expense)			
12	Gain/(Loss) on sale of assets	-	133	-
13	Gain/(Loss) on foreign exchange	-	(1,185)	(442)
14		-	(1,052)	(442)
15	Utility income before income taxes	291,239	330,819	323,562
16	Income taxes	17,111	24,006	15,684
17	Total utility income	$ 274,128	$ 306,813	$ 307,878

Filed: 2016-04-19
EB-2016-0118
Exhibit A
Tab 2
Appendix A
Schedule 3

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

Line No.	Particulars ($000s)	2013 Board-approved Corporate	2013 Board-approved Unregulated Storage	2013 Board-approved Adjustments	2013 Board-approved Utility	2014 Actual Corporate	2014 Actual Unregulated Storage	2014 Actual Adjustments	2014 Actual Utility	2015 Actual Corporate	2015 Actual Unregulated Storage	2015 Actual Adjustments	2015 Actual Utility
		(a)	(b)	(c)	(d)=(a)-(b)+(c)	(e)	(f)	(g)	(h)=(e)-(f)+(g)	(i)	(j)	(k)	(l)=(i)-(j)+(k)
	Operating Revenues:												
1	Gas sales and distribution	1,448,762	-	-	1,448,762	1,778,509	-	(17,010)	1,761,499	1,674,769	-	(15,565) (i)	1,659,203
2	Transportation	156,641	(356)	-	156,997	183,393	(356)	(32,375)	151,373	155,775	(469)	-	156,244
3	Storage	96,441	86,059	-	10,383	82,329	74,546	-	7,783	83,162	75,794	-	7,368
4	Other	24,498	-	(4,300)	20,198	21,201	-	(6,328)	14,874	25,819	-	(5,917) (ii)	19,902
5		1,726,343	85,703	(4,300)	1,636,340	2,065,433	74,190	(55,713)	1,935,529	1,939,524	75,325	(21,483)	1,842,717
	Operating Expenses:												
6	Cost of gas	701,966	539	-	701,427	977,185	1,657	(17,010)	958,517	874,628	2,221	(15,565) (i)	856,842
7	Operating and maintenance expenses	397,112	12,986	(993)	383,132	396,932	14,020	(3,152)	379,760	399,070	14,771	(1,315) (iii)	382,984
8	Depreciation	205,804	9,713	-	196,091	210,640	10,272	-	200,368	223,796	11,577	-	212,219
9	Other financing	-	-	1,179	1,179	-	-	689	689	-	-	820 (iv)	820
10	Property and other taxes	64,674	1,402	-	63,272	65,791	1,468	-	64,324	67,468	1,620	-	65,848
11		1,369,556	24,640	186	1,345,101	1,650,547	27,417	(19,473)	1,603,658	1,564,962	30,189	(16,060)	1,518,713
	Other Income (Expense)												
12	Gain/(Loss) on sale of assets	-	-	-	-	(768)	(901)	-	133	(4)	(4)	-	-
13	Other	-	-	-	-	(1,483)	(1,483)	-	-	(691)	(691)	-	-
14	Gain/(Loss) on foreign exchange	-	-	-	-	(1,814)	(43)	585	(1,185)	(1,614)	(18)	1,154 (v)	(442)
15		-	-	-	-	(4,065)	(2,428)	585	(1,052)	(2,309)	(713)	1,154	(442)
16	Earnings Before Interest and Taxes	$ 356,787	$ 61,063	$ (4,486)	$ 291,239	$ 410,820	$ 44,346	$ (35,654)	$ 330,819	$ 372,254	$ 44,423	$ (4,269)	$ 323,562

Notes:

i) Reclassification of optimization revenue as cost of gas

ii) Demand Side Management Incentive

iii)	Charitable donations	(1,666)
	CDM Program	351
		(1,315)

iv) Facility fees and customer deposit interest

v) Foreign exchange gain on bank balances

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

		2013 Board-approved				2014 Actual				2015 Actual			
Line		Utility Capital Structure		Cost Rate	Return	Utility Capital Structure		Cost Rate	Return	Utility Capital Structure		Cost Rate	Return
No.	Particulars	($000s)	(%)	%	($000s)	($000s)	(%)	%	($000s)	($000s)	(%)	%	($000s)
1	Long-term debt	2,289,139	61.30%	6.53%	149,481	2,502,250	62.93%	6.03%	150,959	2,746,659	64.96%	5.64%	154,972
2	Unfunded short-term debt	(1,287)	(0.03%)	1.31%	(17)	(60,507)	(1.52%)	1.19%	(720)	(143,529)	(3.39%)	0.84%	(1,206)
3	Total debt	2,287,852	61.26%		149,464	2,441,743	61.41%		150,239	2,603,130	61.56%		153,766
4	Preference shares	102,248	2.74%	3.05%	3,117	103,164	2.59%	2.74%	2,825	103,043	2.44%	2.58%	2,659
5	Common equity	1,344,432	36.00%	8.93%	120,058	1,431,510	36.00%	8.93%	127,834	1,522,222	36.00%	8.93%	135,934
6	Total rate base	$ 3,734,532	100.00%		$ 272,639	$ 3,976,418	100.00%		$ 280,898	$ 4,228,395	100.00%		$ 292,359

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

Line No.	Volumes in 10^3m^3	Board-approved 2013 System Sales (a)	ABC-T (b)	ABC-Unbundled (c)	Bundled-T (d)	T-Service (e)	Total (f)
	General Service						
1	Rate M1 Firm	2,271,443	465,977	185,421	16,702	-	2,939,543
2	Rate M2 Firm	378,137	336,728	23,220	237,485	-	975,571
3	Rate 01 Firm	641,423	233,272	-	9,727	-	884,421
4	Rate 10 Firm	155,398	82,428	-	85,062	-	322,887
5	Total General Service	3,446,401	1,118,404	208,642	348,975	-	5,122,423
	Wholesale - Utility						
6	Rate M9 Firm	-	-	-	60,750	-	60,750
7	Rate M10 Firm	48	-	-	141	-	189
8	Total Wholesale - Utility	48	-	-	60,891	-	60,939
	Contract						
9	Rate M4	16,855	-	-	387,823	-	404,678
10	Rate M7	-	-	-	147,143	-	147,143
11	Rate 20 Storage	-	-	-	-	-	-
12	Rate 20 Transportation	13,514	-	-	110,097	506,191	629,802
13	Rate 100 Storage	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	1,895,488	1,895,488
15	Rate T-1 Storage	-	-	-	-	-	-
16	Rate T-1 Transportation	-	-	-	-	548,986	548,986
17	Rate T-2 Storage	-	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	4,880,297	4,880,297
19	Rate T-3 Storage	-	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	272,712	272,712
21	Rate M5	14,152	-	-	520,981	-	535,132
22	Rate 25	42,913	-	-	-	116,643	159,555
23	Rate 30	-	-	-	-	-	-
24	Total Contract	87,433	-	-	1,166,044	8,220,317	9,473,795
25	Total Throughput Volume	3,533,882	1,118,404	208,642	1,575,911	8,220,317	14,657,156

Line No.	Volumes in 10^3m^3	Actual 2014 System Sales (g)	ABC-T (h)	ABC-Unbundled (i)	Bundled-T (j)	T-Service (k)	Total (l)
	General Service						
1	Rate M1 Firm	2,602,598	273,220	53,026	15,560	-	2,944,404
2	Rate M2 Firm	612,196	301,067	7,220	251,462	-	1,171,944
3	Rate 01 Firm	829,132	117,249	-	9,760	-	956,141
4	Rate 10 Firm	191,175	69,786	-	90,362	2,844	354,167
5	Total General Service	4,235,102	761,323	60,246	367,143	2,844	5,426,657
	Wholesale - Utility						
6	Rate M9 Firm	-	-	-	67,138	-	67,138
7	Rate M10 Firm	312	-	-	-	-	312
8	Total Wholesale - Utility	312	-	-	67,138	-	67,450
	Contract						
9	Rate M4	37,330	11,639	-	435,435	-	484,404
10	Rate M7	27,984	2,922	-	361,350	-	392,256
11	Rate 20 Storage	-	-	-	-	-	-
12	Rate 20 Transportation	8,614	-	-	93,899	433,114	535,626
13	Rate 100 Storage	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	1,710,928	1,710,928
15	Rate T-1 Storage	-	-	-	-	-	-
16	Rate T-1 Transportation	-	-	-	-	470,811	470,811
17	Rate T-2 Storage	-	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	4,305,103	4,305,103
19	Rate T-3 Storage	-	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	288,979	288,979
21	Rate M5	14,733	-	-	244,625	-	259,358
22	Rate 25	97,399	-	-	-	89,150	186,550
23	Rate 30	-	-	-	-	-	-
24	Total Contract	186,060	14,561	-	1,135,309	7,298,086	8,634,015
25	Total Throughput Volume	4,421,475	775,883	60,246	1,569,589	7,300,929	14,128,122

Line No.	Volumes in 10^3m^3	Actual 2015 System Sales (m)	ABC-T (n)	ABC-Unbundled (o)	Bundled-T (p)	T-Service (q)	Total (r)
	General Service						
1	Rate M1 Firm	2,583,548	255,785	32,406	17,127	-	2,888,866
2	Rate M2 Firm	579,474	326,911	5,562	277,278	-	1,189,225
3	Rate 01 Firm	826,618	101,871	-	10,455	-	938,944
4	Rate 10 Firm	172,559	74,364	-	93,077	3,625	343,625
5	Total General Service	4,162,199	758,930	37,968	397,938	3,625	5,360,660
	Wholesale - Utility						
6	Rate M9 Firm	-	-	-	66,583	-	66,583
7	Rate M10 Firm	300	-	-	-	-	300
8	Total Wholesale - Utility	300	-	-	66,583	-	66,882
	Contract						
9	Rate M4	31,119	19,047	-	407,162	-	457,328
10	Rate M7	21,253	2,937	-	403,517	-	427,707
11	Rate 20 Storage	-	-	-	-	-	-
12	Rate 20 Transportation	10,943	-	-	90,848	439,048	540,839
13	Rate 100 Storage	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	1,398,114	1,398,114
15	Rate T-1 Storage	-	-	-	-	-	-
16	Rate T-1 Transportation	-	-	-	-	442,947	442,947
17	Rate T-2 Storage	-	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	4,368,501	4,368,501
19	Rate T-3 Storage	-	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	263,235	263,235
21	Rate M5	8,026	2,881	-	197,724	-	208,631
22	Rate 25	93,474	-	-	-	50,839	144,313
23	Rate 30	-	-	-	-	-	-
24	Total Contract	164,815	24,864	-	1,099,251	6,962,684	8,251,614
25	Total Throughput Volume	4,327,314	783,795	37,968	1,563,771	6,966,309	13,679,156

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

Line No.	Volumes in 10^3m^3	Board-approved 2013 System Sales (a)	Board-approved 2013 ABC-T (b)	Board-approved 2013 ABC-Unbundled (c)	Board-approved 2013 Bundled-T (d)	Board-approved 2013 T-Service (e)	Board-approved 2013 Total (f)	Actual 2014 System Sales (g)	Actual 2014 ABC-T (h)	Actual 2014 ABC-Unbundled (i)	Actual 2014 Bundled-T (j)	Actual 2014 T-Service (k)	Actual 2014 Total (l)	Actual 2015 System Sales (m)	Actual 2015 ABC-T (n)	Actual 2015 ABC-Unbundled (o)	Actual 2015 Bundled-T (p)	Actual 2015 T-Service (q)	Actual 2015 Total (r)
	General Service																		
1	Rate M1 Firm	2,271,443	465,977	185,421	16,702	-	2,939,543	2,942,275	308,880	59,947	17,591	-	3,328,692	2,701,384	267,452	33,884	17,908	-	3,020,628
2	Rate M2 Firm	378,137	336,728	23,220	237,485	-	975,571	670,955	329,963	7,913	275,597	-	1,284,428	597,640	337,159	5,737	285,971	-	1,226,506
3	Rate 01 Firm	641,423	233,272	-	9,727	-	884,421	913,183	129,135	-	10,749	-	1,053,067	846,945	104,376	-	10,712	-	962,033
4	Rate 10 Firm	155,398	82,428	-	85,062	-	322,887	204,812	74,764	-	96,807	3,047	379,430	176,638	76,121	-	95,277	3,710	351,747
5	Total General Service	3,446,401	1,118,404	208,642	348,975	-	5,122,423	4,731,226	842,742	67,859	400,744	3,047	6,045,618	4,322,607	785,108	39,621	409,868	3,710	5,560,914
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	60,750	-	60,750	-	-	-	67,138	-	67,138	-	-	-	66,583	-	66,583
7	Rate M10 Firm	48	-	-	141	-	189	312	-	-		-	312	300	-	-	-	-	300
8	Total Wholesale - Utility	48	-	-	60,891	-	60,939	312	-	-	67,138	-	67,450	300	-	-	66,583	-	66,882
	Contract																		
9	Rate M4	16,855	-	-	387,823	-	404,678	37,330	11,639	-	435,435	-	484,404	31,119	19,047	-	407,162	-	457,328
10	Rate M7	-	-	-	147,143	-	147,143	27,984	2,922	-	361,350	-	392,256	21,253	2,937	-	403,517	-	427,707
11	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Rate 20 Transportation	13,514	-	-	110,097	506,191	629,802	8,614	-	-	93,899	433,114	535,626	10,943	-	-	90,848	439,048	540,839
13	Rate 100 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	1,895,488	1,895,488	-	-	-	-	1,710,928	1,710,928	-	-	-	-	1,398,114	1,398,114
15	Rate T-1 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Rate T-1 Transportation	-	-	-	-	548,986	548,986	-	-	-	-	470,811	470,811	-	-	-	-	442,947	442,947
17	Rate T-2 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	4,880,297	4,880,297	-	-	-	-	4,305,103	4,305,103	-	-	-	-	4,368,501	4,368,501
19	Rate T-3 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	272,712	272,712	-	-	-	-	288,979	288,979	-	-	-	-	263,235	263,235
21	Rate M5	14,152	-	-	520,981	-	535,132	14,733	-	-	244,625	-	259,358	8,026	2,881	-	197,724	-	208,631
22	Rate 25	42,913	-	-	-	116,643	159,555	97,399	-	-	-	89,150	186,550	93,474	-	-	-	50,839	144,313
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Contract	87,433	-	-	1,166,044	8,220,317	9,473,795	186,060	14,561	-	1,135,309	7,298,086	8,634,015	164,815	24,864	-	1,099,251	6,962,684	8,251,614
25	Total Throughput Volume	3,533,882	1,118,404	208,642	1,575,911	8,220,317	14,657,156	4,917,599	857,303	67,859	1,603,190	7,301,132	14,747,083	4,487,722	809,972	39,621	1,575,701	6,966,395	13,879,411

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

Line No.	Particulars ($000's)	Board-approved 2013 System Sales (a)	ABC-T (b)	ABC-Unbundled (c)	Bundled-T (d)	T-Service (e)	Total (f)
	General Service						
1	Rate M1 Firm	693,117	58,944	24,671	889	-	777,621
2	Rate M2 Firm	84,792	17,612	2,631	11,466	-	116,501
3	Rate 01 Firm	268,545	66,665	-	1,993	-	337,202
4	Rate 10 Firm	43,957	13,251	-	12,874	-	70,083
5	Total General Service	1,090,412	156,472	27,301	27,222	-	1,301,407
	Wholesale - Utility						
6	Rate M9 Firm	-	-	-	727	-	727
7	Rate M10 Firm	11	-	-	7	-	18
8	Total Wholesale - Utility	11	-	-	734	-	745
	Contract						
9	Rate M4	3,407	-	-	11,786	-	15,193
10	Rate M7	-	-	-	4,127	-	4,127
11	Rate 20 Storage	-	-	-	-	1,057	1,057
12	Rate 20 Transportation	3,304	-	-	10,277	10,637	24,219
13	Rate 100 Storage	-	-	-	-	166	166
14	Rate 100 Transportation	-	-	-	-	15,481	15,481
15	Rate T-1 Storage	-	-	-	-	1,400	1,400
16	Rate T-1 Transportation	-	-	-	-	9,241	9,241
17	Rate T-2 Storage	-	-	-	-	5,976	5,976
18	Rate T-2 Transportation	-	-	-	-	36,193	36,193
19	Rate T-3 Storage	-	-	-	-	1,345	1,345
20	Rate T-3 Transportation	-	-	-	-	3,054	3,054
21	Rate M5	2,801	-	-	12,913	-	15,713
22	Rate 25	10,172	-	-	-	3,273	13,445
23	Rate 30	-	-	-	-	-	-
24	Total Contract	19,684	-	-	39,102	87,824	146,610
25	Subtotal	1,110,107	156,472	27,301	67,058	87,824	1,448,762
26	LRAM						-
27	Average Use / Normalized Average Consumption						-
28	Parkway Obligation Rate Variance						-
29	Capital Pass Through						-
30	Total Revenue					$	1,448,762

Line No.	Particulars ($000's)	Actual 2014 System Sales (g)	ABC-T (h)	ABC-Unbundled (i)	Bundled-T (j)	T-Service (k)	Total (l)
	General Service						
1	Rate M1 Firm	877,544	33,760	7,631	956	-	919,891
2	Rate M2 Firm	148,640	14,441	304	10,983	445	174,813
3	Rate 01 Firm	351,765	31,093	-	1,882	-	384,740
4	Rate 10 Firm	55,416	9,585	-	11,340	145	76,486
5	Total General Service	1,433,365	88,879	7,936	25,161	590	1,555,929
	Wholesale - Utility						
6	Rate M9 Firm	-	-	-	780	-	780
7	Rate M10 Firm	70	-	-	-	-	70
8	Total Wholesale - Utility	70	-	-	780	-	850
	Contract						
9	Rate M4	8,489	334	-	12,845	-	21,668
10	Rate M7	8,009	251	-	7,724	-	15,984
11	Rate 20 Storage	-	-	-	-	1,529	1,529
12	Rate 20 Transportation	2,051	-	-	7,779	10,074	19,905
13	Rate 100 Storage	-	-	-	-	154	154
14	Rate 100 Transportation	-	-	-	-	15,618	15,618
15	Rate T-1 Storage	-	-	-	-	1,521	1,521
16	Rate T-1 Transportation	-	-	-	-	8,702	8,702
17	Rate T-2 Storage	-	-	-	-	8,360	8,360
18	Rate T-2 Transportation	-	-	-	-	40,968	40,968
19	Rate T-3 Storage	-	-	-	-	1,604	1,604
20	Rate T-3 Transportation	-	-	-	-	3,111	3,111
21	Rate M5	3,174	-	-	6,832	-	10,007
22	Rate 25	21,643	-	-	-	2,801	24,443
23	Rate 30	-	-	-	-	58	58
24	Total Contract	43,367	585	-	35,181	94,501	173,633
25	Subtotal	1,476,802	89,463	7,936	61,121	95,090	1,730,413
26	LRAM						786
27	Average Use / Normalized Average Consumption						(2,576)
28	Parkway Obligation Rate Variance						3,585
29	Capital Pass Through						(1,106)
30	Total Revenue					$	1,731,102

Line No.	Particulars ($000's)	Actual 2015 System Sales (m)	ABC-T (n)	ABC-Unbundle (o)	Bundled-T (p)	T-Service (q)	Total (r)
	General Service						
1	Rate M1 Firm	799,970	30,778	4,564	1,004	-	836,316
2	Rate M2 Firm	124,182	15,439	222	11,700	310	151,853
3	Rate 01 Firm	344,837	27,644	-	2,096	-	374,577
4	Rate 10 Firm	48,374	11,048	-	12,778	176	72,375
5	Total General Service	1,317,362	84,909	4,786	27,577	486	1,435,120
	Wholesale - Utility						
6	Rate M9 Firm	-	-	-	805	-	805
7	Rate M10 Firm	69	-	-	-	-	69
8	Total Wholesale - Utility	69	-	-	805	-	874
	Contract						
9	Rate M4	6,352	602	-	13,022	-	19,976
10	Rate M7	6,582	256	-	8,961	-	15,798
11	Rate 20 Storage	-	-	-	-	1,819	1,819
12	Rate 20 Transportation	2,634	-	-	8,895	11,902	23,430
13	Rate 100 Storage	-	-	-	-	89	89
14	Rate 100 Transportation	-	-	-	-	12,423	12,423
15	Rate T-1 Storage	-	-	-	-	1,367	1,367
16	Rate T-1 Transportation	-	-	-	-	8,695	8,695
17	Rate T-2 Storage	-	-	-	-	7,769	7,769
18	Rate T-2 Transportation	-	-	-	-	43,299	43,299
19	Rate T-3 Storage	-	-	-	-	1,420	1,420
20	Rate T-3 Transportation	-	-	-	-	3,426	3,426
21	Rate M5	1,626	92	-	5,767	-	7,485
22	Rate 25	19,543	-	-	-	1,609	21,152
23	Rate 30	-	-	-	-	-	-
24	Total Contract	36,736	950	-	36,645	93,820	168,151
25	Subtotal	1,354,168	85,859	4,786	65,026	94,306	1,604,145
26	LRAM						(872)
27	Average Use / Normalized Average Consumption						10,204
28	Parkway Obligation Rate Variance						(1)
29	Capital Pass Through						553
30	Total Revenue						1,614,029

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 2014						Actual 2015					
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	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	General Service																		
1	Rate M1 Firm	693,117	58,944	24,671	889	-	777,621	892,930	34,352	7,765	973	-	936,020	830,046	30,973	4,593	1,010	-	866,622
2	Rate M2 Firm	84,792	17,612	2,631	11,466	-	116,501	152,465	14,812	312	11,265	456	179,311	129,532	15,585	224	11,810	313	157,464
3	Rate 01 Firm	268,545	66,665	-	1,993	-	337,202	359,459	31,773	-	1,923	-	393,155	351,890	28,014	-	2,130	-	382,034
4	Rate 10 Firm	43,957	13,251	-	12,874	-	70,083	56,398	9,755	-	11,541	147	77,841	49,738	11,243	-	13,017	177	74,175
5	Total General Service	1,090,412	156,472	27,301	27,222	-	1,301,407	1,461,252	90,692	8,078	25,702	604	1,586,327	1,361,206	85,815	4,817	27,967	490	1,480,295
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	727	-	727	-	-	-	780	-	780	-	-	-	805	-	805
7	Rate M10 Firm	11	-	-	7	-	18	70	-	-	-	-	70	69	-	-	-	-	69
8	Total Wholesale - Utility	11	-	-	734	-	745	70	-	-	780	-	850	69	-	-	805	-	874
	Contract																		
9	Rate M4	3,407	-	-	11,786	-	15,193	8,489	334	-	12,845	-	21,668	6,352	602	-	13,022	-	19,976
10	Rate M7	-	-	-	4,127	-	4,127	8,009	251	-	7,724	-	15,984	6,582	256	-	8,961	-	15,798
11	Rate 20 Storage	-	-	-	-	1,057	1,057	-	-	-	-	1,529	1,529	-	-	-	-	1,819	1,819
12	Rate 20 Transportation	3,304	-	-	10,277	10,637	24,219	2,051	-	-	7,779	10,074	19,905	2,634	-	-	8,895	11,902	23,430
13	Rate 100 Storage	-	-	-	-	166	166	-	-	-	-	154	154	-	-	-	-	89	89
14	Rate 100 Transportation	-	-	-	-	15,481	15,481	-	-	-	-	15,618	15,618	-	-	-	-	12,423	12,423
15	Rate T-1 Storage	-	-	-	-	1,400	1,400	-	-	-	-	1,521	1,521	-	-	-	-	1,367	1,367
16	Rate T-1 Transportation	-	-	-	-	9,241	9,241	-	-	-	-	8,702	8,702	-	-	-	-	8,695	8,695
17	Rate T-2 Storage	-	-	-	-	5,976	5,976	-	-	-	-	8,360	8,360	-	-	-	-	7,769	7,769
18	Rate T-2 Transportation	-	-	-	-	36,193	36,193	-	-	-	-	40,968	40,968	-	-	-	-	43,299	43,299
19	Rate T-3 Storage	-	-	-	-	1,345	1,345	-	-	-	-	1,604	1,604	-	-	-	-	1,420	1,420
20	Rate T-3 Transportation	-	-	-	-	3,054	3,054	-	-	-	-	3,111	3,111	-	-	-	-	3,426	3,426
21	Rate M5	2,801	-	-	12,913	-	15,713	3,174	-	-	6,832	-	10,007	1,626	92	-	5,767	-	7,485
22	Rate 25	10,172	-	-	-	3,273	13,445	21,643	-	-	-	2,801	24,443	19,543	-	-	-	1,609	21,152
23	Rate 30	-	-	-	-	-	-	-	-	-	-	58	58	-	-	-	-	-	-
24	Total Contract	19,684	-	-	39,102	87,824	146,610	43,367	585	-	35,181	94,501	173,633	36,736	950	-	36,645	93,820	168,151
25	Subtotal	1,110,107	156,472	27,301	67,058	87,824	1,448,762	1,504,688	91,277	8,078	61,663	95,104	1,760,810	1,398,011	86,765	4,817	65,416	94,310	1,649,319
26	LRAM						-						786						(872)
27	Average Use / Normalized Average Consumption						-						(2,576)						10,204
28	Parkway Obligation Rate Variance						-						3,585						(1)
29	Capital Pass Through						-						(1,106)						553
30	Total Revenue					$	1,448,762					$	1,761,499						1,659,203

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

Line No.	Particulars ($000's)	Board-approved 2013						Actual 2014						Actual 2015					
		System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	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)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	General Service																		
1	Rate M1 Firm	303,298	58,944	24,671	889	-	387,801	363,507	34,352	7,765	973	-	406,596	363,403	30,973	4,593	1,010	-	399,979
2	Rate M2 Firm	19,898	17,612	2,631	11,466	-	51,607	29,874	14,812	312	11,265	456	56,720	27,470	15,585	224	11,810	313	55,402
3	Rate 01 Firm	118,812	41,509	-	928	-	161,249	150,550	20,773	-	1,008	-	172,332	148,300	17,109	-	1,024	-	166,432
4	Rate 10 Firm	9,524	5,578	-	4,876	-	19,979	11,441	4,514	-	4,737	147	20,839	10,190	4,636	-	4,714	177	19,717
5	Total General Service	451,532	123,643	27,301	18,159	-	620,636	555,372	74,451	8,078	17,984	603	656,488	549,363	68,302	4,817	18,559	490	641,531
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	727	-	727	-	-	-	780	-	780	-	-	-	805	-	805
7	Rate M10 Firm	2	-	-	7	-	10	15	-	-	-	-	15	16	-	-	-	-	16
8	Total Wholesale - Utility	2	-	-	734	-	736	15	-	-	780	-	795	16	-	-	805	-	821
	Contract																		
9	Rate M4	514	-	-	11,786	-	12,300	1,442	334	-	12,845	-	14,622	1,114	602	-	13,022	-	14,738
10	Rate M7	-	-	-	4,127	-	4,127	2,949	251	-	7,724	-	10,924	2,964	256	-	8,961	-	12,180
11	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Rate 20 Transportation	434	-	-	2,425	10,637	13,496	230	-	-	2,097	10,074	12,401	335	-	-	2,013	11,902	14,250
13	Rate 100 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	15,481	15,481	-	-	-	-	14,995	14,995	-	-	-	-	12,423	12,423
15	Rate T-1 Storage	-	-	-	-	1,400	1,400	-	-	-	-	1,521	1,521	-	-	-	-	1,367	1,367
16	Rate T-1 Transportation	-	-	-	-	9,241	9,241	-	-	-	-	8,562	8,562	-	-	-	-	8,697	8,697
17	Rate T-2 Storage	-	-	-	-	5,976	5,976	-	-	-	-	8,360	8,360	-	-	-	-	7,769	7,769
18	Rate T-2 Transportation	-	-	-	-	36,193	36,193	-	-	-	-	40,652	40,652	-	-	-	-	43,278	43,278
19	Rate T-3 Storage	-	-	-	-	1,345	1,345	-	-	-	-	1,604	1,604	-	-	-	-	1,420	1,420
20	Rate T-3 Transportation	-	-	-	-	3,054	3,054	-	-	-	-	3,111	3,111	-	-	-	-	3,426	3,426
21	Rate M5	375	-	-	12,913	-	13,288	477	-	-	6,832	-	7,310	275	92	-	5,767	-	6,134
22	Rate 25	1,200	-	-	-	3,273	4,473	2,639	-	-	-	2,801	5,440	2,315	-	-	-	1,609	3,924
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Contract	2,524	-	-	31,250	86,601	120,375	7,738	585	-	29,499	91,679	129,501	7,003	950	-	29,763	91,892	129,607
25	Subtotal	454,058	123,643	27,301	50,143	86,601	741,747	563,125	75,036	8,078	48,263	92,283	786,785	556,382	69,252	4,817	49,126	92,381	771,959
26	LRAM						-						786						(872)
27	Average Use / Normalized Average Consumption						-						(1,132)						8,478
28	Parkway Obligation Rate Variance						-						3,585						(1)
29	Capital Pass Through						-						(1,106)						553
30	Total Revenue						$ 741,747						$ 788,918						780,117

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

		Board-approved 2013						Actual 2014						Actual 2015					
Line No.	Particulars	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	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)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	General Service																		
1	Rate M1 Firm	837,301	157,165	72,389	902	-	1,067,757	976,089	83,200	17,858	1,142	-	1,078,289	1,003,873	74,656	9,991	1,113	-	1,089,633
2	Rate M2 Firm	3,172	2,594	241	771	-	6,778	3,937	2,177	43	783	-	6,940	4,429	2,457	29	837	-	7,752
3	Rate 01 Firm	242,644	80,300	-	343	-	323,287	295,243	35,942	-	595	-	331,780	305,931	30,287	-	639	-	336,857
4	Rate 10 Firm	930	845	-	289	-	2,064	1,181	539	-	294	5	2,019	1,312	579	-	324	5	2,220
5	Total General Service	1,084,047	240,904	72,630	2,305	-	1,399,886	1,276,450	121,858	17,901	2,814	5	1,419,028	1,315,545	107,979	10,020	2,913	5	1,436,462
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	3	-	3	-	-	-	2	-	2	-	-	-	2	-	2
7	Rate M10 Firm	1	-	-	1	-	2	2	-	-	-	-	2	2	-	-	-	-	2
8	Total Wholesale - Utility	1	-	-	4	-	5	2	-	-	2	-	4	2	-	-	2	-	4
	Contract																		
9	Rate M4	11	-	-	104	-	115	18	5	-	131	-	154	18	9	-	132	-	159
10	Rate M7	-	-	-	4	-	4	3	1	-	24	-	28	2	1	-	25	-	28
11	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Rate 20 Transportation	4	-	-	20	39	63	3	-	-	17	28	48	3	-	-	16	28	47
13	Rate 100 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	17	17	-	-	-	-	11	11	-	-	-	-	11	11
15	Rate T-1 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Rate T-1 Transportation	-	-	-	-	35	35	-	-	-	-	36	36	-	-	-	-	37	37
17	Rate T-2 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	29	29	-	-	-	-	22	22	-	-	-	-	22	22
19	Rate T-3 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	1	1	-	-	-	-	1	1	-	-	-	-	1	1
21	Rate M5	5	-	-	139	-	144	8	1	-	73	-	82	6	2	-	67	-	75
22	Rate 25	50	-	-	-	42	92	38	-	-	-	47	85	31	-	-	-	47	78
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Contract	70	-	-	267	163	500	70	7	-	245	145	467	60	12	-	240	146	458
25	Total Number of Customers	1,084,118	240,904	72,630	2,576	163	1,400,391	1,276,522	121,865	17,901	3,061	150	1,419,499	1,315,607	107,991	10,020	3,155	151	1,436,924

*Customer count for storage is included within transportation

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

Line No.	Particulars ($000s)	2013 Board-approved	2014 Actual	2015 Actual
		(a)	(b)	(c)
	Revenue from Regulated Storage Services:			
1	C1 Off-Peak Storage	500	241	603
2	Supplemental Balancing Services	2,000	988	1,283
3	Gas Loans	-	54	38
4	C1 Short Term Firm Peak Storage	7,883	3,235	4,935
5	Short Term Storage and Balancing Services Deferral	-	3,265	508
6	Total Regulated Storage Revenue Net of Deferral	$ 10,383	$ 7,783	$ 7,368
	Revenue from Regulated Transportation Services:			
7	M12 Transportation	120,963	114,743	120,975
8	M12-X Transportation	13,896	14,536	15,445
9	C1 Long Term Transportation	7,039	5,795	6,807
10	C1 Short Term Transportation	11,067	13,251	10,007
11	Gross Exchange Revenue	14,918	7,919	7,739
12	Ratepayer Portion of Exchange Revenue	(13,426)	(7,127)	(6,965)
13	M13 Local Production	424	333	346
14	M16 Transportation	694	657	578
15	Other S&T Revenue	1,423	1,266	1,311
16	Total Regulated Transportation Revenue Net of Deferral	$ 156,997	$ 151,373	$ 156,244

UNION GAS LIMITED
Other Revenue
Year Ended December 31

Line No.	Particulars ($000's)	2013 Board-approved	2014 Actual	2015 Actual
1	Delayed payment charges	6,467	8,214	8,091
2	Account opening charges	7,000	6,553	6,953
3	Billing revenue	3,453	2,064	1,873
4	Mid market transactions	2,000	1,388	955
5	Other operating revenue	1,278	(3,346)	2,030
6	Total other revenue	$ 20,198	$ 14,874	$ 19,902

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

Line No.	Particulars ($000s)	2013 Board-approved (a)	2014 Actual (b)	2015 Actual (c)
1	Salaries/Wages	192,786	211,065	210,164
2	Benefits	81,083	66,488	67,939
3	Materials	9,958	10,576	8,852
4	Employee Training	14,330	12,553	12,962
5	Contract Services	66,376	67,394	70,933
6	Consulting	8,172	8,984	8,226
7	General	18,890	23,042	25,380
8	Transportation and Maintenance	9,761	10,140	9,817
9	Company Used Gas	2,611	2,795	2,689
10	Utility Costs	4,682	5,128	5,102
11	Communications	6,380	5,702	5,900
12	Demand Side Management Programs	24,031	24,450	24,593
13	Advertising	2,386	2,392	2,843
14	Insurance	9,056	8,557	8,548
15	Donations	788	3,451	1,713
16	Financial	1,871	2,580	2,307
17	Lease	4,191	4,283	4,705
18	Cost Recovery from Third Parties	(2,549)	(4,905)	(5,105)
19	Computers	6,465	6,760	8,109
20	Regulatory Hearing & OEB Cost Assessment	4,300	2,966	3,467
21	Outbound Affiliate Services	(13,706)	(16,451)	(15,454)
22	Inbound Affiliate Services	11,888	17,365	19,949
23	Bad Debt	6,250	4,700	5,700
24	Other	139	-	
25	Total	470,139	480,017	489,339
26	Indirect Capitalization	(51,376)	(63,017)	(67,343)
27	Direct Capitalization	(21,652)	(20,068)	(22,926)
28	Total	397,111	396,932	399,070
29	Unregulated Storage	(12,883)	(14,020)	(14,771)
30	Non Utility Earnings Adjustments	(1,096)	(3,152)	(1,315)
31	Total Non Utility Costs	(13,979)	(17,172)	(16,086)
32	Total Net Utility Operating and Maintenance Expense	$ 383,132	$ 379,760	$ 382,984

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

Line No.	Particulars ($000s)	2013 Board-approved	2014 Actual	2015 Actual
		(a)	(b)	(c)
	Determination of Taxable Income			
1	Utility income before interest and income taxes	291,239	330,819	323,562
	Adjustments required to arrive at taxable utility income:			
2	Interest expense	(149,464)	(150,239)	(153,766)
3	Utility permanent differences	4,693	3,110	3,468
4		146,468	183,690	173,264
	Utility timing differences			
5	Capital Cost Allowance	(185,314)	(190,751)	(222,048)
6	Depreciation	196,091	200,368	212,219
7	Depreciation through clearing	2,265	2,799	2,586
8	Other	(32,921)	(57,144)	(58,463)
9	Gas Cost Deferrals and Other (current)	-	(107,221)	114,807
10		(19,879)	(151,949)	49,101
11	Taxable income	$ 126,589	$ 31,741	$ 222,365
	Calculation of Utility Income Taxes			
12	Income taxes (line 11 * line 18)	32,280	8,411	58,927
13	Deferred tax on Gas Cost Deferrals	-	28,414	(30,424)
14	Deferred tax drawdown	(15,169)	(12,819)	(12,819)
15	Total taxes	$ 17,111	$ 24,006	$ 15,684
	Tax Rates			
16	Federal tax	15.00%	15.00%	15.00%
17	Provincial tax	10.50%	11.50%	11.50%
18	Total tax rate	25.50%	26.50%	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)	2014 Actual Depreciable UCC Balance (d)	2014 Actual Rate (%) (e)	2014 Actual CCA (f)	2015 Actual Depreciable UCC Balance (g)	2015 Actual Rate (%) (h)	2015 Actual CCA (i)
	Class										
1	1	Buildings, structures and improvements, services, meters, mains	1,259,974	4%	50,399	1,210,375	4%	48,415	1,201,975	4%	48,079
2	1	Non-residential building acquired after March 19, 2007	83,527	6%	5,012	96,767	6%	5,806	103,367	6%	6,202
3	2	Mains acquired before 1988	147,495	6%	8,850	138,633	6%	8,318	130,333	6%	7,820
4	3	Buildings acquired before 1988	4,279	5%	214	4,060	5%	203	3,860	5%	193
5	6	Other buildings	173	10%	17	160	10%	16	140	10%	14
6	7	Compression equipment acquired after February 22, 2005	165,697	15%	24,855	139,767	15%	20,965	207,713	15%	31,157
7	8	Compression assets, office furniture, equipment	79,640	20%	15,928	90,710	20%	18,142	133,160	20%	26,632
8	10	Transportation, computer equipment	18,611	30%	5,583	20,753	30%	6,226	19,913	30%	5,974
9	12	Computer software, small tools	7,701	100%	7,701	10,511	100%	10,511	9,307	100%	9,307
10	13	Leasehold improvements (1)	332	N/A	113	3,279	N/A	308	2,164	N/A	787
11	17	Roads, sidewalk, parking lot or storage areas	946	8%	76	875	8%	70	800	8%	64
12	38	Heavy work equipment	6,878	30%	2,063	4,583	30%	1,375	4,197	30%	1,259
13	41	Storage assets	8,019	25%	2,005	4,976	25%	1,244	4,112	25%	1,028
14	45	Computers - Hardware acquired after March 22, 2004	246	45%	111	136	45%	61	73	45%	33
15	49	Transmission pipeline additions acquired after February 23, 2005	204,628	8%	16,370	233,225	8%	18,658	302,425	8%	24,194
16	50	Computers hardware acquired after March 18, 2007	22,934	55%	12,614	14,158	55%	7,787	18,905	55%	10,398
17	51	Distribution pipelines acquired after March 18, 2007	556,733	6%	33,404	710,767	6%	42,646	815,117	6%	48,907
18	Total		$ 2,567,813		$ 185,314	$ 2,683,735		$ 190,751	$ 2,957,562		$ 222,048

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	2014 Actual	2015 Actual
1	Total provision for depreciation and amortization before adjustments (per page 3)	-	203,167	215,174
2	Adjustments: vehicle depreciation through clearing	-	2,799	2,955
3	Provision for depreciation amortization and depletion	$ -	$ 200,368	$ 212,219

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

		2013 Board-approved			2014 Actual			2015 Actual		
Line No.	Particulars ($000s)	Average Plant (1)	Rate (%)	Provision	Average Plant (1)	Rate (%)	Provision	Average Plant (1)	Rate (%)	Provision
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Intangible plant:									
1	Franchises and consents	-		-	$ 1,251	Amortized	64	1,237	Amortized	63
2	Intangible plant - Other	-		-	6,354	Amortized	122	6,347	Amortized	122
3		-		-	7,605		186	7,583		185
	Local Storage Plant									
4	Structures and improvements	-	2.85%	-	3,733	2.85%	106	3,938	2.85%	112
5	Gas holders - storage	-	2.54%	-	4,574	2.54%	116	4,574	2.54%	116
6	Gas holders - equipment	-	3.54%	-	15,060	3.54%	533	16,065	3.54%	569
7		-		-	23,368		755	24,577		797
	Storage:									
8	Land rights	-	2.10%	-	31,984	2.10%	672	31,984	2.10%	672
9	Structures and improvements	-	2.50%	-	61,071	2.50%	1,527	61,652	2.50%	1,541
10	Wells and lines	-	2.48%	-	89,625	2.48%	2,223	89,863	2.48%	2,229
11	Compressor equipment	-	2.68%	-	238,811	2.68%	6,400	239,963	2.68%	6,431
12	Measuring & regulating equipment	-	3.11%	-	56,166	3.11%	1,747	56,603	3.11%	1,760
13	Other equipment	-			2,394		516	2,394		474
14		-		-	480,050		13,085	482,460		13,107
	Transmission:									
15	Land rights	-	1.76%	-	39,900	1.76%	706	41,023	1.76%	722
16	Structures and improvements	-	2.03%	-	63,190	2.03%	1,283	86,725	2.03%	1,761
17	Mains	-	1.98%	-	1,130,323	1.98%	22,457	1,215,369	1.98%	24,064
18	Compressor equipment	-	3.23%	-	346,044	3.23%	11,177	431,172	3.23%	13,927
19	Measuring & regulating equipment	-	2.60%	-	165,093	2.60%	4,321	193,205	2.60%	5,023
20		-		-	1,744,551		39,944	1,967,494		45,497
	Distribution - Southern Operations:									
21	Land rights	-	1.65%	-	6,235	1.65%	103	6,592	1.65%	109
22	Structures and improvements	-	2.22%	-	129,561	2.22%	2,902	129,494	2.22%	2,901
23	Services - metallic	-	2.81%	-	116,031	2.81%	3,261	119,504	2.81%	3,358
24	Services - plastic	-	2.51%	-	796,934	2.51%	20,003	816,547	2.51%	20,495
25	Regulators	-	5.00%	-	63,131	5.00%	3,204	66,525	5.00%	3,385
26	Regulator and meter installations	-	2.80%	-	68,909	2.80%	1,929	70,457	2.80%	1,940
27	Mains - metallic	-	2.83%	-	434,385	2.83%	12,293	448,560	2.83%	12,694
28	Mains - plastic	-	2.31%	-	548,519	2.31%	12,671	566,435	2.31%	13,085
29	Measuring & regulating equipment	-	3.66%	-	33,601	3.66%	1,230	36,098	3.66%	1,321
30	Meters	-	3.82%	-	241,700	3.82%	9,236	258,217	3.82%	9,864
31	Other equipment	-		-	-		-	-		-
32		-		-	$ 2,439,005		$ 66,832	$ 2,518,431		$ 69,152

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

		2013 Board-approved			2014 Actual			2015 Actual		
Line No.	Particulars ($000s)	Average Plant (1)	Rate (%)	Provision	Average Plant (1)	Rate (%)	Provision	Average Plant (1)	Rate (%)	Provision
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Distribution plant - Northern & Eastern Operations:									
1	Land rights	-	1.71%	-	$ 9,535	1.71%	163	9,666	1.71%	165
2	Structures & improvements	-	2.41%	-	63,772	2.41%	1,537	64,478	2.41%	1,554
3	Services - metallic	-	3.22%	-	98,889	3.22%	3,184	101,243	3.22%	3,260
4	Services - plastic	-	2.60%	-	399,976	2.60%	10,399	417,625	2.60%	10,858
5	Regulators	-	5.00%	-	24,636	5.00%	1,232	26,959	5.00%	1,348
6	Regulator and meter installations	-	2.92%	-	30,124	2.92%	879	30,413	2.92%	888
7	Mains - metallic	-	3.02%	-	405,255	3.02%	12,239	421,221	3.02%	12,721
8	Mains - plastic	-	2.38%	-	214,401	2.38%	5,103	217,028	2.38%	5,165
9	Compressor equipment	-		-	-	-	-	-	-	-
10	Measuring & regulating equipment	-	3.77%	-	120,627	3.77%	4,548	125,249	3.77%	4,722
11	Meters	-	4.03%	-	62,000	4.03%	2,499	67,927	4.03%	2,737
12	Other distribution equipment	-		-	-	-	-	-	-	-
13		-		-	1,429,216		41,783	1,481,810		43,419
	General:									
14	Structures and improvements	-	1.92%		48,158	1.92%	1,646	53,555	1.92%	1,927
15	Office furniture and equipment	-	6.67%	-	11,624	6.67%	769	11,773	6.67%	780
16	Office equipment - computers	-	25.00%	-	75,583	25.00%	18,826	76,413	25.00%	18,117
17	Transportation equipment	-	13.27%	-	51,225	13.27%	6,844	53,310	13.27%	7,132
18	Heavy work equipment	-	6.92%	-	14,672	6.92%	1,023	14,940	6.92%	1,043
19	Tools and other equipment	-	6.67%	-	32,252	6.67%	2,132	33,424	6.67%	2,213
20	Communications equipment & structures	-	6.67%	-	14,266	6.67%	942	15,517	6.67%	1,026
21	Other equipment	-		-	-	-	-	-	-	-
22		-		-	247,780		32,182	258,933		32,239
23	Regulatory Assets	-		-	251,103		8,400	321,738		10,779
24	Sub-total	-		-	6,622,677		203,167	7,063,026		215,174
25	Total provision for depreciation and amortization			-			203,167			215,174
26	Depreciation through clearing			-			2,799			2,955
27		-		-	$ 6,622,677		$ 200,368	$ 7,063,026		$ 212,219

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

Line No.	Particulars ($000's)	2013 Board-approved	2014 Actual	2015 Actual
		(a)	(b)	(c)
1	Storage	11,562	7,418	5,916
2	Transmission	113,795	191,089	394,851
3	Distribution	131,797	162,379	172,968
4	General	37,215	47,458	44,508
5	Other	53,333	68,300	73,106
6	Total	$ 347,702	$ 476,644	$ 691,349
	Less: Parkway West Reliability, and Brantford-Kirkwall/Parkway D Project	80,000	139,085	206,233
		$ 267,702	$ 337,559	$ 485,116

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

Line No.	Particulars ($000s)	2013 Board-approved	2014 Actual	2015 Actual
		(a)	(b)	(c)
	Gas Utility Plant			
1	Gross plant at cost	6,361,532	6,674,254	7,029,496
2	Less: accumulated depreciation	(2,754,070)	(2,868,946)	(2,994,815)
3	Net utility plant	3,607,462	3,805,308	4,034,681
	Working Capital and Other Components			
4	Cash working capital	20,007	20,665	20,688
5	Gas in storage and line pack gas	163,109	174,285	180,264
6	Balancing gas	72,963	65,947	68,895
7	ABC receivable (gas in storage)	(44,901)	(32,327)	(27,915)
8	Inventory of stores, spare equipment	29,618	28,192	26,773
9	Prepaid and deferred expenses	4,955	5,133	5,603
10	Customer deposits	(48,231)	(35,783)	(38,584)
11	Customer interest	(764)	(307)	(179)
12	Total working capital and other components	196,757	225,805	235,545
13	Total rate base before deduction of accumulated deferred income taxes	3,804,218	4,031,113	4,270,226
14	Accumulated deferred income taxes	(69,686)	(54,695)	(41,831)
15	Total rate base	$ 3,734,532	$ 3,976,418	$ 4,228,395

UNION GAS LIMITED
Allocation of Fuel

Line No.	Particulars (GJ)	Board-approved	%	2015 Actual	%	2014 Actual	%	2013 Actual	%
		(a)	(b)	(c)	(d)	(c)	(d)	(e)	(f)
1	M12	3,616,843	77%	2,115,225	62%	1,862,928	63%	3,612,833	79%
2	Other	1,057,714	23%	1,286,425	38%	1,093,774	37%	965,831	21%
3	Total Fuel	4,674,557	100%	3,401,650	100%	2,956,702	100%	4,578,664	100%

UNION GAS LIMITED
Earnings Sharing Calculation
Calendar Year Ending December 31, 2015

Line No.	Particulars ($000s)	2015	Unregulated Storage	Adjustments		2015 Utility
		(a)	(b)	(c)		(d)=(a)-(b)+(c)
	Operating Revenues					
1	Gas Sales	1,674,769	-	(15,565)	i	1,659,203
2	Transportation	155,775	(469)	-		156,244
3	Storage	83,162	75,794	-		7,368
4	Other	25,819	-	(5,917)	ii	19,902
5		1,939,524	75,325	(21,483)		1,842,717
	Operating Expenses					
6	Cost of gas	874,628	2,221	(15,565)	i	856,842
7	Operating and maintenance expenses	399,070	14,771	(1,315)	iii	382,984
8	Depreciation	223,796	11,577	-		212,219
9	Other financing	-	-	820	iv	820
10	Property and other taxes	67,468	1,620	-		65,848
11		1,564,962	30,189	(16,060)		1,518,713
	Other					
12	Gain / (Loss) on sale of assets	(4)	(4)	-		(0)
13	Other / Huron Tipperary	(691)	(691)	-		-
14	Gain / (Loss) on foreign exchange	(1,614)	(18)	1,154	v	(442)
15		(2,309)	(713)	1,154		(442)
16	Earnings before interest and taxes	372,254	44,423	(4,269)		323,562
17	Income taxes					15,684
18	Total utility income subject to earnings sharing					307,878
	Less debt and preference share return components					
19	Long-term debt					154,972
20	Unfunded short-term debt					(1,206)
21	Preferred dividend requirements					2,659
22						156,425
	Less shareholder portions of:					
23	Net short-term storage revenue (after tax)					330
24	Net optimization activity (after tax)					569
25						899
26	Earnings subject to sharing					150,554
27	Common equity					1,522,222
28	Return on common equity (line 26 / line 27)					9.89%
29	Benchmark return on common equity + 100 basis points					9.93%
30	50% earnings sharing % (line 28 - line 29, maximum 1%)					0.00%
31	90% earnings sharing % (if line 30=1%, then line 28 - line 29 - line 30)					0.00%
32	50% earnings sharing $ (line 27 x line 30 x 50%)					-
33	90% earnings sharing $ (line 27 x line 31 x 90%)					-
34	Total earnings sharing $ (line 32 + line 33)					-
35	Pre-tax earnings sharing (line 34 / (1 minus tax rate)					-

Notes:

i Reclassification of optimization revenue as cost of gas

ii Demand-side management incentive

iii	Donations	(1,666)
	CDM program	351
		(1,315)

iv Facility fees and customer deposit interest

v Foreign exchange gain on bank balances

UNION GAS LIMITED
Continuity of Property, Plant and Equipment
Calendar Year Ending December 31, 2015

Line No.	Particulars ($000's)		Balance Dec. 31/14 (a)	Capital Additions (b)	Transfers (c)	Retirements (d)		Balance Dec. 31/15 (e)
	Unregulated Gas Plant in Service:							
	Underground storage plant:							
1	Land	$	2,096		33		$	2,129
2	Land rights		21,667		8,263			29,930
3	Structures and improvements		21,596	192	3,888	(1)		25,675
4	Wells and lines		92,181	8,627	17,583	(1)		118,390
5	Compressor equipment		153,811	187	8,828			162,826
6	Measuring & regulating equipment		22,440	29	1,899			24,368
7	Base pressure gas		22,928	339	4,435			27,702
8	Other equipment		-					-
9		$	336,719	9,374	44,930	(2)	$	391,021
	General plant:							
10	Land	$	17				$	17
11	Structures & improvements		1,566	655		(181)		2,041
12	Office furniture & equipment		394	72		(55)		411
13	Office equipment - computers		6,717	940		(637)		7,020
14	Transportation equipment		2,351	123	(1)	(119)		2,355
15	Heavy work equipment		674	27	0	(32)		669
16	Tools & work equipment		1,108	124	0	(93)		1,139
17	Communication equipment		467	96		(16)		547
18	Other general equipment		-					-
19		$	13,294	2,038	-	(1,133)	$	14,199
20	Total gas plant in service	$	350,013	11,412	44,930	(1,135)	$	405,220
21	Gas plant under construction		11,875	(3,167)				8,708
22	Total unregulated property plant and equipment	$	361,888	8,245	44,930	(1,135)	$	413,928

UNION GAS LIMITED
Continuity of Accumulated Depreciation
Calendar Year Ending December 31, 2015

Line No.	Particulars ($000's)	Balance Dec. 31/14	Transfers	Provisions	Retirements	Net Salvage /(Costs)	Balance Dec. 31/15
		(a)	(b)	(c)	(d)	(e)	(f)
	Unregulated Gas Plant in Service:						
	Underground storage plant:						
1	Land rights	$ 7,971	796	562			$ 9,328
2	Structures & improvements	8,431	852	728	(0)		10,011
3	Wells and lines	27,829	3,161	2,236	(1)		33,224
4	Compressor equipment	45,585	1,889	5,249	-		52,723
5	Measuring & regulating equipment	10,114	1,213	515	-		11,842
6		$ 99,930	7,910	9,289	(1)	-	$ 117,128
	General plant:						
7	Structures & improvements	458		79	(181)		356
8	Office furniture & equipment	206		32	(55)		183
9	Office equipment - computers	4,226		1,686	(637)		5,275
10	Transportation equipment	852	(0)	254	(119)	10	996
11	Heavy work equipment	67	0	37	(32)		73
12	Tools and other equipment	565	0	90	(93)		562
13	Communication equipment	283		42	(16)		309
14		$ 6,657	(0)	2,220	(1,133)	10	$ 7,754
15	Total unregulated gas plant in service	$ 106,587	7,910	11,509	(1,134)	10	$ 124,882

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2015

Line No.	Particulars ($000's)	UNREGULATED
1	Total unregulated provision for depreciation and amortization before adjustments (per page 3)	11,509
	Adjustments:	
2	Vehicle depreciation through clearing	(19)
3	Asset Retirement Obligation expense for Unregulated storage wells	86
4	Unregulated provision for depreciation amortization and depletion	**11,577**

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2015

Line No.	Particulars ($000's)		Average Plant (1) (a)	Rate (%) (b)		Total Provision
	Storage:					
1	Land rights	$	25,799	Allocatioı	$	562
2	Structures and improvements		22,049	Allocation		728
3	Wells and lines		102,580	Allocation		2,236
4	Compressor equipment		157,196	Allocation		5,249
5	Measuring & regulating equipment		21,640	Allocation		515
6	Other equipment					
7		$	329,263		$	9,289
	General:					
8	Structures & improvements	$	1,804	Allocatioı	$	79
9	Office furniture and equipment		403	Allocation		32
10	Office equipment - computers		6,869	Allocation		1,686
11	Transportation equipment		2,353	Allocation		254
12	Heavy work equipment		672	Allocation		37
13	Tools and other equipment		1,124	Allocation		90
14	Communications equipment		507	Allocation		42
15	Other equipment		-			
16		$	13,730		$	2,220
17	Sub-total		342,994			11,509
18	Total unregulated provision for depreciation and amortization before adjustments				$	11,509
19	Vehicle depreciation through clearing					(19)
20	Asset Retirement Obligation expense for Unregulated storage wells					86
21	Unregulated provision for depreciation amortization and depletion		342,994		$	**11,577**

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

UNION GAS LIMITED
Service Quality Indicator Results

S.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM
S.2.1.9.A – TELEPHONE ANSWERING PERFORMANCE
S.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 dividedby 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-15	89,990	102,670	87.6
Feb-15	70,366	91,292	77.1
Mar-15	83,245	103,791	80.2
Apr-15	84,256	108,259	77.8
May-15	96,289	125,120	77.0
Jun-15	74,305	95,434	77.9
Jul-15	70,907	89,987	78.8
Aug-15	88,174	113,152	77.9
Sep-15	73,045	91,958	79.4
Oct-15	83,983	122,912	68.3
Nov-15	70,796	82,983	85.3
Dec-15	59,125	66,234	89.3
Total	944,480	1,193,792	79.1

S.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 decemial 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-15	1,696	82,650	2.1
Feb-15	4,023	72,595	5.5
Mar-15	3,548	80,490	4.4
Apr-15	3,687	86,263	4.3
May-15	3,373	101,100	3.3
Jun-15	3,454	78,472	4.4
Jul-15	3,038	73,927	4.1
Aug-15	2,741	92,548	3.0
Sep-15	2,934	76,168	3.9
Oct-15	7,706	102,860	7.5
Nov-15	1,677	69,238	2.4
Dec-15	1,163	54,057	2.2
Total	39,040	970,368	4.0

S.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM
S.2.1.9.B – BILLING PERFORMANCE
S.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-15	1,362,796	10,555	3,975	Change in load, previously low	90	Vacant, seasonal use (crop
Feb-15	1,427,254	9,304	3,860	estimate/read, previous vacant,	185	dryer), stopped meter,
Mar-15	1,441,419	13,649	8,015	seasonal use.	601	previous high estimate/read.
Apr-15	1,429,938	17,569	14,984		64	
May-15	1,430,162	17,490	14,929		537	
Jun-15	1,432,044	20,541	16,422		2,052	
Jul-15	1,435,274	19,399	15,992		539	
Aug-15	1,437,801	17,412	14,606		133	
Sep-15	1,438,391	17,653	14,710		77	
Oct-15	1,440,008	12,389	8,967		457	
Nov-15	1,442,612	9,062	6,049		254	
Dec-15	1,446,197	8,109	4,723		597	
Total	17,163,896	173,132	127,232		5,586	

S.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM
S.2.1.9.C – METER READING PERFORMANCE
S.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-15	2,003	1,413,529	0.1
Feb-15	4,135	1,413,954	0.3
Mar-15	6,893	1,414,713	0.5
Apr-15	5,228	1,414,545	0.4
May-15	2,323	1,414,184	0.2
Jun-15	1,576	1,414,080	0.1
Jul-15	1,177	1,414,502	0.1
Aug-15	1,444	1,415,732	0.1
Sep-15	1,894	1,417,587	0.1
Oct-15	2,359	1,422,512	0.2
Nov-15	1,240	1,426,446	0.1
Dec-15	928	1,429,804	0.1
Total	31,200	17,011,588	0.2

S.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM

S.2.1.9.D – SERVICE APPOINTMENT RESPONSE TIME

S.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-15	16,061	16,222	99.0%
Feb-15	11,817	11,961	98.8%
Mar-15	15,964	16,089	99.2%
Apr-15	13,544	13,712	98.8%
May-15	13,127	13,315	98.6%
Jun-15	14,222	14,447	98.4%
Jul-15	14,301	14,499	98.6%
Aug-15	13,458	13,631	98.7%
Sep-15	15,572	15,691	99.2%
Oct-15	19,853	20,048	99.0%
Nov-15	16,178	16,381	98.8%
Dec-15	12,510	12,679	98.7%
TOTAL	176,607	178,675	98.8%

S.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-15	161	161		100.0%
Feb-15	144	143	Meter exchange was booked for UG to complete, but had already been assigned to a 3rd party contractor to complete on behalf of UG.	99.3%
Mar-15	125	124	Rep was using a vehicle without onboard laptop, and did not manage work per commitments. Dispatcher thought the order had been completed and did not confirm with Rep.	99.2%
Apr-15	168	168		100.0%
May-15	188	187	Dispatcher did not check the 12:30 pm report listing any missed morning commitments.	99.5%
Jun-15	225	225		100.0%
Jul-15	198	198		100.0%
Aug-15	173	173		100.0%
Sep-15	119	119		100.0%
Oct-15	195	194	Field Rep was not able to update order status on his laptop. Dispatcher assumed the order had been completed.	99.5%
Nov-15	203	203		100.0%
Dec-15	169	169		100.0%
TOTAL	2068	2064		99.8%

S.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM
S.2.1.9.E – GAS EMERGENCY RESPONSE
S.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-15	1,114	1,137	98.0%
Feb-15	1,349	1,385	97.4%
Mar-15	1,237	1,256	98.5%
Apr-15	1,059	1,068	99.2%
May-15	1,087	1,103	98.5%
Jun-15	1,093	1,106	98.8%
Jul-15	1,133	1,147	98.8%
Aug-15	1,135	1,146	99.0%
Sep-15	1,140	1,162	98.1%
Oct-15	1,284	1,299	98.8%
Nov-15	1,188	1,199	99.1%
Dec-15	1,067	1,079	98.9%
TOTAL	13,886	14,087	98.6%

S.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM
S.2.1.9.C – CUSTOMER COMPLAINT WRITTEN RESPONSE
S.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-15	203	203	100.0
Feb-15	193	193	100.0
Mar-15	262	262	100.0
Apr-15	248	248	100.0
May-15	215	215	100.0
Jun-15	250	250	100.0
Jul-15	203	203	100.0
Aug-15	223	223	100.0
Sep-15	197	197	100.0
Oct-15	201	201	100.0
Nov-15	189	189	100.0
Dec-15	180	180	100.0
Total	2,564	2,564	100.0

S.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM
S.2.1.9.G – RECONNECTION RESPONSE TIME
S.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-15	167	185	90.3%
Feb-15	80	83	96.4%
Mar-15	77	81	95.1%
Apr-15	690	716	96.4%
May-15	992	1,050	94.5%
Jun-15	1,329	1,402	94.8%
Jul-15	1,409	1,506	93.6%
Aug-15	1,179	1,286	91.7%
Sep-15	1,418	1,575	90.0%
Oct-15	2,103	2,450	85.8%
Nov-15	935	1,145	81.7%
Dec-15	406	486	83.5%
TOTAL	10,785	11,965	90.1%

ALLOCATION AND DISPOSITION OF 2015 DEFERRAL ACCOUNT BALANCES AND 2015 EARNINGS SHARING AMOUNT

The purpose of this evidence is to address the allocation and disposition of 2015 deferral account balances identified at Tab 1, Appendix A, Schedule 1. There is no 2015 earnings sharing to allocate to rate classes, as described at Tab 2.

The allocation of 2015 deferral account balances to rate classes appears at Tab 3, Appendix A, Schedule 1. Tab 3, Appendix A, Schedule 2 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. Tab 3, Appendix A, Schedule 3, provides the estimated bill impacts of the proposed disposition for general service customers in Union South and Union North.

With the exception of the Deferral Clearing Variance Account (179-132), Tax Variance Account (179-134), Brantford-Kirkwall/Parkway D Project Costs Deferral Account (179-137), Energy East Pipeline Consultation Costs Deferral Account (179-139), Unaccounted for Gas (UFG) Price Variance Account (179-141) and Lobo C Compressor/Hamilton-Milton Pipeline Project Costs Deferral Account (179-142), the allocation of 2015 deferral account balances to rate classes is consistent with the allocation methodologies approved by the Board in Union's 2014 Deferral Account Disposition proceeding (EB-2015-0010) or in Union's 2013 Cost of Service proceeding (EB-2011-0210).

2015 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), the Upstream Transportation Optimization Account (179-131), and the gas supply commodity and gas supply transportation-related balances in the Deferral Clearing Variance Account (179-132).

Spot Gas Variance Account

There is no balance in the Spot Gas Variance Account (179-107) at December 31, 2015.

Unabsorbed Demand Cost Variance Account

Union proposes that the balance in the 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 DP 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 2015 rates.

The UDC associated with Union South is applicable to sales service customers only. Accordingly, Union proposes that the portion of the balance in the UDC Variance Account (179-108) related to Union South be allocated to sales service customers only based on forecast sales service volumes.

Gas Supply Review Consultant Costs

There is no balance in the Gas Supply Review Consultant Costs Deferral Account (179-128) at December 31, 2015.

Upstream Transportation Optimization

Union proposes to allocate the balance in the Upstream Transportation Optimization Deferral 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 Centra MDA, Union WDA, Union SSMDA, Union NDA, Union NCDA and Union EDA) have been allocated to Union North. Transportation optimization net revenues generated using upstream transportation long-haul contracts designed to serve Union South (the Union 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.

Deferral Clearing Variance Account – Gas Supply Commodity and Transportation

Union proposes to allocate the gas supply commodity and gas supply transportation-related balances in the Deferral Clearing Variance Account (179-132) to rate classes based on the differences between the forecast and actual volumes associated with the disposition of deferral account balances for each rate class, per Tab 1, Appendix A, Schedule 7.

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 TransCanada FT transportation demand costs. This approach ensures that transportation optimization margin is allocated to Union North sales service and bundled DP customers consistent with the manner in which this margin is included in Board-approved gas supply transportation rates.

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

2015 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.

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 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 2015 rates.

OTHER DEFERRAL ACCOUNTS

There is no balance in the Unbundled Services Unauthorized Storage Overrun Deferral Account (179-103) at December 31, 2015.

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

There is no balance in the Carbon Dioxide Offset Credits Deferral Account (179-117) at

December 31, 2015.

There is no balance in the IFRS Conversion Costs Account (179-120) at December 31, 2015.

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 2015 DSM costs in Board-approved rates.

Union proposes to allocate the delivery-related balance in the Deferral Clearing Variance Account (179-132) to rate classes based on the differences between the forecast and actual volumes associated with the disposition of deferral account balances for each rate class, per Tab 1, Appendix A, Schedule 7.

Union proposes to allocate the balance in the Normalized Average Consumption ("NAC") Deferral Account (179-133) to General Service rate classes in proportion to the margin variances by rate class resulting from the difference between the actual NAC and the target NAC included in Board-approved rates.

Union is proposing to allocate the balance in the Tax Variance Deferral Account (179-134) to rate classes in proportion to the 2013 Board-approved allocation of rate base. This approach is consistent with how tax changes are allocated in board-approved rates.

There is no balance in the Unaccounted for Gas ("UFG") Volume Variance Account (179-135) at December 31, 2015.

Union proposes to allocate the balance in the Parkway West Project Costs Deferral Account (179-136) to rate classes in proportion to the difference between the actual Project costs and the forecasted Project costs included in 2015 Rates (EB-2014-0271). Union determined the actual Project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2015 Parkway West Project costs.

Union proposes to allocate the balance in the Brantford-Kirkwall/Parkway D Project Costs Deferral Account (179-137) to rate classes in proportion to the difference between the actual Project costs and the forecasted Project costs included in 2015 Rates (EB-2014-0271). Consistent with the methodology described in Union's Brantford-Kirkwall/Parkway D Project application (EB-2013-0074), Union determined the actual Project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2015 Brantford-Kirkwall/Parkway D Project costs.

There is no balance in the Parkway Obligation Rate Variance Account (179-138) at December 31, 2015.

Union is proposing to allocate the balance in the Energy East Pipeline Consultation Costs Deferral Account (179-139) to rate classes in proportion to 2013 Board-approved Administrative and General O&M Expense per Exhibit G3, Tab 2, Schedule 2, updated for the EB-2011-0210 Board Decision.

Union is proposing to allocate the balance in the UFG Price Variance Account (179-141) to rate classes in proportion to the 2013 Board-approved allocation of UFG costs to customers for which Union provides fuel. This allocation is consistent with the allocation of the UFG price-related variance recovered in the Spot Gas Variance Account (179-107) in Union's 2013 Deferral Disposition proceeding (EB-2014-0145).

Union proposes to allocate the balance in the Lobo C Compressor/Hamilton-Milton Pipeline Project Costs Deferral Account (179-142) to rate classes in proportion to the difference between the actual Project costs and the forecasted Project costs included in 2015 Rates (EB-2014-0271). Consistent with the methodology described in Union's 2016 Dawn Parkway Expansion Project application (EB-2014-0261), Union determined the actual Project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2015 Lobo C Compressor/Hamilton-Milton Pipeline Project costs.

DISPOSITION OF 2015 DEFERRAL ACCOUNT BALANCES

For General Service Rate M1, Rate M2, Rate 01 and Rate 10 customers Union proposes to dispose of the net 2015 deferral account balances prospectively, over the October 1, 2016 to March 31, 2017 time period. The prospective refund / recovery approach over six months is consistent with how Union disposed of its 2014 deferral account and earnings sharing balances in EB-2015-0010.

For in-franchise contract and ex-franchise rate classes, Union is proposing to dispose of the net 2015 delivery-related deferral account balances as a one-time adjustment with October 2016 bills customers receive in November 2016. This approach is consistent with the methodology used for the disposition of 2014 deferral account and earnings sharing balances in EB-2015-0010.

GENERAL SERVICE BILL IMPACTS

General Service bill impacts are presented at Tab 3, Appendix A, Schedule 3. For a Rate M1 sales service residential customer in Union South with annual consumption of 2,200 m^3, the charge for the period October 1, 2016 to March 31, 2017 is $7.13. This $7.13 charge consists of a delivery-related charge of $3.87 (line 13, column (c)) and a commodity-related charge of $3.26 (line 14, column (c)). For a bundled direct purchase residential customer the charge is $3.87.

For a Rate 01 sales service residential customer in Union North with annual consumption of 2,200 m^3, the charge for the period October 1, 2016 to March 31, 2017 is $19.47. This $19.47

charge consists of a delivery-related charge of $10.72 (line 1, column (c)) and a gas transportation-related charge of $8.75 (line 3, column (c)). For a bundled direct purchase residential customer the charge is $19.47.

UNION GAS LIMITED
Allocation of 2015 Deferral Account Balances

			Union North					Union South															
Line No.	Particulars ($000's)	Acct No.	Rate 01	Rate 10	Rate 20	Rate 100	Rate 25	M1	M2	M4	M5A	M7	M9	M10	T1	T2	T3	M12	M13	Excess Utility	C1	M16	Total (1)
		(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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(704)	(261)	(93)	-	-	1,167	254	11	3	10	-	0	-	-	-	-	-	-	-	-	388
3	Gas Supply Review Consultant Costs	179-128	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Upstream Transportation Optimization	179-131	3,457	1,189	412	-	103	2,915	485	22	18	-	-	0	-	-	-	-	-	-	-	-	8,600
5	Deferral Clearing Variance Account - Supply (2)	179-132	-	-	-	-	-	102	62	4	(3)	7	-	0	-	-	-	-	-	-	-	-	172
6	Deferral Clearing Variance Account - Transport (2)	179-132	1,237	428	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,665
7	Total Gas Supply Related Deferrals		3,990	1,356	319	-	103	4,184	801	36	19	17	-	0	-	-	-	-	-	-	-	-	10,825
	Storage Related Deferrals:																						
8	Short-Term Storage and Other Balancing Services	179-70	76	20	5	0	-	172	58	19	0	7	2	0	16	117	15	-	-	-	-	-	508
	Delivery Related Deferrals:																						
9	Unbundled Services Unauthorized Storage Overrun	179-103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Gas Distribution Access Rule (GDAR) Costs	179-112	176	-	-	-	-	584	-	-	-	-	-	-	-	-	-	-	-	-	-	-	760
11	Carbon Dioxide Offset Credits	179-117	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	IFRS Conversion Costs	179-120	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Conservation Demand Management	179-123	(25)	(8)	(7)	(12)	-	(70)	(26)	(11)	(18)	(6)	-	-	(12)	(18)	-	-	-	-	-	-	(213)
14	Deferral Clearing Variance Account - Delivery (2)	179-132	324	196	-	-	-	(108)	906	-	-	-	-	-	-	-	-	-	-	-	-	-	1,317
15	Normalized Average Consumption (NAC)	179-133	4,276	1,026	-	-	-	4,699	545	-	-	-	-	-	-	-	-	-	-	-	-	-	10,546
16	Tax Variance	179-134	(11)	(2)	(1)	(1)	(0)	(23)	(4)	(1)	(1)	(0)	(0)	(0)	(1)	(3)	(0)	(12)	(0)	(0)	(0)	(0)	(60)
17	Unaccounted for Gas (UFG) Volume Variance Account	179-135	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Parkway West Project Costs	179-136	60	(1)	5	7	3	259	28	10	8	3	0	0	9	45	2	(778)	0	3	4	0	(334)
19	Brantford-Kirkwall/Parkway D Project Costs	179-137	163	22	18	15	5	376	50	13	13	4	1	0	9	34	3	(152)	0	5	(0)	(0)	579
20	Parkway Obligation Rate Variance	179-138	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Energy East Pipeline Consultation Costs	179-139	27	2	2	2	1	69	6	2	3	1	0	0	2	5	1	13	0	1	0	0	137
23	Unaccounted for Gas (UFG) Price Variance Account	179-141	(66)	(21)	(7)	(0)	-	(277)	(92)	(38)	(50)	(14)	(6)	-	-	-	-	-	(8)	-	-	(6)	(585)
22	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	179-142	(108)	(15)	(12)	(10)	(4)	(245)	(33)	(8)	(8)	(3)	(0)	(0)	(5)	(20)	(2)	142	(0)	(4)	1	0	(335)
24	Total Delivery-Related Deferrals		4,815	1,199	(3)	(0)	5	5,264	1,381	(33)	(54)	(15)	(5)	0	2	44	4	(788)	(8)	4	5	(5)	11,812
25	Total 2015 Storage and Delivery Disposition (Line 8 + Line 24)		4,891	1,219	3	0	5	5,436	1,439	(14)	(53)	(9)	(3)	0	18	161	19	(788)	(8)	4	5	(5)	12,320
26	Total 2015 Deferral Account Disposition (Line 7 + Line 25)		8,882	2,575	322	0	108	9,621	2,240	22	(35)	8	(3)	0	18	161	19	(788)	(8)	4	5	(5)	23,145
27	2015 Earnings Sharing (3)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Grand Total (Line 26 + Line 27)		8,882	2,575	322	0	108	9,621	2,240	22	(35)	8	(3)	0	18	161	19	(788)	(8)	4	5	(5)	23,145

Notes:
(1) Exhibit A, Tab 1, Appendix A, Schedule 1.
(2) Exhibit A, Tax 1, Appendix A, Schedule 7, pp. 2-3.
(3) Exhibit A, Tab 2, Appendix B, Schedule 1.

UNION GAS LIMITED
General Service Unit Rates for Prospective Recovery/(Refund) - Delivery
2015 Deferral Account Disposition

Line No.	Particulars	Rate Class	2015 Deferral Balances ($000's) (a)	2015 Earnings Sharing Mechanism ($000's) (b)	Deferral Balance for Disposition ($000's) (c) = (a+b)	Forecast Volume (10^3m^3) (1) (d)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3) (e) = (c/d)*100
1	Small Volume General Service	01	4,891	-	4,891	790,336	0.6189
2	Large Volume General Service	10	1,219	-	1,219	258,683	0.4713
3	Small Volume General Service	M1	5,436	-	5,436	2,359,719	0.2304
4	Large Volume General Service	M2	1,439	-	1,439	882,624	0.1630

Notes:
(1) Forecast volume for the period October 1, 2016 to March 31, 2017.

UNION GAS LIMITED
General Service Unit Rates for Prospective Recovery/(Refund) - Gas Supply Transportation
2015 Deferral Account Disposition

Line No.	Particulars	Rate Class	2015 Deferral Balances ($000's)	2015 Earnings Sharing Mechanism ($000's)	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)	(d)	(e) = (c/d)*100
1	Small Volume General Service	01	3,990	-	3,990	790,336	0.5049
2	Large Volume General Service	10	1,356	-	1,356	257,433	0.5268

Notes:
(1) Forecast volume for the period October 1, 2016 to March 31, 2017.

UNION GAS LIMITED
Unit Rates for Prospective Recovery/(Refund) - Gas Supply Commodity
2015 Deferral Account Disposition

Line No.	Particulars	Rate Class	2015 Deferral Balances ($000's)	2015 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	Forecast Volume (10^3m^3) (1)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3) (2)
			(a)	(b)	(c) = (a+b)	(d)	(e) = (c/d)*100
1	Small Volume General Service	M1	4,184	-	4,184	2,104,190	0.1942
2	Large Volume General Service	M2	801	-	801	457,042	0.1942
3	Firm Com/Ind Contract	M4	36	-	36	19,180	0.1942
4	Interruptible Com/Ind Contract	M5	19	-	19	5,994	0.1942
5	Special Large Volume Contract	M7	17	-	17	17,842	0.1942
6	Small Wholesale	M10	0	-	0	279	0.1942
7	Total				5,057	2,604,528	0.1942

Notes:
(1) Forecast sales service volumes for the period October 1, 2016 to March 31, 2017.
(2) Unit rate for prospective recovery/refund for each rate class equal to the gas supply commodity weighted-average unit rate.

UNION GAS LIMITED
Contract Unit Rates for One-Time Adjustment - Delivery
2015 Deferral Account Disposition

Line No.	Particulars	Rate Class	2015 Deferral Balances ($000's)	2015 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2015 Actual Volume (10^3m^3)	Unit Rate (cents/m^3)
			(a)	(b)	(c) = (a+b)	(d)	(e) = (c/d)*100
	Union North						
1	Medium Volume Firm Service (1)	20	(1)	-	(1)	102,074	(0.0005)
2	Medium Volume Firm Service (2)	20T	(2)	-	(2)	438,518	(0.0005)
3	Large Volume High Load Factor (2)	100T	(0)	-	(0)	1,398,188	(0.0000)
4	Large Volume Interruptible	25	5	-	5	147,757	0.0034
	Union South						
5	Firm Com/Ind Contract	M4	(14)	-	(14)	457,209	(0.0030)
6	Interruptible Com/Ind Contract	M5	(53)	-	(53)	208,864	(0.0255)
7	Special Large Volume Contract	M7	(9)	-	(9)	427,949	(0.0020)
8	Large Wholesale	M9	(3)	-	(3)	66,511	(0.0044)
9	Small Wholesale	M10	0	-	0	301	0.0566
10	Contract Carriage Service	T1	18	-	18	443,869	0.0040
11	Contract Carriage Service	T2	161	-	161	4,365,603	0.0037
12	Contract Carriage- Wholesale	T3	19	-	19	263,235	0.0071

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
2015 Deferral Account Disposition

Line No.	Particulars	Rate Class	2015 Deferral Balances ($000's)	2015 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2015 Actual Volume/ Demand	Billing Units	Unit Volumetric/ Demand Rate
			(a)	(b)	(c) = (a+b)	(d)		(e) = (c/d)*100
	Gas Supply Transportation (cents/m^3)							
1	Medium Volume Firm Service	20	319	-	319	5,688	10^3m^3/d	5.6135
2	Large Volume Interruptible	25	103	-	103	97,426	10^3m^3	0.1054
	Storage ($/GJ)							
3	Bundled-T Storage Service	20T/100T	6	-	6	147,504	GJ/d	0.0386

UNION GAS LIMITED
Storage and Transportation Service Amounts for Disposition
2015 Deferral Account Disposition

Line No.	Particulars ($000's) (1)	Rate Class	2015 Deferral Balances	2015 Earnings Sharing Mechanism	Deferral Balance for Disposition
			(a)	(b)	(c)
1	Storage and Transportation	M12	(788)	-	(788)
2	Local Production	M13	(8)	-	(8)
3	Short-Term Cross Franchise	C1	5	-	5
4	Storage Transportation Service	M16	(5)	-	(5)

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

UNION GAS LIMITED
General Service Customer Bill Impacts

Line No.	Particulars	Rate Component	Unit Rate for Prospective Recovery/(Refund) (cents/m³) (1)	Volume (m³) (2)	Bill Impact ($)
			(a)	(b)	(c) = (a x b) / 100
1	Rate 01	Delivery	0.6189	1,733	10.72
2		Commodity	-	1,733	-
3		Transportation	0.5049	1,733	8.75
4			1.1238		19.47
5	Sales Service				19.47
6	Direct Purchase Bundled T				19.47
7	Rate 10	Delivery	0.4713	66,961	315.59
8		Commodity	-	66,961	-
9		Transportation	0.5268	66,961	352.75
10			0.9981		668.33
11	Sales Service				668.33
12	Direct Purchase Bundled T				668.33
13	Rate M1	Delivery	0.2304	1,679	3.87
14		Commodity	0.1942	1,679	3.26
15			0.4246		7.13
16	Sales Service				7.13
17	Direct Purchase				3.87
18	Rate M2	Delivery	0.1630	55,772	90.91
19		Commodity	0.1942	55,772	108.31
20			0.3572		199.22
21	Sales Service				199.22
22	Direct Purchase				90.91

Notes:
(1) Tab 3, Appendix A, Schedule 2, pages 1-3, column (e).
(2) Average consumption, per customer, for the period October 1, 2016 to March 31, 2017.
Rate 01 volume based on annual consumption of 2,200 m^3.
Rate 10 volume based on annual consumption of 93,000 m^3.
Rate M1 volume based on annual consumption of 2,200 m^3.
Rate M2 volume based on annual consumption of 73,000 m^3.

INCREMENTAL TRANSPORTATION CONTRACTING ANALYSIS

Introduction

Pursuant to Union's 2005-0520 Settlement Agreement[1], 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. TransCanada Empress to Union WDA and Empress to Union MDA (2 years) Transportation Contracts
2. TransCanada Empress to Union SSMDA (5 year) Transportation Contract
3. TransCanada Empress to Union WDA (1 year) Transportation Contract
4. TransCanada Union Parkway Belt to Union CDA (1 year) Transportation Contract
5. DTE Energy (1 year) Transportation Contract
6. DTE Energy (35 month) Transportation Contract
7. Panhandle (1 year) Transportation Contract
8. Market Based Transportation - Dominion South Point to Dawn (1 year) Transportation Contract

[1] EB-2005-0520 Settlement Agreement, page 13, subsection 3.1, paragraph 2; and, Appendix B – Incremental Transportation Contracting Analysis.

1. TRANSCANADA EMPRESS TO UNION WDA AND EMPRESS TO UNION MDA (2 YEARS) TRANSPORTATION CONTRACTS

Capacity History

Historically, the use of upstream diversions on TransCanada, although a discretionary service, had been extremely reliable. For many years Union planned for, and utilized, upstream diversions to meet the peak day requirements of the Union NDA. However, in 2013, TransCanada's long-haul transportation contracting and system operations changed such that upstream diversions were no longer highly reliable. As such, Union began experiencing interruptions of upstream diversions in December 2013. In response, Union needed to reduce the reliance on diversions in the gas supply portfolio by rebalancing the Union North portfolio to align firm contracts delivery points with areas requiring firm capacity.

New Capacity

Union entered into two firm long-haul transportation contracts with TransCanada for capacity of 11,527 GJ/d from Empress to the Union WDA and 1,043 GJ/d from Empress to the Union MDA. These new contracts replaced contracts held from Empress to the Union NDA of 12,570 GJ/d.

Rationale for Transportation Capacity

By contracting for firm long-haul transportation capacity directly to the Union WDA and the Union MDA respectively, Union no longer relies on interruptible diversions to serve peak day demand in the Union WDA and Union MDA.

The benefits of this capacity are:

1. Provides firm transportation capacity to meet the firm design day loads within the Union WDA and Union MDA;
2. Union WDA and Union MDA demand charges are cheaper than the capacity turned back from the Union NDA and are no longer reliant on upstream diversions;
3. Contract is renewable and has an end date that aligns with the gas year;
4. Firm transportation purchase is consistent with the gas supply principal of ensuring secure and reliable gas supply to Union's service territory at a reasonable cost; and,
5. Deliveries to meet design day demand in the Union MDA and Union WDA will no longer be subject to interruptions.

Empress to Union WDA Contract Parameters

- Transportation Provider: TransCanada Pipelines Limited
- Service: (FT) Firm Gas Transportation Service – Renewable

- Term: November 1, 2015 through October 31, 2017
- Capacity: 11,527 GJ/day
- Current Rate: $1.0110 Cdn/GJ at 100% load factor (includes abandonment surcharge, exclusive of fuel)
- Primary Receipt Point: Empress
- Delivery Point: Union WDA
- Renewal Rights: Per TransCanada Firm Transportation Tariff (24 month notice required)

Empress to Union MDA Contract Parameters

- Transportation Provider: TransCanada Pipelines Limited
- Service: (FT) Firm Gas Transportation Service – Renewable
- Term: November 1, 2015 through October 31, 2017
- Capacity: 1,043 GJ/d
- Current Rate: $0.7039 Cdn/GJ at 100% load factor (includes abandonment surcharge, exclusive of fuel)
- Primary Receipt Point: Empress
- Delivery Point: Centra MDA
- Renewal Rights: Per TransCanada Firm Transportation Tariff (24 month notice required)

Incremental Contracting Analysis Form

This capacity replaces Union NDA contracts that were not renewed. Since TransCanada is the only pipeline that provides transportation to the Union WDA and Union MDA, a landed cost analysis is not applicable.

2. TRANSCANADA EMPRESS TO UNION SSMDA (5 YEAR) TRANSPORTATION CONTRACT

Capacity History

Union holds 8,843 GJ/d of firm transportation capacity from Empress to Union SSMDA on the TransCanada system and 35,022 GJ/d of Storage Transportation Service ("STS") withdrawals that can be utilized to meet the design day requirements in the Union SSMDA. TransCanada has not typically had excess capacity to contract on a firm basis into the Union SSMDA.

New Capacity

In 2014 and 2015, TransCanada identified the ability to offer limited incremental firm capacity into the SSMDA, on the condition customers' sign up for a 5-year term. On September 28th, 2015, Union bid for 12,800 GJ/d of firm transportation capacity in the TransCanada New Capacity Open Season ("NCOS") from Empress to Union SSMDA. Union was subsequently awarded all requested capacity. As specified in the NCOS, Union was required to execute a Financial Assurances Agreement and a firm transportation contract for an initial 5-year contract term.

Rationale for Transportation Capacity

The Union North transportation portfolio utilized significant STS withdrawals to meet firm demands in the Union SSMDA. Given STS withdrawals are interruptible between April 1 and October 31 of each year, Union did not have sufficient firm transportation to meet forecasted firm loads between April 1 and October 31.

Acquiring new capacity into the Union SSMDA fulfills two requirements. First, the incremental firm transportation would meet a portion of the forecasted Union North design day shortfall. Winter STS withdrawals can be pooled away from the Union SSMDA delivery area to meet needs in other Union North delivery areas. Second, the new capacity would also provide additional April 1 and October 31 firm transportation into the Union SSMDA to meet firm loads in summer months.

The benefits of this capacity are:

1. Provides firm transportation capacity to meet the firm design day loads in Union North;
2. Contract is renewable and has an end date that aligns with the gas year;
3. Provides firm transportation assets to meet Union firm demands in the Union SSMDA in the April through October period when STS withdrawals are interruptible; and,

4. Firm transportation 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
- Term: November 1, 2015 through October 31, 2020
- Volume: 12,800 GJ/day
- Current Rate: $1.4135 Cdn/GJ at 100% load factor (includes abandonment surcharge, exclusive of fuel)
- Receipt Point: Empress
- Delivery Point: Union SSMDA
- Renewal Rights: Per TransCanada Firm Transport Tariff (24 month notice required)

Incremental Contracting Analysis Form

As this capacity is only available from TransCanada, and it is the only path offered, a landed cost analysis is not applicable.

3. TRANSCANADA EMPRESS TO UNION WDA (1 YEAR) TRANSPORTATION CONTRACT

New Capacity

Union entered into a one-year, firm transportation long-haul contract with TransCanada for capacity of 1,503 GJ/d from Empress to the Union WDA.

Rationale for Transportation Capacity

In order to meet the peak day requirements in the Union North, 1,503 GJ/d of firm transportation capacity was required to the Union WDA. Union is only forecasting a one-year transportation shortfall as Union will gain access to existing firm transportation long-haul capacity that is temporarily assigned to other customers effective November 1, 2016.

The benefits of this capacity are:

1. Provides firm transportation capacity to meet the firm design day loads within the Union WDA to cover a one year shortfall;
2. Contract is one year in duration which aligns with the gas year avoiding excess capacity in future years; and,
3. Firm transportation contract is consistent with the gas supply principal of ensuring secure and reliable gas supply to Union's service territory at a reasonable cost.

Empress to Union WDA Contract Parameters

- Transportation Provider: TransCanada Pipelines Limited
- Service: (FT) Firm Gas Transportation Service
- Term: November 1, 2015 through October 31, 2016
- Volume: 1,503 GJ/d
- Current Rate: $1.0110 Cdn/GJ at 100% load factor (includes abandonment surcharge, exclusive of fuel)
- Primary Receipt Point: Empress
- Delivery Point: Union WDA

Incremental Contracting Analysis Form

The only firm transportation capacity available to the Union WDA was TransCanada Empress to Union WDA. Thus, a landed cost comparison is not applicable.

4. TRANSCANADA UNION PARKWAY BELT TO UNION CDA (1 YEAR) TRANSPORTATION CONTRACT

Capacity History

As discussed in EB-2014-0182[2], TransCanada had not historically required that Union contract for volumes transported from Parkway to the Union CDA. Prior to the start of

[2] EB-2014-0182, Exhibit A, Tab 5, Page 3.

winter 2011/2012, TransCanada informed Union that it would need to contract for these volumes going forward.

From 2011 through to 2015, Union contracted for capacity to the Union CDA in order to comply with TransCanada's requirements. In 2011, TransCanada only offered a portion of the capacity required as renewable firm transportation and all remaining capacity offered was non-renewable ("FT-NR"). The capacity requirements for each subsequent year were determined by the annual Gas Supply Plan, and Union purchased transportation capacity from the secondary market since additional firm short-haul transportation to the Union CDA was not offered by TransCanada. A limited number of parties hold capacity to the Union CDA, so the contract terms varied over time depending on what was offered by secondary market participants. In the summer of 2015, TransCanada informed Union that it could provide the capacity to the Union CDA that Union had otherwise relied on the secondary market to provide.

Union requested and received Board approval for leave to construct the Burlington Oakville facilities in EB-2014-0182. This project is designed to feed the existing and growing needs of the Burlington – Oakville market. Once the Burlington Oakville facilities are placed into service Union will no longer require services from other providers to meet the needs of this market area.

New Capacity

In August of 2015, TransCanada held an Existing Capacity Open Season offering up to 92,000 GJ/d of capacity from Union Parkway Belt to the Union CDA. On August 28, 2015, Union was able to secure a one-year, FT-NR contract with TransCanada to transport 61,888 GJ/d from Union Parkway Belt to the Union CDA commencing November 1, 2015.

Rationale for Transportation Capacity

This new contract replaces a secondary market contract that Union had in place to the Union CDA in previous years, and it bridges Union's transportation needs until the Burlington Oakville facilities are in service (targeted for November 1, 2016).

The benefits of this capacity are:

1. Provides firm transportation capacity to meet the firm design day loads within the Union CDA;
2. Firm transportation purchase is consistent with the gas supply principal of ensuring secure and reliable gas supply to Union's service territory at a reasonable cost;
3. Contract expiry lines up with expected in service date for the Burlington Oakville facilities which, in conjunction with existing Union facilities, will provide for the increasing demand requirements in the Union CDA; and,

4. TransCanada service is less expensive than what Union had been paying for market based services in previous years.

Contract Parameters

- Transportation Provider: TransCanada Pipelines Limited
- Service: (FT) Firm Gas Transportation Service
- Term: November 1, 2015 through October 31, 2016
- Volume: 61,888 GJ/d
- Current Rate: $0.1595 Cdn/GJ at 100% load factor (includes abandonment surcharge, exclusive of fuel)
- Receipt Point: Union Parkway Belt
- Delivery Point: Union CDA

Incremental Contracting Analysis Form

The only firm primary transportation path available to the Union CDA is on the TransCanada Mainline system. Union requires incremental capacity to transport gas already on Union’s system into the Union CDA. There is no incremental supply purchase associated with this transportation. Therefore, in lieu of a landed cost analysis, the table below illustrates the transportation options available to Union to meet the requirements in the Union CDA.

Options include:

Provider	Path	Price/Term	Total Cost ($ CDN)
TransCanada	Union Parkway Belt to Union CDA	FT Toll $4.7672 ($/GJ/mo) Abandonment Surcharge $0.08466 ($/GJ/mo) 12-month term	**$3,603,263** ($4.7672 + $0.08466) * 12 * 61,888
3rd Party Market (underpinned by TransCanada contracted capacity)	Union Parkway Belt to Union CDA	$0.96 ($/GJ/d) 5-month term (Nov 1 to Mar 31)	**$8,971,284** ($0.96 * 151 * 61,888)
TransCanada	Empress to Union CDA	FT Toll $54.58058 ($/GJ/mo) Abandonment Surcharge $4.69885 ($/GJ/mo) 12-month term	**$44,024,224** ($54.58058+$4.69885) * 12 * 61,888

5. DTE ENERGY (1 YEAR) TRANSPORTATION CONTRACT

Capacity History

Union held a contract for 10,000 Dth/d (10,551 GJ/d) at a 100% load factor rate of $0.035 US/Dth, with a one-year term commencing November 1, 2014 and expiring October 31, 2015. This capacity has receipt point flexibility as it allows Union to purchase supply at either the Michcon Generic receipt point or Willow Run receipt point and flow the gas to the Union (St. Clair) interconnect for ultimate delivery to Dawn. Union had the right to extend the contract for one additional year with a minimum three months of notice. Union provided the landed cost analysis for the original contract as part of the 2014 Disposition of Deferral Account Balances evidence.[3]

Extended Capacity

Union exercised the one-year extension right on the existing 10,000 Dth/d DTE Energy transportation contract at the same 100% load factor rate of $0.035 US/Dth. This capacity will now expire October 31, 2016. This capacity is used to meet the gas supply requirements of Union South customers.

Rationale for Transportation Capacity

Union's Gas Supply Plan supports the DTE Energy capacity in order for Union to meet forecasted demand within the Union South sales service customer base. The landed cost of this gas is forecast to be competitive with supply flowing on alternative upstream pipelines.

The benefits of this capacity are:

1. Landed cost of gas flowing to Union along this route is competitively priced and has an end date that aligns with the gas year;
2. Contract supports Union's objective of structuring a portfolio with a diversity of contract terms and supply basins;

[3] EB-2015-0010, Exhibit A, Tab 4, p. 9

3. Low UDC exposure relative to alternative upstream pipeline routes due to the low demand charge on this route;
4. Provides a fixed-rate toll which provides toll certainty on a portion of Union's upstream transportation;
5. Provides Union receipt point flexibility; and,
6. Lands gas at St. Clair to support diversity of deliveries and system integrity.

Contract Parameters

- Transportation Provider: DTE Energy
- Service: Firm Transportation
- Extension Term: November 1, 2016 through October 31, 2017
- Volume: 10,000 Dth/d (10,551 GJ/d)
- Rate: $0.035 US/Dth at 100% Load Factor (exclusive of fuel)
- Receipt Point: Michcon Generic or Willow Run
- Delivery Point: Union (St. Clair)

Incremental Contracting Analysis Form

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

6. DTE Energy (35 Month) Transportation Contract

Capacity History

Union had originally signed agreements with NEXUS for capacity that would be implemented in two phases. The first phase would have NEXUS providing Union with 75,000 Dth/d (79,125 GJ/d) of transportation capacity for two years commencing November 1, 2015 by using existing pipeline infrastructure in Michigan and Ontario. Phase 2, commencing November 1, 2017, was similar to how the NEXUS project is now structured, providing Union 150,000 Dth/d (158,258 GJ/d) of transportation capacity from Kensington, Ohio to the DTE interconnect with Union. Phase 1 was subsequently removed from the NEXUS project scope, leaving Union with a temporary capacity shortfall in its transportation portfolio.

New Capacity

Union was able to acquire a new contract for 60,000 Dth/d (63,303 GJ/d) at a 100% load factor rate of $0.050 US/Dth, with a 35-month term commencing December 1, 2015 and expiring the earlier of October 31, 2018 or the in-service date for NEXUS. This capacity has receipt point flexibility as it allows Union to purchase supply at either the Michcon Generic receipt point or the Panhandle Pipeline interconnect with DTE and flow the gas to the Union (St. Clair) interconnect for ultimate delivery to Dawn. This capacity is used to meet the gas supply requirements of Union South customers.

Union requested a December 1, 2015 start date to align with the expiry of the Alliance/Vector contracts on November 30, 2015.

Rationale for Transportation Capacity

Union's Gas Supply Plan supports the DTE Energy capacity in order for Union to meet forecasted demand within the Union South sales service customer base. The landed cost of this gas is forecast to be competitive with supply flowing on alternative upstream pipelines and generates a lower landed cost than the Alliance/Vector supplies it replaces. The benefits of this capacity are:

1. Landed cost of gas flowing to Union along this route is competitively priced and is lower than the arrangements it replaces;
2. Contract supports Union's objective of structuring a portfolio with a diversity of contract terms and supply basins;
3. Firm transportation contract is consistent with the gas supply principal of ensuring secure and reliable gas supply to Union's service territory at a reasonable cost;
4. Low UDC exposure relative to alternative upstream pipeline routes due to the low demand charge on this route;
5. Provides a fixed-rate toll which provides toll certainty on a portion of Union's upstream transportation;
6. Provides Union receipt point flexibility;
7. Lands gas at St. Clair to support diversity of deliveries and system integrity;
8. Start date lines up with expiry of Union's Alliance/Vector contracts; and,

9. End date linked to the in-service date for NEXUS transportation capacity, providing portfolio flexibility to accommodate changes in the service date for NEXUS.

Contract Parameters

- Transportation Provider: DTE Energy
- Service: Firm Transportation
- Start Date: December 1, 2015
- End Date: The earlier of NEXUS in-service date or October 31, 2018
- Volume: 60,000 Dth/d (63,303 GJ/d)
- Current Rate: $0.050 US/Dth at 100% load factor (exclusive of fuel)
- Receipt Point(s): Michcon Generic, interconnect of PEPL/DTE Gas Co.
- Delivery Point(s): Union (St. Clair)

Incremental Contracting Analysis Form

Tab 4, Appendix A, Schedule 2 shows a comparison of landed costs for the DTE Energy 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.

7. PANHANDLE (1 YEAR) TRANSPORTATION CONTRACT

Capacity History

Union holds 27,000 Dth/d (28,487 GJ/d) of firm transportation on Panhandle Eastern Pipeline Company, LP (Panhandle) 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/d (28,487 GJ/d), Union held a contract for 10,000 Dth/d (10,551 GJ/d) of incremental firm transportation on Panhandle (Panhandle Field Zone to Ojibway) beginning November 1, 2013, with a one-year term that expired on October 31, 2014. In 2014, Union contracted to extend this 10,000 Dth/d (10,551 GJ/d) contract to October 31, 2015 expiry date. Union provided the landed cost analysis for the original contract as part of the 2014 Disposition of Deferral Account Balances evidence.[4].

Renewed Capacity

Union has exercised its Right of First Refusal (ROFR) rights on its existing contract for 10,000 Dth/d (10,551 GJ/d) at a 100% load factor rate of $0.4265 US/Dth, for a one-year term commencing November 1, 2015 and expiring October 31, 2016.

[4] EB-2015-0010, Exhibit A, Tab 4, p. 7.

Rationale for Transportation Capacity

Union's Gas Supply Plan supports the Panhandle capacity to meet forecasted demand for Union South sales service customers. 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. 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 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. Provides a fixed-rate toll which provides toll certainty on a portion of Union's supply;
5. Lands gas at Ojibway to support diversity of deliveries and support system integrity. Deliveries to the Ojibway interconnect reinforce the Windsor area market and supplement Union transmission capabilities from Dawn; and,
6. Provides Union with both receipt and delivery flexibility within the path.

Contract Parameters

- Transportation Provider: Panhandle Eastern Pipe Line Company, LP
- Service: Firm Transportation

- Term: November 1, 2015 through October 31, 2016
- Volume: 10,000 Dth/d (10,551 GJ/d)
- Current Rate: $0.4265 US/Dth at 100% Load Factor (exclusive of fuel)
- Primary Receipt Point: Panhandle Field Zone (Cheyenne Plains)
- Delivery Point: Union (Ojibway)
- Renewal Rights: Right of First Refusal

Incremental Contracting Analysis Form

Tab 4, Appendix A, Schedule 1 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 1 is in the format agreed upon in the EB-2005-0520 Settlement Agreement

8. MARKET BASED TRANSPORTATION - DOMINION SOUTH POINT TO DAWN (1 YEAR) TRANSPORTATION CONTRACT

New Capacity

Union entered into a contract for firm transportation capacity of 20,000 Dth/d (21,101 GJ/d) from Dominion South Point to Dawn for a one-year term starting November 1, 2015. This capacity is provided by a marketer that is able to provide a firm service from Dominion South Point to Dawn. Union delivers gas on the Dominion Gas Transmission system at the point denoted as Dominion South Point and then Union receives an equivalent amount of gas at Dawn. This contract will allow Union to develop relationships with potential NEXUS suppliers in Appalachia and gain experience purchasing Marcellus/Utica supply.

Rationale for Transportation Capacity

Union has contracted for capacity on the new proposed NEXUS pipeline, which will directly connect the growing supplies from the Appalachian basin to the Dawn hub. Union sought, and was granted, pre-approval for the NEXUS contract cost consequences from the Board[5]. In order to seek business relationships with producers located in the Appalachian basin, Union sought market based options to allow Union to purchase supplies in the Appalachian area. By contracting for market based transportation services that originate at Dominion South Point, Union is able to purchase gas supply at Dominion South Point, a very liquid and active location for most Appalachian producers and marketers. This service will allow Union to work with a variety of suppliers in the Appalachian region in order to gain additional experience and form relationships prior to the in-service date of NEXUS.

The benefits of this capacity are:

1. Landed cost of gas flowing to Union along this route is competitively priced and has an end date that aligns with the gas year;
2. Contract supports Union's objective of structuring a portfolio with a diversity of contract terms and supply basins;

[5] EB-2015-0166 / EB-2015-0175

3. Provides a fixed-rate toll which provides toll certainty on a portion of Union's upstream transportation; and,
4. Provides access to a receipt point where Appalachian producers and marketers are active, allowing Union to build and establish relationships with key suppliers in anticipation of the NEXUS transportation capacity starting in 2017.

Contract Parameters

- Service: Market Based Transportation
- Term: November 1, 2015 through October 31, 2016
- Volume: 20,000 Dth/d (21,101 GJ/d)
- Current Rate: $1.2575 US/Dth at 100% load factor, (exclusive of fuel)
- Receipt Point: Dominion South Point
- Delivery Point: Dawn

Incremental Contracting Analysis Form

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

UNION GAS LIMITED
2015-2016 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)	**TCPL Niagara**	Niagara	-0.415	2.9522	0.1212	0.0000	0.0000	0.1212	$3.07	**$3.61**	Kirkwall
	Dawn	Dawn	-0.016	3.3517	0.0000	0.0000	0.0000	0.0000	$3.35	**$3.94**	Dawn
*	**Marcellus to Dawn Market Based Transportation**	Marcellus - Dom Sth Pt	-1.231	2.1365	1.2680	0.0000	0.0000	1.2680	$3.40	**$4.00**	Dawn
*	**Michcon to St. Clair**	SE Michigan	-0.065	3.3022	0.0618	0.0000	0.0614	0.1233	$3.43	**$4.03**	Dawn
(2)	**Vector 2014**	Chicago	-0.095	3.2722	0.1900	0.0018	0.0314	0.2232	$3.50	**$4.11**	Dawn
	Vector 1 Year (Mkt Quote)	Chicago	-0.095	3.2722	0.2100	0.0018	0.0314	0.2432	$3.52	**$4.13**	Dawn
*(2)	**PEPL (2012-2017)**	Panhandle Field Zone	-0.349	3.0184	0.3200	0.0441	0.1455	0.5096	$3.53	**$4.15**	Ojibway
(2)	**Vector (2008-2016)**	Chicago	-0.095	3.2722	0.2500	0.0018	0.0314	0.2832	$3.56	**$4.18**	Dawn
	GLGT to TCPL	Northern Michigan	-0.055	3.3122	0.2718	0.0074	0.0202	0.2995	$3.61	**$4.25**	Dawn
(2)	**Trunkline/Panhandle**	Trunkline Field Zone - ELA	-0.097	3.2701	0.1923	0.0299	0.1321	0.3543	$3.62	**$4.26**	Ojibway
(2)	**PEPL - (2014-2015)**	Panhandle Field Zone	-0.349	3.0184	0.4200	0.0441	0.1455	0.6096	$3.63	**$4.27**	Ojibway
(2)	**Trunkline/Panhandle**	Trunkline Field Zone 1A	-0.082	3.2851	0.1923	0.0275	0.1254	0.3452	$3.63	**$4.27**	Ojibway
(2)	**Panhandle Longhaul (2010-2017)**	Panhandle Field Zone	-0.349	3.0184	0.4251	0.0441	0.1455	0.6147	$3.63	**$4.27**	Ojibway
	ANR-Michcon-Union (Gulf)	ANR South East	-0.098	3.2697	0.3884	0.0161	0.1397	0.5442	$3.81	**$4.48**	Dawn
(2)	**Alliance/Vector (2000-2015)**	CREC	-0.904	2.4635	1.6035	-0.3772	0.1368	1.3631	$3.83	**$4.50**	Dawn
	ANR-GLGT-TCPL	Fayetteville	-0.071	3.2965	0.5364	0.0216	0.0981	0.6561	$3.95	**$4.65**	Dawn
(1)	**TCPL SWDA**	Empress	-0.630	2.7374	1.2078	0.0000	0.0635	1.2713	$4.01	**$4.71**	Dawn
(2)	**TCPL CDA**	Empress	-0.630	2.7374	1.3103	0.0000	0.0745	1.3848	$4.12	**$4.85**	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 Jan 27, 2015		
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 =	$1.240 CDN	From Bank of Canada Closing Rate Jan 27, 2015
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	
Union's Analysis Completed:	Jan 2015		

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

Note: Previously filed in EB-2015-0166/EB-2015-0175, Exhibit JTI.2, Page 45, Attachment 1

UNION GAS LIMITED
2015-2018 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	-0.049	4.3431	0.1923	0.0275	0.1658	0.3856	$4.73	**$5.73**	Ojibway
(2)	**Vector (2014-2017)**	Chicago	0.151	4.5436	0.1886	0.0018	0.0436	0.2340	$4.78	**$5.79**	Dawn
(2)	**PEPL (2012-2017)**	Panhandle Field Zone	-0.135	4.2572	0.3200	0.0441	0.2052	0.5693	$4.83	**$5.85**	Ojibway
(2)	**Vector (2000-2017)**	Chicago	0.151	4.5436	0.2500	0.0018	0.0436	0.2954	$4.84	**$5.86**	Dawn
(2)	**Vector (2008-2016)**	Chicago	0.151	4.5436	0.2500	0.0018	0.0436	0.2954	$4.84	**$5.86**	Dawn
(2)	**TCPL Niagara**	Niagara	0.257	4.6492	0.1884	0.0000	0.0068	0.1952	$4.84	**$5.87**	Kirkwall
(2)	**DTE to St. Clair (2014-2015)**	SE Michigan	0.329	4.7216	0.0640	0.0000	0.0878	0.1518	$4.87	**$5.90**	Dawn
*	**DTE to St. Clair (2015-2018)**	SE Michigan	0.329	4.7216	0.0790	0.0000	0.0878	0.1668	$4.89	**$5.92**	Dawn
	Dawn	Dawn	0.527	4.9190	0.0000	0.0000	0.0000	0.0000	$4.92	**$5.96**	Dawn
(2)	**PEPL - (2014-2015)**	Panhandle Field Zone	-0.135	4.2572	0.4251	0.0441	0.2052	0.6744	$4.93	**$5.97**	Ojibway
(2)	**Panhandle Longhaul (2010-2017)**	Panhandle Field Zone	-0.135	4.2572	0.4251	0.0441	0.2052	0.6744	$4.93	**$5.97**	Ojibway
	ANR-Michcon-Union (Gulf)	ANR South East	0.025	4.4178	0.4056	0.0161	0.1888	0.6105	$5.03	**$6.09**	Dawn
	ANR-GLGT-TCPL	Fayetteville	-0.052	4.3406	0.5797	0.0216	0.1291	0.7305	$5.07	**$6.14**	Dawn
	GLGT to TCPL	Northern Michigan	0.329	4.7209	0.3151	0.0074	0.0288	0.3513	$5.07	**$6.14**	Dawn
(2)	**Alliance/Vector (2000-2015)**	CREC	-0.692	3.7004	1.5824	-0.3713	0.2055	1.4166	$5.12	**$6.20**	Dawn
(1)	**TCPL SWDA**	Empress	-0.581	3.8118	1.4749	0.0000	0.1482	1.6231	$5.43	**$6.58**	Dawn
(2)	**TCPL CDA**	Empress	-0.581	3.8118	1.6006	0.0000	0.1571	1.7577	$5.57	**$6.75**	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	Nov 2015 - Oct 2016	Nov 2016 - Oct 2017	Nov 2017 - Oct 2018	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
Henry Hub (NYMEX)	Henry Hub	$3.94	$4.55	$4.69	$4.39	
Trunkline/Panhandle	Trunkline Field Zone 1A	$3.90	$4.50	$4.63	$4.34	3.82%
Vector (2014-2017)	Chicago	$4.14	$4.70	$4.79	$4.54	0.96%
PEPL (2012-2017)	Panhandle Field Zone	$3.83	$4.41	$4.53	$4.26	4.82%
Vector (2000-2017)	Chicago	$4.14	$4.70	$4.79	$4.54	0.96%
Vector (2008-2016)	Chicago	$4.14	$4.70	$4.79	$4.54	0.96%
TCPL Niagara	Niagara	$3.98	$4.92	$5.04	$4.65	0.15%
DTE to St. Clair (2014-2015)	SE Michigan	$4.43	$4.81	$4.92	$4.72	1.86%
DTE to St. Clair (2015-2018)	SE Michigan	$4.43	$4.81	$4.92	$4.72	1.86%
Dawn	Dawn	$4.68	$4.98	$5.10	$4.92	0.00%
PEPL - (2014-2015)	Panhandle Field Zone	$3.83	$4.41	$4.53	$4.26	4.82%
Panhandle Longhaul (2010-2017)	Panhandle Field Zone	$3.83	$4.41	$4.53	$4.26	4.82%
ANR-Michcon-Union (Gulf)	ANR South East	$3.97	$4.57	$4.71	$4.42	4.27%
ANR-GLGT-TCPL	Fayetteville	$3.90	$4.50	$4.63	$4.34	2.98%
GLGT to TCPL	Northern Michigan	$4.43	$4.81	$4.92	$4.72	0.61%
Alliance/Vector (2000-2015)	CREC	$3.35	$3.74	$4.01	$3.70	5.55%
TCPL SWDA	Empress	$3.46	$3.86	$4.12	$3.81	3.89%
TCPL CDA	Empress	$3.46	$3.86	$4.12	$3.81	4.12%

Sources for Assumptions:

Gas Supply Prices (Col D):	ICF Q1 2015 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 =	$1.278 CDN	From Bank of Canada Closing Rate March 16, 2015
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	
Union's Analysis Completed:	March 2015		

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

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2016 Annual Stakeholder Meeting

April 13, 2016

Meeting Agenda

Opening Comments	**Mark Kitchen** *Director, Regulatory Affairs*
2015 Financial Results	**Sherri Steingart** *Controller*
2015/2016 Winter Experience	**Chris Shorts** *Director*
2015/2016 Gas Supply Plan	**Chris Shorts** *Director*
Facilities Expansions	**Paolo Mastronardi** *Manager, Business Development*

Meeting Agenda

Residential Customer Perceptions of Union Gas	**Jeff Okrucky** *Director, Distribution Marketing*
Asset Management Plan	**Matt Wood** *Director, Operations Management Systems*
Cap and Trade	**Mark Kitchen** *Director, Regulatory Affairs*
Wrap-up	**Mark Kitchen** *Director, Regulatory Affairs*

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.

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2015 Financial Results

Sherri Steingart
Controller

Agenda

- 2015 Utility Financial Results
- Capital Spend
- Deferral Accounts
  - Short-Term Storage & Other Balancing Services
  - Transportation Optimization
  - Normalized Average Consumption ("NAC")
  - Demand Side Management ("DSM") Activity
- 2016 Trends and Cost Pressures
- Service Quality Requirements and Billing Performance

2015 Utility Financial Results

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Particulars ($000s)	Earnings Before Interest and Taxes	Rate Base	Return on Equity
2013 Board-approved	291,239	3,734,532	8.93%
2014 Actual			
Weather normalized	302,305	3,976,418	9.23%
Weather	28,514		
2014 Total	330,819	3,976,418	10.69%
2015 Actual			
Weather normalized	314,582	4,228,395	9.46%
Weather	8,980		
2015 Total	323,562	4,228,395	9.89%

Capital Spend

Particulars ($000s)	Actual 2014	Actual 2015	Variance
Storage	7,418	5,916	(1,502)
Transmission	191,089	394,851	203,762
Distribution	162,379	172,968	10,589
General	47,458	44,508	(2,950)
Other	68,300	73,106	4,806
Total	476,644	691,349	214,705

Deferral Accounts

Short-Term Storage & Other Balancing Services

Particulars ($000s)	Board-approved	Actuals	Variance
Net margin (pre-tax)[1]	5,056	4,492	564
Less: Shareholder portion (10%)	(505)	(449)	(56)
Ratepayer portion (90%)	4,551	4,043	508
Less: Subsidy in rates	(4,551)	(4,551)	-
Deferral Balance Receivable	**-**	**508**	**(508)**

[1] Board-approved 11.3 PJ vs. Actual 5.0 PJ

Transportation Optimization

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Particulars ($000s)	Board-approved	Actuals	Variance
Base exchanges	9,118	7,739	(1,379)
FT-RAM exchanges	5,800	-	(5,800)
Total exchanges revenue (pre-tax)	14,918	7,739	(7,179)
Less: Shareholder portion (10%)	(1,492)	(774)	718
Ratepayer portion (90%)	13,426	6,965	(6,461)
Less: Subsidy in rates	(13,426)	(15,565)	(2,139)
Deferral Balance Receivable	**-**	**8,600**	**(8,600)**

NAC

Table 1: 2015 NAC Deferral Account ($000s)

Deferral Balance Component	Rate 01	Rate 10	Rate M1	Rate M2	All Rates
Delivery Revenue Balances	2,819	747	3,211	1,353	8,130
Storage Revenue Balances	1,270	397	669	262	2,598
Storage Cost Balances	166	(122)	797	(1,070)	(229)
Interest	21	4	22	-	47
Total NAC Deferral Balance	**4,276**	**1,026**	**4,699**	**545**	**10,546**

Table 2: 2015 Target and Actual NAC (m3/customer)

	Rate 01	Rate 10	Rate M1	Rate M2
2015 Target NAC	2,901	169,025	2,761	169,121
2015 Actual NAC	2,799	162,078	2,676	163,129
Change in NAC (Target - Actual NAC)	**102**	**6,947**	**85**	**5,992**

DSM Activity

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Costs	DSM Variance Account ($000s) Board-approved	Actual	Deferral Variance
RA - Residential	3,425	5,450	(2,025)
RA - C/I	11,761	11,368	393
Total Resource Acquisition	15,186	16,819	(1,633)
Large Industrial	4,910	3,210	1,700
Low Income	7,406	7,701	(295)
Market Transformation	1,494	1,405	89
Portfolio	3,592	3,044	548
Incremental Projects	-	214	(214)
Total	**32,588**	**32,393**	**195**

Scorecard	DSM Incentives ($000s)
Resource Acquisition	4,787
Large Industrial T1/R100	-
Low Income	2,195
Market Transformation	567
Total	**7,548**

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

2016 Trends & Cost Pressures

- Salary inflation – trends at 1.5% - 2%
- Employer benefit costs
- Increase in line locates
- Sewer safety inspections
- Pipeline integrity (O&M and Capital)
- Reinforcements
- Maintenance Capital (municipal projects, bare & unprotected pipe)
- Facility operating costs (rent and maintenance)
- IT software maintenance costs
- Postage prices
- Foreign exchange sensitivity
- Insurance premiums

Service Quality Requirements and Billing Performance

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Service Quality Requirements	Target	Actual
Call Answering Service Level - Annual	75.0%	79.1%
Call Answering Service Level - Monthly	40.0%	>40.0% each month
Abandon Rate	<10%	4.0%
Meter Reading Performance Measurement	<0.5%	0.2%
Appointments Met Within the Designated Time Period	85.0%	98.8%
Time to Reschedule a Missed Appointment	100.0%	99.8%
Percentage of Emergency Calls Responded Within One Hour	90.0%	98.6%
Number of Days to Provide a Written Response	80.0%	100.0%
Number of Days to Reconnect a Customer	85.0%	90.1%

Billing Performance	Actual
Total Number of Billings	17,163,896
Total Number of Manual Checks Done as per QAP	173,132
Total Number of Manual Checks Done when Meter Reads Show Excessively High Usage as per QAP Criteria	127,232
Total Number of Manual Checks Done when Meter Reads Show Excessively Low Usage as per QAP Criteria	5,586

2015/2016 Gas Supply Update

Chris Shorts
Director

Gas Supply Plan Agenda

- 2015/16 Winter Experience
- Gas Supply Outlook
  - 2015/2016 Plan
  - Future Trends that may impact the Gas Supply Plan

2015/16 Winter Experience

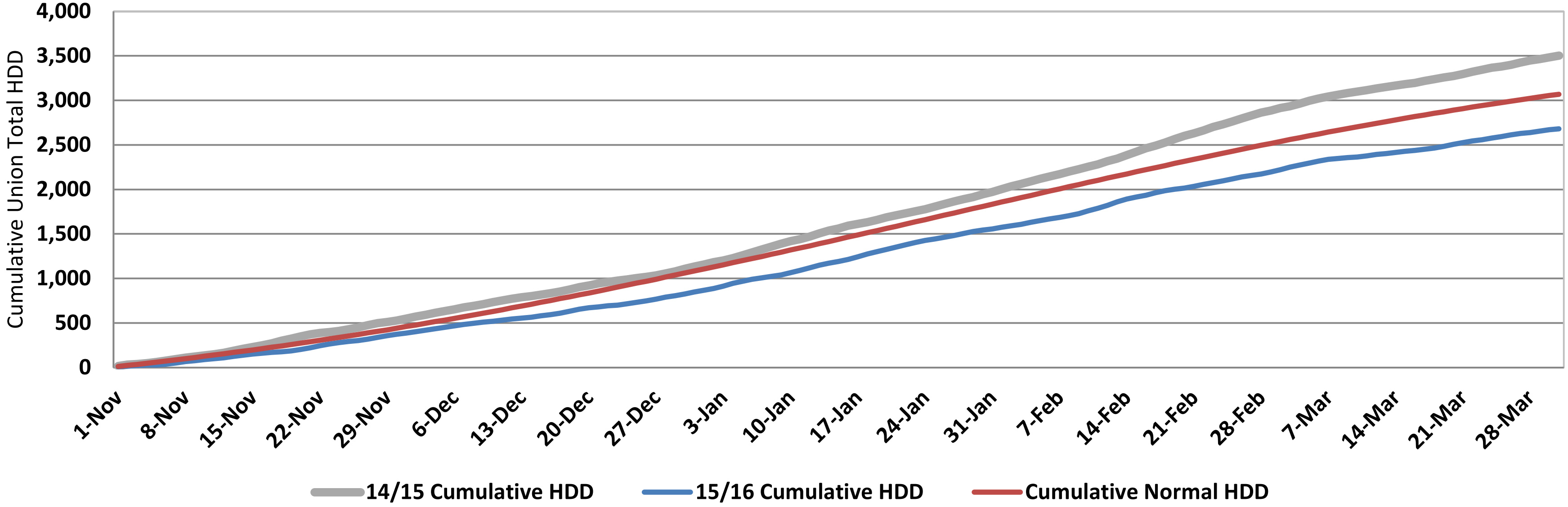
Overall Winter Experience

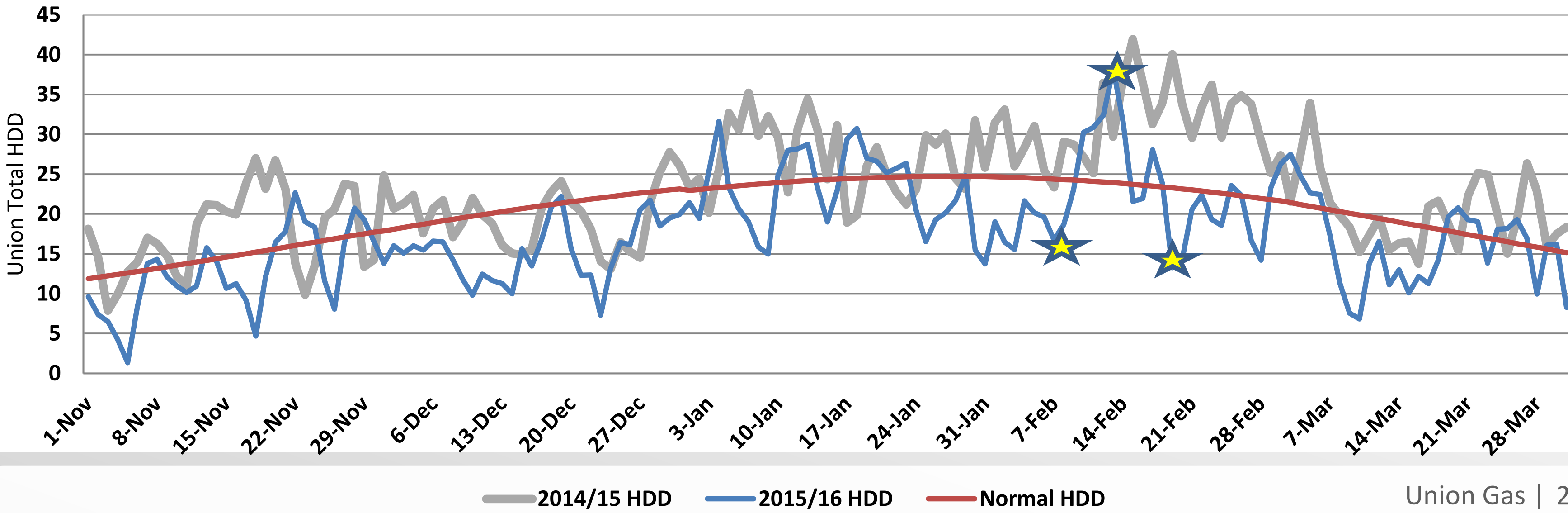
- W15/16 Actuals vs Normal (Union Merged)

Month	% Warmer than Normal	% Colder than Normal
November	15.3%	-
December	26.3%	-
January	5.2%	-
February	6.6%	-
March	13.0%	-

12.8% warmer than normal in Winter 2015/16

A Winter Tale of Two Extremes





Winter Peak Days (Feb 12/13, 2016)

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Weather stations that came within 10% of design day:

Delivery Area	Weather Station	Max Day (HDD)	Design Day (HDD)	% of Design
NDA	Earlton	49.3	54.8	90%
NDA	Timmins	50.4	55.7	90%
NDA	North Bay	48.9	52.5	93%
EDA	Kingston	44.3	47.1	94%
NCDA	Muskoka	49.3	49.0	101%

Even in warm winters, extreme cold must be planned for

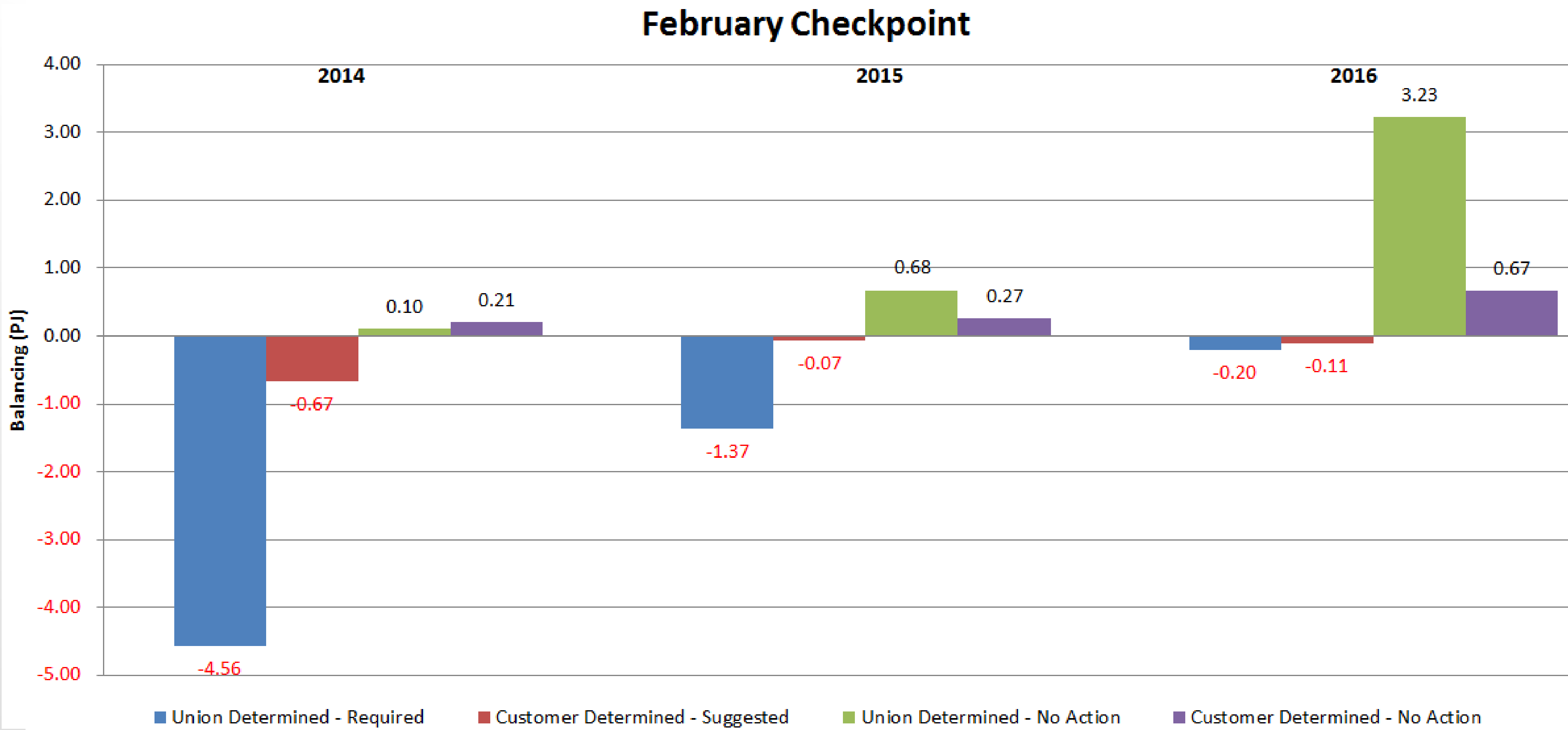
Winter Interruptions

Impacted Distribution Customers

- 72 on Panhandle System (Union South)
  - 1 interruption notice, totaling 2 full days
- 10 on Sudbury System (Union NDA)
  - 1 interruption notice, totaling 1 full day
- 1 on Madoc System (Union EDA)
  - 1 interruption notice, totaling 2 full days

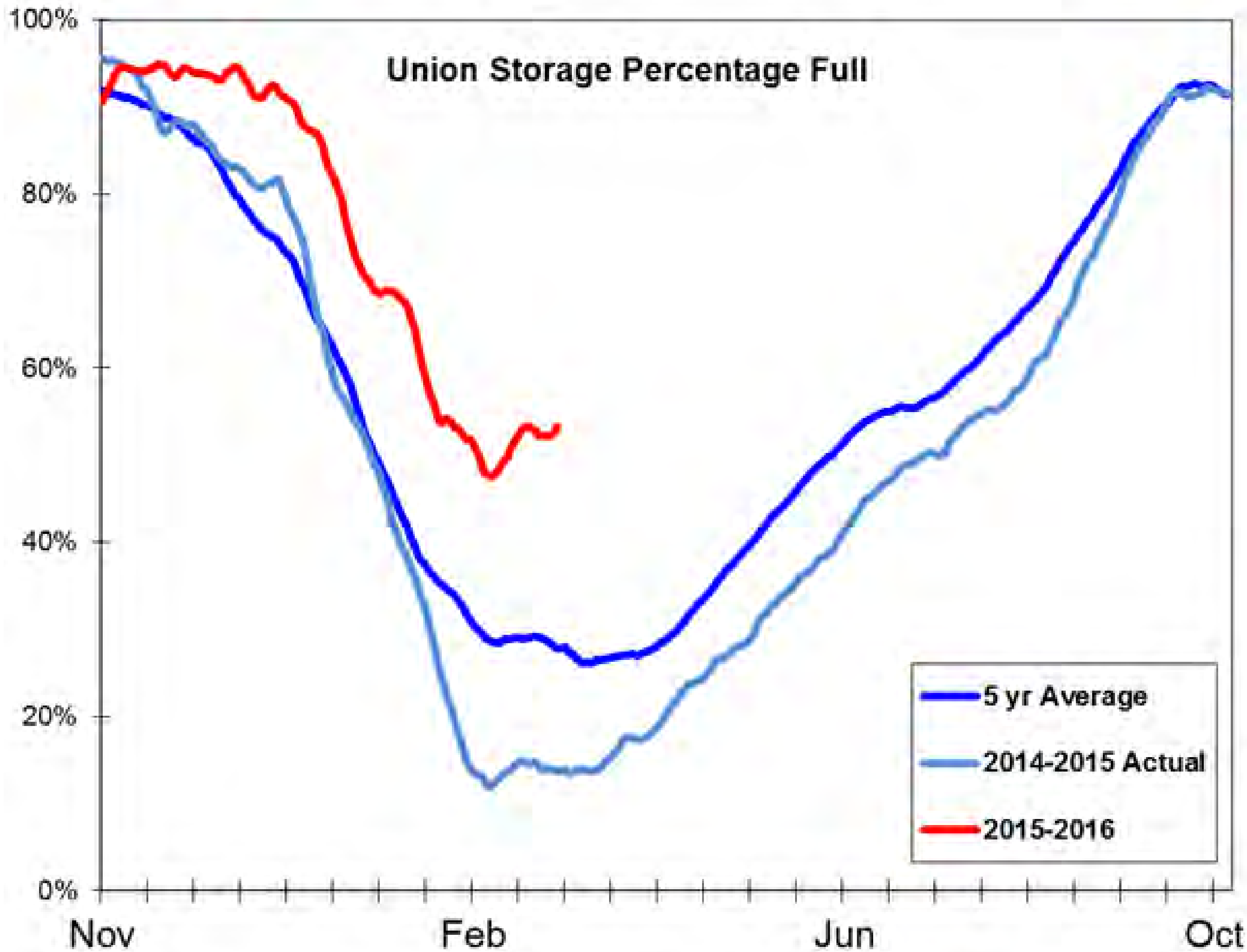
Minimal distribution interruption when compared to last two winters

Bundled Direct Purchases ("DP") February Checkpoint Balancing



Due to the warm winter, Bundled DP customers were not required to deliver as much gas to meet checkpoint

Storage Level



Union will end the winter with a large amount of gas in storage

Winter Natural Gas Prices

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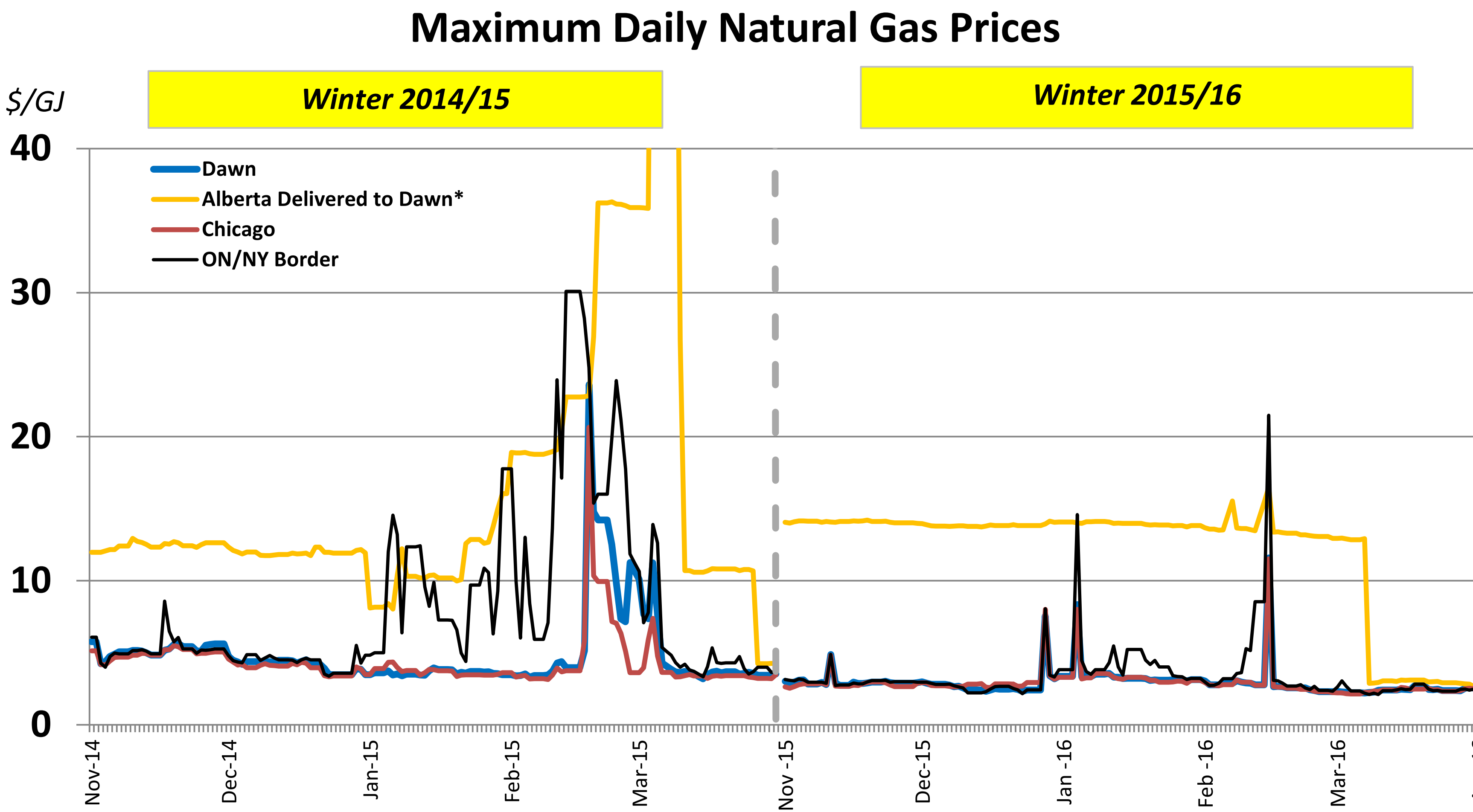
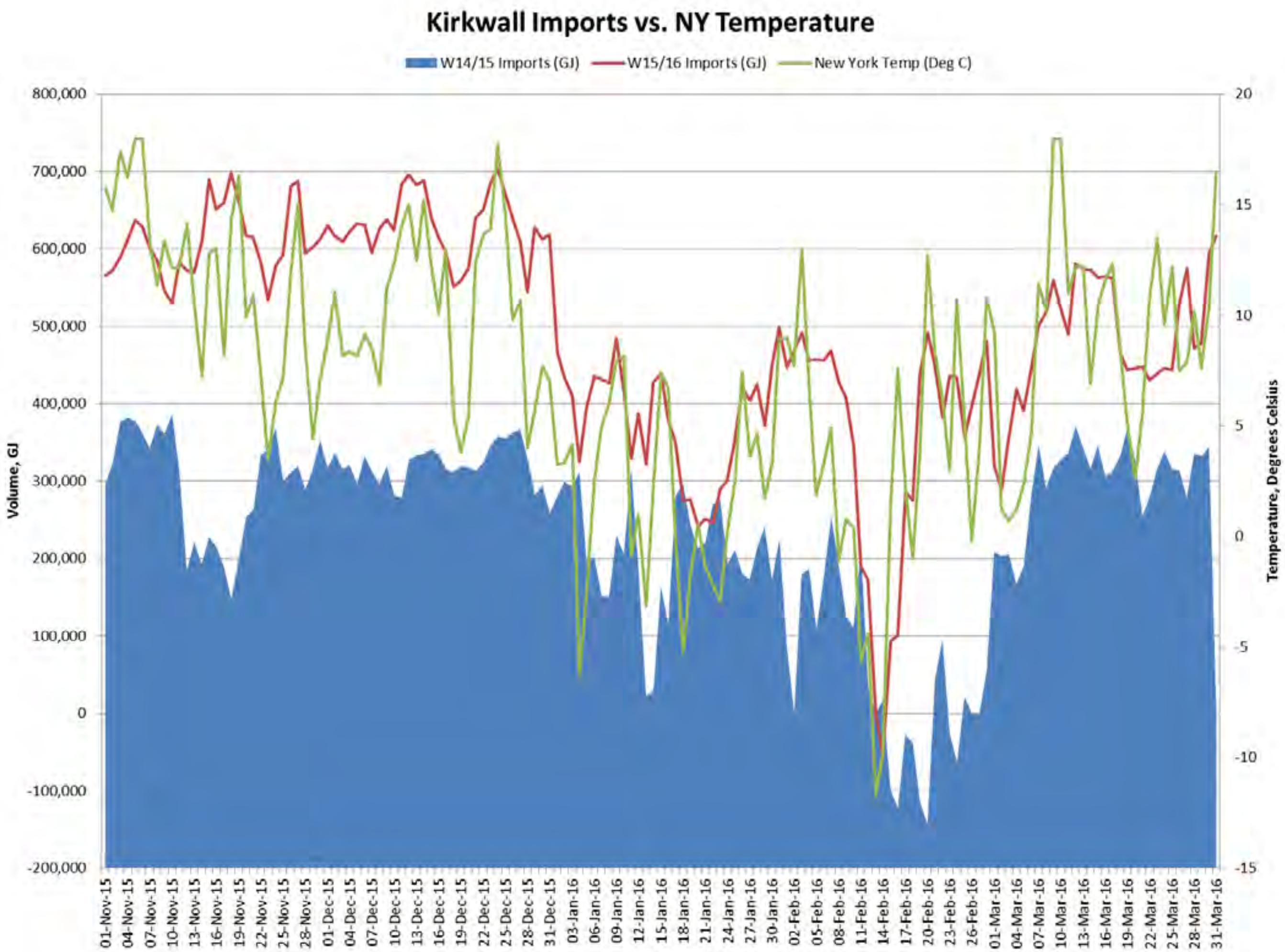


***NOTE:** *Delivered using TransCanada interruptible service*

Dawn daily gas prices were lower and more stable than previous winter

Winter Extremes in Northeast



Temperatures in neighbouring jurisdictions directly impact amount of gas coming into Ontario

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Gas Supply Outlook

2015/2016 Plan

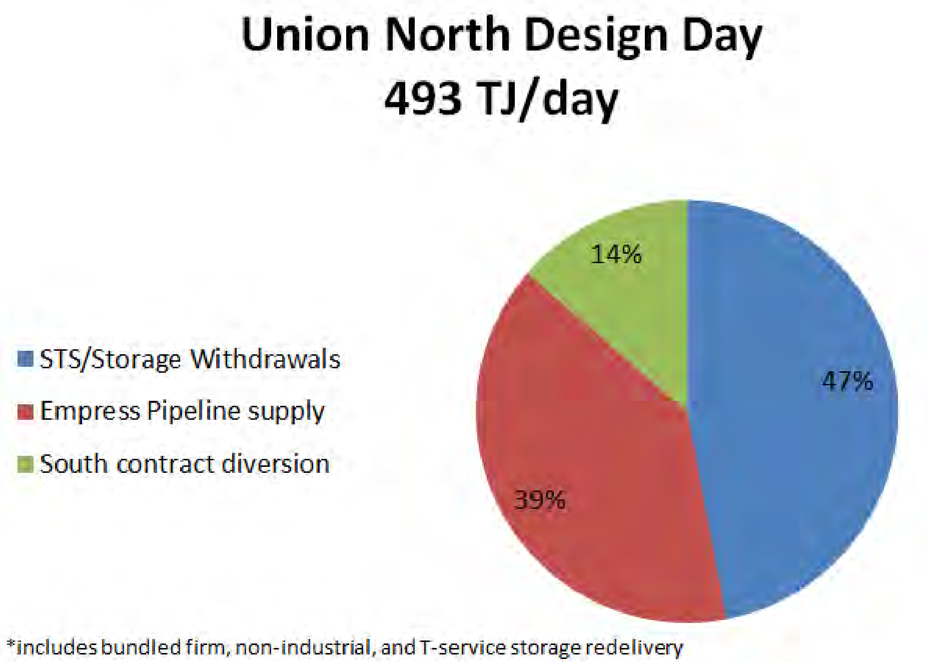
Gas Supply Plan Overview

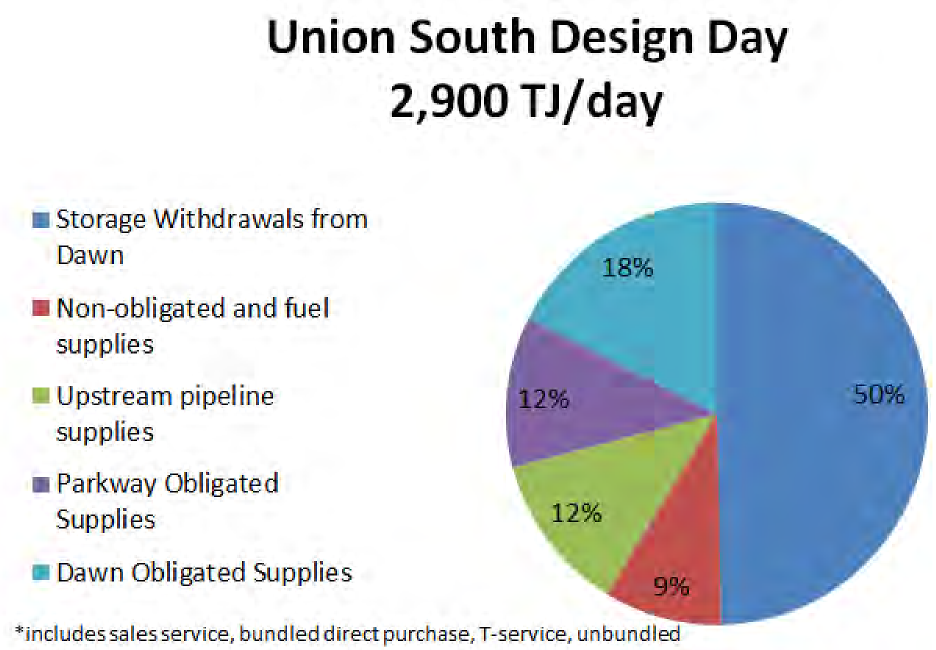
- Plan period covers November 1, 2015 to October 31, 2016
- The corresponding Gas Supply Memorandum was filed September 22, 2015 as part of Union's 2016 Rates application (EB-2015-0116)

Key Outcomes of the Gas Supply Plan

- TransCanada Pipeline Limited ("TransCanada") long-haul to short-haul contract conversion in the EDA and NDA has been delayed but is expected for November 1, 2016
- Plan is contingent upon completion of the King's North Project by TransCanada
- Sales service demands grew by 10.4 PJ over the previous plan
  - Increase of 9.1 PJ in the General Service market
- In-franchise storage allocation at November 2015 is 95.0 PJ
  - Increase of approximately 1.4 PJ over the previous plan
- No planned Unabsorbed Demand Charge ("UDC") for Union South and 15.5 PJ for Union North

Union Design Day Supplies





- Increase in design day requirement from 2014/15 to 2015/16
  - Union North – 14 TJ/day
  - Union South – 33 TJ/day

Upstream Transportation Portfolio

- **Union South Changes**
  - Expired – 84,405 GJ/d of Alliance/Vector
    - » *Acquired - 63,304 GJ/d of DTE Energy (Michcon), and 21,101 of Market Based Transportation from Dominion South Point*
  - Renewed - 10,551 GJ/d on Panhandle Eastern and 10,551 GJ/d on DTE Energy (Michcon)
  - Dawn Planned Purchases - 24,500 GJ/d of supply
- **Union North Changes**
  - Acquired - 12,800 GJ/d of TCPL Empress to Union SSMDA and 1,503 GJ/d of TransCanada Empress to Union WDA
  - Reduction - 12,570 GJ/d in Union's contracted capacity from Empress to the Union NDA
    - » *Acquired - 11,527 GJ/d from Empress to the Union WDA*
    - » *Acquired - 1,043 GJ/d from Empress to the Union MDA*
- **Union CDA Changes**
  - Expired – 60,000 GJ/d of Union CDA market-based contracts
    - » *Acquired – 61,888 GJ/d of TransCanada Union Parkway Belt to Union CDA (includes growth of 1,888 GJ/d)*
  - Renewed – 16,000 GJ/d of TransCanada Union Parkway Belt to Union CDA, and 8,000 GJ/d of TransCanada Union Dawn to Union CDA

Please refer to EB-2015-0116, Exhibit A, Tab 3, Appendix C and D for a complete listing of contracts effective November 1, 2015

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Gas Supply Outlook

Future Trends

Recent Decisions

- Dawn Based Reference Price
  - Changes to the reference price and associated commodity rates for Union South and Union North
  - Creation of Empress Based Reference Price for North West Zone (MDA, WDA, SSMDA)
  - Creation of Dawn Based Reference Price for North East Zone (NDA, NCDA, EDA)
  - Changes to Union North transportation and storage rates for the North East and North West Zones to reflect the changes in the gas supply portfolio
  - Access to Dawn for Union North bundled DP customers
  - Subject to completion of TransCanada King's North Project
  - Planned implementation January 1, 2017
- Dawn to Parkway Expansions (2015, 2016 and 2017)
- Burlington Oakville Project
- NEXUS Long-Term Contract
- Access to Dawn for Union North T-service Customers

Future Trends Being Monitored

- TransCanada Expansion Project Completion
- TransCanada Energy East and Eastern Mainline Projects
- TransCanada Storage Transportation Service (“STS”) Service
  - TransCanada has filed evidence with the NEB proposing changes to the STS Service
  - Union’s STS costs would dramatically increase under TransCanada’s proposal, barring no other contracting changes
    - » *Union will evaluate options to rebalance portfolio depending on NEB decision*
- Cap and Trade
- DSM

Facilities Expansions

Paolo Mastronardi

Manager, Business Development

2015 Dawn Parkway Projects

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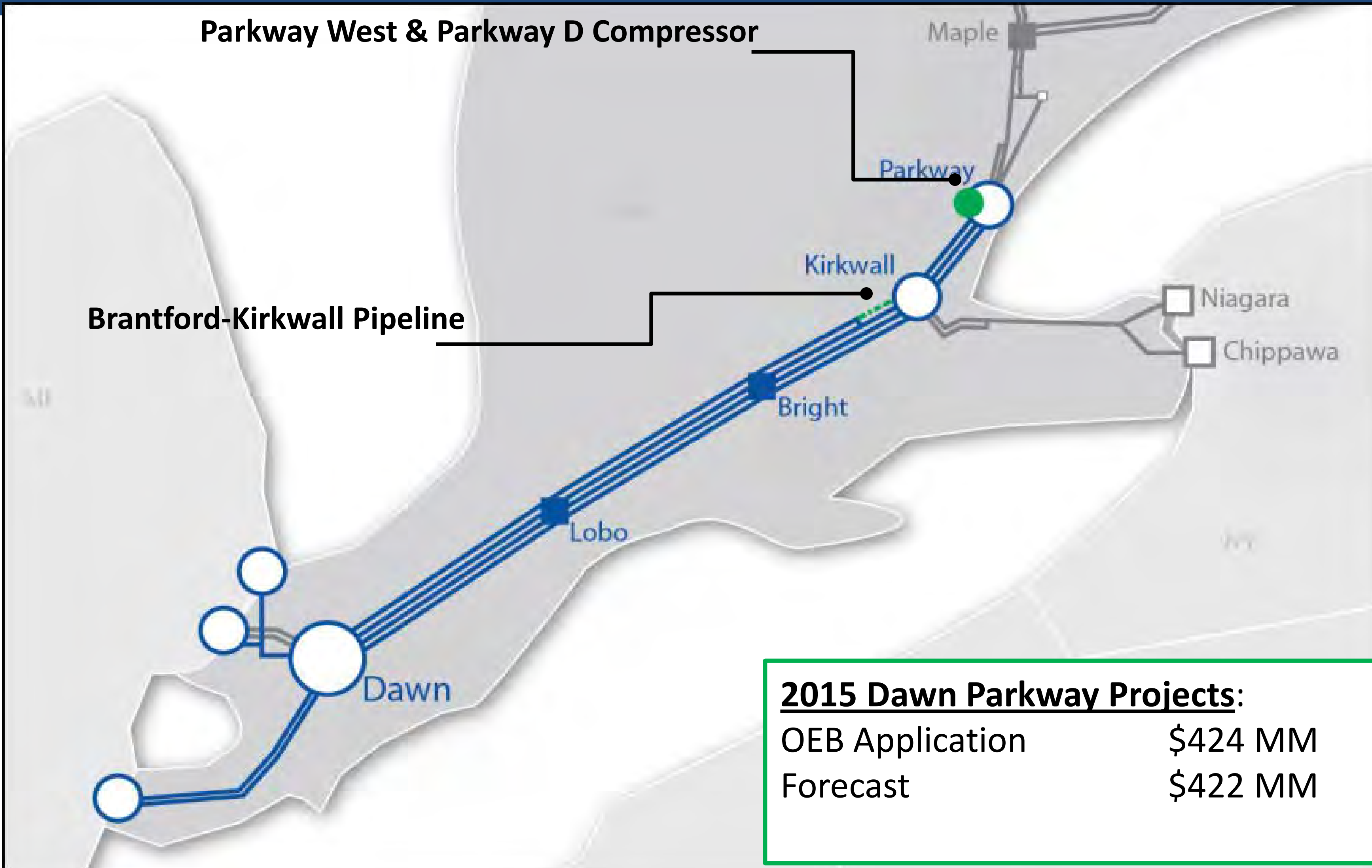
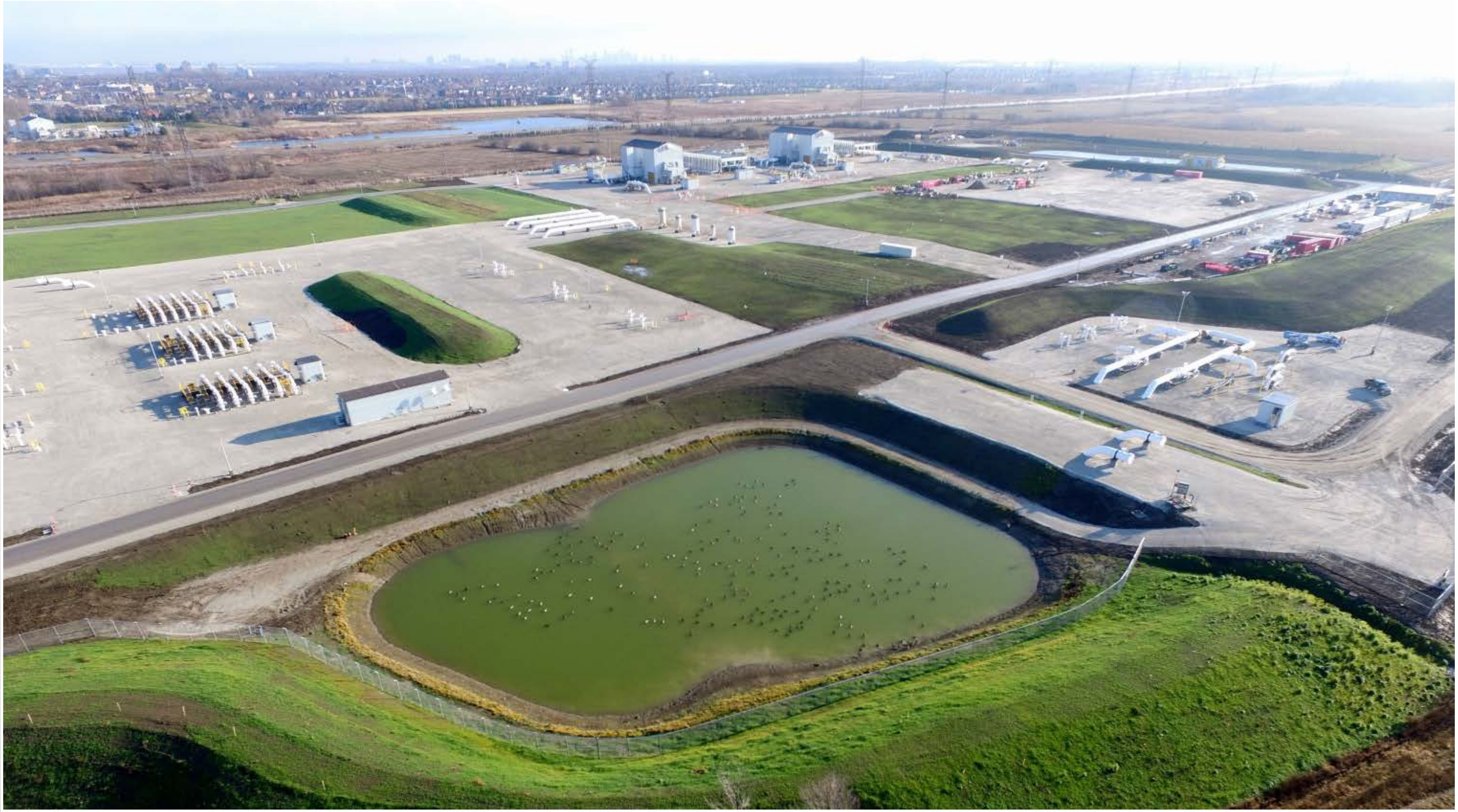


2015 Dawn Parkway Projects:	
OEB Application	$424 MM
Forecast	$422 MM

2015 Dawn Parkway Projects
Parkway West



2015 Dawn Parkway Projects
Brantford - Kirkwall

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2015 Sarnia Expansion Project

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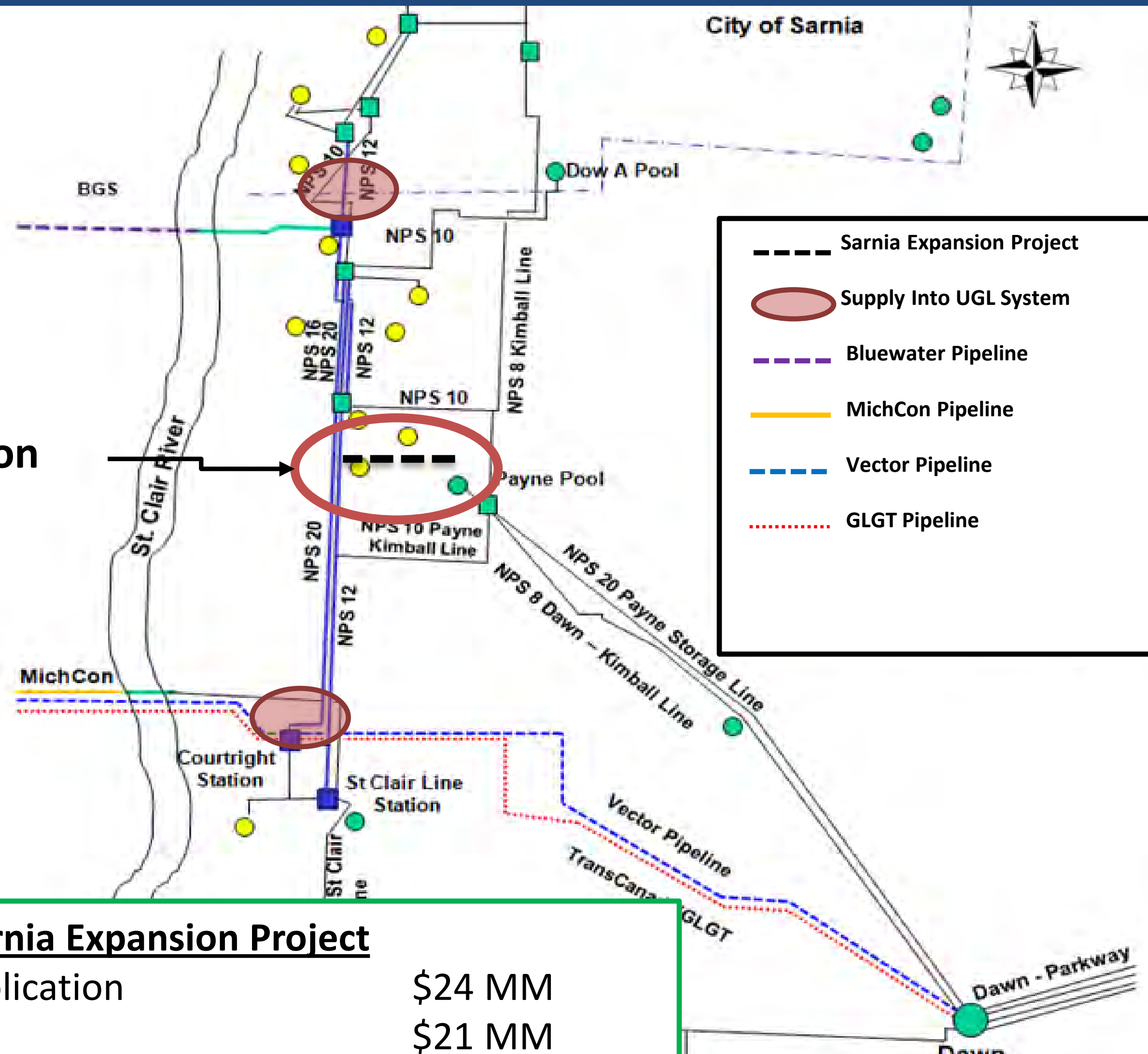
Sarnia Expansion Project



2015 Sarnia Expansion Project	
OEB Application	$24 MM
Forecast	$21 MM

2016 Dawn Parkway Expansion

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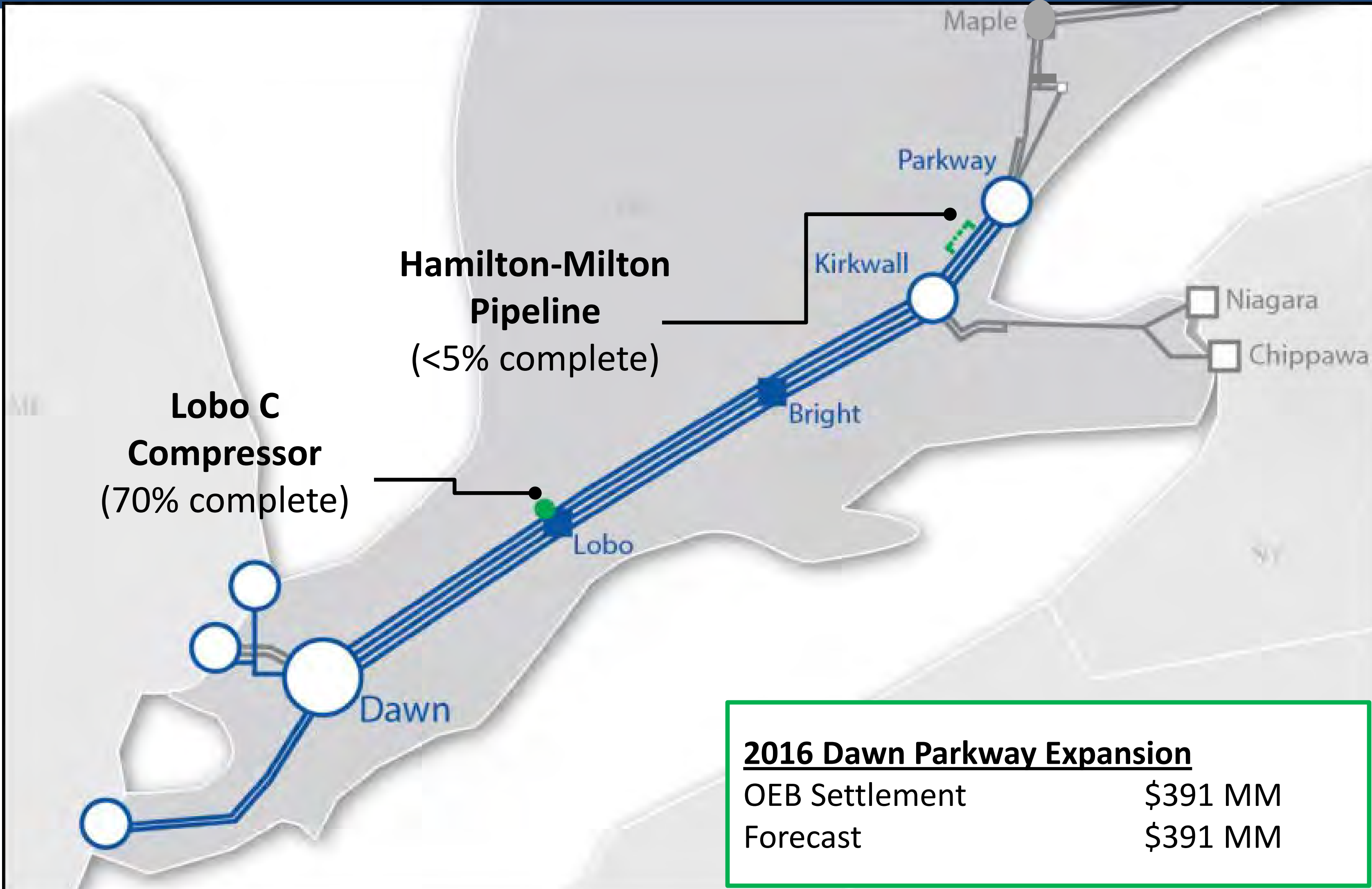
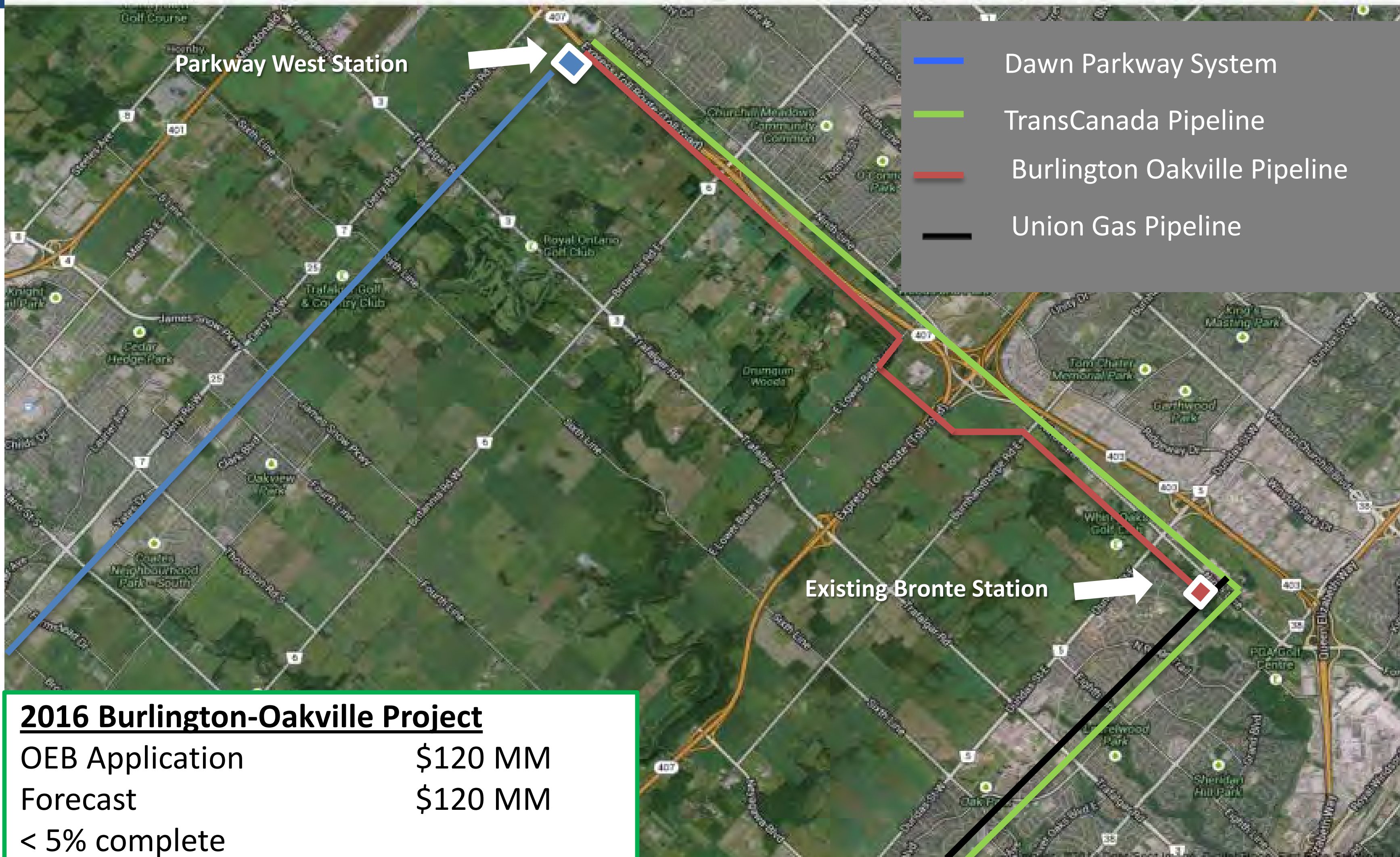


2016 Dawn Parkway Expansion	
OEB Settlement	$391 MM
Forecast	$391 MM

2016 Dawn Parkway Expansion
Lobo C

2016 Burlington Oakville Project

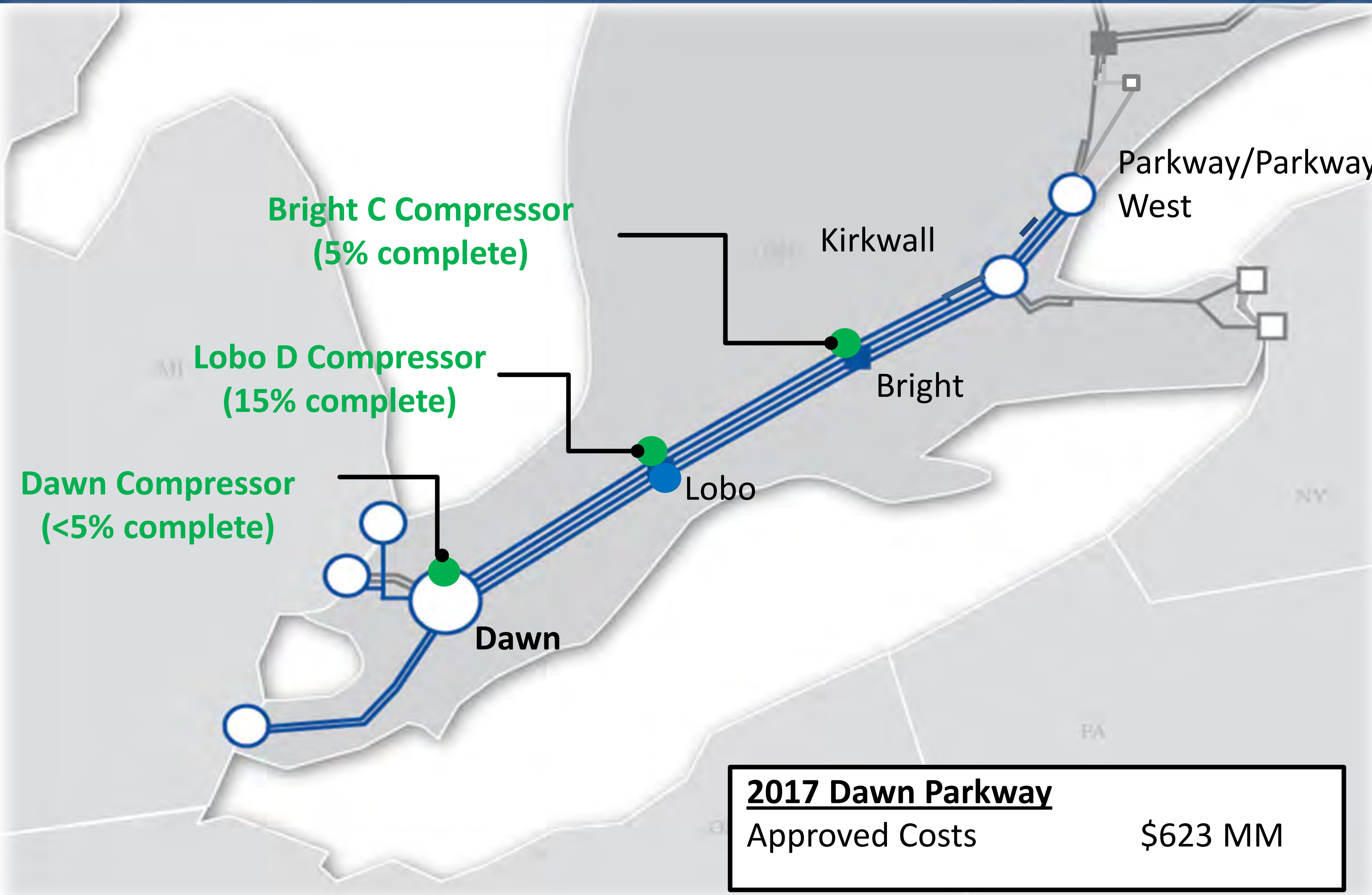


<u>2016 Burlington-Oakville Project</u>

OEB Application	$120 MM
Forecast	$120 MM
< 5% complete	

Burlington Oakville Project

2017 Dawn Parkway Projects



2017 Dawn Parkway	
Approved Costs	$623 MM

2017 Dawn Parkway Projects
Lobo D

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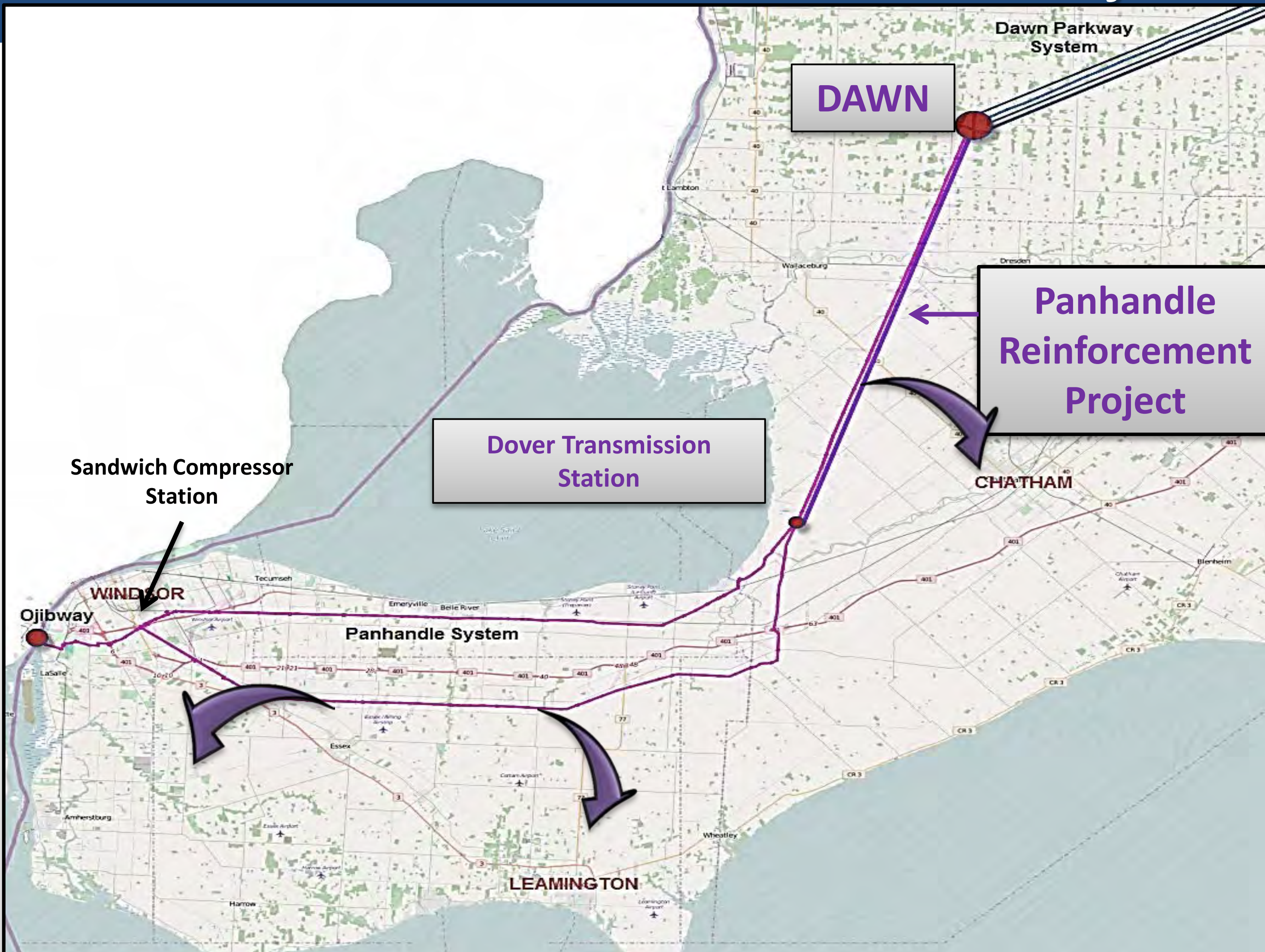
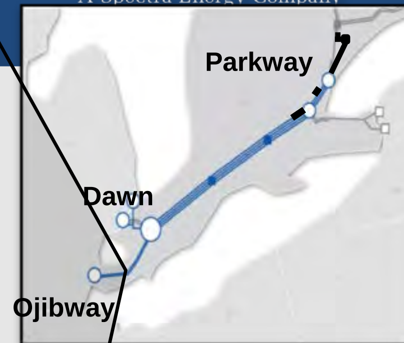
2017 Dawn Parkway Projects
Bright C

2017 Panhandle Reinforcement Project





2017 Panhandle Reinforcement Project Summary

- Growing in-franchise markets along Union's Panhandle System
- Scope – Lift and lay (remove existing NPS 16 and install NPS 36)
- Incremental capacity of over 100 TJ/d
- Alternatives Reviewed
- OEB filing – June 2016
- Target In-service – November 1, 2017

Future Dawn Parkway Expansion
2018 Open Season Results

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- Open season closed – January 22, 2016
- 142 TJ/d of bids accepted
  - 92 TJ/d of Dawn to Parkway (D-P)
  - 50 TJ/d of Kirkwall to Parkway (K-P)
- Executing contracts for up to 75 TJ/d Dawn to Parkway (D-P)
- No facilities required to support 2018 Open Season

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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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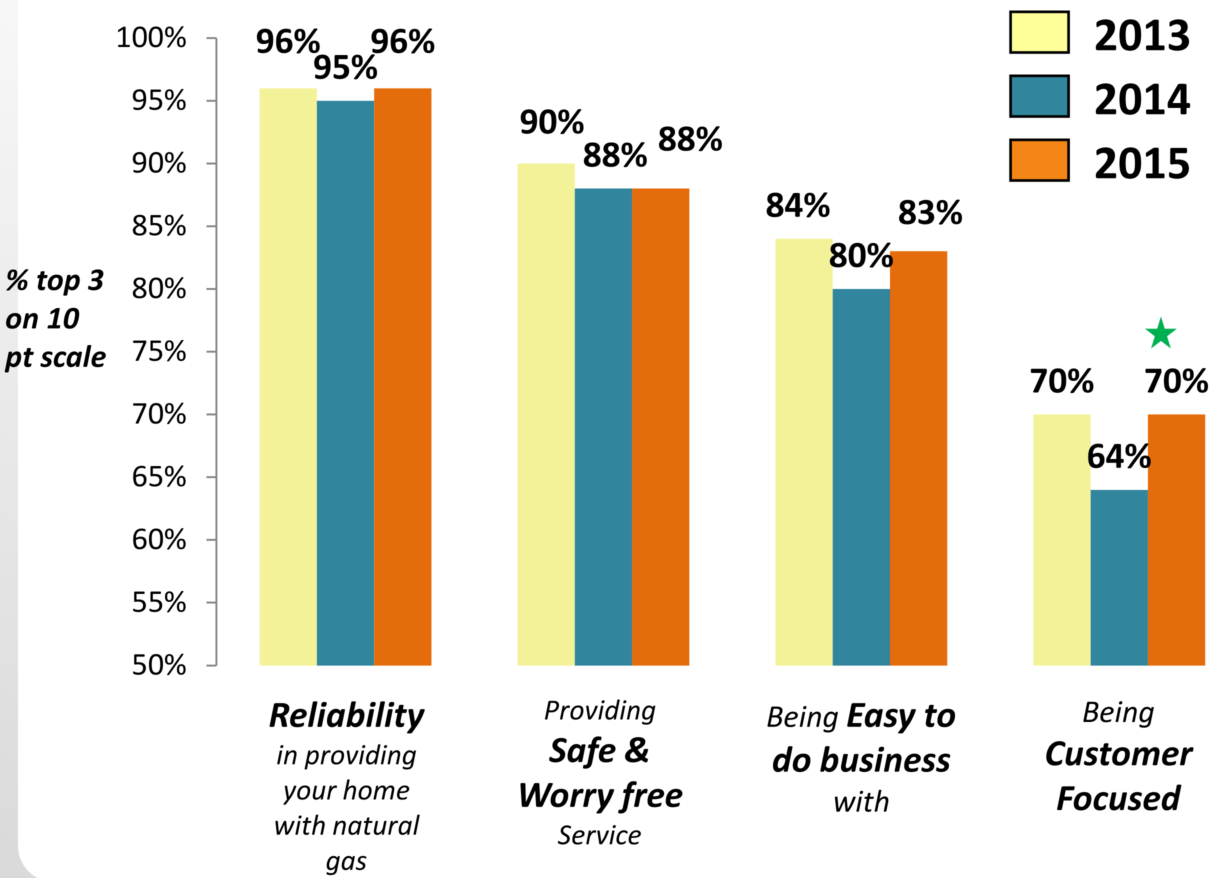
Key Indicators

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



- ✓ *Green ★ indicates statistically significant increase over 2014*
- ✓ *Winter of 2013/14 and subsequent price increases reflected in less positive view of Union in 2014 ("easy to do business" and "customer focus").*
- ✓ *Ratings rebounded in 2015 as prices decreased.*
- ✓ *Ratings continue to be supported by positive customer experience at points of touch:*
  - *High responsiveness as indicated by 88% 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*

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Asset Management Plan

Matt Wood
Director, Operations Management Systems

Asset Management System Agenda

- Asset Management Plan ("AMP")
- Hazard Identification & Risk Management

Asset Management Plan

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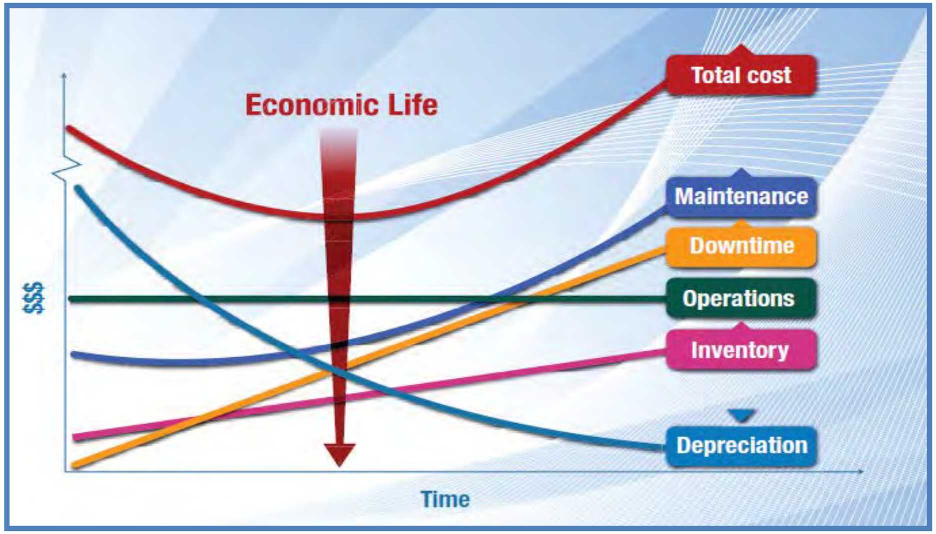
An asset management plan ("AMP") is a forecast of how Union Gas will invest in its assets over the next 10 years, both as a result of growth and maintenance, to deliver optimal benefit to its customers, shareholders, and the public.

The plan will be developed to identify the following:

- Forecast growth
- Asset Lifecycle Management (Maintenance)
- Continuous Improvement opportunities



Source: CGA Guiding Document on Asset Management

With a specific focus on benefits to the customer.

Asset Management Plan

ISO 55000 defines asset management as supporting "the realization of value while balancing financial, environmental and social costs, risk, quality of service and performance related to assets"

An Asset Management Plan will help Union:

- Prioritize asset maintenance based on compliance, reduction of risk, benefit to the customer, and performance of the assets
- Provide improved forecasts of customer growth to ensure system reinforcements are optimally sized
- Identify potential synergies between required maintenance and forecast growth
- Support the optimization of asset life cycle costs through improved data analysis and early identification of maintenance issues
- Ensure assets in common groupings or "classes" are managed in a consistent manner

"An asset management plan provides the direction to and expectations for an individual asset, or for a portfolio, group, or class of assets"

- ISO 55000

AMP - Project Scope & Deliverables

Project Scope

- All Union Gas assets
  - Gas Carrying
  - Facilities
  - Fleet
  - Information Technology
- Development of 10 year forecasts for growth and maintenance
- Process improvements to allow long-term forecasting
- Development of the Plan and supporting input

Deliverables

- Identification of gaps and closure plans
- Business process updates
- Sustainment processes
- 2017-2027 Asset Management Plan

Approach to AMP Work

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Q1 2016	Q2	Q3	Q4	Q1 2017	Q2	Q3

Initiation - Define Requirements

- Project kick-off
- Finalize project charter
- Initiate work on gathering/developing plan requirements

Develop Content

- Gather/develop plan requirements
- Incorporate information into plan
- Develop/update processes

Issue Plan

- Approve and issue first Asset Management Plan
- Refine processes for sustainment

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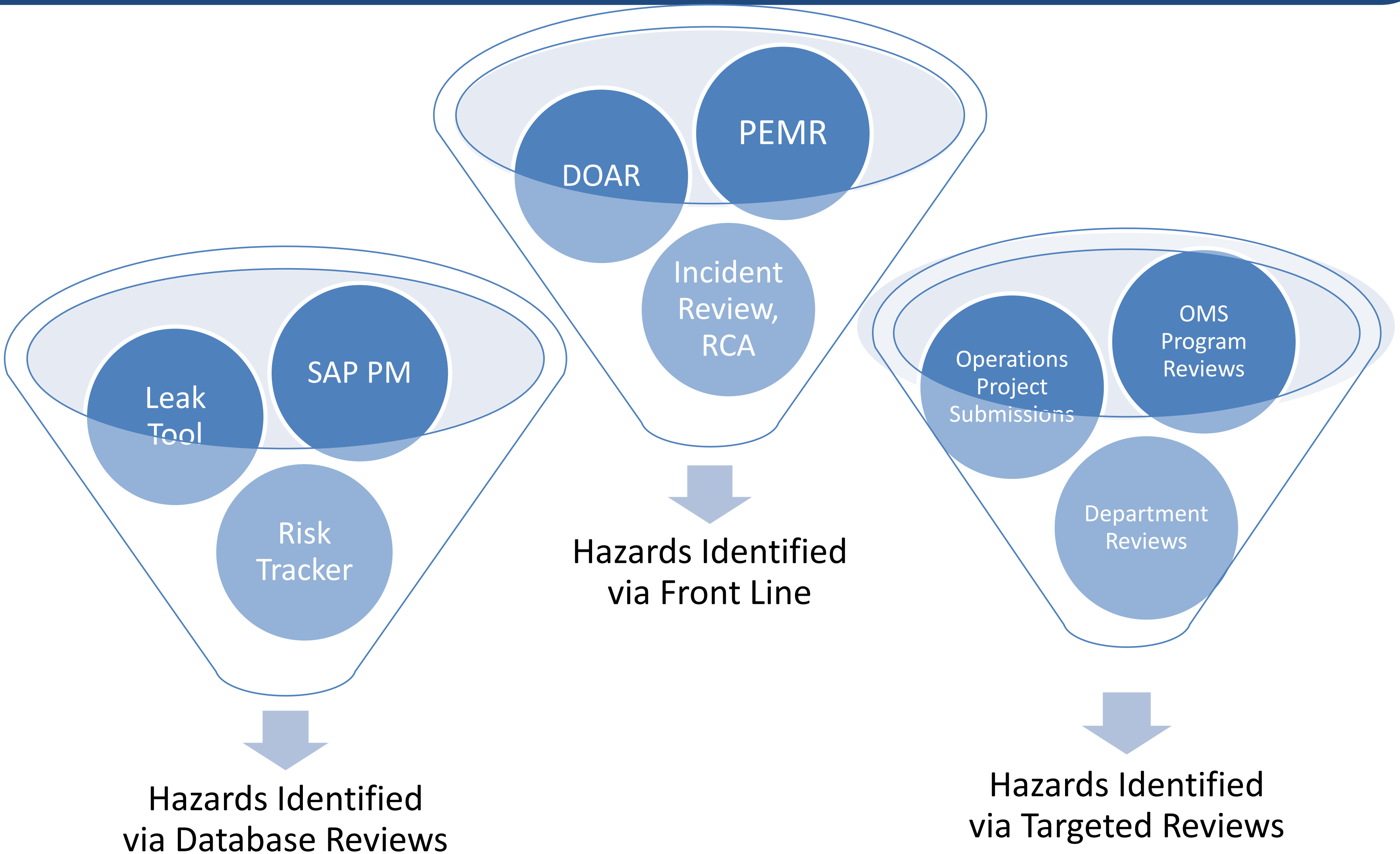
Hazard Identification & Risk Assessment

Hazard Identification



Risk Assessment

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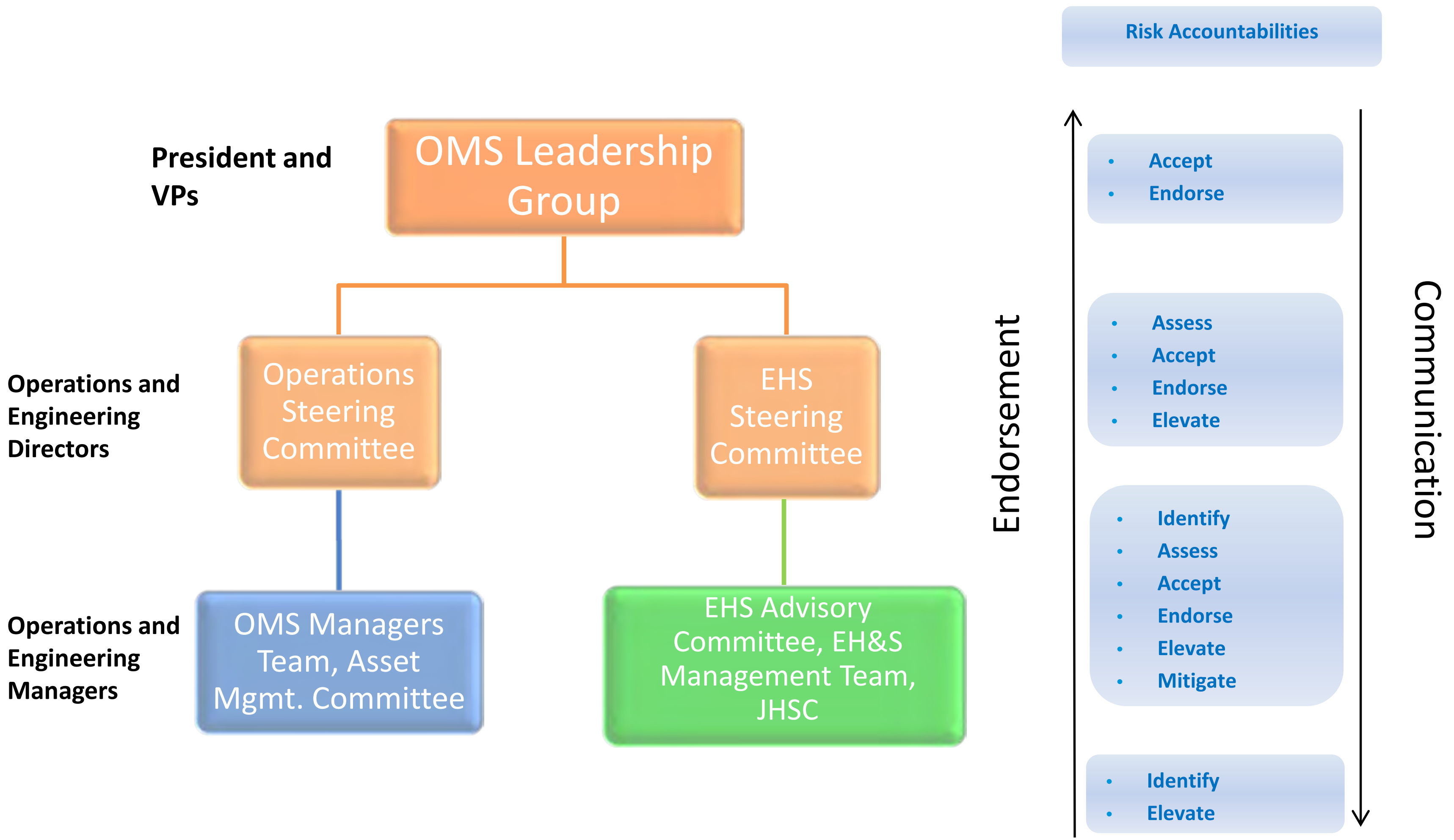
- Risk Assessments
  - Processes, Procedures and Standards are in place to ensure consistency in Risk Assessments
  - Risk Reviews are primarily based on HAZOP theory
  - Maintenance capital spend prioritization

- Union Gas Risk Matrix

Likelihood/Probability		C1	C2	C3	C4	C5
ALMOST CERTAIN	L5	III	II	II	I	I
LIKELY	L4	III	III	II	II	I
OCCASIONAL	L3	IV	III	III	II	II
RARE	L2	IV	III	III	III	II
REMOTE	L1	IV	IV	IV	III	III
		Consequence				

Risk Governance



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Cap and Trade

Mark Kitchen

Director, Regulatory Affairs

Cap and Trade

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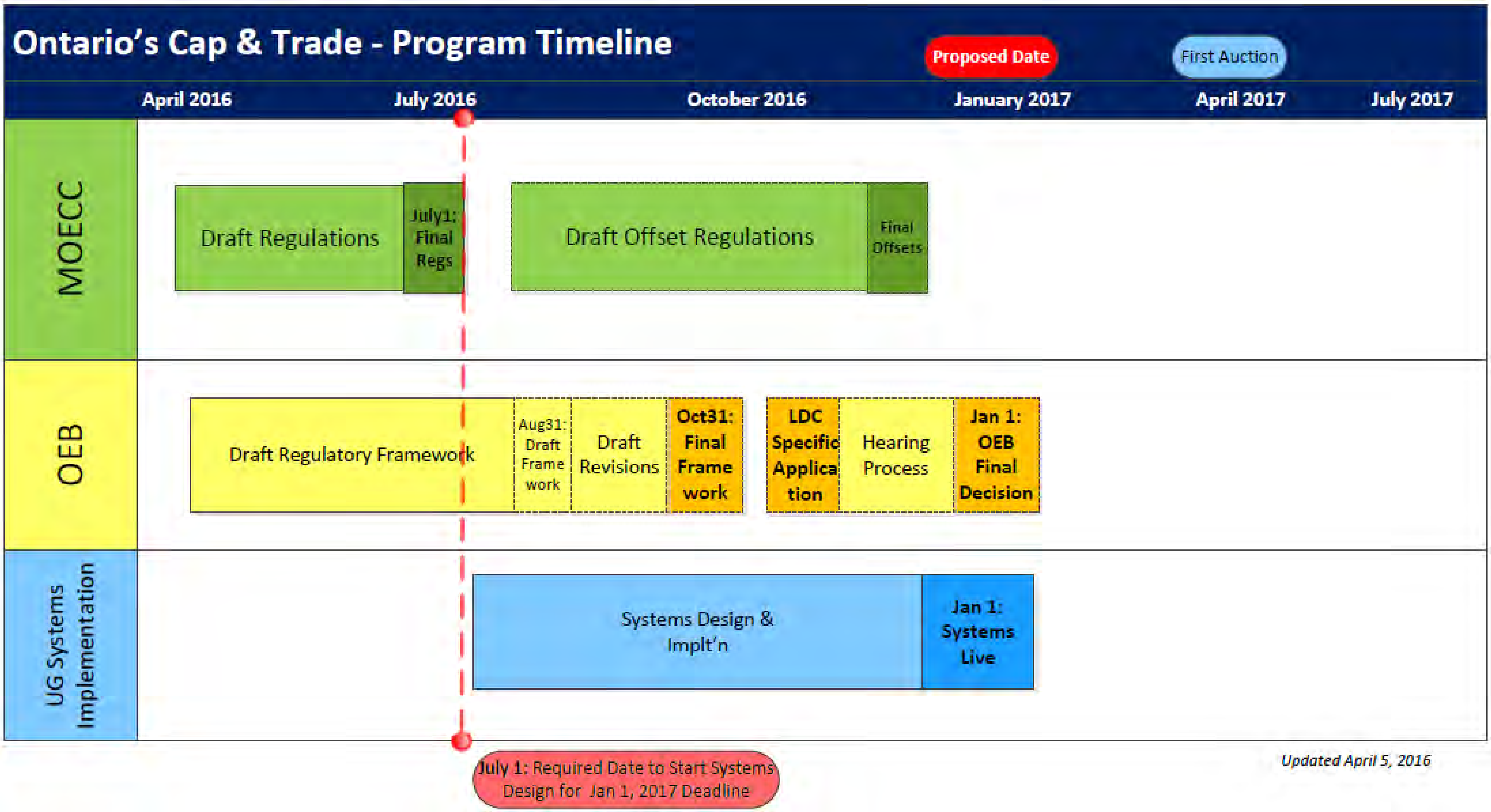

Cap and Trade

Cap and Trade (“C&T”) Framework – Timing Considerations

- Current timing for OEB Cap and Trade Framework and utility specific applications will not allow for implementation on January 1, 2017
- Union’s third-party service provider requires 6 months’ notice to implement changes to our customer billing system
- Union wants to meet the January 1, 2017 implementation date to:
  - Meet Ontario government objective
  - Permit customer billing during the high volume winter season
  - Allow Union to enter into Q1 2017 allowance auction
  - Avoid significant billing adjustments

Cap and Trade

Solution is to have an OEB interim rate order issued no later than July 1, 2016

- Union needs to implement a separate line on its customers' bills for C&T to:
  - Separately track revenue for deferral account disposition
  - Drive customer behavioural changes
- Need to distinguish customers who are covered by Union, those who receive free allowances, those who are large emitters, and those who opt-out
- Union will provide a robust customer communications plan in support of the interim rate order

Wrap-up

Mark Kitchen
Director, Regulatory Affairs

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Recognized by:

Dow Jones Sustainability Indexes
Member 2012/13

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