

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

1 **2015 DEFERRAL ACCOUNT BALANCES**

2
3 **2015 YEAR-END DEFERRAL ACCOUNT BALANCES**

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

- 6 a) Gas Supply accounts;
7 b) Storage accounts; and,
8 c) Other accounts.

9
10 The net balance in the above deferral accounts results in a \$23.145 million debit from
11 ratepayers. This total includes balances as at December 31, 2015. Interest has been
12 calculated on account balances according to the Board-approved accounting orders. The
13 applicable short-term interest rate used was 1.47% for the months of January through
14 March and 1.10% for the months April through December as prescribed by the Board in
15 EB-2006-0117.

16
17 Tab 1, Appendix A, Schedule 1 provides a summary of the deferral account balances.

1 GAS SUPPLY DEFERRAL ACCOUNTS

2 Account No. 179-107 Spot Gas Variance Account

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

8

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

10 The balance in the UDC Variance Account is not prospectively recovered or refunded as
11 part of the approved Quarterly Rate Adjustment Mechanism ("QRAM"). It has therefore
12 been included in this submission. The debit balance of \$0.388 million in the UDC
13 Variance Account is the difference between the actual UDC incurred by Union and the
14 amount of UDC collected in rates.

15

16 *UDC Recovery in Rates*

17 To meet customer demands across Union's franchise area and to meet the targeted
18 (planned) storage inventory levels at October 31, Union's 2015 Board-approved rates
19 included planned unutilized pipeline capacity of 6.3 PJ in Union North and 0 PJ in Union
20 South. The UDC volumes included in rates is based on the Gas Supply Plan as filed in

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

3

4 In Union North, UDC is part of planned operations due to the requirement to hold
5 sufficient TransCanada Pipeline Limited ("TransCanada") firm transportation ("FT")
6 capacity and other firm assets (both storage and transportation related) to meet design day
7 needs. Assets required to meet design day demands are greater than what is required to
8 meet average daily demand, and therefore results in planned unutilized pipeline capacity
9 and UDC. In a warmer than normal year, Union may also incur UDC in Union South, as
10 well as additional UDC in Union North, to rebalance supply with lower demands. Union
11 manages its Union North and Union South transportation portfolios on an integrated basis
12 and will determine the pipeline to leave unutilized, if necessary, based on the least cost
13 option. Consequently, UDC is managed on an integrated basis.

14

15 Union collected \$5.629 million in rates for UDC during 2015 and recorded an associated
16 interest credit of \$0.010 million. Actual UDC costs in 2015 were \$9.905 million offset by
17 \$3.260 million in released capacity value and further offset by a credit of \$0.618 million
18 related to a change in contracted capacity on Centra Transmission Holdings and Centra
19 Pipeline Minnesota ("CTHI / CPMI"), resulting in a net cost of \$6.027 million (please
20 see Table 2).

1 The variance between the amounts collected in rates and the actual UDC costs, including
2 an interest credit of \$0.010 million, results in a net debit in the UDC Variance Account of
3 \$0.388 million (please see Table 1). The UDC costs and the credit related to a change in
4 contracted capacity are described in more detail later in this evidence.
5
6 Table 1 provides the derivation of the UDC Variance Account balances by operations
7 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	<u>(1,057)</u>	<u>1,445</u>	<u>388</u>

8
9 A description of each item follows:

10
11 *UDC Collected in Rates*

12 2015 Board-approved rates include \$5.580 million of UDC associated with planned
13 unutilized pipeline capacity in Union North and \$0 associated with planned unutilized
14 pipeline capacity in Union South. The total cost of UDC in rates assumes TransCanada
15 final tolls effective July 1, 2015 including the TransCanada abandonment surcharge. On

1 an actual basis in 2015, Union recovered \$5.629 million in Union North (due to higher
2 throughput than forecast) and \$0 in Union South.

3
4 *UDC Costs Incurred*

5 In 2015, the planned unutilized pipeline capacity reflected in the Gas Supply Plan was
6 12.1 PJ¹. The actual unutilized capacity in 2015 was 13.4 PJ.

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

14
15 Consequently, Union reduced purchases in the summer of 2015 by 7.0 PJ. In addition,
16 planned unutilized pipeline capacity in the summer of 2015 was 6.5 PJ offset by supply
17 requirements that were greater than forecast by 0.1 PJ resulting in total unutilized
18 pipeline capacity of 13.4 PJ.

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

1 The costs reflected in the UDC Variance Account are the total demand charges for
2 unutilized pipeline capacity totaling \$9.905 million offset, in part, by revenue generated
3 from pipeline transportation releases totaling \$3.260 million. Unutilized upstream
4 transportation capacity due to supply that is ultimately not required, is released and sold
5 on the secondary market to minimize UDC. Revenues generated from the transportation
6 releases are credited to the UDC Variance Account mitigating the overall UDC impact as
7 shown in Table 2.

8

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	<u>6,027</u>

9

10 In addition, consistent with the approach in 2013 and 2014 deferrals, Union has reflected
11 a credit of \$0.618 million in the UDC Variance Account to capture a volume variance
12 related to capacity contracted with CTHI / CPMI. In Union North, Union contracts for
13 capacity on CTHI / CPMI to move gas into Union's Manitoba Delivery Area ("MDA").
14 Union's MDA is connected to the TransCanada Mainline at the Spruce interconnect in
15 the TransCanada Centra MDA by CTHI / CPMI. In Union's 2013 Cost of Service filing
16 (EB-2011-0210), Union reflected the then contracted capacity on CTHI / CPMI of 8,473
17 GJ/d. Union has since reduced the contracted capacity on these pipelines to 5,572 GJ/d

1 for a reduction of 2,143 GJ/d effective November 1, 2012 and a further reduction of 758
2 GJ/d effective November 1, 2014. The reduction in costs for this contract is \$0.618
3 million in 2015 and this amount has been recorded in the UDC Variance Account to pass
4 through the benefit of this contract change to Union North sales service and bundled
5 Direct Purchase ("DP") customers. The credit will be booked on an ongoing basis each
6 month until such time that Union can reflect the updated volumes in Union's 2017 Rates
7 application.

8
9 *Interest*

10 Interest associated with UDC amounted to a credit of \$0.010 million for Union North and
11 \$0 for Union South for a net credit of \$0.010 million.

12
13 *(Credit)/Debit to Operations areas*

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

1 Account No. 179-128 Gas Supply Review Consultant Cost

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

4
5 Account No. 179-131 Upstream Transportation Optimization

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

10
11 In setting rates for 2015, the Board approved a forecast of optimization revenue of
12 \$14.918 million². 90% of that amount, or \$13.426 million, was credited to ratepayers in
13 the Board-approved 2015 rates.³ On an actual basis, consistent with the method approved
14 in its EB-2011-0210 Decision and Rate Order, Union credited \$15.565 million in rates to
15 ratepayers during 2015, \$2.139 million greater than the Board-approved amount of
16 \$13.426 million. The credit is due to Union's actual sales service volumes exceeding the
17 forecast sales service volumes in rates.⁴

18
19 Union earned \$7.739 million in net revenues from upstream transportation optimization
20 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.

1 \$6.965 million, is to be credited to customers. As stated above, \$15.565 million has
2 already been credited through rates; therefore, \$8.600 million (\$6.965 million less
3 \$15.565 million) is to be collected from ratepayers through this deferral account
4 disposition.

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

9
10 STORAGE DEFERRAL ACCOUNTS

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

12 The Short-Term Storage and Other Balancing Services Deferral Account includes
13 revenues from C1 Off-Peak Storage, Gas Loans, Enbridge LBA, Supplemental Balancing
14 Services and C1 Short-Term Firm Peak Storage. The net revenue for Short-Term Storage
15 and Other Balancing Services is determined by deducting the costs incurred to provide
16 service from the gross revenue.

17
18 There is a debit balance in the Short-Term Storage and Other Balancing Services Deferral
19 Account of \$0.508 million. The balance is calculated by comparing \$4.043 million (90%
20 of the actual 2015 Short-Term Storage and Other Balancing Services net revenue of

1 \$4.492 million) to the net revenue included in rates of \$4.551 million in the EB-2011-
2 0210 Rate Order. The details of the balance are found at Tab 1, Appendix A, Schedule 3.

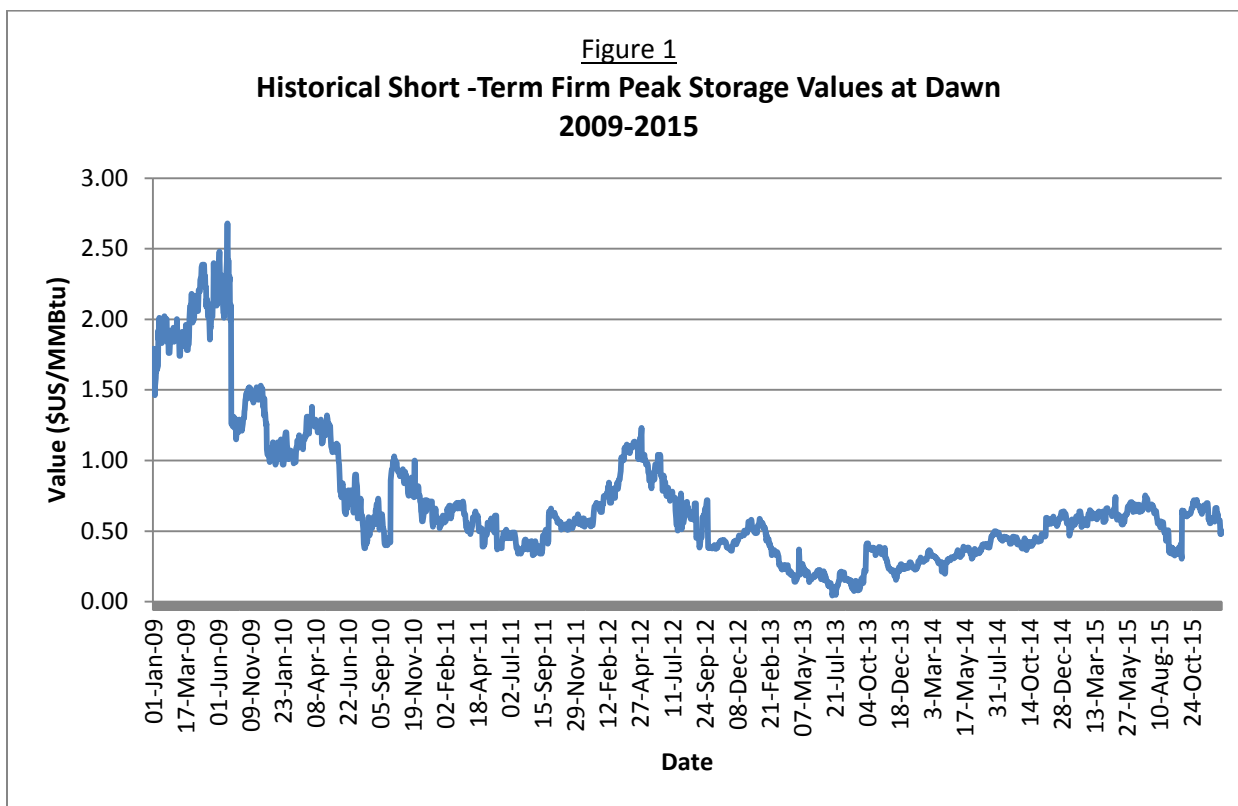
3
4 Actual 2015 revenues from C1 Off Peak Storage, Gas Loans and all other Balancing
5 services of \$1.924 million were \$0.576 million lower than the 2013 Board-approved
6 forecast of \$2.500 million.

7
8 The C1 Short-Term Firm Peak Storage revenues (Utility) of \$4.935 million were \$2.948
9 million lower than the 2013 Board-approved forecast of \$7.883 million. The difference
10 between the Board-approved forecast revenue for 2013 and the actual revenue in 2015
11 was due to a decrease in excess utility storage capacity available for sale. Actual utility
12 requirements were higher in 2015 which reduced the amount available for sale as C1
13 Short-Term Firm Peak Storage for 2015/2016 winter (5.0 PJ) compared to the 2013
14 Board-approved forecast (11.3 PJ). Union's customers received the value of storage
15 directly through the use of the storage space, rather than indirectly, through the sale of
16 short-term storage.

17
18 The increase in the actual utility storage requirement of 1.4 PJ in 2015 (resulting in a
19 decrease in the C1 Short-Term Peak Storage available for sale from 6.4 PJ in 2014 to 5.0
20 PJ in 2015) is a result of increases in consumption in both the general service and the
21 contract markets. The general service market required 0.2 PJ of additional storage in

1 2015 over the Board-approved amount due to growth in the number of customers. The
2 contract market required 1.2 PJ of additional storage over the Board-approved amount
3 due to increased production activity by industrial customers. The storage requirement for
4 the general service market was calculated using the Board-approved aggregate excess
5 methodology and the storage requirement for the contract market was calculated using
6 either the Board-approved aggregate excess methodology or the 15 X obligated Daily
7 Contracted Quantity (“DCQ”) storage methodology.

8
9 The 2013 Board-approved forecast implied an annual average value for C1 Short-Term
10 Firm Peak Storage of \$0.70/GJ (\$7.883 million/11.3 PJ), and the actual average annual
11 C1 Short-Term Firm Peak Storage value in 2015 was \$0.99/GJ (\$4.935 million/5.0 PJ)
12 please see Figure 1 for Short-Term Peak Storage values in US dollars.



1

2

3 *Non-Utility Storage Balances for 2015*

4 In its EB-2011-0210 Decision, the Board directed Union to file a report similar to that

5 ordered in EB-2011-0038 to monitor the inventory related to non-utility storage

6 operations.

7

8 Tab 1, Appendix A, Schedule 4 shows the non-utility inventory balances for October and

9 November of 2015.

1 During the 2015 injection season, the non-utility storage balance peaked on November
2 19, 2015 at 97% of available space with a balance of 84.5 PJ compared to available space
3 of 86.8 PJ. At October 31, 2015 (the date to which Union manages its storage balance),
4 the non-utility balance was 91% of available space. Due to warmer than normal weather,
5 customers injected into storage throughout November. The balance stayed below the total
6 non-utility available space of 100% for the rest of 2015.

7
8 In EB-2011-0210, the Board further ordered Union to file a calculation for a storage
9 encroachment payment from Union's non-utility business to Union's utility business, if
10 Union's non-utility business encroached on Union's utility space. There was no
11 encroachment of utility space in 2015 and therefore no calculation applies.

12
13 *Sale of Non-Utility Storage Space*

14 Union prioritizes the sale of its utility storage ahead of the sale of its short-term non-
15 utility storage and allocates short-term peak storage margins between utility and non-
16 utility as directed by the Board in EB-2011-0210, Decision and Order, pp. 116-117.

17 Margins from short-term peak storage services are proportionately split between the
18 utility and non-utility customers based on the utility and non-utility share of the total
19 quantity of short-term peak storage sold each calendar year. Short-term peak sales
20 include any sale of storage space for a term of less than two years.

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

5
6 Total revenue from the sale of C1 Short-Term Peak Storage (Utility) in 2015 was \$4.935
7 million.

8
9 Details of the above sales are reflected in Tab 1, Appendix A, Schedule 5.

10
11 OTHER DEFERRAL ACCOUNTS

12 Account No. 179-103 Unbundled Services Unauthorized Storage Overrun

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

16
17 Account No. 179-112 Gas Distribution Access Rule ("GDAR") Costs

18 The GDAR Deferral Account records the difference between the actual costs required to
19 implement the appropriate process and system changes to achieve compliance with
20 GDAR and the costs included in rates as approved by the Board.

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

- 3 1. On October 14, 2011, the Board issued a Notice of Amendment to a Rule –
4 Residential Customer Service Amendments to the Gas Distribution Access
5 Rule under docket number EB-2010-0280. Union incurred \$1.475 million in
6 capital costs in 2011 and 2012 to implement the amendments to GDAR.
- 7 2. On September 6, 2012, the Board issued a Notice of Amendment to a Rule –
8 Eligible Low-Income Customer Service Policy Amendments to the GDAR,
9 also under docket number EB-2010-0280. Union incurred \$0.278 million in
10 capital costs in 2012 to implement the Low Income Amendments to the
11 GDAR.
- 12 3. On March 28, 2013 the Board issued a Notice of Amendment to a Rule –
13 Amendments to the Natural Gas Reporting and Record Keeping Requirements
14 in Relation to Residential and Low Income Customer Service Policies, also
15 under docket number EB-2010-0280. Union incurred \$0.468 million in
16 capital costs in 2013 to implement the amendments to GDAR.

17
18 The capital costs relating to the three Amendments to a Rule discussed above can be
19 found at Table 3. The costs include those associated with incremental internal resources
20 and expenses as well as Contractor services. Union's retail CIS system, Banner, is an
21 outsourced solution provided by Vertex Business Services ("Vertex"). Vertex is

1 responsible for the sustainment and operation of the system as well as any required
2 infrastructure changes. All system changes are completed by Vertex and charged to
3 Union.

4 Table 3
5 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	<u>\$1,475</u>	<u>\$278</u>	<u>\$468</u>	<u>\$2,221</u>

6
7 Consistent with Union's 2013 and 2014 Deferrals Disposition proceedings (EB-2014-
8 0145 and EB-2015-0010), Union replaced the capital costs with the annual revenue
9 requirement related to the capital costs as outlined in Table 4. Accordingly, the 2015
10 GDAR Deferral Account has a debit balance of \$0.760 million. The revenue requirement
11 will continue to be included in the respective future deferral disposition proceedings.

12 Table 4
13 GDAR Costs by Year
14

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

1 Account No. 179-117 Carbon Dioxide Offset Credits

2 There is no balance in this deferral account. The account was created in accordance with
3 the Board's Decision in the EB-2006-0021 proceeding to record the amounts representing
4 proceeds from the sale of or other dealings in carbon dioxide offset credits earned as a
5 result of Union's Demand Side Management ("DSM") activities.

6
7 Account No. 179-120 International Financial Reporting Standards ("IFRS") Conversion
8 Costs

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

13
14 Account No. 179-123 Conservation Demand Management ("CDM")

15 In its EB-2010-0055 Decision and Order, which granted approval for Union's 2011 DSM
16 Plan, the Board ordered Union to establish a deferral account to track revenues associated
17 with CDM activities, to be shared 50/50 between Union and ratepayers. The Board
18 approved the accounting order for Union's CDM Deferral Account in Union's 2011
19 Rates application (EB-2010-0148). The balance in the 2015 CDM Deferral Account is a
20 credit of \$0.213 million, which includes 50% of total net revenues of \$0.422 million, plus
21 interest of \$0.002 million.

1 In 2015 Union delivered three CDM programs on behalf of various electric local
2 distribution companies (“LDCs”) including:

- 3 1) High Performance New Construction Generation 2 (“HPNC2”);
- 4 2) Key Account Management (“KAM”); and,
- 5 3) Commercial Conservation Account Management (“CCAM”).

6
7 HPNC2 is an Independent Electricity System Operator (“IESO”) -funded program to
8 encourage builders of commercial, industrial, institutional and agricultural facilities to
9 reduce electricity demand and/or consumption by designing and building new buildings
10 or major renovations with higher energy efficient equipment and systems (i.e. lighting,
11 space cooling, ventilation etc.) than required by the building code. Union contracted with
12 Hydro One Networks Inc. to deliver HPNC2 in 2015.

13
14 KAM is an IESO-funded CDM program meant to assist major industrial customers
15 (average monthly peak demand greater than 5MW) in developing capital projects that
16 support industrial energy management and electricity efficiency. Union contracted with
17 Hydro One Networks Inc. to deliver the KAM services in 2015.

18
19 The CCAM program supports capital investments in equipment that reduces electrical
20 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

<u>Line</u> <u>No.</u>	<u>Particulars (\$000's)</u>	<u>HPNC2</u>	<u>KAM</u>	<u>CCAM</u>	<u>Total</u>
1	Revenues	242	708	1,182	2,132
2	Costs	<u>164</u>	<u>592</u>	<u>954</u>	<u>1,710</u>
3	Net Revenues	78	116	228	<u><u>\$422</u></u>
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-

1 approved deferral account balances in Union's 2013 Deferral Account Disposition (EB-
2 2014-0145) and an under-recovery of \$0.824 million for the Board-approved deferral
3 account balances in Union's 2013 Demand Side Management ("DSM") Deferral Account
4 Disposition proceeding (EB-2014-0273). Details are reflected in Tab 1, Appendix A,
5 Schedule 7.

6
7 *Union's 2013 Deferral Account Disposition (EB-2014-0145)*

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

14
15 Actual volumes for the period January 1, 2015 to June 30, 2015 averaged approximately
16 14% higher than forecast due to colder weather in the first three months of 2015. As a
17 result of the actual volumes being greater than the forecasted volumes, Union refunded
18 \$22.296 million, or \$2.317 million to ratepayers in excess of the deferral account
19 balances approved for prospective disposition in EB-2014-0145. Please see Tab 1,
20 Appendix A, Schedule 7, page 2, column (f) for the actual disposition of deferral
21 accounts and column (g) for the variance between forecast and actual disposition.

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

2 In its EB-2014-0273 Decision, the Board approved the prospective disposition of Union's
3 2013 DSM deferral account balances to general service rate classes. Union was directed
4 to dispose of the deferral account balances to general service rate classes through a
5 temporary rate adjustment beginning with its next QRAM application. Accordingly, the
6 amount to be collected from ratepayers was processed as part of Union's July 1, 2015
7 QRAM Application (EB-2015-0187).

8
9 As described at EB-2015-0187, Appendix E, p. 3, the prospective disposition of the 2013
10 DSM deferral account balances to general service rate classes was based on forecast
11 volumes from July 1, 2015 to December 31, 2015. The total balance to be recovered
12 from general service rate classes was \$5.522 million. Please see Tab 1, Appendix A,
13 Schedule 7, page 3, column (e), based on the forecasted volumes as noted in column (a).

14
15 Actual volumes for the period July 1, 2015 to December 31, 2015 averaged
16 approximately 15% lower than forecast due to warmer weather in the last two months of
17 2015. As a result of the actual volumes being lower than the forecast volumes, Union
18 only recovered \$4.698 million, or \$0.824 million less than the amount approved for
19 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).

1 *Target and Actual NAC*

2 The 2015 target NAC for each rate class was approved by the Board in Union's 2015
3 Rates proceeding (EB-2014-0271). The 2013 actual NAC, weather normalized using the
4 2015 weather normal, was used to determine the 2015 target NAC. Setting the 2015
5 target NAC based on the 2013 actual NAC recognizes that over the two-year span to the
6 current year, any saved volumes and associated lost revenues due to DSM activities will
7 be captured by the variance between the target and actual consumption. This is due to the
8 inclusion of the DSM saved volumes within the actual reported consumption.

9
10 The 2015 actual NAC for each rate class is weather normalized using the 2015 weather
11 normal, which is based on the Board-approved 50:50 blended weather methodology,
12 incorporating both the 30-year average and 20-year declining trend estimates of annual
13 heating degree-days.

14
15 Table 6 provides the 2015 target and 2015 actual NAC by rate class.

<u>Table 6</u>				
<u>2015 Target and Actual NAC (m³/customer)</u>				
<u>Line</u>		Rate	Rate	Rate
<u>No.</u>		01	10	M1
				M2
		(a)	(b)	(c)
				(d)
1	2015 Target NAC	2,901	169,025	2,761
2	2015 Actual NAC	2,799	162,078	2,676
3	Change in NAC (Target - Actual NAC)	102	6,947	85
				5,992

1 *Delivery and Storage Revenues*

2 The deferral account balance is calculated by multiplying the variance between the
3 weather normalized target NAC and the weather normalized actual NAC by the 2013
4 Board-approved number of customers and the 2015 Board-approved delivery and storage
5 rates for each general service rate class. A credit balance in the NAC Deferral Account
6 reflects that the actual NAC is greater than the target NAC, while a debit balance in the
7 NAC Deferral Account reflects that the actual NAC is less than the target NAC.
8
9 Table 7 provides the NAC Deferral Account balances by rate class.

Table 7
2015 NAC Deferral Account

<u>Line</u> <u>No.</u>	<u>Particulars (\$000s)</u>	<u>Rate</u> <u>01</u> (a)	<u>Rate</u> <u>10</u> (b)	<u>Rate</u> <u>M1</u> (c)	<u>Rate</u> <u>M2</u> (d)	<u>All</u> <u>Rates</u> (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

10

11 *Storage Costs*

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

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

6
7 To determine the change in storage requirements for each general service rate class due to
8 NAC variances, Union calculated the NAC volume variance between its 2015/2016 Gas
9 Supply Plan and the 2013 Board-approved volumes multiplied by the 2013 Board-
10 approved number of customers.

11
12 Using the Board-approved aggregate excess methodology, Union then calculated the
13 change in storage requirements for each of the general service rate classes due to
14 variances in NAC. The storage requirements for general service rate classes effective
15 November 1, 2015 are determined using the 2015/2016 Gas Supply Plan volumes which
16 represent the April 1, 2015 to March 31, 2016 period. These general service rate class
17 storage requirements are then used in the calculation of the total in-franchise utility
18 storage space requirement at November 1, 2015. The difference between the total in-
19 franchise utility storage requirement and the total 100 PJ of utility storage represents the
20 excess utility storage capacity available for sale ("excess utility space") at November 1,
21 2015.

1 For Rate M1, the NAC volume variance between the 2015/2016 Gas Supply Plan and the
2 2013 Board-approved volumes was a decrease of 1.89 PJ. The majority of the NAC
3 volume decrease occurred in the summer months, which increased the Rate M1 storage
4 requirement by 1.12 PJ. This resulted in increased storage costs of \$0.797 million (please
5 see Table 7, line 3, column c).

6
7 For Rate M2, the NAC volume variance between the 2015/2016 Gas Supply Plan and the
8 2013 Board-approved volumes was an increase of 7.54 PJ. The majority of the NAC
9 volume variance increase occurred in the summer months, which decreased the Rate M2
10 storage requirement by 1.50 PJ and resulted in decreased storage costs of \$1.070 million
11 (please see Table 7, line 3, column d).

12
13 For Rate 01, the NAC volume variance between the 2015/2016 Gas Supply Plan and the
14 2013 Board-approved volumes was an increase of 1.67 PJ. The NAC volume variance
15 increase was slightly higher in the winter months than the summer, which increased the
16 Rate 01 storage requirement by 0.20 PJ and increased storage costs by \$0.166 million
17 (please see Table 7, line 3, column a).

18
19 For Rate 10, the NAC volume variance between the 2015/2016 Gas Supply Plan and the
20 2013 Board-approved volumes was an increase of 1.48 PJ. The majority of the NAC

1 volume variance increase occurred in the summer months, which decreased the Rate 10
2 storage requirement by 0.15 PJ and resulted in decreased storage costs of \$0.122 million
3 (please see Table 7, line 3, column b).

4
5 Overall, the NAC volume variance between the 2015/2016 Gas Supply Plan and the 2013
6 Board-approved volumes resulted in a decrease in general service storage requirements of
7 0.33 PJ (0.38 PJ in Union South offset by 0.05 PJ in Union North). Accordingly, Union
8 has included a storage cost credit of \$0.229 million, related to the volume variance, in the
9 NAC Deferral Account. Please see Table 8 for a summary of the change in general
10 service storage requirements due to NAC volume variances by rate class.

11
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	<u>(1.50)</u>	Rate 10	<u>(0.15)</u>
Total South	<u><u>(0.38)</u></u>	Total North	<u><u>0.05</u></u>

12
13 The reduction in storage activity has decreased storage deliverability costs, the
14 commodity-related costs at Dawn and storage inventory carrying costs.

15
16 The 0.33 PJ reduction in general service storage requirements due to NAC volume
17 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 m³/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 m³/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.

1 For Rate 01, actual NAC is less than target NAC by 102 m³/customer (please see Table
2 6). This results in a delivery and storage revenue charge of \$4.089 million (\$2.819
3 million and \$1.270 million respectively) (please see Table 7, line 1 and 2). In addition,
4 the NAC volume variance increased the Rate 01 storage requirement by 0.20 PJ.
5 Accordingly, Union must recover an additional \$0.166 million (Table 7, Line 3) to
6 recognize the increase in Rate 01 storage requirements.

7
8 For Rate 10, actual NAC is less than target NAC by 6,947 m³/customer (please see Table
9 6). This results in a delivery and storage revenue charge of \$1.144 million (\$0.747
10 million and \$0.397 million respectively) (please see Table 7, line 1 and 2). In addition,
11 the NAC volume variance decreases the Rate 10 storage requirement by 0.15 PJ.
12 Accordingly, Union must refund \$0.122 million (Table 7, Line 3) to recognize the
13 decrease in Rate 10 storage requirements.

14
15 Account No. 179-134 Tax Variance Deferral Account

16 The establishment of the Tax Variance Deferral Account was approved through the EB-
17 2013-0202 Settlement Agreement. The purpose of this account is to record 50% of the
18 variance in costs resulting from the difference between the actual tax rates and the
19 approved tax rates included in rates as approved by the Board. For 2015, there is no
20 impact related to income tax, however, a credit balance of \$0.060 million is included in

1 the deferral account related to Harmonized Sales Tax (“HST”) changes as discussed
2 below.

3
4 On July 1, 2010, HST came into effect in Ontario, combining provincial and federal
5 taxes. On July 1, 2015, the input tax credit (“ITC”) recapture for compressor fuel costs,
6 and certain Operations and Maintenance (“O&M”) and capital costs, was reduced as
7 follows:

- 8 • 100% for the period from July 1, 2010 to June 30, 2015;
- 9 • 75% for the period from July 1, 2015 to June 30, 2016;
- 10 • 50% for the period from July 1, 2016 to June 30, 2017;
- 11 • 25% for the period from July 1, 2017 to June 30, 2018; and,
- 12 • 0% on or after July 1, 2018.

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

18
19 To calculate the 2015 Tax Variance Deferral Account balance related to HST changes,
20 Union reviewed its transactions from July 1 to December 31, 2015 for:

- 1 a) Capital and O&M purchases that are subject to the ITC recapture reduction
2 including specified Meals and Entertainment costs, specified Road Vehicles and
3 related Fuel costs, specified Energy costs, and specified Telecommunications
4 costs; and,
5 b) Compressor Fuel costs.
6

7 For 2015, the Tax Variance Deferral Account is a credit balance of \$0.060 million. The
8 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

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

9

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

11 There is no balance in this account. The establishment of the UFG Volume Deferral
12 Account was approved through the EB-2013-0202 Settlement Agreement. The purpose
13 of this account is to capture the difference between Union's actual UFG costs and Board-
14 approved UFG costs included in Union's rates, related to UFG volumes variances as a

1 percentage of throughput volumes (please see Table 10, line 6). The amount of the UFG
2 volume deferral account to be cleared to customers is subject to a symmetrical dead-band
3 of \$5 million, with amounts within such dead-band being to Union's account only. For
4 2015, Union's actual UFG expense had a UFG percent volume variance of \$3.6 million
5 lower (favourable) than Board-approved. There is no balance in the UFG Volume
6 Deferral Account for 2015 because this year-end variance is within the \$5 million
7 threshold.

8

Table 10
2015 UFG Variances from Board-approved

<u>Line No.</u>	<u>Particulars (\$ Millions)</u>	<u>2015 Actual</u>	<u>Board- approved</u>	<u>Variance</u>
		<u>(a)</u>	<u>(b)</u>	<u>(c) = (b - a)</u>
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	<u>9.1</u>	<u>13.4</u>	<u>4.3</u>
<u>Variance Analysis</u>				
4	Price Variance ⁽¹⁾			0.4
5	Throughput Variance			0.2
6	UFG % Volume Variance ⁽²⁾			3.6
7	Non-Utility Allocation Variance			<u>0.1</u>
8	Total UFG Variance			<u>4.3</u>

(1) Reference Price included in Board-approved was $\$210.506 / 10^3 \text{m}^3$
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.

1 Account No. 179-136 Parkway West Project Costs

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

6
7 The deferral account has a total credit balance of \$0.334 million. This balance consists of
8 a \$0.319 million credit, which represents the difference between the \$6.373 million
9 included in 2015 Rates (EB-2014-0271) and the calculation of the actual revenue
10 requirement for 2015 of \$6.054 million as shown in Table 11. The remaining \$0.015
11 million credit represents a true-up to the 2014 revenue requirement of a \$0.751 million
12 credit included in the 2014 Deferral Disposition (EB-2015-0010) and the recalculated
13 actual 2014 revenue requirement of a \$0.766 million credit to adjust the long-term debt
14 rate from the estimate of 4.0% to the actual of 3.82%.

1 *2015 Deferral Balance*

Table 11
2015 Parkway West Project Rate Base and Revenue Requirement

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

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:
 $\$103.750 \text{ million} * 64\% * 3.82\% = \$2.537 \text{ million plus}$
 $\$103.750 \text{ million} * 36\% * 8.93\% = \$3.335 \text{ 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.

1 *Capital Expenditures*

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

4

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)

5

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

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

4
5 Dawn-Parkway valve nest costs were \$3.908 million higher than the costs included in the
6 2015 Board-approved rates due to delay in placing the connection of the 48" pipeline into
7 service in 2015 originally estimated for 2014.

8
9 The station headers costs were \$7.456 million lower than the costs included in the 2015
10 Board-approved rates. This was associated with a portion of the station header put into
11 service in 2014 which was necessary to service the Enbridge measurement facilities.
12 Increase in material and labour costs were offset by contingencies.

13
14 Interconnect/TransCanada measurement station costs were \$3.878 million lower than the
15 costs included in the 2015 Board-approved rates. This was a result of the project scope
16 changing from an NPS 42" interconnect pipeline between the Parkway West site and the
17 Parkway East TransCanada measurement site to a new measurement station at the
18 Parkway West site. Higher material costs were offset by lower labour costs and
19 contingencies.

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

7
8 *Average Investment*

9 The average investment has increased by \$1.617 million over the costs included in the
10 2015 Board-approved rates due to in-service timing and capital expenditure differences.

11
12 As noted in Union’s 2014 Deferral Disposition proceeding (EB-2015-0010), capital
13 expenditures for the Parkway West Project were \$6.951 million higher in 2014 than the
14 Board-approved capital expenditures. This has the effect of raising the opening balance in
15 2015 for purposes of calculating the average investment.

16
17 This is offset by the reduced capital spend in 2015 and the fact that the monthly timing
18 differences from the original estimate were lower in 2015 as certain compressor and
19 pipeline components were put into service in November 2015 rather than the original
20 October 2015 estimate.

1 *Operating Expenses*

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

6

7 The increase in depreciation expense of \$0.045 million relates to a full year's
8 depreciation expense on assets put into service in 2014 in excess of those included in
9 2014 rates (2014 Actual - \$80.9 million; 2014 rates - \$73.9 million) offset by lower
10 depreciation expense on lower actual capital expenditures in 2015 than included in 2015
11 rates.

12

13 The \$0.155 million property tax decrease relates to the assessed value of the Parkway
14 West land. The estimate of \$0.290 million in the 2015 Board-approved rates was based
15 on an assumption that the land would have a commercial assessed value and a
16 commercial tax rate. The Municipal Property Tax Assessment Corporation did not
17 reassess the land in 2015 and actual property taxes for 2015 were based on a farmland
18 assessed value and a residential tax rate. It is expected that the reassessment will occur in
19 2016.

1 *Required Return*

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

9

10 When Union prepared the Parkway West Project application (EB-2012-0433) the long-
11 term debt rate used was 4.0%. In 2015, when the project was brought into service, Union
12 issued debt which reduced the average long-term debt rate to 3.82%. This rate will be
13 used to calculate the debt portion of the utility required return through to and including
14 2018.

15

16 *Income Taxes*

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

1 The \$0.021 million “Income Taxes-Equity Return” increase relates to an increase in the
2 tax impact of the equity component of the required return resulting from an increase in
3 average investment.

4
5 The \$0.241 million “Income Taxes-Timing Differences” increase relates to a lower
6 Capital Cost Allowance deduction due to lower actual capital expenditures than included
7 in 2015 Board-approved rates.

8
9 Account No. 179-137 Brantford-Kirkwall/Parkway D Project Costs

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

14
15 The deferral account has a debit balance of \$0.579 million, which represents the
16 difference between the \$0.077 million credit included in 2015 rates (EB-2014-0271) and
17 the calculation of the actual revenue requirement for 2015 of a \$0.502 million as shown
18 in Table 13.

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

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

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:

$$\$24.2 \text{ million} * 64\% * 3.82\% = \$0.591 \text{ million plus}$$

$$\$24.2 \text{ million} * 36\% * 8.93\% = \$0.777 \text{ million for a total of } \$1.368 \text{ million.}$$
- (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.

1 *Capital Expenditures*

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

4

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

<u>Line No.</u>	<u>Particulars (\$000's)</u>	<u>2015 Board-approved (a)</u>	<u>2015 Actuals (b)</u>	<u>Difference (c) = (b - a)</u>
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)

5

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

9

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

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

3
4 Structures costs were \$0.332 million lower than the costs included in the 2015 Board-
5 approved rates. The original estimate included an auxiliary building for Parkway Plant D
6 and the Parkway West project included an auxiliary building for the Parkway West LCU
7 Plant. Both plants share one auxiliary building with the full amount charged to the
8 Parkway West LCU Plant.

9
10 The compressor equipment costs were \$19.358 million lower than the costs included in
11 the 2015 Board-approved rates. The design of the Parkway Plant D was not yet complete
12 at the time of the estimate, and actual costs for labour and material were lower than
13 estimated. Permitting and land development costs originally included in the Parkway
14 Plant D estimate were charged to the Parkway West LCU project. Lower labour costs
15 were also realized due to contingencies included in the estimate that were not required.
16 Interest during construction was lower due to rate reduction and timing of spend.

17
18 *Average Investment*

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

1 Compressor and measurement equipment were put into service in September 2015 rather
2 than the original November 2015 estimate. These early in-service expenditures are
3 partially offset by the decreased capital expenditures seen in November and December
4 2015, as explained above.

5
6 *Operating Expenses*

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

9
10 The \$0.258 million depreciation expense decrease relates to the decrease in in-service
11 capital expenditures of \$12.027 million in 2015.

12
13 *Required Return*

14 The \$0.009 million required return increase relates to an increase in the average rate base
15 investment in 2015 from \$23.533 million to \$24.171 million. The Board-approved
16 required return calculation was derived using a capital structure of 64% long-term debt at
17 4% and 36% equity at the Board-approved rate of return of 8.93%. The 2015 actual
18 required return calculation was derived using a capital structure of 64% long-term debt at
19 3.82%, and 36% equity at the Board-approved rate of return of 8.93%.

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

6
7 *Income Tax*

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

10
11 The \$0.912 million "Income Taxes-Utility Timing Difference" decrease relates primarily
12 to a lower actual Capital Cost Allowance versus the 2015 Board-approved amount due to
13 the lower capital expenditures in 2015 versus Board-approved.

14
15 Account No. 179-138 Parkway Obligation Rate Variance

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

1 2016 Rates proceeding (EB-2015-0116), there was no additional PDO shift during
2 2015. Accordingly, there are no timing differences to account for in this deferral
3 account.

4
5 Account No. 179-139 Energy East Pipeline Consultation Costs

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

11
12 Account No. 179-141 Unaccounted for Gas ("UFG") Price Variance Account

13 Consistent with the Board's Decision in Union's EB-2015-0010 proceeding, the UFG
14 Price Variance Account will capture the variance between the average monthly price of
15 Union's purchases and the applicable Board-approved reference price, applied to Union's
16 actual UFG volumes. For 2015, the balance in the UFG Price Variance Account is a
17 credit to ratepayers of \$0.581 million plus interest of \$0.004 million for a total credit of
18 \$0.585 million.

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

4

5 The actual average weighted cost of the Union South gas portfolio in 2015 was
6 \$159/ 10^3m^3 . Relative to Board-approved reference prices included in rates, the weighted
7 average variance is \$45.08/ 10^3m^3 . Please see to Union's QRAM application EB-2015-
8 0340 (at Tab 1, Schedule 3, p. 4) and EB-2016-0040 (at Tab 1, Schedule 3, p. 4) for
9 detailed costs by month. Accordingly, the UFG Price Variance Account has a credit
10 balance of \$0.581 million, as shown in Table 15.

Table 15
Calculation of 2015 UFG Price Deferral

<u>Line</u> <u>No.</u>		<u>UFG Volumes</u> <u>(10³m³)</u>
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)	<u>12.887</u>
		<u>Deferral</u> <u>Calculation</u>
4	UFG Volumes - Utility Ratepayer (2)	12.887
5	Price Variance (3)	\$ 45.08
		<u>\$ 0.581</u>

- (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.

1

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

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

8

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

- 1 Union's 2015 rates (EB-2014-0271) and the balance represents the calculation of the
- 2 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

<u>Line No.</u>	<u>Particulars (\$000's)</u>	<u>2015 Board-approved (a)</u>	<u>2015 Actuals (b)</u>	<u>Difference (c) = (b - a)</u>
	<u>Rate Base Investment</u>			
1	Capital Expenditures	-	14,058	14,058
2	Average Investment	-	2,259	2,259
	<u>Revenue Requirement Calculation:</u>			
	<u>Operating Expenses:</u>			
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
	<u>Income Taxes:</u>			
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:
 $\$2.3 \text{ million} * 64\% * 4.40\% = \$0.064 \text{ million plus}$
 $\$2.3 \text{ million} * 36\% * 8.93\% = \$0.072 \text{ 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.

1 *Capital Expenditures*

2 The actual capital expenditures on 2015 in-service assets increased by \$14.058 million
3 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

4

5 Per Union's Dawn Parkway 2016 Expansion Project proceeding (EB-2014-0261) there
6 were no Lobo Compressor Plant costs included in the 2015 Board-approved rates. In
7 order to meet construction schedules and have the plant available for the 2016/17
8 operating season, piping and auxiliary facilities were placed in service by November
9 2015.

1 *Average Investment*

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

5

6 *Operating Expenses*

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

9

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

12

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

14

15 *Required Return*

16 The \$0.136 million required return increase relates to the average rate base investment in
17 2015 being \$2.259 million greater than expected. The 2015 actual required return
18 calculation was derived using a capital structure of 64% long-term debt at 4.4%, and 36%
19 common equity at the Board-approved return of 8.93%. The required return calculation is
20 consistent with that filed and approved in the Lobo C Compressor/Hamilton-Milton
21 Pipeline Project (EB-2014-0261, Exhibit A, Tab 10, Schedule 1).

1 *Income Taxes*

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

4

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

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

			Filed
Line	Account		Balance ¹
No.	Number	Account Name	(\$000's)
<u>Gas Supply Accounts:</u>			
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
<u>Storage Accounts:</u>			
8	179-70	Short-Term Storage and Other Balancing Services	508
<u>Other:</u>			
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 LIMITEDUpstream Transportation Optimization Deferral Account (No. 179-131)

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

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 (a)	Actual 2014 (b)	Actual 2015 (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 on 11.3 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

<u>Date</u>	<u>Entitlement</u> (PJ)	<u>Balance</u> (PJ)	<u>% Full</u> (%)	<u>Date</u>	<u>Entitlement</u> (PJ)	<u>Balance</u> (PJ)	<u>% Full</u> (%)
01-Oct-15	86.8	69.7	80%	01-Nov-15	86.8	79.9	92%
02-Oct-15	86.8	70.7	81%	02-Nov-15	86.8	80.6	93%
03-Oct-15	86.8	71.4	82%	03-Nov-15	86.8	81.4	94%
04-Oct-15	86.8	72.1	83%	04-Nov-15	86.8	81.6	94%
05-Oct-15	86.8	72.5	83%	05-Nov-15	86.8	82.4	95%
06-Oct-15	86.8	73.3	84%	06-Nov-15	86.8	83.4	96%
07-Oct-15	86.8	74.2	85%	07-Nov-15	86.8	83.6	96%
08-Oct-15	86.8	74.5	86%	08-Nov-15	86.8	83.7	96%
09-Oct-15	86.8	74.9	86%	09-Nov-15	86.8	83.7	96%
10-Oct-15	86.8	75.6	87%	10-Nov-15	86.8	83.6	96%
11-Oct-15	86.8	76.5	88%	11-Nov-15	86.8	83.7	96%
12-Oct-15	86.8	77.5	89%	12-Nov-15	86.8	83.7	96%
13-Oct-15	86.8	78.0	90%	13-Nov-15	86.8	83.5	96%
14-Oct-15	86.8	78.0	90%	14-Nov-15	86.8	83.5	96%
15-Oct-15	86.8	78.3	90%	15-Nov-15	86.8	83.8	97%
16-Oct-15	86.8	78.3	90%	16-Nov-15	86.8	84.0	97%
17-Oct-15	86.8	78.2	90%	17-Nov-15	86.8	84.0	97%
18-Oct-15	86.8	77.9	90%	18-Nov-15	86.8	84.3	97%
19-Oct-15	86.8	78.0	90%	19-Nov-15	86.8	84.5	97%
20-Oct-15	86.8	78.2	90%	20-Nov-15	86.8	84.5	97%
21-Oct-15	86.8	78.2	90%	21-Nov-15	86.8	84.4	97%
22-Oct-15	86.8	78.4	90%	22-Nov-15	86.8	84.1	97%
23-Oct-15	86.8	78.5	90%	23-Nov-15	86.8	83.6	96%
24-Oct-15	86.8	79.1	91%	24-Nov-15	86.8	83.4	96%
25-Oct-15	86.8	79.4	91%	25-Nov-15	86.8	83.8	96%
26-Oct-15	86.8	79.2	91%	26-Nov-15	86.8	84.1	97%
27-Oct-15	86.8	79.1	91%	27-Nov-15	86.8	84.5	97%
28-Oct-15	86.8	79.1	91%	28-Nov-15	86.8	84.5	97%
29-Oct-15	86.8	79.1	91%	29-Nov-15	86.8	84.4	97%
30-Oct-15	86.8	78.9	91%	30-Nov-15	86.8	84.2	97%
31-Oct-15	86.8	79.1	91%				

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: m ³		2,901	169,025	2,761	169,121	
2	2015 Actual NAC: m ³		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 ³ m 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)		<u>\$4,276</u>	<u>\$1,026</u>	<u>\$4,699</u>	<u>\$545</u>	<u>\$10,546</u>

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

Line No.	Particulars (\$000's)	2015				
		2013 Deferral Disposition EB-2014-0145 (\$000) (a)	2013 DSM Deferral Disposition EB-2014-0273 (\$000) (b)	Total (\$000) (c) = (a) + (b)	Interest (\$000) (d)	Total Variance With Interest (\$000) (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	<u>171</u>	<u></u>	<u>171</u>	<u>1</u>	<u>172</u>
4	Total Deferral Account Amounts	<u><u>2,317</u></u>	<u><u>824</u></u>	<u><u>3,141</u></u>	<u><u>13</u></u>	<u><u>3,154</u></u>

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	Actual Volume	Volume Variance	Unit Rate for Prospective Recovery/(Refund)	Forecast	Actual	Variance
			(10 ³ m ³) (1)	(10 ³ m ³)	(10 ³ m ³)	(cents/m ³) (2)	(\$000)	(\$000)	(\$000)
			(a)	(b)	(c) = (a) - (b)	(d)	(e) = (a) * (d)/100	(f) = (b) * (d)/100	(g) = (e) - (f)
<u>General Service for Prospective Recovery(Refund) - Delivery</u>									
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		<u>3,273,803</u>	<u>3,735,509</u>	<u>(461,706)</u>		<u>(5,597)</u>	<u>(6,085)</u>	<u>488</u>
<u>General Service for Prospective Recovery(Refund) - Gas Supply Transportation</u>									
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 Transportation		<u>777,569</u>	<u>875,808</u>	<u>(98,239)</u>		<u>(13,138)</u>	<u>(14,796)</u>	<u>1,658</u>
<u>Prospective Recovery/(Refund) - Gas Supply Commodity</u>									
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		<u>1,998,897</u>	<u>2,272,982</u>	<u>(274,086)</u>		<u>(1,244)</u>	<u>(1,415)</u>	<u>171</u>
16	Total						<u>(19,979)</u>	<u>(22,296)</u>	<u>2,317</u>

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

Line No.	Particulars	Rate Class	2015						
			Forecast Volume (10 ³ m ³) (1)	Actual Volume (10 ³ m ³)	Volume Variance (10 ³ m 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)
	<u>General Service for Prospective Recovery(Refund) - Delivery</u>								
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		<u>2,115,637</u>	<u>1,791,721</u>	<u>323,916</u>		<u>5,522</u>	<u>4,698</u>	<u>824</u>
6	Total						<u>5,522</u>	<u>4,698</u>	<u>824</u>

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).

1 **2015 UTILITY RESULTS AND EARNINGS SHARING**

2 **2015 UTILITY RESULTS**

3 For the year ended December 31, 2015 Union's actual revenue sufficiency from utility
4 operations is \$16.7 million which is \$17.6 million lower than the 2014 revenue
5 sufficiency of \$34.3 million. Table 1 provides the results from Union's actual utility
6 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 (a)	Actual 2014 (b)	Actual 2015 (c)	Increase/ (decrease) 2015 vs. 2014 (d) = (c) - (b)
1	Gas sales and distribution revenue	1,448.8	1,761.5	1,659.2	
2	Cost of gas	<u>701.4</u>	<u>958.5</u>	<u>856.8</u>	
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	<u>17.1</u>	<u>24.0</u>	<u>15.7</u>	<u>(8.3)</u>
9	Utility income	274.1	306.8	307.9	1.1
10	Cost of Capital	<u>272.6</u>	<u>280.9</u>	<u>294.7</u>	<u>13.8</u>
11	Revenue deficiency / (sufficiency) after tax	(1.5)	(25.9)	(13.2)	12.7
12	Provision for income taxes on deficiency / (sufficiency)	<u>(0.5)</u>	<u>(9.3)</u>	<u>(4.7)</u>	<u>4.6</u>
13	Distribution revenue deficiency/(sufficiency)	(2.0)	(35.2)	(17.9)	17.3
14	Shareholder portion of short-term storage revenue	0.5	0.1	0.4	0.3
15	Shareholder portion of optimization activity	<u>1.5</u>	<u>0.8</u>	<u>0.8</u>	<u>(0.0)</u>
16	Total revenue deficiency/(sufficiency)	<u>-</u>	<u>(34.3)</u>	<u>(16.7)</u>	<u>17.6</u>

1

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

3 below.

1 Gas Distribution Margin

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

6
7 Transportation Revenue

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

13
14 Other Revenue

15 The increase in other revenue of \$5 million relative to 2014 was mainly driven by the
16 Board's Decision in Union's 2012 Deferrals Account Disposition proceeding (EB-2013-
17 0109) disallowing Union's proposal to establish a new Deferral Clearing Variance
18 Account to capture differences between deferral balances approved for disposition and
19 amounts prospectively refunded to or recovered from customers. The Board's Decision
20 disallowing the new deferral account was reflected in Union's actual 2014 Other
21 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

1 and operating expenses; column (b) removes revenues and costs associated with Union's
2 non-utility storage operations; column (c) makes adjustments that would normally be
3 made under cost of service to arrive at utility income. To arrive at utility earnings for the
4 purposes of earnings sharing, income taxes, interest and preferred dividends, and the
5 shareholder portion of net short term storage revenue and net optimization activity, are
6 deducted. The adjustments are discussed in more detail below.

7
8 Non-Utility Storage Operations

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

12
13 Adjustments

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

16 A) Demand Side Management ("DSM") Incentive

17 B) Charitable Donations

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

20 D) Other

1 A) DSM Incentive

2 Other revenue includes the revenue recorded for the DSM Incentive of \$5.917 million.
3 The DSM Incentive amount is an incentive to the company to encourage it to actively
4 pursue DSM activities. To ensure that the full amount of the DSM Incentive accrues to
5 the company and that the incentive is maintained, the DSM Incentive revenue is removed
6 from the earnings sharing calculation.
7

8 B) Charitable Donations

9 Charitable donation costs incurred by the utility are not allowable as deductions from
10 utility earnings and as a result \$1.666 million in costs have been removed.
11

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

13 Facility fees, customer deposit interest and foreign exchange on bank balances are
14 recorded in the company's corporate results as interest expense. Since these items should
15 be included in utility earnings, and are not part of the utility interest calculation they need
16 to be adjusted. As a result, facility fees and customer deposit interest of \$0.820 million
17 have been added to operating expenses and foreign exchange gain on bank balances of
18 \$1.154 million has been included in other expenses to arrive at utility earnings.
19

20 D) Other

21 In Union's corporate results, the transportation optimization built into distribution rates

1 was reclassified to transportation revenue as an offset to the actual optimization revenue
2 earned. In order to align with Board-approved presentation, this adjustment of \$15.565
3 million has been shown as a cost of gas reduction.

4
5 Amounts relating to the Conservation Demand Management (“CDM”) program of \$0.351
6 million have been removed from operating and maintenance expenses because of a
7 separate deferral sharing mechanism in place.

8
9 Income Taxes

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

12
13 Current utility income taxes are calculated using utility income before interest and taxes
14 less deemed interest costs, and permanent and timing differences to arrive at taxable
15 income multiplied by the current tax rates. The calculation can be found at Tab 2,
16 Appendix A, Schedule 14.

17
18 Interest and Preferred Dividends

19 The calculation of interest and preferred dividends is the same approach used for rate
20 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 (a)	Actual 2014 (b)	Actual 2015 (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

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

Line No.	Particulars (\$000s)	2013 Board-approved				2014 Actual				2015 Actual			
		Corporate	Unregulated Storage	Adjustments	Utility	Corporate	Unregulated Storage	Adjustments	Utility	Corporate	Unregulated Storage	Adjustments	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

Line No.	Particulars	2013 Board-approved				2014 Actual				2015 Actual			
		Utility Capital Structure (\$000s)	(%)	Cost Rate %	Return (\$000s)	Utility Capital Structure (\$000s)	(%)	Cost Rate %	Return (\$000s)	Utility Capital Structure (\$000s)	(%)	Cost Rate %	Return (\$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	<u>\$ 3,734,532</u>	<u>100.00%</u>		<u>\$ 272,639</u>	<u>\$ 3,976,418</u>	<u>100.00%</u>		<u>\$ 280,898</u>	<u>\$ 4,228,395</u>	<u>100.00%</u>		<u>\$ 292,359</u>

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 ³ m ³	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)
	<u>General Service</u>																		
1	Rate M1 Firm	2,271,443	465,977	185,421	16,702	-	2,939,543	2,602,598	273,220	53,026	15,560	-	2,944,404	2,583,548	255,785	32,406	17,127	-	2,888,866
2	Rate M2 Firm	378,137	336,728	23,220	237,485	-	975,571	612,196	301,067	7,220	251,462	-	1,171,944	579,474	326,911	5,562	277,278	-	1,189,225
3	Rate 01 Firm	641,423	233,272	-	9,727	-	884,421	829,132	117,249	-	9,760	-	956,141	826,618	101,871	-	10,455	-	938,944
4	Rate 10 Firm	155,398	82,428	-	85,062	-	322,887	191,175	69,786	-	90,362	2,844	354,167	172,559	74,364	-	93,077	3,625	343,625
5	Total General Service	3,446,401	1,118,404	208,642	348,975	-	5,122,423	4,235,102	761,323	60,246	367,143	2,844	5,426,657	4,162,199	758,930	37,968	397,938	3,625	5,360,660
	<u>Wholesale - Utility</u>																		
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
	<u>Contract</u>																		
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	4,421,475	775,883	60,246	1,569,589	7,300,929	14,128,122	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 ³ m ³	Board-approved 2013				
		System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service
		(a)	(b)	(c)	(d)	(e)
						Total (f)
<u>General Service</u>						
1	Rate M1 Firm	2,271,443	465,977	185,421	16,702	-
2	Rate M2 Firm	378,137	336,728	23,220	237,485	-
3	Rate 01 Firm	641,423	233,272	-	9,727	-
4	Rate 10 Firm	155,398	82,428	-	85,062	-
5	Total General Service	3,446,401	1,118,404	208,642	348,975	-
<u>Wholesale - Utility</u>						
6	Rate M9 Firm	-	-	-	60,750	-
7	Rate M10 Firm	48	-	-	141	-
8	Total Wholesale - Utility	48	-	-	60,891	-
<u>Contract</u>						
9	Rate M4	16,855	-	-	387,823	-
10	Rate M7	-	-	-	147,143	-
11	Rate 20 Storage	-	-	-	-	-
12	Rate 20 Transportation	13,514	-	-	110,097	506,191
13	Rate 100 Storage	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	1,895,488
15	Rate T-1 Storage	-	-	-	-	-
16	Rate T-1 Transportation	-	-	-	-	548,986
17	Rate T-2 Storage	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	4,880,297
19	Rate T-3 Storage	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	272,712
21	Rate M5	14,152	-	-	520,981	-
22	Rate 25	42,913	-	-	-	116,643
23	Rate 30	-	-	-	-	-
24	Total Contract	87,433	-	-	1,166,044	8,220,317
25	Total Throughput Volume	3,533,882	1,118,404	208,642	1,575,911	8,220,317

Actual 2014					
System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
(g)	(h)	(i)	(j)	(k)	(l)
2,942,275	308,880	59,947	17,591	-	3,328,692
670,955	329,963	7,913	275,597	-	1,284,428
913,183	129,135	-	10,749	-	1,053,067
204,812	74,764	-	96,807	3,047	379,430
4,731,226	842,742	67,859	400,744	3,047	6,045,618
-	-	-	67,138	-	67,138
312	-	-	-	-	312
312	-	-	67,138	-	67,450
37,330	11,639	-	435,435	-	484,404
27,984	2,922	-	361,350	-	392,256
-	-	-	-	-	-
8,614	-	-	93,899	433,114	535,626
-	-	-	-	-	-
-	-	-	-	1,710,928	1,710,928
-	-	-	-	-	-
-	-	-	-	470,811	470,811
-	-	-	-	-	-
-	-	-	-	4,305,103	4,305,103
-	-	-	-	-	-
-	-	-	-	288,979	288,979
14,733	-	-	244,625	-	259,358
97,399	-	-	-	89,150	186,550
-	-	-	-	-	-
186,060	14,561	-	1,135,309	7,298,086	8,634,015
4,917,599	857,303	67,859	1,603,190	7,301,132	14,747,083

Actual 2015					
System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
(m)	(n)	(o)	(p)	(q)	(r)
2,701,384	267,452	33,884	17,908	-	3,020,628
597,640	337,159	5,737	285,971	-	1,226,506
846,945	104,376	-	10,712	-	962,033
176,638	76,121	-	95,277	3,710	351,747
4,322,607	785,108	39,621	409,868	3,710	5,560,914
-	-	-	66,583	-	66,583
300	-	-	-	-	300
300	-	-	66,583	-	66,882
31,119	19,047	-	407,162	-	457,328
21,253	2,937	-	403,517	-	427,707
-	-	-	-	-	-
10,943	-	-	90,848	439,048	540,839
-	-	-	-	-	-
-	-	-	-	1,398,114	1,398,114
-	-	-	-	-	-
-	-	-	-	442,947	442,947
-	-	-	-	-	-
-	-	-	-	4,368,501	4,368,501
-	-	-	-	-	-
-	-	-	-	263,235	263,235
8,026	2,881	-	197,724	-	208,631
93,474	-	-	-	50,839	144,313
-	-	-	-	-	-
164,815	24,864	-	1,099,251	6,962,684	8,251,614
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						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-Unbundle	Bundled-T	T-Service	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
<u>General Service</u>																			
1	Rate M1 Firm	693,117	58,944	24,671	889	-	777,621	877,544	33,760	7,631	956	-	919,891	799,970	30,778	4,564	1,004	-	836,316
2	Rate M2 Firm	84,792	17,612	2,631	11,466	-	116,501	148,640	14,441	304	10,983	445	174,813	124,182	15,439	222	11,700	310	151,853
3	Rate 01 Firm	268,545	66,665	-	1,993	-	337,202	351,765	31,093	-	1,882	-	384,740	344,837	27,644	-	2,096	-	374,577
4	Rate 10 Firm	43,957	13,251	-	12,874	-	70,083	55,416	9,585	-	11,340	145	76,486	48,374	11,048	-	12,778	176	72,375
5	Total General Service	1,090,412	156,472	27,301	27,222	-	1,301,407	1,433,365	88,879	7,936	25,161	590	1,555,929	1,317,362	84,909	4,786	27,577	486	1,435,120
<u>Wholesale - Utility</u>																			
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
<u>Contract</u>																			
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	1,476,802	89,463	7,936	61,121	95,090	1,730,413	1,354,168	85,859	4,786	65,026	94,306	1,604,145
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						\$ 1,731,102						1,614,029

UNION GAS LIMITED
Total 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						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)
	<u>General Service</u>																		
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
	<u>Wholesale - Utility</u>																		
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
	<u>Contract</u>																		
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					\$	<u>1,448,762</u>					\$	<u>1,761,499</u>						<u>1,659,203</u>

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)
	<u>General Service</u>																		
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
	<u>Wholesale - Utility</u>																		
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
	<u>Contract</u>																		
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					\$	<u>741,747</u>					\$	<u>788,918</u>						<u>780,117</u>

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

Line No.	Particulars	Board-approved 2013					
		System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(a)	(b)	(c)	(d)	(e)	(f)
	<u>General Service</u>						
1	Rate M1 Firm	837,301	157,165	72,389	902	-	1,067,757
2	Rate M2 Firm	3,172	2,594	241	771	-	6,778
3	Rate 01 Firm	242,644	80,300	-	343	-	323,287
4	Rate 10 Firm	930	845	-	289	-	2,064
5	Total General Service	1,084,047	240,904	72,630	2,305	-	1,399,886
	<u>Wholesale - Utility</u>						
6	Rate M9 Firm	-	-	-	3	-	3
7	Rate M10 Firm	1	-	-	1	-	2
8	Total Wholesale - Utility	1	-	-	4	-	5
	<u>Contract</u>						
9	Rate M4	11	-	-	104	-	115
10	Rate M7	-	-	-	4	-	4
11	Rate 20 Storage	-	-	-	-	-	-
12	Rate 20 Transportation	4	-	-	20	39	63
13	Rate 100 Storage	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	17	17
15	Rate T-1 Storage	-	-	-	-	-	-
16	Rate T-1 Transportation	-	-	-	-	35	35
17	Rate T-2 Storage	-	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	29	29
19	Rate T-3 Storage	-	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	1	1
21	Rate M5	5	-	-	139	-	144
22	Rate 25	50	-	-	-	42	92
23	Rate 30	-	-	-	-	-	-
24	Total Contract	70	-	-	267	163	500
25	Total Number of Customers	1,084,118	240,904	72,630	2,576	163	1,400,391

Actual 2014					
System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
(g)	(h)	(i)	(j)	(k)	(l)
976,089	83,200	17,858	1,142	-	1,078,289
3,937	2,177	43	783	-	6,940
295,243	35,942	-	595	-	331,780
1,181	539	-	294	5	2,019
1,276,450	121,858	17,901	2,814	5	1,419,028
-	-	-	2	-	2
2	-	-	-	-	2
2	-	-	2	-	4
18	5	-	131	-	154
3	1	-	24	-	28
-	-	-	-	-	-
-	-	-	-	-	-
-	-	-	-	11	11
-	-	-	-	-	-
-	-	-	-	36	36
-	-	-	-	-	-
-	-	-	-	22	22
-	-	-	-	-	-
-	-	-	-	1	1
8	1	-	73	-	82
38	-	-	-	47	85
-	-	-	-	-	-
70	7	-	245	145	467
1,276,522	121,865	17,901	3,061	150	1,419,499

Actual 2015					
System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
(m)	(n)	(o)	(p)	(q)	(r)
1,003,873	74,656	9,991	1,113	-	1,089,633
4,429	2,457	29	837	-	7,752
305,931	30,287	-	639	-	336,857
1,312	579	-	324	5	2,220
1,315,545	107,979	10,020	2,913	5	1,436,462
-	-	-	2	-	2
2	-	-	-	-	2
2	-	-	2	-	4
18	9	-	132	-	159
2	1	-	25	-	28
-	-	-	-	-	-
-	-	-	-	-	-
-	-	-	-	11	11
-	-	-	-	-	-
-	-	-	-	37	37
-	-	-	-	-	-
-	-	-	-	22	22
-	-	-	-	-	-
-	-	-	-	1	1
6	2	-	67	-	75
31	-	-	-	47	78
-	-	-	-	-	-
60	12	-	240	146	458
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 (a)	2014 Actual (b)	2015 Actual (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	\$ <u>10,383</u>	\$ <u>7,783</u>	\$ <u>7,368</u>
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	\$ <u>156,997</u>	\$ <u>151,373</u>	\$ <u>156,244</u>

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 (a)	2014 Actual (b)	2015 Actual (c)
	<u>Determination of Taxable Income</u>			
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		<u>146,468</u>	<u>183,690</u>	<u>173,264</u>
	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		<u>(19,879)</u>	<u>(151,949)</u>	<u>49,101</u>
11	Taxable income	<u>\$ 126,589</u>	<u>\$ 31,741</u>	<u>\$ 222,365</u>
	<u>Calculation of Utility Income Taxes</u>			
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	<u>(15,169)</u>	<u>(12,819)</u>	<u>(12,819)</u>
15	Total taxes	<u>\$ 17,111</u>	<u>\$ 24,006</u>	<u>\$ 15,684</u>
	<u>Tax Rates</u>			
16	Federal tax	15.00%	15.00%	15.00%
17	Provincial tax	10.50%	11.50%	11.50%
18	Total tax rate	<u>25.50%</u>	<u>26.50%</u>	<u>26.50%</u>

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

Line No.	Particulars (\$000s)	2013 Board-approved			2014 Actual			2015 Actual		
		Depreciable UCC Balance	Rate (%)	CCA	Depreciable UCC Balance	Rate (%)	CCA	Depreciable UCC Balance	Rate (%)	CCA
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(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

Line No.	Particulars (\$000s)	2013 Board-approved				2014 Actual				2015 Actual		
		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

Line No.	Particulars (\$000s)	2013 Board-approved				2014 Actual			2015 Actual		
		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 (a)	2014 Actual (b)	2015 Actual (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 (a)	2014 Actual (b)	2015 Actual (c)
	<u>Gas Utility Plant</u>			
1	Gross plant at cost	6,361,532	6,674,254	7,029,496
2	Less: accumulated depreciation	<u>(2,754,070)</u>	<u>(2,868,946)</u>	<u>(2,994,815)</u>
3	Net utility plant	<u>3,607,462</u>	<u>3,805,308</u>	<u>4,034,681</u>
	<u>Working Capital and Other Components</u>			
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	<u>(764)</u>	<u>(307)</u>	<u>(179)</u>
12	Total working capital and other components	<u>196,757</u>	<u>225,805</u>	<u>235,545</u>
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	<u>(69,686)</u>	<u>(54,695)</u>	<u>(41,831)</u>
15	Total rate base	<u>\$ 3,734,532</u>	<u>\$ 3,976,418</u>	<u>\$ 4,228,395</u>

UNION GAS LIMITEDAllocation 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 (a)	Unregulated Storage (b)	Adjustments (c)	2015 Utility (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		<u>1,939,524</u>	<u>75,325</u>	<u>(21,483)</u>	<u>1,842,717</u>
	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		<u>1,564,962</u>	<u>30,189</u>	<u>(16,060)</u>	<u>1,518,713</u>
	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		<u>(2,309)</u>	<u>(713)</u>	<u>1,154</u>	<u>(442)</u>
16	Earnings before interest and taxes	<u>372,254</u>	<u>44,423</u>	<u>(4,269)</u>	323,562
17	Income taxes				<u>15,684</u>
18	Total utility income subject to earnings sharing				<u>307,878</u>
	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					<u>156,425</u>
	Less shareholder portions of:				
23	Net short-term storage revenue (after tax)				330
24	Net optimization activity (after tax)				<u>569</u>
25					<u>899</u>
26	Earnings subject to sharing				<u>150,554</u>
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%)				<u>-</u>
34	Total earnings sharing \$ (line 32 + line 33)				<u>-</u>
35	Pre-tax earnings sharing (line 34 / (1 minus tax rate))				<u>-</u>

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)
	<u>Unregulated Gas Plant in Service:</u>					
	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		<u>\$ 336,719</u>	<u>9,374</u>	<u>44,930</u>	<u>(2)</u>	<u>\$ 391,021</u>
	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		<u>\$ 13,294</u>	<u>2,038</u>	<u>-</u>	<u>(1,133)</u>	<u>\$ 14,199</u>
20	Total gas plant in service	<u>\$ 350,013</u>	<u>11,412</u>	<u>44,930</u>	<u>(1,135)</u>	<u>\$ 405,220</u>
21	Gas plant under construction	<u>11,875</u>	<u>(3,167)</u>			<u>8,708</u>
22	Total unregulated property plant and equipment	<u>\$ 361,888</u>	<u>8,245</u>	<u>44,930</u>	<u>(1,135)</u>	<u>\$ 413,928</u>

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

Line No.	Particulars (\$000's)	Balance Dec. 31/14 (a)	Transfers (b)	Provisions (c)	Retirements (d)	Net Salvage /(Costs) (e)	Balance Dec. 31/15 (f)
	<u>Unregulated Gas Plant in Service:</u>						
	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		<u>\$ 99,930</u>	<u>7,910</u>	<u>9,289</u>	<u>(1)</u>	<u>-</u>	<u>\$ 117,128</u>
	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		<u>\$ 6,657</u>	<u>(0)</u>	<u>2,220</u>	<u>(1,133)</u>	<u>10</u>	<u>\$ 7,754</u>
15	Total unregulated gas plant in service	<u>\$ 106,587</u>	<u>7,910</u>	<u>11,509</u>	<u>(1,134)</u>	<u>10</u>	<u>\$ 124,882</u>

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	<u><u>11,577</u></u>

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	Allocation	\$ 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	Allocation	\$ 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 divided by the number of calls received by a distributor's general inquiry number (CASL should be rounded to the first decimal number, e.g. 74.45% becomes 74.5%)
OEB Approved Standard: Yearly performance shall be 75% with a minimum monthly standard of 40%

Month	Number of Calls Reaching a Distributor's General Inquiry Number Answered Within 30 Seconds (1)	Number of Calls Received by a Distributor's General Inquiry Number (2)	Call Answering Service Level (%) (3 = 1 / 2 * 100)
Jan-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 decimal number, e.g. 8.55% becomes 8.6%)
OEB Approved Standard: Performance shall not exceed 10% on a yearly basis

Month	Number of Calls abandoned 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	Total Number of Manual Checks Done as	Total Number of Manual Checks Done When Meter Reads Show Excessively High	Brief Explanation for Excessively High Usage (In 100 Words or less)	Total Number of Manual Checks Done When Meter Reads Show Excessively Low	Brief Explanation for Excessively Low Usage (In 100 Words or less)
	(1)	(2)	(3)	(4)	(5)	(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).

1 **2015 GAS SUPPLY RELATED DEFERRAL ACCOUNTS**

2 The gas supply related deferral accounts include the Spot Gas Variance Account (179-107),
3 the Unabsorbed Demand Cost (“UDC”) Variance Account (179-108), the Gas Supply Review
4 Account (179-128), the Upstream Transportation Optimization Account (179-131), and the
5 gas supply commodity and gas supply transportation-related balances in the Deferral Clearing
6 Variance Account (179-132).

7
8 Spot Gas Variance Account

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

10
11 Unabsorbed Demand Cost Variance Account

12 Union proposes that the balance in the UDC Variance Account (179-108) related to Union
13 North be allocated to the firm Rate 01, Rate 10 and Rate 20 sales service and bundled DP
14 customers in proportion to 2013 Board-approved excess of peak day demands over average
15 annual demands. This allocation is consistent with the allocation of UDC in approved 2015
16 rates.

17
18 The UDC associated with Union South is applicable to sales service customers only. Accordingly,
19 Union proposes that the portion of the balance in the UDC Variance Account (179-108) related to
20 Union South be allocated to sales service customers only based on forecast sales service volumes.

1 Gas Supply Review Consultant Costs

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

5 Upstream Transportation Optimization

6 Union proposes to allocate the balance in the Upstream Transportation Optimization Deferral
7 Account (179-131) between Union North and Union South rate classes based on the upstream
8 transportation contracts used to serve each delivery area. Transportation optimization net
9 revenues generated using upstream transportation long-haul contracts and STS contracts
10 designed to serve Union North (with delivery points of Centra MDA, Union WDA, Union
11 SSMDA, Union NDA, Union NCDA and Union EDA) have been allocated to Union North.
12 Transportation optimization net revenues generated using upstream transportation long-haul
13 contracts designed to serve Union South (the Union CDA delivery point) have been allocated
14 to Union South. Specifically, with respect to capacity assignments, the net revenue from each
15 capacity assignment has been attributed to either the Union North or Union South based on the
16 delivery point.

18 Deferral Clearing Variance Account – Gas Supply Commodity and Transportation

19 Union proposes to allocate the gas supply commodity and gas supply transportation-related
20 balances in the Deferral Clearing Variance Account (179-132) to rate classes based on the
21 differences between the forecast and actual volumes associated with the disposition of deferral

1 account balances for each rate class, per Tab 1, Appendix A, Schedule 7.

2

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

8

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

13

14 **2015 NON- GAS SUPPLY RELATED DEFERRAL ACCOUNTS**

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

17

18 **STORAGE-RELATED DEFERRAL ACCOUNTS**

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

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

5
6 Union proposes to allocate the portion of the balance related to Union South rate classes in
7 proportion to the 2013 Board-approved design (peak) day demand.

8
9 The proposed disposition is also consistent with the allocation methodology for storage and
10 other balancing services margin approved in Union's 2015 rates.

11
12 **OTHER DEFERRAL ACCOUNTS**

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

15
16 Union proposes to allocate the balance in the Gas Distribution Access Rule ("GDAR") Costs
17 Deferral Account (179-112) in proportion to the 2013 Board-approved average number of
18 customers in Rate 01 and Rate M1.

19
20 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.

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

3
4 Union proposes to allocate the balance in the Parkway West Project Costs Deferral Account
5 (179-136) to rate classes in proportion to the difference between the actual Project costs and
6 the forecasted Project costs included in 2015 Rates (EB-2014-0271). Union determined the
7 actual Project costs by rate class by updating the 2013 Board-approved cost allocation study to
8 include the actual 2015 Parkway West Project costs.

9
10 Union proposes to allocate the balance in the Brantford-Kirkwall/Parkway D Project Costs
11 Deferral Account (179-137) to rate classes in proportion to the difference between the actual
12 Project costs and the forecasted Project costs included in 2015 Rates (EB-2014-0271).
13 Consistent with the methodology described in Union’s Brantford-Kirkwall/Parkway D Project
14 application (EB-2013-0074), Union determined the actual Project costs by rate class by
15 updating the 2013 Board-approved cost allocation study to include the actual 2015 Brantford-
16 Kirkwall/Parkway D Project costs.

17
18 There is no balance in the Parkway Obligation Rate Variance Account (179-138) at December
19 31, 2015.

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

5
6 Union is proposing to allocate the balance in the UFG Price Variance Account (179-141) to
7 rate classes in proportion to the 2013 Board-approved allocation of UFG costs to customers for
8 which Union provides fuel. This allocation is consistent with the allocation of the UFG price-
9 related variance recovered in the Spot Gas Variance Account (179-107) in Union's 2013
10 Deferral Disposition proceeding (EB-2014-0145).

11
12 Union proposes to allocate the balance in the Lobo C Compressor/Hamilton-Milton Pipeline
13 Project Costs Deferral Account (179-142) to rate classes in proportion to the difference
14 between the actual Project costs and the forecasted Project costs included in 2015 Rates (EB-
15 2014-0271). Consistent with the methodology described in Union's 2016 Dawn Parkway
16 Expansion Project application (EB-2014-0261), Union determined the actual Project costs by
17 rate class by updating the 2013 Board-approved cost allocation study to include the actual
18 2015 Lobo C Compressor/Hamilton-Milton Pipeline Project costs.

19
20 **DISPOSITION OF 2015 DEFERRAL ACCOUNT BALANCES**

21 For General Service Rate M1, Rate M2, Rate 01 and Rate 10 customers Union proposes to

1 dispose of the net 2015 deferral account balances prospectively, over the October 1, 2016 to
2 March 31, 2017 time period. The prospective refund / recovery approach over six months is
3 consistent with how Union disposed of its 2014 deferral account and earnings sharing balances
4 in EB-2015-0010.

5
6 For in-franchise contract and ex-franchise rate classes, Union is proposing to dispose of the net
7 2015 delivery-related deferral account balances as a one-time adjustment with October 2016
8 bills customers receive in November 2016. This approach is consistent with the methodology
9 used for the disposition of 2014 deferral account and earnings sharing balances in EB-2015-
10 0010.

11
12 **GENERAL SERVICE BILL IMPACTS**

13 General Service bill impacts are presented at Tab 3, Appendix A, Schedule 3. For a Rate M1
14 sales service residential customer in Union South with annual consumption of 2,200 m³, the
15 charge for the period October 1, 2016 to March 31, 2017 is \$7.13. This \$7.13 charge consists
16 of a delivery-related charge of \$3.87 (line 13, column (c)) and a commodity-related charge of
17 \$3.26 (line 14, column (c)). For a bundled direct purchase residential customer the charge is
18 \$3.87.

19
20 For a Rate 01 sales service residential customer in Union North with annual consumption of
21 2,200 m³, the charge for the period October 1, 2016 to March 31, 2017 is \$19.47. This \$19.47

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

UNION GAS LIMITED
Allocation of 2015 Deferral Account Balances

Line No.	Particulars (\$000's)	Acct No.	Union North					Union South														Total (1)	
			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
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)		(t)
<u>Gas Supply Related Deferrals:</u>																							
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	<u>1,237</u>	<u>428</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>1,665</u>	
7	Total Gas Supply Related Deferrals		<u>3,990</u>	<u>1,356</u>	<u>319</u>	<u>-</u>	<u>103</u>	<u>4,184</u>	<u>801</u>	<u>36</u>	<u>19</u>	<u>17</u>	<u>-</u>	<u>0</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>10,825</u>	
<u>Storage Related Deferrals:</u>																							
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	
<u>Delivery Related Deferrals:</u>																							
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)	(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	(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	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	<u>(108)</u>	<u>(15)</u>	<u>(12)</u>	<u>(10)</u>	<u>(4)</u>	<u>(245)</u>	<u>(33)</u>	<u>(8)</u>	<u>(8)</u>	<u>(3)</u>	<u>(0)</u>	<u>(0)</u>	<u>(5)</u>	<u>(20)</u>	<u>(2)</u>	<u>142</u>	<u>(0)</u>	<u>(4)</u>	<u>1</u>	<u>0</u>	<u>(335)</u>
24	Total Delivery-Related Deferrals		<u>4,815</u>	<u>1,199</u>	<u>(3)</u>	<u>(0)</u>	<u>5</u>	<u>5,264</u>	<u>1,381</u>	<u>(33)</u>	<u>(54)</u>	<u>(15)</u>	<u>(5)</u>	<u>0</u>	<u>2</u>	<u>44</u>	<u>4</u>	<u>(788)</u>	<u>(8)</u>	<u>4</u>	<u>5</u>	<u>(5)</u>	<u>11,812</u>
25	Total 2015 Storage and Delivery Disposition (Line 8 + Line 24)		<u>4,891</u>	<u>1,219</u>	<u>3</u>	<u>0</u>	<u>5</u>	<u>5,436</u>	<u>1,439</u>	<u>(14)</u>	<u>(53)</u>	<u>(9)</u>	<u>(3)</u>	<u>0</u>	<u>18</u>	<u>161</u>	<u>19</u>	<u>(788)</u>	<u>(8)</u>	<u>4</u>	<u>5</u>	<u>(5)</u>	<u>12,320</u>
26	Total 2015 Deferral Account Disposition (Line 7 + Line 25)		<u>8,882</u>	<u>2,575</u>	<u>322</u>	<u>0</u>	<u>108</u>	<u>9,621</u>	<u>2,240</u>	<u>22</u>	<u>(35)</u>	<u>8</u>	<u>(3)</u>	<u>0</u>	<u>18</u>	<u>161</u>	<u>19</u>	<u>(788)</u>	<u>(8)</u>	<u>4</u>	<u>5</u>	<u>(5)</u>	<u>23,145</u>
27	2015 Earnings Sharing (3)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
28	Grand Total (Line 26 + Line 27)		<u>8,882</u>	<u>2,575</u>	<u>322</u>	<u>0</u>	<u>108</u>	<u>9,621</u>	<u>2,240</u>	<u>22</u>	<u>(35)</u>	<u>8</u>	<u>(3)</u>	<u>0</u>	<u>18</u>	<u>161</u>	<u>19</u>	<u>(788)</u>	<u>(8)</u>	<u>4</u>	<u>5</u>	<u>(5)</u>	<u>23,145</u>

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 ³ m 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) (a)	2015 Earnings Sharing Mechanism (\$000's) (b)	Deferral Balance for Disposition (\$000's) (c) = (a+b)	Forecast Volume (10 ³ m ³) (1) (d)	Unit Rate for Prospective Recovery/(Refund) (cents/m ³) (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) (a)	2015 Earnings Sharing Mechanism (\$000's) (b)	Deferral Balance for Disposition (\$000's) (c) = (a+b)	Forecast Volume (10 ³ m ³) (1) (d)	Unit Rate for Prospective Recovery/(Refund) (cents/m ³) (2) (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) (a)	2015 Earnings Sharing Mechanism (\$000's) (b)	Deferral Balance for Disposition (\$000's) (c) = (a+b)	2015 Actual Volume (10 ³ m ³) (d)	Unit Rate (cents/m ³) (e) = (c/d)*100
<u>Union North</u>							
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
<u>Union South</u>							
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) (a)	2015 Earnings Sharing Mechanism (\$000's) (b)	Deferral Balance for Disposition (\$000's) (c) = (a+b)	2015 Actual Volume/Demand (d)	Billing Units	Unit Volumetric/Demand Rate (e) = (c/d)*100
<u>Gas Supply Transportation (cents/m³)</u>								
1	Medium Volume Firm Service	20	319	-	319	5,688	10 ³ m ³ /d	5.6135
2	Large Volume Interruptible	25	103	-	103	97,426	10 ³ m ³	0.1054
<u>Storage (\$/GJ)</u>								
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 (a)	2015 Earnings Sharing Mechanism (b)	Deferral Balance for Disposition (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/m ³) (1) (a)	Volume (m ³) (2) (b)	Bill Impact (\$) (c) = (a x b) / 100
1	<u>Rate 01</u>	Delivery	0.6189	1,733	10.72
2		Commodity	-	1,733	-
3		Transportation	0.5049	1,733	8.75
4			<u>1.1238</u>		<u>19.47</u>
5	Sales Service				19.47
6	Direct Purchase Bundled T				19.47
7	<u>Rate 10</u>	Delivery	0.4713	66,961	315.59
8		Commodity	-	66,961	-
9		Transportation	0.5268	66,961	352.75
10			<u>0.9981</u>		<u>668.33</u>
11	Sales Service				668.33
12	Direct Purchase Bundled T				668.33
13	<u>Rate M1</u>	Delivery	0.2304	1,679	3.87
14		Commodity	0.1942	1,679	3.26
15			<u>0.4246</u>		<u>7.13</u>
16	Sales Service				7.13
17	Direct Purchase				3.87
18	<u>Rate M2</u>	Delivery	0.1630	55,772	90.91
19		Commodity	0.1942	55,772	108.31
20			<u>0.3572</u>		<u>199.22</u>
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 m³.
Rate 10 volume based on annual consumption of 93,000 m³.
Rate M1 volume based on annual consumption of 2,200 m³.
Rate M2 volume based on annual consumption of 73,000 m³.

1 **INCREMENTAL TRANSPORTATION CONTRACTING ANALYSIS**

2 Introduction

3 Pursuant to Union's 2005-0520 Settlement Agreement¹, the purpose of this evidence is to
4 provide the analysis used by Union to support its decision to enter into firm transportation
5 capacity on the following contracts:

6 1. TransCanada Empress to Union WDA and Empress to Union MDA (2 years)

7 Transportation Contracts

8 2. TransCanada Empress to Union SSMDA (5 year) Transportation Contract

9 3. TransCanada Empress to Union WDA (1 year) Transportation Contract

10 4. TransCanada Union Parkway Belt to Union CDA (1 year) Transportation Contract

11 5. DTE Energy (1 year) Transportation Contract

12 6. DTE Energy (35 month) Transportation Contract

13 7. Panhandle (1 year) Transportation Contract

14 8. Market Based Transportation - Dominion South Point to Dawn (1 year)

15 Transportation Contract

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

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

3 Capacity History

4 Historically, the use of upstream diversions on TransCanada, although a discretionary
5 service, had been extremely reliable. For many years Union planned for, and utilized,
6 upstream diversions to meet the peak day requirements of the Union NDA. However, in
7 2013, TransCanada's long-haul transportation contracting and system operations changed
8 such that upstream diversions were no longer highly reliable. As such, Union began
9 experiencing interruptions of upstream diversions in December 2013. In response, Union
10 needed to reduce the reliance on diversions in the gas supply portfolio by rebalancing the
11 Union North portfolio to align firm contracts delivery points with areas requiring firm
12 capacity.

13
14 New Capacity

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

1 Rationale for Transportation Capacity

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

5
6 The benefits of this capacity are:

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

18
19 Empress to Union WDA Contract Parameters

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

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

9

10 Empress to Union MDA Contract Parameters

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

1 Incremental Contracting Analysis Form

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

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

7 **CONTRACT**

8 Capacity History

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

15 New Capacity

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

1 Rationale for Transportation Capacity

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

6

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

13

14 The benefits of this capacity are:

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

- 1 4. Firm transportation purchase is consistent with the gas supply principal of ensuring
2 secure and reliable gas supply to Union's service territory at a reasonable cost.

3
4 Contract Parameters

- 5 • Transportation Provider: TransCanada Pipelines Limited
6 • Service: (FT) Firm Gas Transportation Service
7 • Term: November 1, 2015 through October 31, 2020
8 • Volume: 12,800 GJ/day
9 • Current Rate: \$1.4135 Cdn/GJ at 100% load factor (includes abandonment
10 surcharge, exclusive of fuel)
11 • Receipt Point: Empress
12 • Delivery Point: Union SSMDA
13 • Renewal Rights: Per TransCanada Firm Transport Tariff (24 month notice
14 required)

15
16 Incremental Contracting Analysis Form

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

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

2 **CONTRACT**

3 New Capacity

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

6
7 Rationale for Transportation Capacity

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

12
13 The benefits of this capacity are:

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

1 Empress to Union WDA Contract Parameters

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

10
11 Incremental Contracting Analysis Form

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

14
15 **4. TRANSCANADA UNION PARKWAY BELT TO UNION CDA (1 YEAR)**

16 **TRANSPORTATION CONTRACT**

17 Capacity History

18 As discussed in EB-2014-0182², TransCanada had not historically required that Union
19 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.

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

3

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

15

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

1 New Capacity

2 In August of 2015, TransCanada held an Existing Capacity Open Season offering up to
3 92,000 GJ/d of capacity from Union Parkway Belt to the Union CDA. On August 28,
4 2015, Union was able to secure a one-year, FT-NR contract with TransCanada to transport
5 61,888 GJ/d from Union Parkway Belt to the Union CDA commencing November 1,
6 2015.

7
8 Rationale for Transportation Capacity

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

12
13 The benefits of this capacity are:

- 14 1. Provides firm transportation capacity to meet the firm design day loads within the
15 Union CDA;
- 16 2. Firm transportation purchase is consistent with the gas supply principal of ensuring
17 secure and reliable gas supply to Union's service territory at a reasonable cost;
- 18 3. Contract expiry lines up with expected in service date for the Burlington Oakville
19 facilities which, in conjunction with existing Union facilities, will provide for the
20 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.

1 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
3 rd 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

2

3 **5. DTE ENERGY (1 YEAR) TRANSPORTATION CONTRACT**

4 Capacity History

5 Union held a contract for 10,000 Dth/d (10,551 GJ/d) at a 100% load factor rate of \$0.035
6 US/Dth, with a one-year term commencing November 1, 2014 and expiring October 31,
7 2015. This capacity has receipt point flexibility as it allows Union to purchase supply at
8 either the Michcon Generic receipt point or Willow Run receipt point and flow the gas to
9 the Union (St. Clair) interconnect for ultimate delivery to Dawn. Union had the right to
10 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.

1 **6. DTE ENERGY (35 MONTH) TRANSPORTATION CONTRACT**

2 Capacity History

3 Union had originally signed agreements with NEXUS for capacity that would be
4 implemented in two phases. The first phase would have NEXUS providing Union with
5 75,000 Dth/d (79,125 GJ/d) of transportation capacity for two years commencing
6 November 1, 2015 by using existing pipeline infrastructure in Michigan and Ontario.
7 Phase 2, commencing November 1, 2017, was similar to how the NEXUS project is now
8 structured, providing Union 150,000 Dth/d (158,258 GJ/d) of transportation capacity from
9 Kensington, Ohio to the DTE interconnect with Union. Phase 1 was subsequently
10 removed from the NEXUS project scope, leaving Union with a temporary capacity
11 shortfall in its transportation portfolio.

12
13 New Capacity

14 Union was able to acquire a new contract for 60,000 Dth/d (63,303 GJ/d) at a 100% load
15 factor rate of \$0.050 US/Dth, with a 35-month term commencing December 1, 2015 and
16 expiring the earlier of October 31, 2018 or the in-service date for NEXUS. This capacity
17 has receipt point flexibility as it allows Union to purchase supply at either the Michcon
18 Generic receipt point or the Panhandle Pipeline interconnect with DTE and flow the gas to
19 the Union (St. Clair) interconnect for ultimate delivery to Dawn. This capacity is used to
20 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,

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

4
5 Contract Parameters

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

14
15 Incremental Contracting Analysis Form

16 Tab 4, Appendix A, Schedule 2 shows a comparison of landed costs for the DTE Energy
17 contract relative to the alternatives reviewed by Union at the time the decision to acquire
18 the capacity was made. Schedule 2 is in the format agreed upon in the EB-2005-0520
19 Settlement Agreement.

1 **7. PANHANDLE (1 YEAR) TRANSPORTATION CONTRACT**

2 Capacity History

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

7
8 In addition to the 27,000 Dth/d (28,487 GJ/d), Union held a contract for 10,000 Dth/d
9 (10,551 GJ/d) of incremental firm transportation on Panhandle (Panhandle Field Zone to
10 Ojibway) beginning November 1, 2013, with a one-year term that expired on October 31,
11 2014. In 2014, Union contracted to extend this 10,000 Dth/d (10,551 GJ/d) contract to
12 October 31, 2015 expiry date. Union provided the landed cost analysis for the original
13 contract as part of the 2014 Disposition of Deferral Account Balances evidence.⁴

14
15 Renewed Capacity

16 Union has exercised its Right of First Refusal (ROFR) rights on its existing contract for
17 10,000 Dth/d (10,551 GJ/d) at a 100% load factor rate of \$0.4265 US/Dth, for a one-year
18 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

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

7

8 Incremental Contracting Analysis Form

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

13

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

16 New Capacity

17 Union entered into a contract for firm transportation capacity of 20,000 Dth/d (21,101
18 GJ/d) from Dominion South Point to Dawn for a one-year term starting November 1,
19 2015. This capacity is provided by a marketer that is able to provide a firm service from
20 Dominion South Point to Dawn. Union delivers gas on the Dominion Gas Transmission
21 system at the point denoted as Dominion South Point and then Union receives an
22 equivalent amount of gas at Dawn. This contract will allow Union to develop relationships

1 with potential NEXUS suppliers in Appalachia and gain experience purchasing
2 Marcellus/Utica supply.

3
4 Rationale for Transportation Capacity

5 Union has contracted for capacity on the new proposed NEXUS pipeline, which will
6 directly connect the growing supplies from the Appalachian basin to the Dawn hub. Union
7 sought, and was granted, pre-approval for the NEXUS contract cost consequences from
8 the Board⁵. In order to seek business relationships with producers located in the
9 Appalachian basin, Union sought market based options to allow Union to purchase
10 supplies in the Appalachian area. By contracting for market based transportation services
11 that originate at Dominion South Point, Union is able to purchase gas supply at Dominion
12 South Point, a very liquid and active location for most Appalachian producers and
13 marketers. This service will allow Union to work with a variety of suppliers in the
14 Appalachian region in order to gain additional experience and form relationships prior to
15 the in-service date of NEXUS.

16
17 The benefits of this capacity are:

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

⁵ EB-2015-0166 / EB-2015-0175

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

6

7 Contract Parameters

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

14

15 Incremental Contracting Analysis Form

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

UNION GAS LIMITED
2015-2016 Transportation Contracting Analysis

	Route (A)	Point of Supply (B)	Basis Differential \$US/mmBtu (C)	Supply Cost \$US/mmBtu (D) = Nymex + C	Unitized Demand Charge \$US/mmBtu (E)	Commodity Charge \$US/mmBtu (F)	Fuel Charge \$US/mmBtu (G)	100% LF Transportation Inclusive of Fuel \$US/mmBtu (I) = E + F + G	Landed Cost \$US/mmBtu (J) = D + I	Landed Cost \$Cdn/G (K)	Point of Delivery (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, Exhibt JTI.2, Page 45, Attachment 1

UNION GAS LIMITED
2015-2018 Transportation Contracting Analysis

	Route (A)	Point of Supply (B)	Basis Differential \$US/mmBtu (C)	Supply Cost \$US/mmBtu (D) = Nymex + C	Unitized Demand Charge \$US/mmBtu (E)	Commodity Charge \$US/mmBtu (F)	Fuel Charge \$US/mmBtu (G)	100% LF Transportation Inclusive of Fuel \$US/mmBtu (I) = E + F + G	Landed Cost \$US/mmBtu (J) = D + I	Landed Cost \$Cdn/G (K)	Point of Delivery (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.



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. SQL 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.



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

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

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

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

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



uniongas

A Spectra Energy Company



2015/2016 Gas Supply Update

Chris Shorts
Director

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



uniongas

A Spectra Energy Company



2015/16 Winter Experience

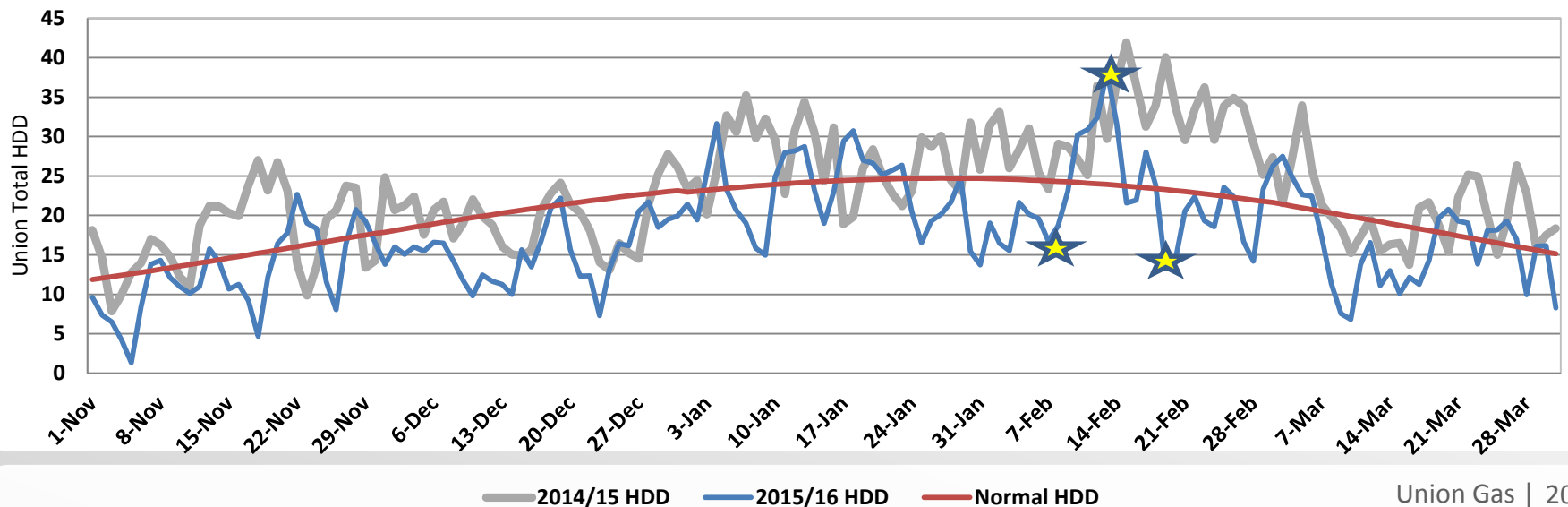
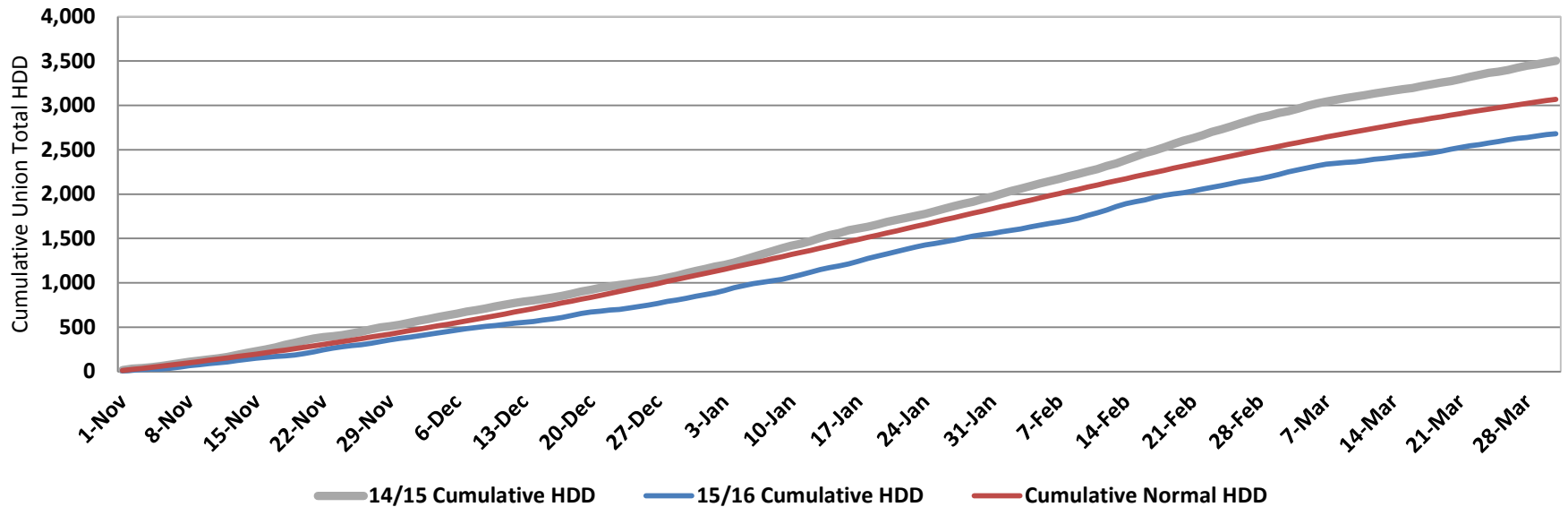
Overall Winter Experience

- 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)

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

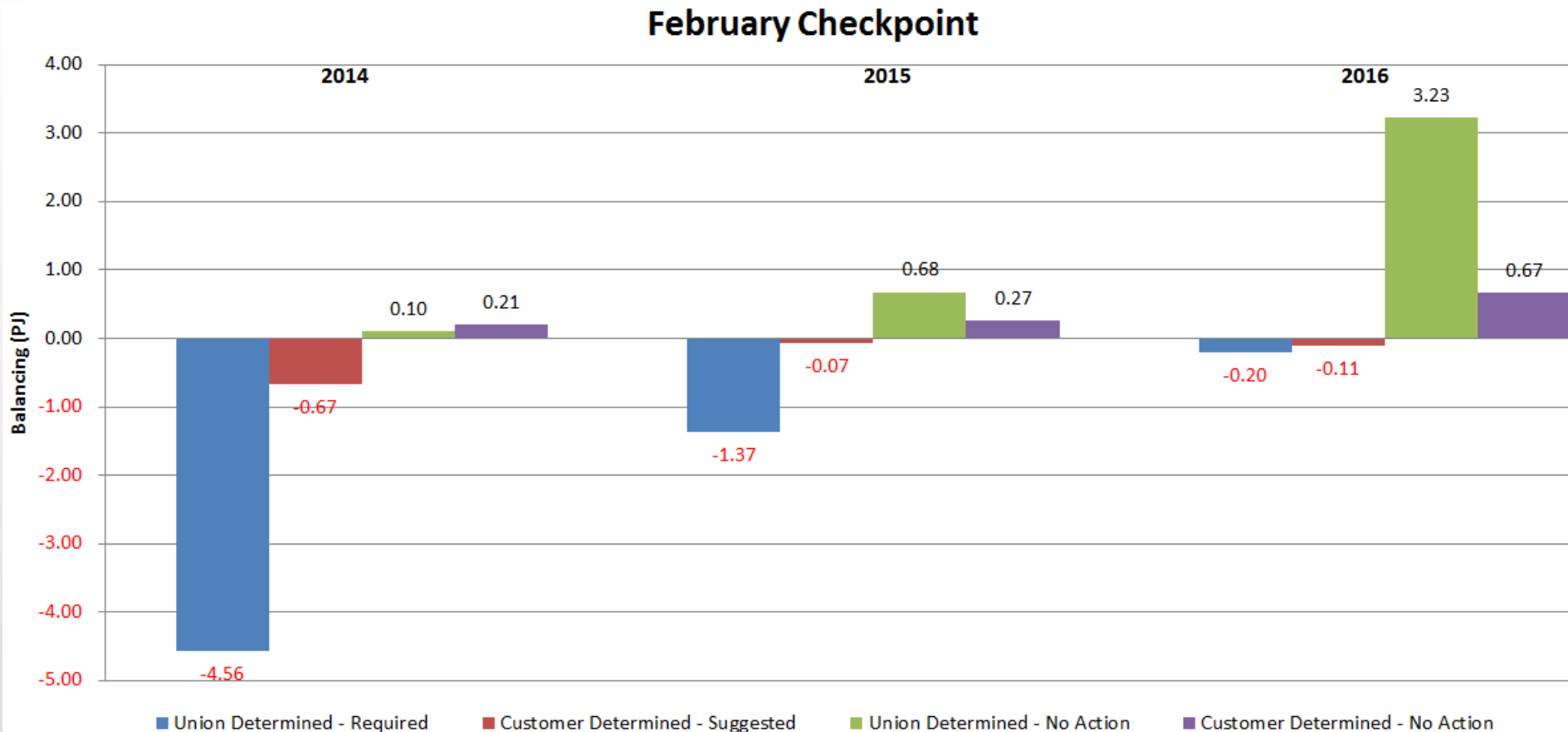
Winter Interruptions

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

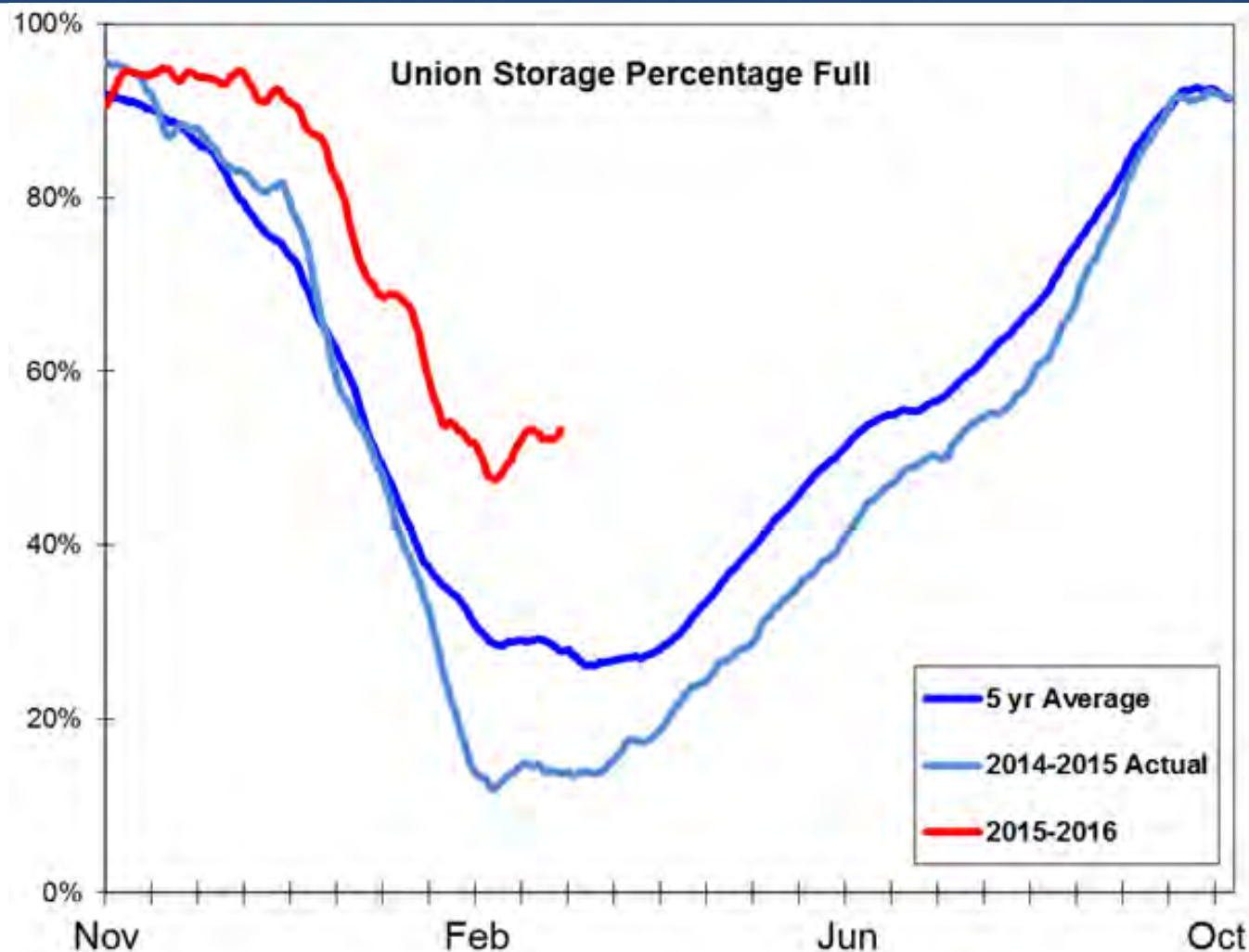
Minimal distribution interruption when compared to last two winters

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

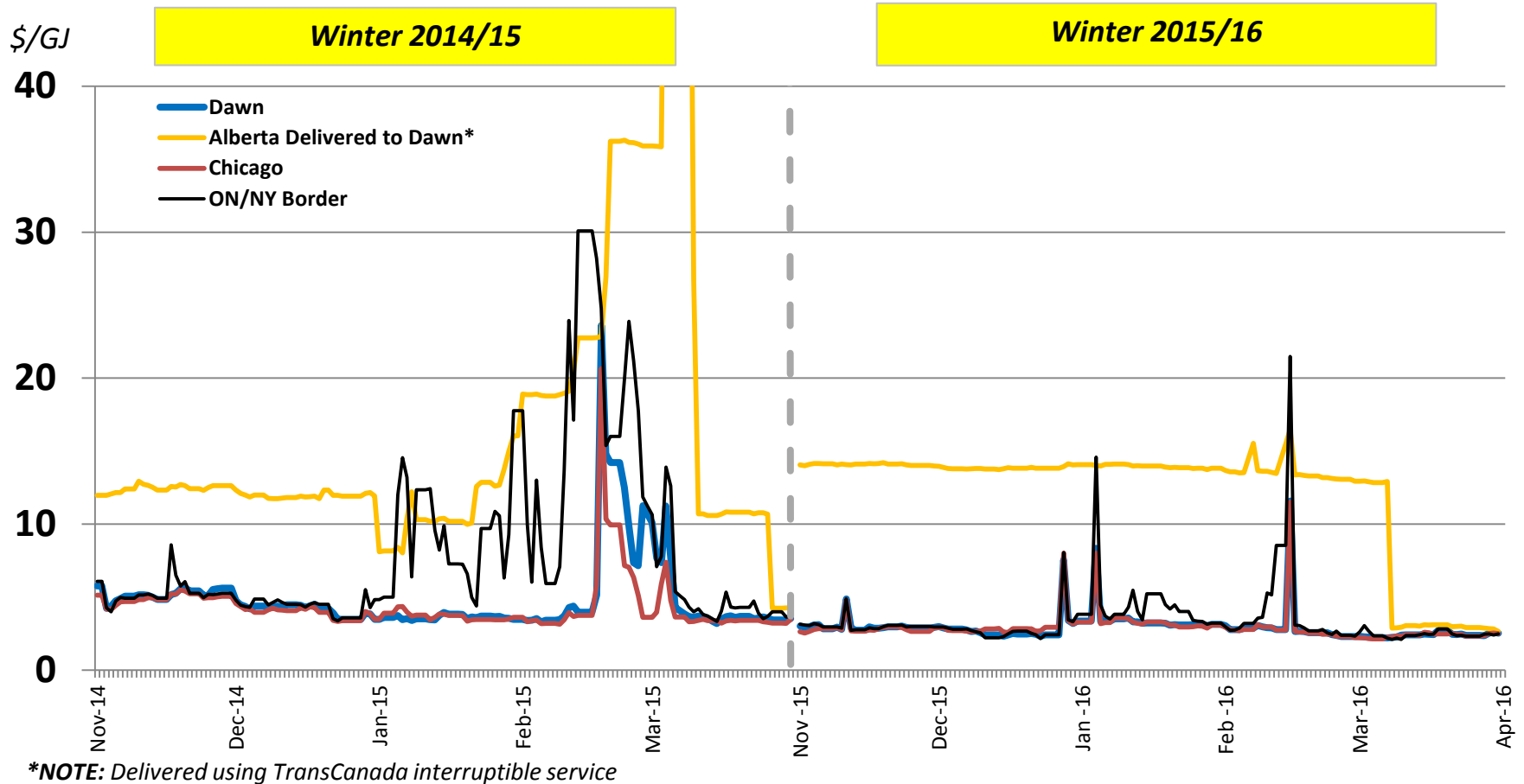
Storage Level



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

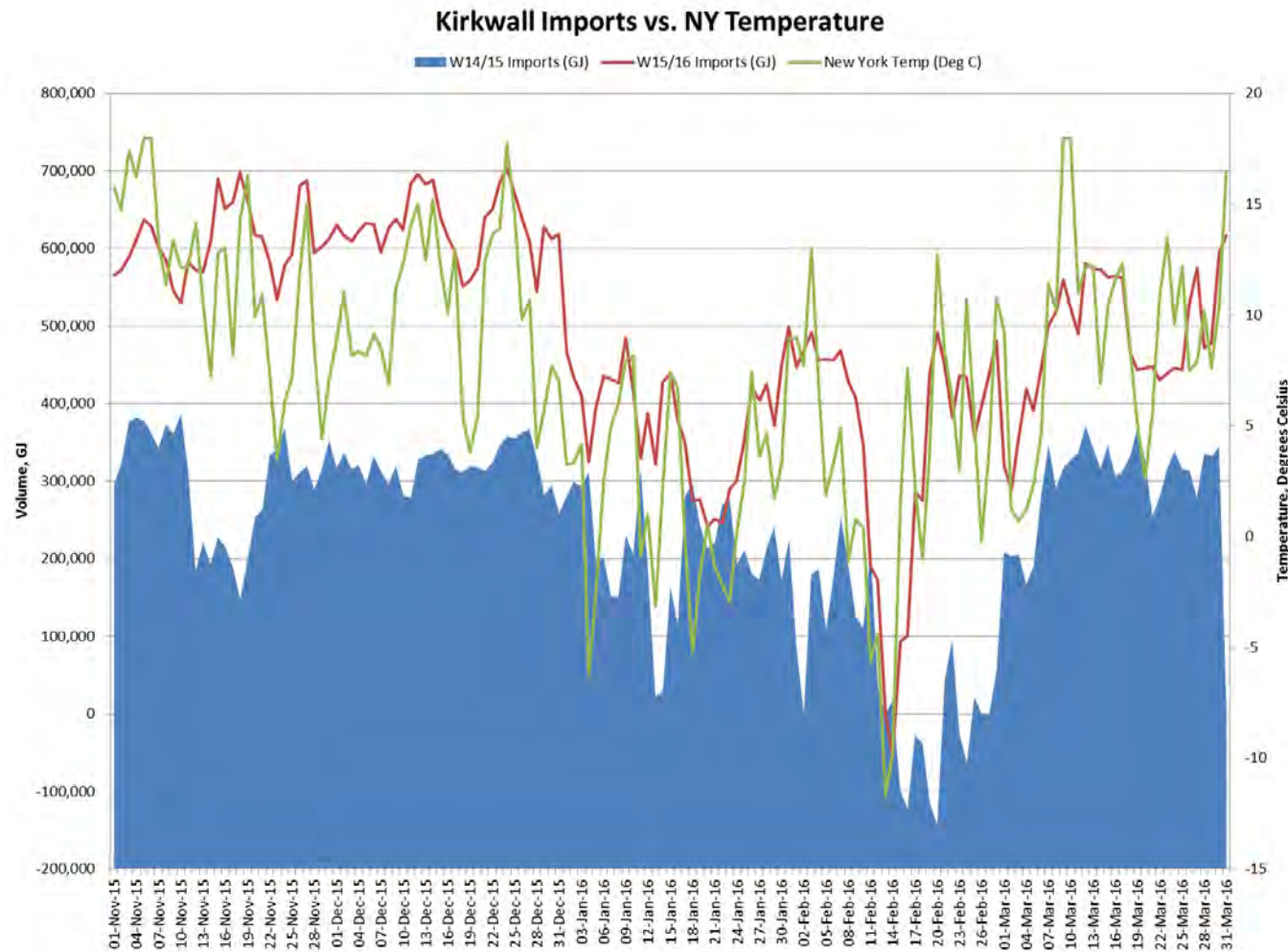
Winter Natural Gas Prices

Maximum Daily Natural Gas Prices



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



Gas Supply Outlook

2015/2016 Plan

Gas Supply Plan Overview

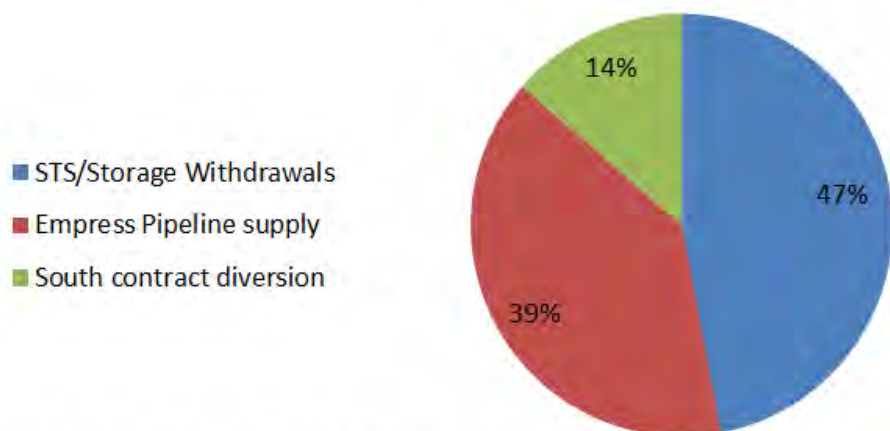
- Plan period covers November 1, 2015 to October 31, 2016
- The corresponding Gas Supply Memorandum was filed September 22, 2015 as part of Union's 2016 Rates application (EB-2015-0116)

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

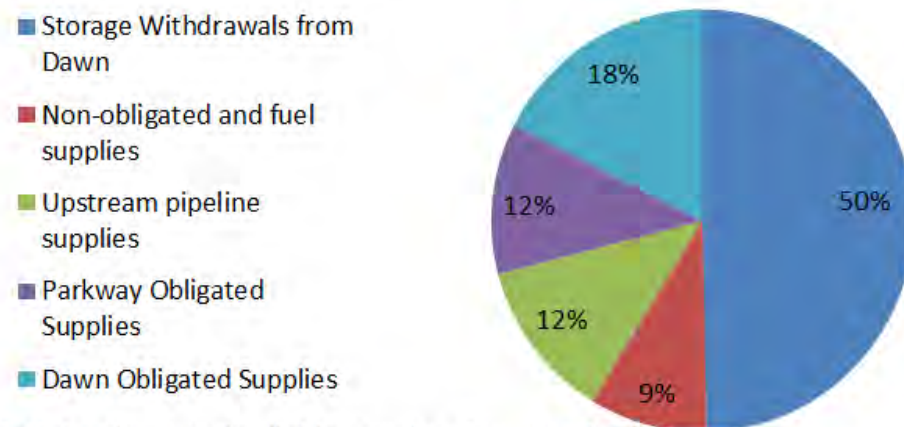
Union Design Day Supplies

Union North Design Day 493 TJ/day



*includes bundled firm, non-industrial, and T-service storage redelivery

Union South Design Day 2,900 TJ/day



*includes sales service, bundled direct purchase, T-service, unbundled

- 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



uniongas

A Spectra Energy Company



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



uniongas

A Spectra Energy Company

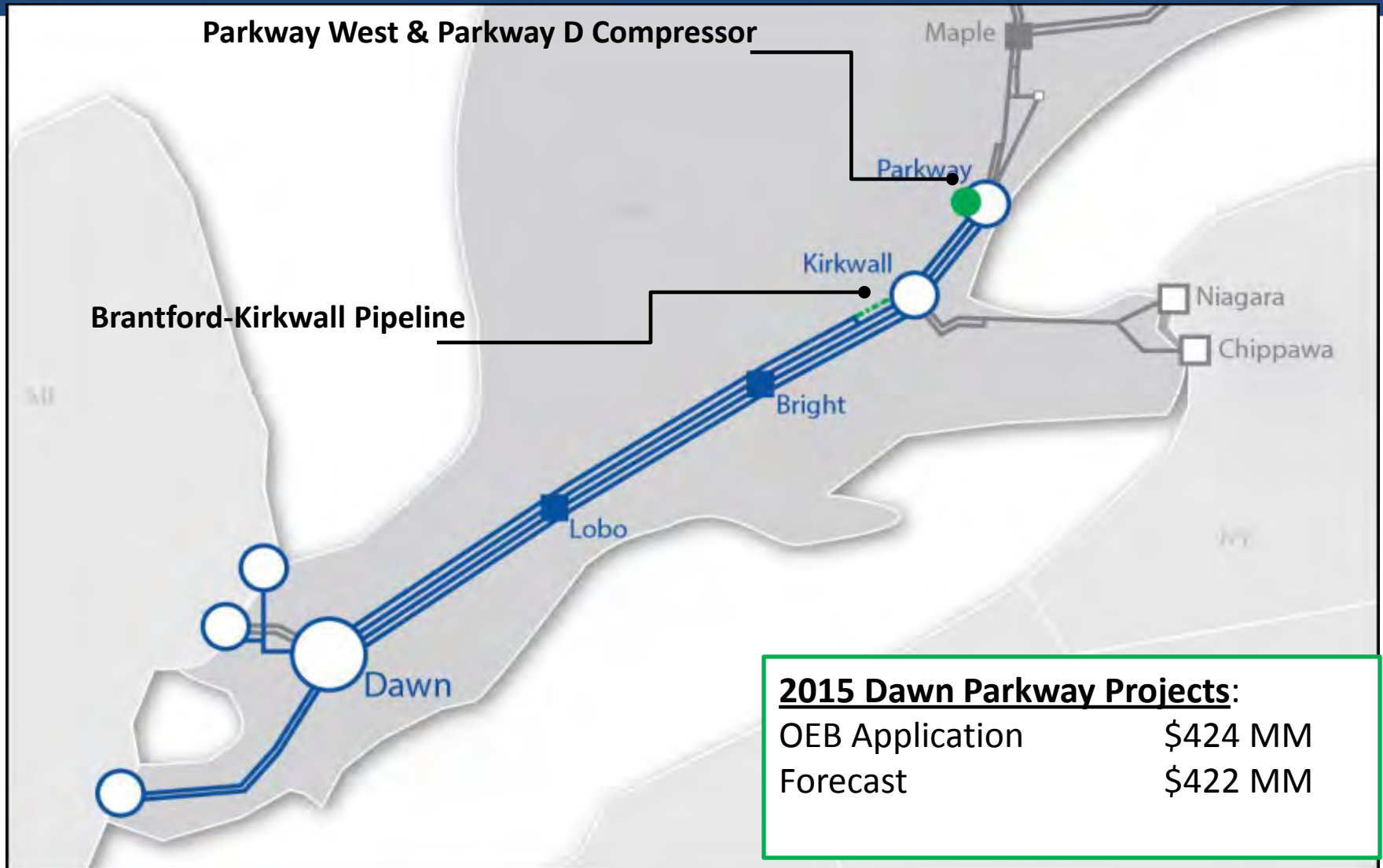


Facilities Expansions

Paolo Mastronardi

Manager, Business Development

2015 Dawn Parkway Projects



2015 Dawn Parkway Projects Parkway West

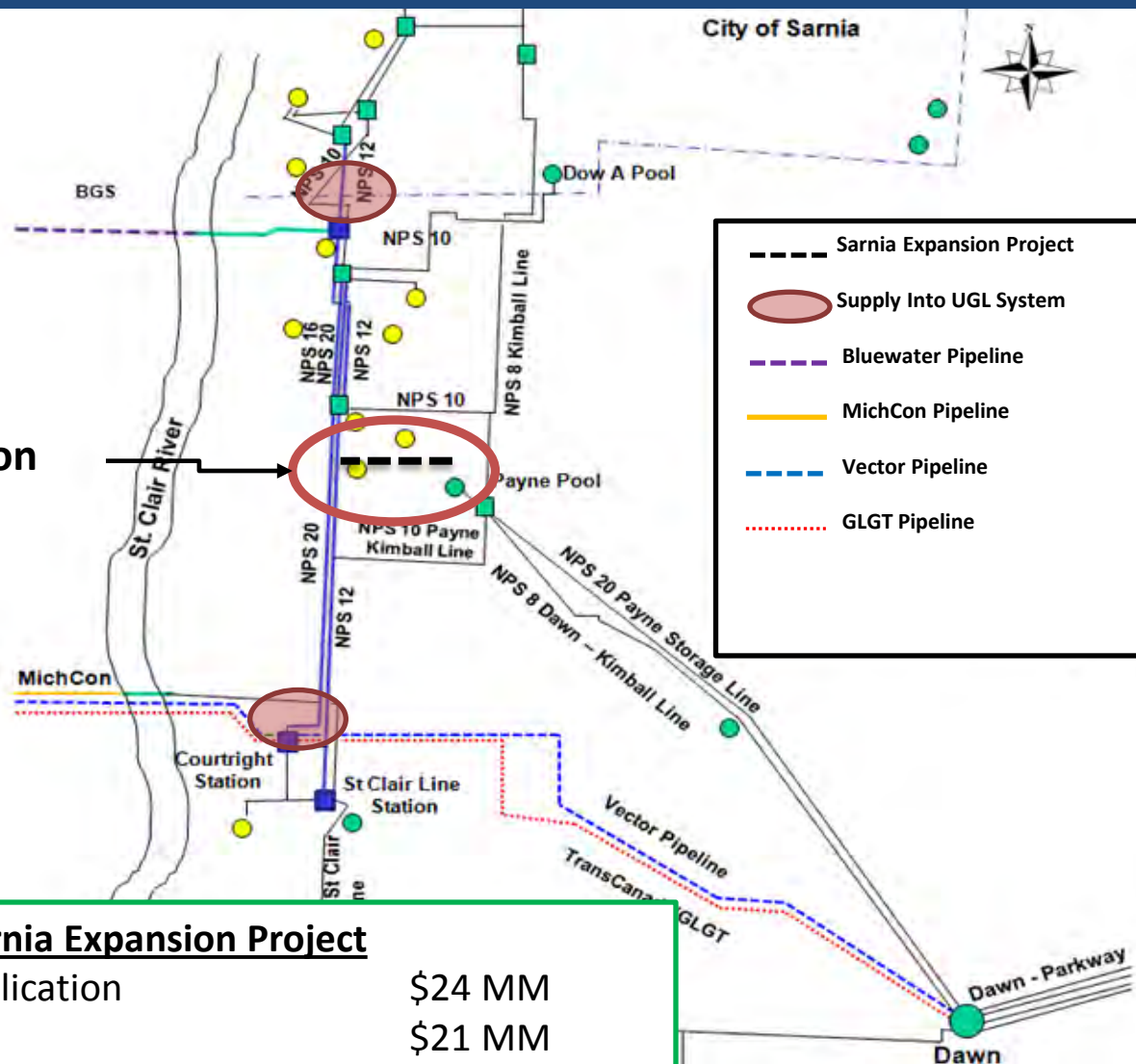


2015 Dawn Parkway Projects Brantford - Kirkwall



2015 Sarnia Expansion Project

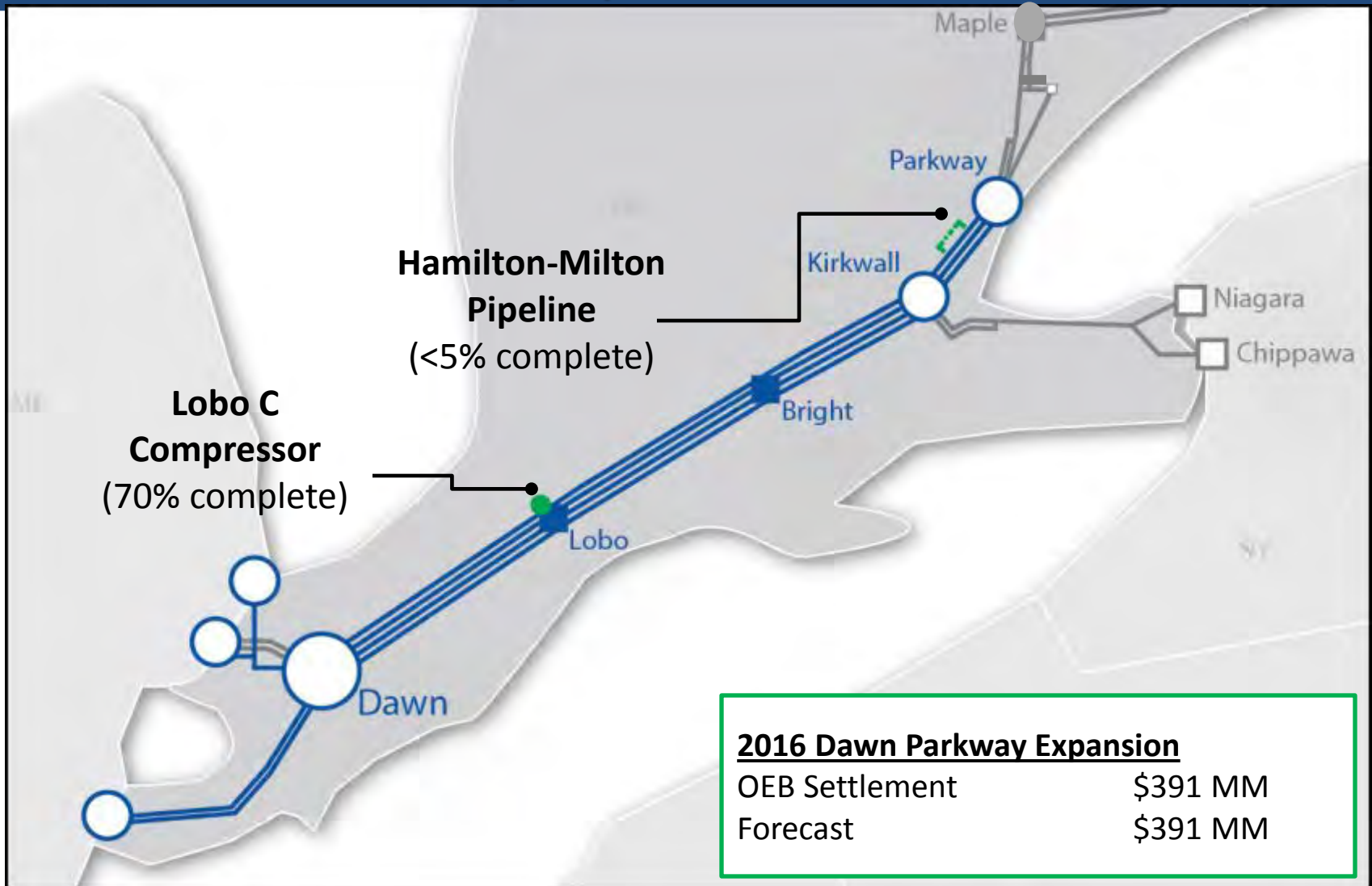
Sarnia Expansion Project



2015 Sarnia Expansion Project

OEB Application	\$24 MM
Forecast	\$21 MM

2016 Dawn Parkway Expansion



2016 Dawn Parkway Expansion Lobo C



2016 Burlington Oakville Project



2016 Burlington-Oakville Project

OEB Application \$120 MM

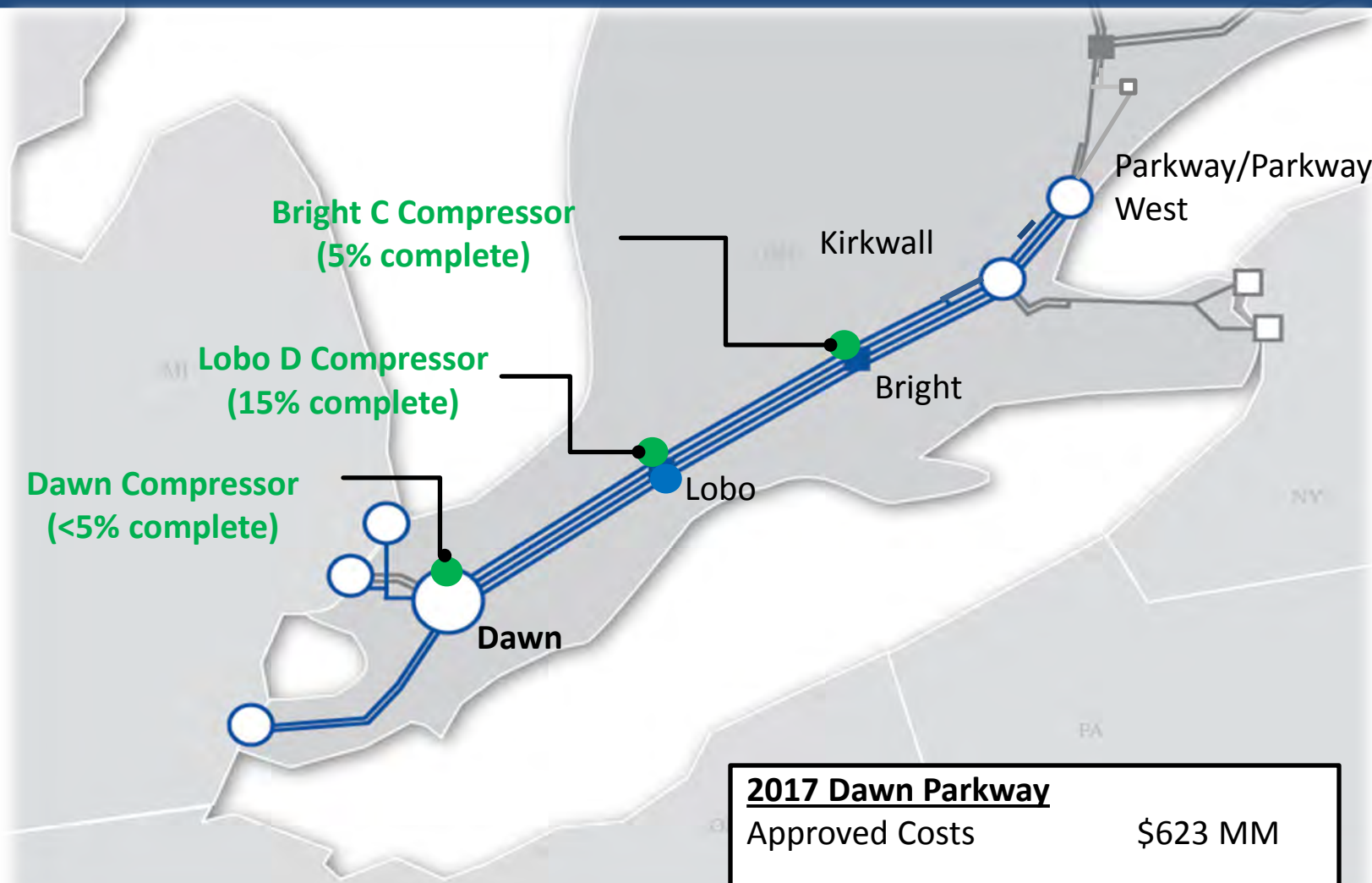
Forecast \$120 MM

< 5% complete

Burlington Oakville Project



2017 Dawn Parkway Projects



2017 Dawn Parkway Projects

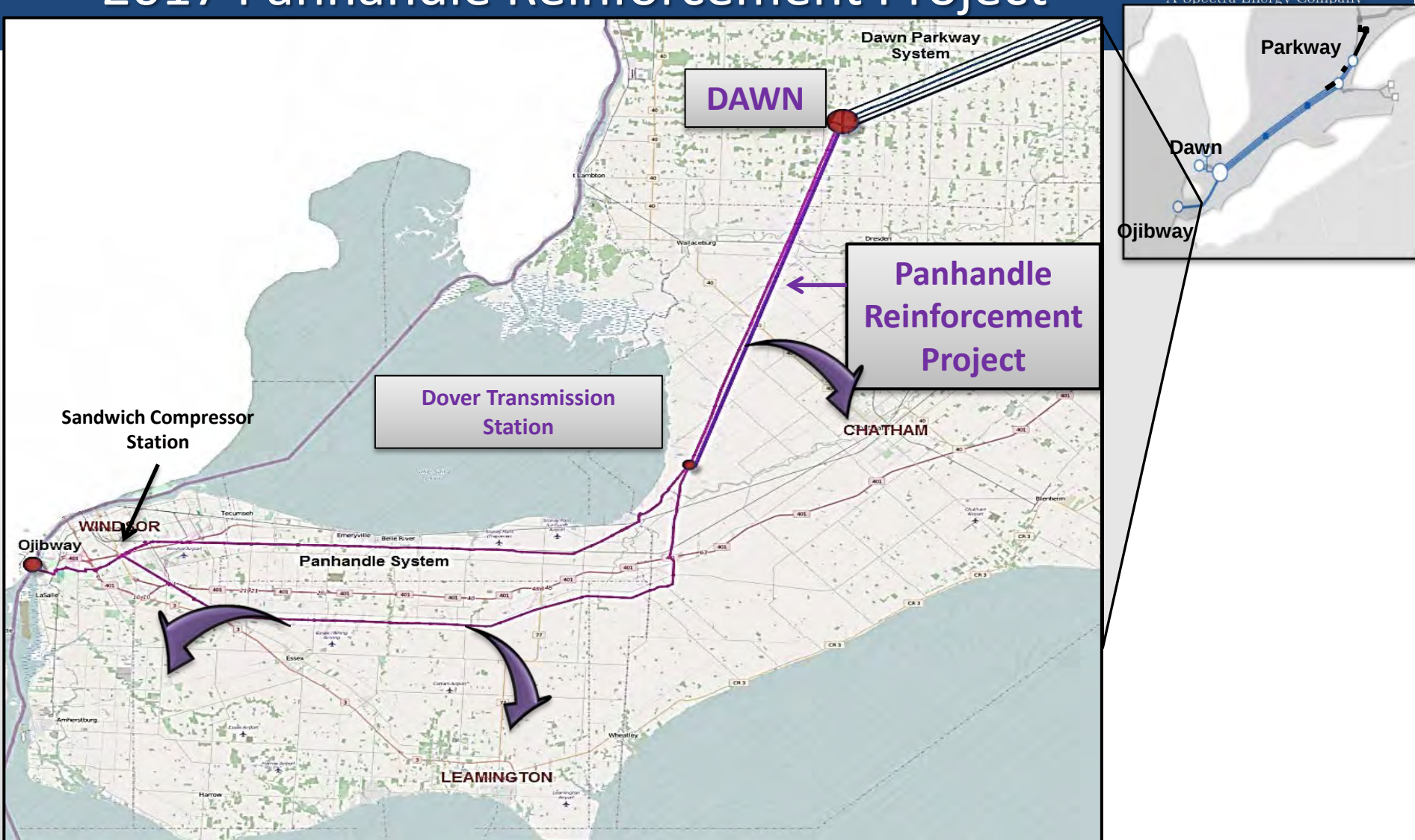
Lobo D



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

- 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



Residential Customer Perceptions of Union Gas

Jeff Okrucky
Director, Distribution Marketing

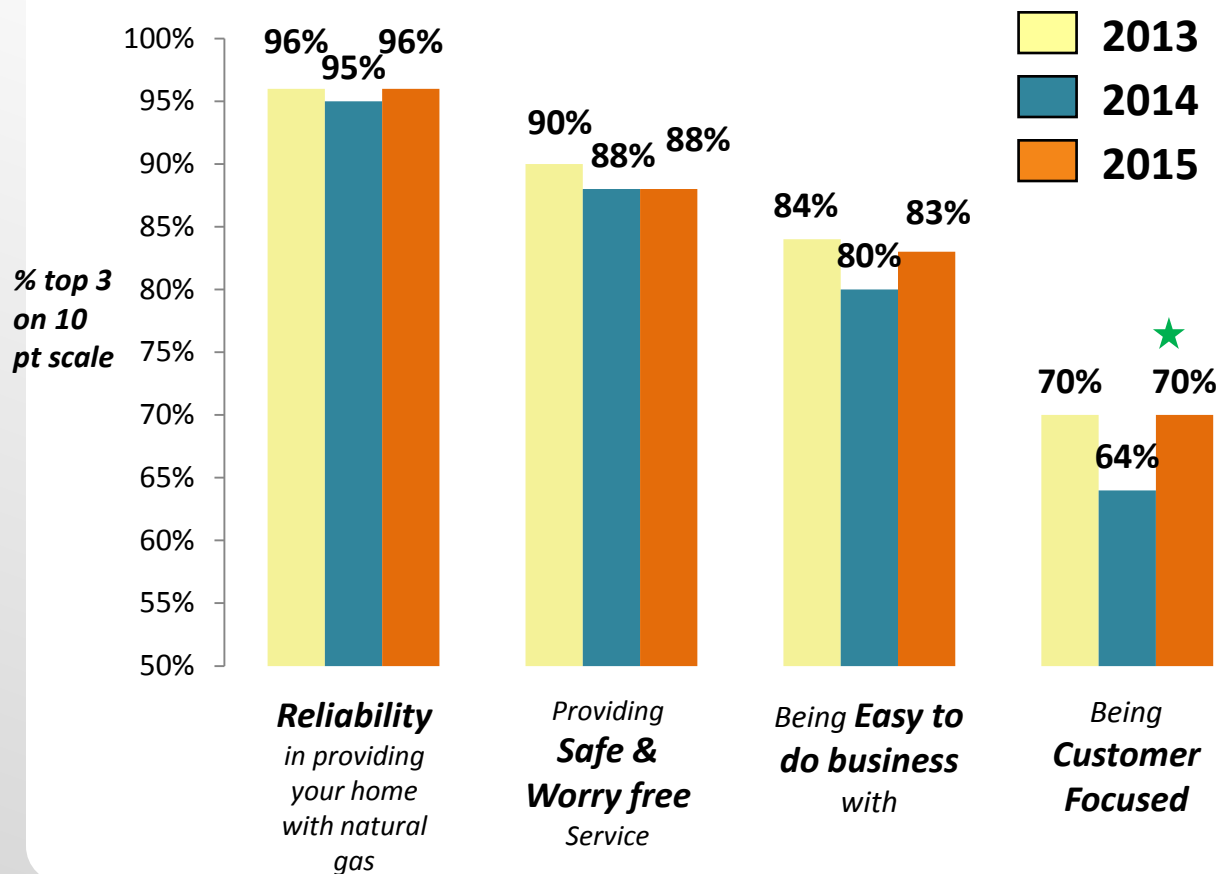
Measuring Customer Perceptions

- 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

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



uniongas

A Spectra Energy Company



Asset Management Plan

Matt Wood

Director, Operations Management Systems

Asset Management System Agenda

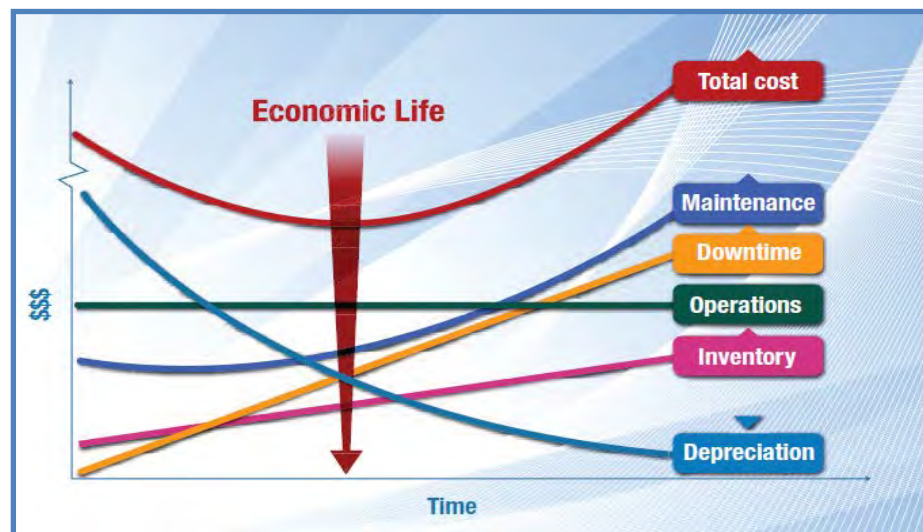
- Asset Management Plan (“AMP”)
- Hazard Identification & Risk Management

Asset Management Plan

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

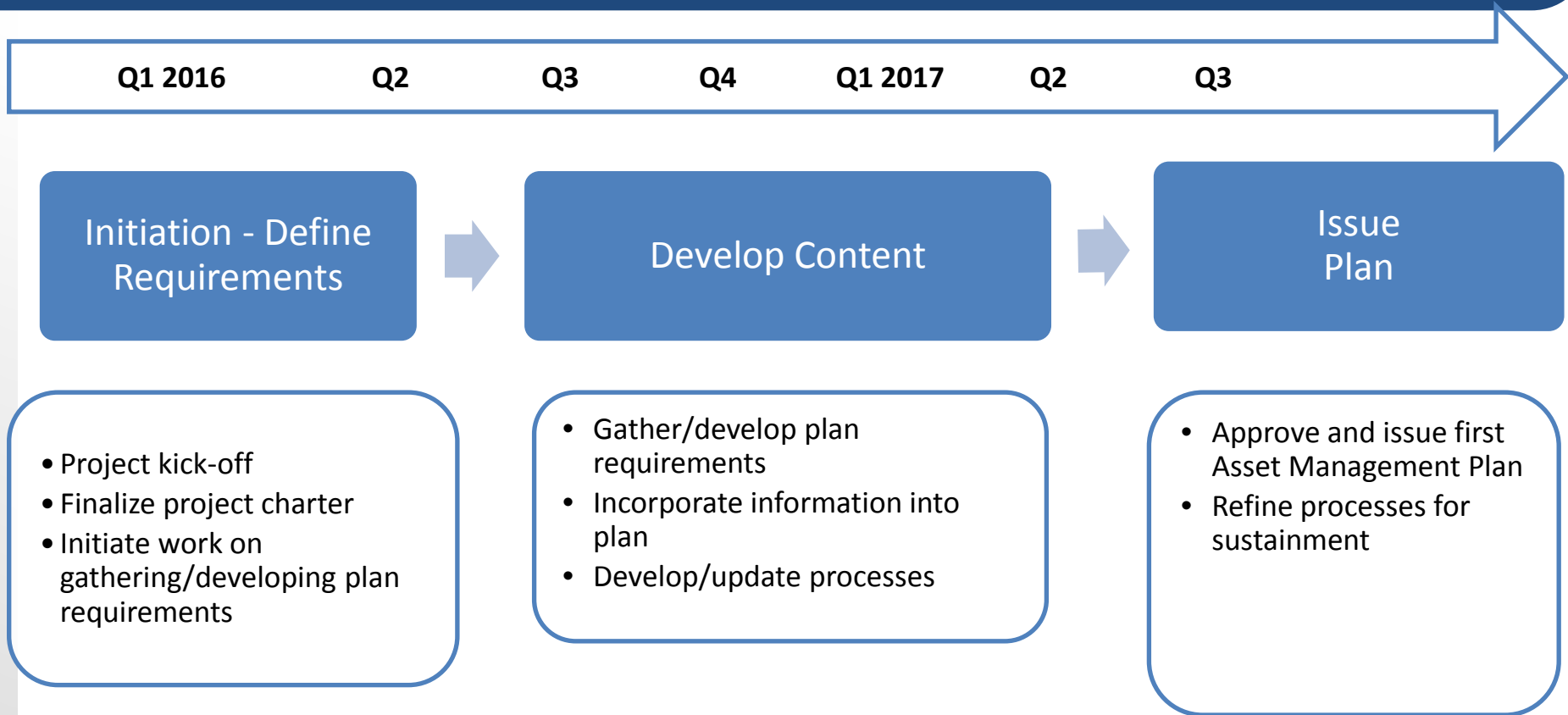
Project Scope

- 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





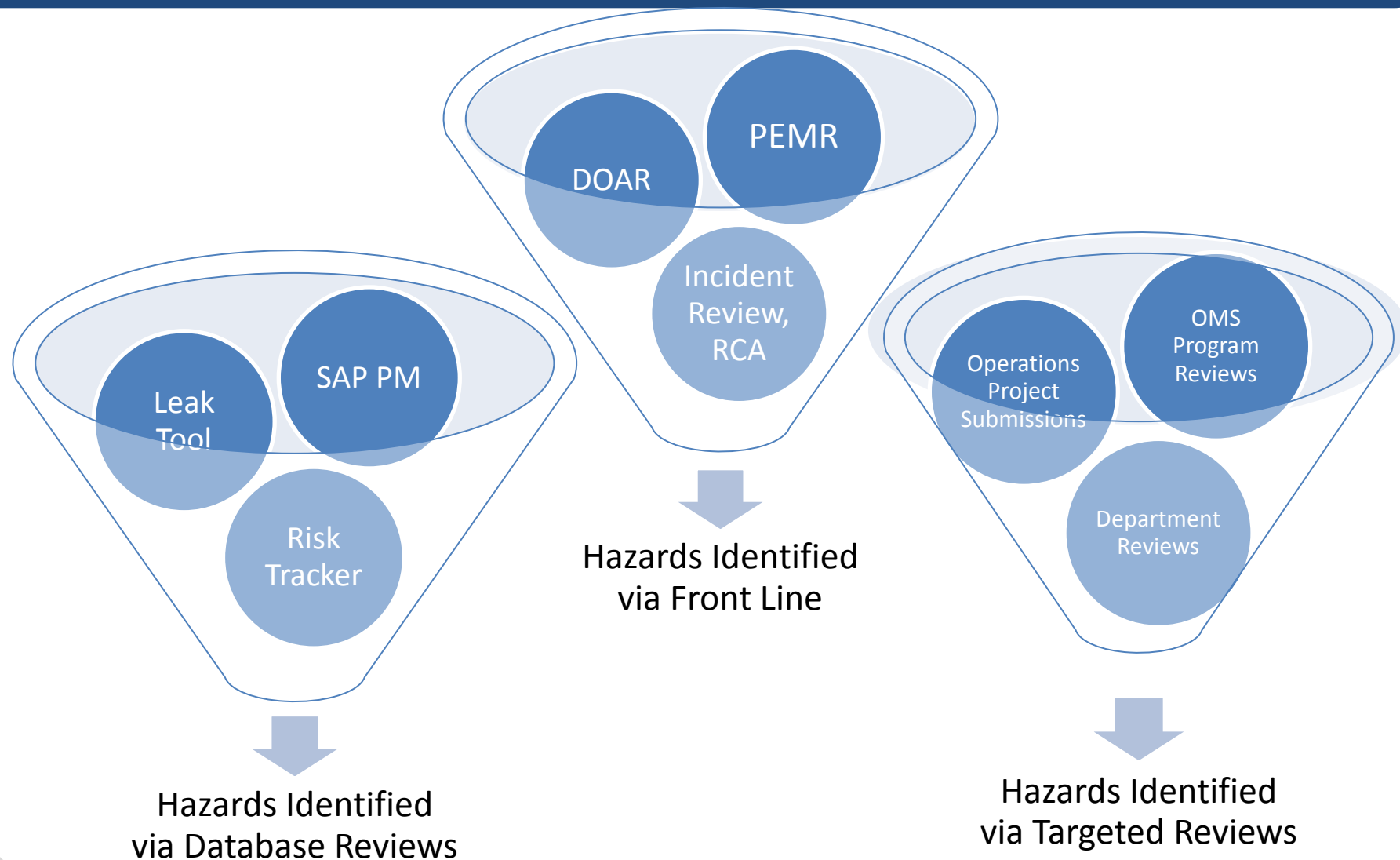
uniongas

A Spectra Energy Company



Hazard Identification & Risk Assessment

Hazard Identification



Risk Assessment

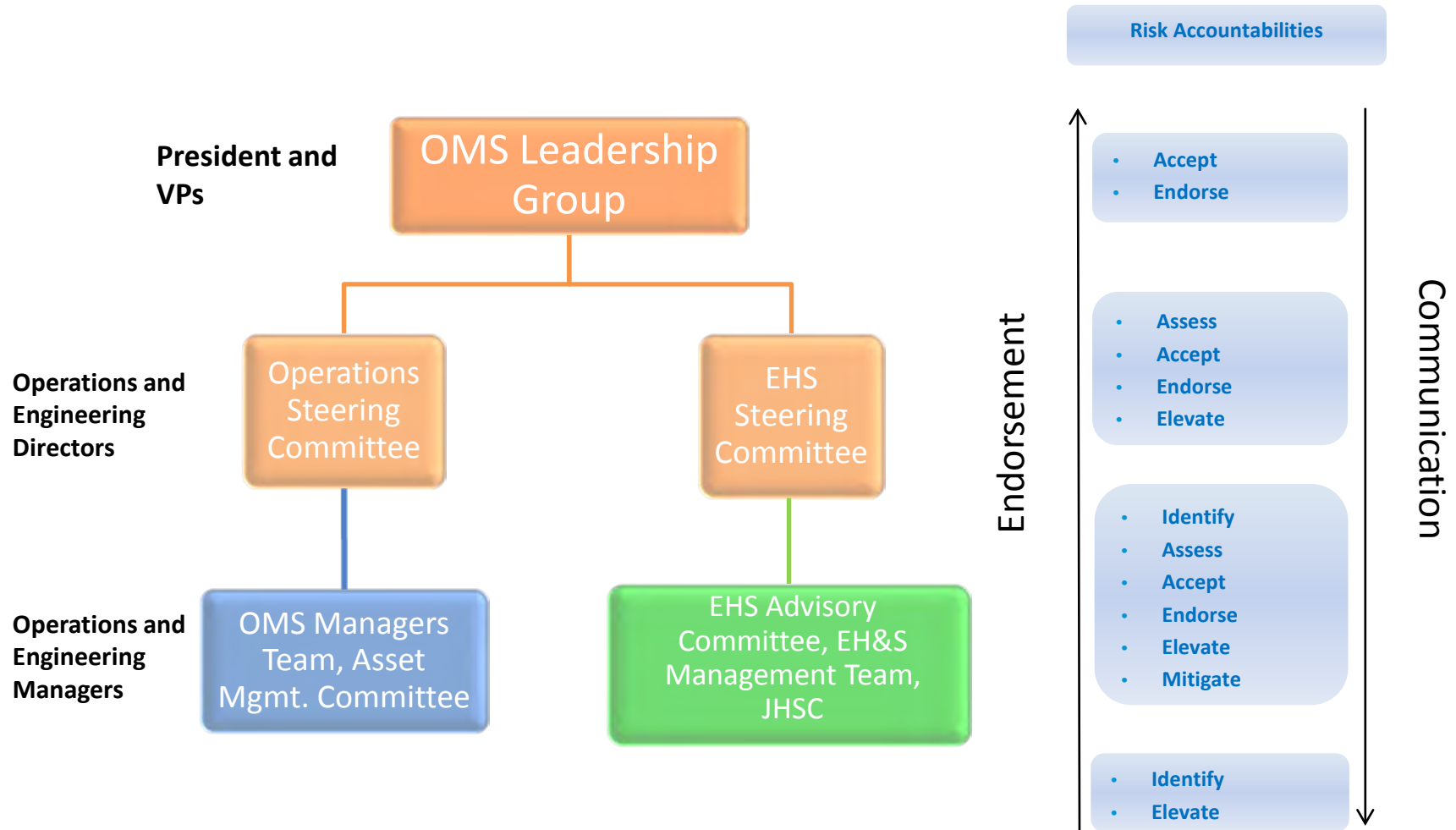
• Risk Assessments

- 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

ALMOST CERTAIN	L5	Likelihood/Probability	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				
			C1	C2	C3	C4	C5

Risk Governance





uniongas

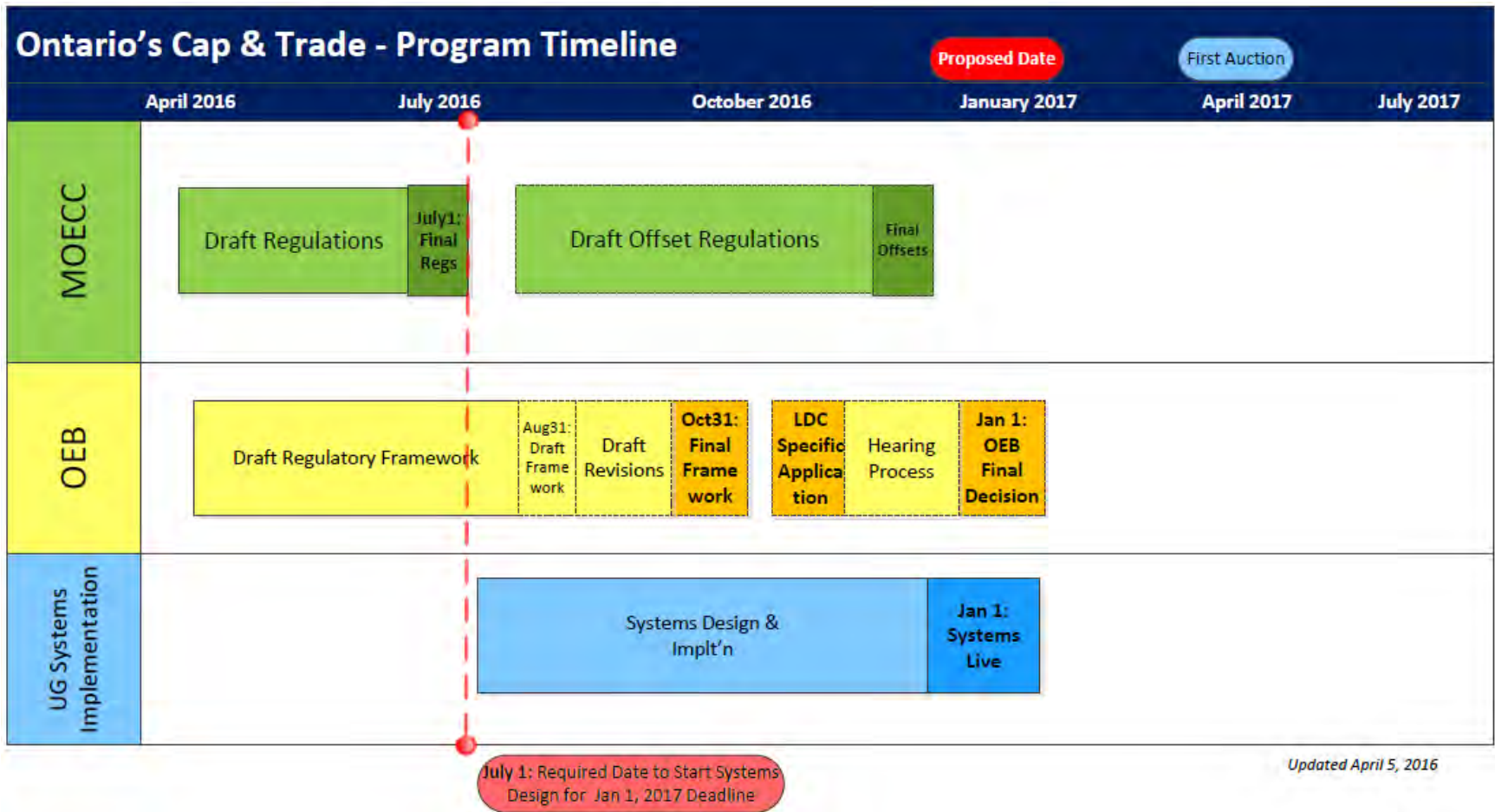
A Spectra Energy Company



Cap and Trade

Mark Kitchen
Director, Regulatory Affairs

Cap and Trade



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



uniongas

A Spectra Energy Company



Wrap-up

Mark Kitchen
Director, Regulatory Affairs



uniongas

A Spectra Energy Company



SE
LISTED
NYSE



Recognized by:

