K1.3

EB-2016-0186

Union Gas Limited

Application for approval to construct a natural gas pipeline in the Township of Dawn Euphemia, the Township of St. Clair and the Municipality of Chatham-Kent and approval to recover the costs of the pipeline

<u>BOMA's COMPENDIUM</u>

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approach which involved incremental gas supply arriving at Ojibway combined with the construction of incremental pipeline facilities. As stated in Exhibit A, Tab 6, there are no stand-alone commercial services that can be contracted with a pipeline company or secondary market that would deliver natural gas via the Panhandle System into the Market distribution networks that will eliminate the need for additional pipeline and station facilities. Union evaluates project alternatives based on their ability to provide reliable, secure and diverse supplies to Union's customers at a prudent cost. Union determined this combination alternative is not preferred as there is limited benefit to bringing additional supply to Ojibway (see Exhibit A, Tab 6). Union also evaluated an alternative that involved the installation of a Liquefied Natural Gas ("LNG") plant along the Panhandle System. As stated in Exhibit A, Tab 6, this alternative is not viable as it cannot meet the required in-service date of November 1, 2017 given the extended time required to construct the facilities and when considering capital and operating costs, it is more expensive.

The preferred alternative ("the Project") involves the removal of the existing NPS 16 Panhandle pipeline between Dawn and Dover Transmission and replacing it with a new NPS 36 pipeline. As detailed in Exhibit A, Tab 6, the preferred alternative provides a number of benefits including:

- provides market assurance in meeting the growing near term firm demands for the next five years;
- positions the Panhandle System and laterals connecting the distribution network to meet long term Market growth in the most efficient manner;
- eliminates O&M costs related to future integrity and other maintenance specific to the existing NPS 16 Panhandle pipeline;

Greenhouse market in Leamington and Kingsville[2] but has not expanded or reinforced the Panhandle System. This growth has increased the utilization of the Panhandle System to move gas from the Dawn Hub to the Market and the Panhandle System is nearing capacity.

The Panhandle System also flows from Ojibway east to the Market. Approximately 10% or 60 TJ/d of the demand on the Panhandle System is served through Union's gas supply (to serve system customers) delivered at Ojibway on Design Day. Union relies on these firm deliveries in Design Day analysis of the Panhandle System to help reduce the physical transportation needs from Dawn. Ojibway provides some interconnectivity to the Dawn Hub, enables access to natural gas supplies shipped through the PEPL system in the U.S. and contributes to the security and diversity of supply to the Dawn Hub. Ojibway is not a liquid trading point (it has limited buyers and sellers), but is a trans-shipment point between two pipeline systems. Currently, two ex-franchise shippers (C1) have transportation contracts to transport natural gas from Ojibway to the Dawn Hub on a year round basis. Union must be able to transport these volumes on the Panhandle System on a firm basis as requested by the shipper. However, Union cannot rely on these volumes at Ojibway when designing the system.

The amount of natural gas Union can accept from PEPL and transport from Ojibway toward Dawn is limited by the minimum daily Windsor area consumption and the capacity of the Sandwich Compressor Station located in Tecumseh. Currently, Union has a maximum capability to accept imports of 115 TJ/d at Ojibway on a yearly basis (summer month limitation).

[2] Leamington Expansion Phase I (2013) EB-2012-0431 and 2016 Leamington Expansion Pipeline Project (EB-2016-0013)

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 3, p.7, lines 13-18; Exhibit A, Tab 7

Union has indicated that the uncertainty created by Cap and Trade and the CCAP has driven the need to calculate the revenue requirement and resulting rate impacts based on an estimated 20-year useful life of the project versus 50 years as per OEB approved depreciation rates. Union further notes that depreciating the asset over a 20-year useful life better aligns the cost with the timing of the reported restrictions and potential elimination of natural gas heating in homes and businesses.

a) In the OEB Proceeding on Community Expansion (EB-2016-0004), Union proposed revising the period for commercial/industrial load to a maximum 40 year term for heating load as compared to the current 20 year term used in the economic test under the E.B.O. 188 Guidelines. Why has Union proposed a different approach in the current application considering that both applications coincide with the Province's announcement of its climate change initiatives?

b) Has Union informed its large volume (contract) customers about its proposed approach of calculating rates using an estimated 20-year useful life of the project as compared to the OEB approved useful life of approximately 50 years?

c) Please outline the risks to Union if the OEB were to approve the existing depreciation period as opposed to the Union recommended useful life of the proposed project. Please quantify the magnitude and likelihood of the risks to the regulated entity with reference to the value of its rate base and remaining asset lives.

Response:

a) Union filed its EB-2015-0179 Community Expansion application on July 23, 2015, prior to the announcement of the Ontario government's Climate Change Action Plan ("CCAP").

The intent of EB-2016-0004 was to address generic issues deemed common to all natural gas distributors and new entrants seeking to provide gas distribution services in communities that do not have access to natural gas. Utility specific or project-specific depreciation rates were not in scope. However, while Union's utility specific community expansion model included a longer depreciation period, the CCAP had not fully manifested itself at the time of the hearing and, as further detailed in the response to part c) below, the impact of CCAP on the depreciation of Union's overall rate base will be considered as part of the next rebasing proceeding.

b) Yes. Union informed all large volume customers of the proposed rate impact in its Factsline communication that was sent to all large volume customers June 24, 2016. (see Attachment 1) The Factsline also had a link to Union's Panhandle Reinforcement Project evidence that compares the proposed rate calculation to the current useful life standard.

   Union also met with the following large customer trade associations: IGUA, APPrO, CME, and OGVG. Union reviewed its proposal with these industry representatives which included the 20 year useful life for depreciation.

c) There is an immediate need for this reinforcement of the Panhandle System based on the forecast market demands and lack of available firm capacity on the Panhandle System. Union expects demand to continue to grow at least in the medium-term, even when DSM impacts are considered. However, over the long-term there is increased risk to natural gas demand due to uncertainties presented by the CCAP. Union describes the level of risk in the short, medium and long-term below.

   When considering the impacts of CCAP, it is important to consider that the policy environment which existed at the time of Union's application was very uncertain. Based on final CCAP, there is no longer specific language or intent to "ban" natural gas and the Ontario government has reiterated its support for natural gas, and for extending natural gas to communities that do not currently have access. However, despite remaining policy uncertainty, Union continues to strive to meet customer requirements to support economic growth. Moving forward, Union will need to continue to closely monitor the potential impact of policy changes on its system and utilization in order to adjust and make changes as necessary.

   Short-term Impacts:

   As stated above, there is an immediate need for the reinforcement of the Panhandle System. The need for this Project has been demonstrated through the market forecast and written evidence in Exhibit A, Tab 4 (Benefit to Ontario) and Exhibit A, Tab 5 (Facilities and Growth), as well as the many letters of support from municipalities and customers. Union's forecasted demands will result in the capacity from this Project being fully subscribed after five (5) years.

   It is unlikley there will be any material impact of CCAP/DSM on natural gas demand within this time frame. In fact, data released by the Ministry of Environment and Climate Change quantifies that 2.8 MT CO2e of abatement across Ontario ("ON Abatement") will result from the introduction of the cap-and-trade program by 2020[1] (Attachment 2). This represents less than 2% of Ontario emissions.

To further demonstrate market commitment, Union is in the process of entering into binding 5-year agreements for incremental firm contract rate service served from the Panhandle Reinforcement Project beginning November, 2017. Union has, in the past, backstopped major pipeline expansions (ie. Dawn Parkway) with contractual commitments from ex-franchise customers who will be using the capacity. Although the term contract does not require customers to pay for this incremental firm capacity with any up front aid for the transmission pipeline, Union is making a significant investment to provide customers with the firm capacity that they have been asking for and it is appropriate for customers to demonstrate their commitment to the Panhandle Reinforcement Project though contractual commitments. In addition, this helps demonstrate to other ratepayers and stakeholders that the facilties are required. This 5-year commitment also ensures that customers in this area are treated in a similar fashion as those who recently received firm capacity. Those customers supported the distribution build specific to their area needs through an aid to construct charge or term contract. This approach will continue with further distribution reinforcements, the need for which Union continues to evaluate given recent requests and market growth. The 5-year contract term related to the Panhandle System Reinforcement facilities is in line with Union's projection of future required reinforcement on the Panhandle System.

Medium-term Impact:

It is Union's view that the Panhandle System once expanded in 2017, will continue to be used for at least the next 20 years. Union believes that the demand on the Panhandle System is sustainable at least over the next 20 years based on specific identified projects, reasonable generic growth, projections based on historical experience, market knowledge and the continuing economic advantage that natural gas has over alternative fuels.

Union does not expect the CCAP to change the expected use of the Panhandle System over the short to medium term for the following reasons:

- The main driver for the Project is largely due to growth in the greenhouse market, not by the residential or small commercial buildings, which is the focus of the CCAP.
- Consumer behavioural change (as identified in the government analysis in Attachment 2) is not significant in the foreseeable future.
- Even if consumer behaviour change was more significant in the short to medium term, extensive experience with DSM programs has illustrated that the reduction in consumption as a result of DSM programs is not sufficient to offset load growth in the market and the resulting need for facilities on peak day. In fact, peak day usage has

[1] "Impact Modelling and Analysis of Ontario Cap and Trade Program", EnviroEconomics, slide 12, provided at Attachment 2.

increased in spite of energy conservation initiatives such as DSM programs administered by Union.

- It is reasonable to assume that changes to peak day demand will take significant time to materialize; it would rely on the development and wide-spread adoption of new technologies, and would also require investment on behalf of consumers and businesses (eg. change in equipment).

Notwithstanding any of the above, if there were impacts from CCAP/DSM in the medium term that Union has not forecasted, the impact would not affect the currently proposed factilities. Rather, Union would expect it to delay future reinforcement required beyond the proposed facilities or Union could reduce upstream transportation or delivered supply at Ojibway to mitigate decreasing demand requirements and maintain utilization of the Panhandle System.

Long-term Impact (beyond 20 years):

While Union does not expect material impacts to natural gas peak day demand in the medium term, it is reasonable to expect that, over the long term, there is increased risk to natural gas demand due to uncertainties presented by the CCAP. For example, the CCAP introduces a new "Net Zero Carbon" requirement for small buildings by 2030 at the latest, with initial changes in 2020. "Net Zero Carbon" is not clearly defined in the CCAP, and is not a term that is understood or utilized by industry, homebuilders, and homebuilder associations. Given this, Union is unsure what Net Zero Carbon is or the impact it will have on future construction or on major renovations. In addition, there is no information with regards to future CCAP's that extend beyond 2020, and the potential of these impacts to natural gas consumption over the long term. This creates uncertainty for Union, its customers, and investors.

Such uncertainty is impossible to quantify in terms of impact, or timing. However, it does present the risk that at some future point, customer behaviour may change peak day requirements, or new technologies may be more widely adopted, and this could impact Union's facilities. Union does not expect such changes to occur within the short to medium term. However, it is possible that it will occur within the typical 40 to 50 year depreciation period and as such Union has proposed the 20 year depreciation term as a means of addressing this risk.

In the event that CCAP does have a material impact sooner than anticipated, a 20-year term for depreciation will mitigate the risk of any excess capacity for ratepayers. For example, if major load changes where to occur in year 15 of a 20 year depreciaton period, the pipe would be 75% depreciated. If major changes occurred in year 15 of a 50 year depreciation period, the pipe would only be 30% depreciated. Assuming Board-approved deprecation rates, the rate base associated with the Project would be $157 million at the end of 20 years; while under Union's proposal the rate base associated with the facilities would be $9 million at the end of 20 years.

As shown at Exhibit A, Tab 8, Schedule 1, line 11, the 2017 and 2018 revenue requirements associated with the Project based on Union's proposal to depreciate the assets over a 20-year useful life are approximately $32.2 million ($5.0 million and $27.2 million respectively).

At Exhibit A, Appendix B, Schedule 1, line 11 Union has provided the 2017 and 2018 revenue requirements for the Project based on Board-approved depreciation rates. The 2017 and 2018 revenue requirements are $18.0 million ($0.3 million and $17.7 million respectively).

Accordingly, the change in revenue requirements for 2017 and 2018 between Union's proposal and Board-approved depreciation rates is a reduction of $14.2 million. Should the Board reject Union's proposal to depreciate the Project assets over a 20-year useful life, Union will address the impacts of the Board's decision as part of its 2019 rebasing application.

The proposal to change the depreciation rate now enables the recovery of the investment from all customers rather than expecting to recover the investment later from the customers that remain on the system.

The benefit of reducing the depreciation period now to 20 years is that it recovers the investment from as many customers as soon as possible which will minimize the future rate impact to customers. Further, as discussed above Union would also have the option of decreasing upstream transportation commitments or delivered supply at Ojibway to mitigate the decreasing demand requirements on the Panhandle System. This would result in a higher utilization of the Project and an efficient use of the asset.

Please see the response at Exhibit B.Staff.3.

UNION GAS LIMITED
Panhandle Reinforcement Project Revenue Requirement

Line No.	Particulars ($000's)	As Filed (20 Years Depreciation) 2017	2018	OEB Approved Depreciation Rates 2017	2018	30 Years Depreciation 2017	2018	40 Years Depreciation 2017	2018	50 Years Depreciation 2017	2018
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Rate Base Investment										
1	Capital Expenditures	243,651	20,818	243,651	20,818	243,651	20,818	243,651	20,818	243,651	20,818
2	Average Investment	26,990	241,849	28,751	249,046	27,992	245,941	28,492	247,987	28,793	249,214
	Revenue Requirement Calculation:										
	Operating Expenses:										
3	Operating and Maintenance Expenses (1)	3	15	3	15	3	15	3	15	3	15
4	Depreciation Expense (2)	6,008	12,536	2,486	5,185	4,005	8,357	3,004	6,268	2,403	5,014
5	Property Taxes	261	1,569	261	1,569	261	1,569	261	1,569	261	1,569
6	Total Operating Expenses	6,271	14,120	2,750	6,769	4,268	9,941	3,267	7,852	2,666	6,598
7	Required Return (5.775% x line 2) (3)	1,559	13,966	1,660	14,382	1,616	14,203	1,645	14,321	1,663	14,392
	Income Taxes:										
8	Income Taxes - Equity Return (4)	312	2,799	333	2,882	324	2,846	330	2,870	333	2,884
9	Income Taxes - Utility Timing Differences (5)	(3,123)	(3,706)	(4,393)	(6,356)	(3,845)	(5,213)	(4,206)	(5,966)	(4,423)	(6,418)
10	Total Income Taxes	(2,811)	(907)	(4,060)	(3,474)	(3,521)	(2,366)	(3,876)	(3,096)	(4,090)	(3,534)
11	Total Revenue Requirement (line 6 + line 7 + line 10)	5,019	27,179	350	17,677	2,364	21,778	1,036	19,077	239	17,456
12	Incremental Project Revenue	250	1,572	250	1,572	250	1,572	250	1,572	250	1,572
13	Net Revenue Requirement (line 11 - line 12)	4,768	25,607	100	16,105	2,113	20,206	786	17,505	(11)	15,884

Notes:

(1) Expenses include incremental O&M for stations and pipe.

(2) Depreciation expense based on the term requested in the Interogatory.

(3) The required return of 5.775% assumes a capital structure of 64% long-term debt at 4.00% and 36% common equity at the 2013 Board-approved return of 8.93% (0.64 x 0.0400 + 0.36 x 0.0893).
For the "As Filed", the 2018 required return calculation is as follows:
$241.849 million x 64% x 4.00% = $6.191 million plus
$241.849 million x 36% x 8.93% = $7.775 million for a total of $13.966 million.

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

(5) 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

June 24, 2016

Union Gas Receives Approval for Rate Changes Effective July 1, 2016

factsline

Union Gas received approval from the Ontario Energy Board (OEB) for a change in rates effective July 1, 2016.

These rate changes include the following items:
- Updated 2016 distribution rates (Incentive Regulation)
- July 2016 Quarterly Rate Adjustment Mechanism (QRAM)

Updated 2016 Distribution Rates

When 2016 distribution rates were approved in December 2015, they included the approved 2015 Demand Side Management (DSM) budget as a placeholder while we awaited a decision on the 2015-2020 DSM Plan proceeding. Now that a decision on the 2015-2020 DSM Plan proceeding has been received from the OEB, Union Gas is updating its 2016 rates to include the approved 2016 DSM budget. Customers will see a change in rates going forward (in most cases an increase) from what was approved in December 2015.

Since this rate change is effective January 1, 2016, there will also be a one-time rate adjustment included on July 2016 bills to collect the difference in rates for the January to June 2016 period. Please contact your Union Gas account manager once you receive your July invoice if you have questions about your individual adjustment.

Rate Changes for Union Gas North Customers

The average rate change for contract rate customers in Union Gas North is shown below. Individual bill impacts will vary and will depend upon a customer's use of natural gas.

Rate class	Updated Incentive Regulation Avg. Price Change (cents/m^3)	QRAM Delivery Rate Change (cents/m^3)	Approved Total Delivery Rate Change (cents/m^3)
Rate 20	0.1373	0.0025	0.1398
Rate 25	0.0235	0.0000	0.0235
Rate 100	(0.0318)	0.0000	(0.0318)

Balancing Transaction Fees

Balancing transaction fees will be updated effective July 1, 2016. For current rates, please see the Balancing Transaction Fee Schedule.

Rate 01 and Rate 10 Customers

Rate 01 and Rate 10 will also be changing effective July 1, 2016. Customers can locate current information on these rates on our website or in the notice included with their July bill.

Rate Changes for Union Gas South Customers

	Current Utility Sales (cents/m³)	New Approved Utility Sales (cents/m³)	Change (cents/m³)
Gas Commodity Rate	9.6231	10.1666	0.5435
Gas-Price Adjustment	(0.4178)	(0.4420)	(0.0242)
Transportation	3.9625	4.0983	0.1358

The average rate change for contract customers in Union Gas South is shown below. Individual bill impacts will vary and will depend upon a customer's use of natural gas.

Rate class	Updated Incentive Regulation Avg. Price Change (cents/m³)	QRAM Delivery Rate Change (cents/m³)	Approved Total Delivery Rate Change (cents/m³)
Rate M4	0.5544	0.0080	0.5624
Rate M5A	0.3364	0.0076	0.3440
Rate M7	0.4400	0.0085	0.4485
Rate M9	0.0393	0.0076	0.0469
Rate M10	0.4751	0.0109	0.4860
Rate T1	0.0368	0.0000	0.0368
Rate T2	0.0714	0.0000	0.0714
Rate T3	0.1161	0.0000	0.1161

Balancing Transaction Fees

Balancing transaction fees will be updated effective July 1, 2016. For current rates, please see the Balancing Transaction Fee Schedule.

Rate M1 and Rate M2 Customers

Rate M1 and Rate M2 will also be changing effective July 1, 2016. Customers can locate current information on these rates on our website or in the notice included with their July bill.

A look ahead - Upcoming items that impact rates

- **2014 DSM deferral clearing** – We are currently awaiting a decision from the OEB. At this time we are targeting October 2016 to clear these balances.
- **2015 non-DSM deferral clearing** – This application is currently under review as part of the OEB approval process and will be implemented as soon as possible following the OEB's decision.

- The **Parkway Delivery Commitment Incentive (PDCI)** credit begins effective November 1, 2016 for customers who are obligated to deliver to Parkway. Payment of the PDCI to Direct Purchase customers is by way of a credit on the bill to the Bundled Transportation or T1/T2/T3 contract holder.
- Union Gas is currently planning to file our **2017 distribution rates** application in September 2016.

More information on these initiatives will follow over the coming months.

Union Gas files an application for the Panhandle Reinforcement Project

On June 10, 2016, Union Gas filed an application to the Ontario Energy Board (OEB) for the Panhandle Reinforcement Project (EB-2016-0186). This project has a targeted in-service date of November 1, 2017, but will be dependent upon approval from the OEB.

Union Gas' Panhandle Transmission System supplies reliable natural gas to a diverse customer base within the Chatham to Windsor market. Natural gas demand has seen significant growth in recent years and is straining the capacity of the current transmission pipeline serving the area. Additional growth is forecasted in the area which cannot be accommodated by the existing natural gas transmission system. This pipeline expansion from Dawn Hub to Dover Transmission Station would support market growth along the entire Panhandle Transmission System, addressing expressed market concerns regarding availability of firm natural gas services.

If approved, this project will have overall rate impacts.

Estimated rate impacts of the proposed Panhandle Reinforcement Project

Rate Class	Estimated Delivery Charge Impact	Estimated Total Bill Impact (Incl. commodity based on Union Gas' April QRAM)
Rate M1	2%	1%
Rate M2	6-8%	2%
Rate M4	24-27%	4-6%
Rate M7	17-19%	2-5%
Rate T1	14-16%	2%
Rate T2	18-20%	1%

Estimated rate impacts are based on the current OEB approved distribution rates.

Natural Gas delivers low cost, reliable energy to the province. Upgrading the size of the existing pipeline provides additional benefits: using primarily the existing footprint reduces the need for additional land rights and creates less environmental impact and eliminates future operating and maintenance costs on the pipeline being removed.

Updates will be provided once a decision has been reached by the OEB.

If you have any questions about this edition of Factsline, please contact Patrick Boyer.

External link for publishing:
http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/531574/view/UNION_APPL_PanhandleReinforcement_20160610.PDF

6A

1 MULTI-YEAR INCENTIVE RATEMAKING FRAMEWORK

The parties agree that Union's regulated rates over the IRM term will be set by applying the Incentive Regulation Mechanism described below to Base Rates being Union's 2013 Board-approved rates adjusted in the manner hereinafter described.

1.1 Incentive Regulation Mechanism

(Complete Settlement)

The parties agree that a multi-year Price Cap Index ("PCI") mechanism will be used to set regulated distribution, transmission and storage rates over the IRM term which are a function of:

- An inflation factor (I);
- A productivity factor (X);
- Certain non-routine adjustments (Z factors);
- Certain predetermined pass-throughs (Y factors); and,
- An adjustment for normalized average consumption (NAC),

all as further set out in this Agreement.

The parties further agree that rates each year will be adjusted as described below and as set out in Appendix I to this Agreement which illustrates how 2014 rates will be determined.

1. The base year adjustments to 2013 Board-approved revenue set forth in Section 1.2 below will be allocated to rate classes, and within each rate class to the rate components, as set out in Appendix E attached. Subject to any changes ordered by the Board as a result of the resolution of the issues set forth in Section 13.3 of this Agreement, the adjusted 2013 Board-approved revenues would be the base revenues to which the PCI mechanism adjustments will apply for 2014.

2. Prior year Y factor amounts that are embedded in base rates will be deducted from those rates on a class by class basis and within each rate class from the revenues applicable to rate components, to get base revenue net of Y factor amounts. For example, the Demand Side Management ("DSM") budget, upstream transportation costs and capital pass-through costs (if any) included in 2013 rates will be deducted from the approved revenue to be collected from each class, and within each class from each component of rates, prior to the application of inflation net of productivity.

6B

- Upstream gas costs
- Upstream transportation costs
- Incremental DSM costs (as determined in EB-2011-0327 and in any subsequent DSM proceeding)
- LRAM for the contract rate classes
- Unaccounted for gas ("UFG") volume variances
- Major Capital Additions (as defined below)

These Y factors are each described in more detail below.

6.1 Upstream Gas Costs

The parties agree that changes in upstream gas costs, as approved through the QRAM process, or as otherwise determined by the Board, will be passed through to ratepayers through the gas commodity deferral accounts cleared during the QRAM process, through rates during the annual rate setting or through the earnings sharing and deferral accounts clearing processes. That is, the pass-through of upstream gas costs will be unchanged in both substance and procedure from the 2013 Board-approved pass-through mechanisms.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

6.2 Upstream Transportation Costs

The parties agree that changes in upstream transportation costs that underpin Union's gas supply plan will be passed through to ratepayers through the gas supply deferral accounts or as otherwise determined by the Board, and through rates during the annual rate setting or the earnings sharing

6c

Y-factor treatment also applies to additional capital projects that result in net delivery revenue requirement impacts over the IRM term which meet the requisite criteria specified below.

The criteria that must be met for any capital project to quality for Y factor treatment are as follows: 6

i) A minimum increase, or a minimum decrease, of $5 million in net delivery revenue requirement for a single new project (the "Rate Impact Threshold"). For the purposes of making this determination, capital costs are those costs relating to that capital project as defined under the applicable accounting rules. For the purpose of determining whether the Rate Impact Threshold is met, the net delivery revenue requirement associated with the capital project for each of the years from the in-service year until 2018 shall be calculated; should the net delivery revenue requirement exceed the Rate Impact Threshold in any year, the project would meet the Rate Impact Threshold criterion. The rate adjustment for each year will be based on the forecast net delivery revenue requirement impacts for each specific year, subject to true-up to actual as discussed in subparagraph (viii) below.

In determining net delivery revenue requirement for any year, the following parameters will be applied:

- Depreciation expense will be calculated using 2013 Board-approved depreciation rates;
- Required return assumes a capital structure of 64% long-term debt and 36% common equity;

6D

8 Z FACTORS

(Complete Settlement)

The parties agree that for prospective or historical cost increases/decreases to qualify for pass through as a "Z factors", the cost increases/decreases must:

1. causally relate to an external event that is beyond the control of utility's management;
2. result from, or relate to, a type of risk;
   a. for which a prudent utility would not be expected to take risk mitigation steps; and,
   b. which is out of the realm of the basic undertaking of the utility (per EB-2011-0277 Decision, page 13);
3. not otherwise be reflected in the price cap index;
4. be prudently incurred; and,
5. meet the materiality threshold of $4.0 million of annual net delivery revenue requirement impact per Z factor event. Net delivery revenue requirement will be defined in the same manner as set forth in Section 6.6 above.

The parties agree that changes in the amounts of taxes payable by Union through the 2014-2018 IRM term resulting from changes to Federal and/or Provincal legislation and/or regulations thereunder are Z factors and will be shared 50:50, as applied to the tax level reflected in rates. Treating 50% of tax changes as a Z factor is consistent with the Board's findings in its EB-2007-0606/EB-2007-0615 Decision (dated July 31, 2008).

As during the 2008-2012 IRM term, Union will continue to calculate the variance between current year tax rates and calculation methods/rules to those used in current Board-approved

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 3, p.12; Exhibit A, Tab 9, p.7; Exhibit A, Tab 9, Schedule 4, p.1

Union will use "lift and lay" construction process. Majority of the existing pipeline will be removed from the ground. The existing pipeline will be abandoned in place at certain locations at major road crossings and watercourse crossing.

According to the updated CSA Z662-15 "Oil and Gas Pipeline Systems" clause 10.16, which sets the requirements for pipelines abandonment, a documented abandonment plan is required.

a) Did Union prepare abandonment plans, as required under the CSAZ663 section 10.16.1, that address the two methods of pipeline abandonment Union proposed for the Project?

b) If so, please file executive summary of the plans.

c) If no, please describe how will Union adhere to the requirements of section 10.16 of the CSA Z662-15 and indicate when will the pipeline abandonment plans be completed.

Response:

a) Union is currently preparing abandonment plans for the removal of the NPS 16 pipeline that will address the abandonment requirements contained in CSA Z662-15, clause 10.16.

b) Please see response to part a) above.

c) Union will adhere to all requirements in CSA Z662-15 clause 10.16, with regards to pipeline abandonment. It is anticipated that the abandonment plans will be completed by year end.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: Exhibit A, Tab 3, p.6

a)

i. Given that the Premier has recently stated that the government is not banning natural gas or forcing anyone off it, and the fact that more work will be done to achieve longer term efficiency targets (much of which will presumably be undertaken by Union itself under DSM programs), and the government's support for renewable natural gas, why does Union see a need to propose a huge increase in the depreciation component of the revenue requirement at this time?

ii. Why propose an interim solution at this time, in the middle of an IRM regime, rather than wait until the next rebasing which is only two years away?

b) Has Union approached the government to clarify that any stranded costs arising as a result of policy changes will one of the items be covered by revenue from the cap and trade levy? If not, why not?

c) What other options has Union explored?

d)

i. Has Union conducted any analyses, either internally or by third parties, to assess the potential for stranded assets due to the implementation of the Ontario Government's GHG program? If so, please provide these analyses, as well as any proposals made to the Union Board on the GHG issue.

ii. If not, please provide the rationale and the calculations and underpinning the proposal to change the weighted average useful life of its assets from fifty years to twenty years.

e) Has Union considered the utility of a hearing on the issue of a GHG impact on the gas utility industry, either separately or as part of its next rebasing case?

f) Can Union cite any precedents either in Canada or elsewhere when energy regulators have approved this radical change to the rate-making principles to address the alleged risks to gas utilities arising from the implementation of GHG reduction policies? Please provide, or provide links to, any known decisions, consultative, or studies.

Response:

9A

a)

i. Please see the response at Exhibit B.Staff.4 c).

ii. Union's application (for incremental facilities) is brought in response to the immediate need and forecasted market demands and lack of available firm capacity on the Panhandle System (see Exhibit A, Tab 3, p.4, lines 12-13). This application is also where cost recovery will be addressed.

Please see the response at Exhibit B.Staff.4 c).

b) No. The purpose of the CCAP is to use cap and trade proceeds to reduce greenhouse gas emissions. Union is focused on the use of cap and trade proceeds (via CCAP) to fund natural gas solutions that leverage existing natural gas infrastructure, provide economic efficiencies and environmental benefits to customers.

Please see the response at Exhibit B.Staff.4 c).

c) Please see the response to part b) above.

d) i./ii.)

By reference to "GHG program", Union assumes this is in reference to the CCAP and/or the cap and trade program. Union has not conducted any such analyses either internally or externally in relation to these to assess the potential for stranded assets.

Please see the response at Exhibit B.Staff.4 c).

e) Union has not considered a separate hearing on the issue of GHG impacts on the natural gas utility industry. However, Union notes that the impact of Cap and Trade on regulated rates is addressed in EB-2015-0363 "Consultation to Develop a Regulatory Framework for Natural Gas Distributors' Cap and Trade Compliance Plans".

Union continues to work with the government on CCAP programs and believes that natural gas will be part of the solution for reducing emissions, with RNG and CNG as examples. Future review may be required but it is too early to determine. Union expects any forecast impacts will be reflected in future rate cases, if applicable.

f) There are examples of the OEB and NEB addressing accelerated depreciation rates based on factors other than physical life of the assets. These are outlined below:

The OEB made provision for accelerated cost recovery of assets by adjusting depreciation in EB-2009-0152 Report of the Board (*Regulatory Treatment of Infrastructure Investment in* *connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario)* issued January 15, 2010:

"3.2.3 Accelerated Cost Recovery: Adjusting Depreciation

Traditionally, depreciation has been based on the useful life of a utility asset (in other words, the expected period of time during which it will be productive). Adjusting depreciation to reflect a contract term that is related to the use of a utility asset (such as a power purchase agreement executed by a connecting generator), or to align it with the life of a related non-utility asset (such as a connecting generation facility), is another way to reduce risk, thereby facilitating timely investment. In addition, allowing shorter depreciation periods where appropriate not only improves cash flow for the utility but should also result in a lower aggregate cost of capital over the life of the asset as the result of an accelerated decline in rate base.

The Board will therefore consider allowing utilities some flexibility in the useful life assumptions and thus the depreciation rates. Specifically, a utility may apply to use depreciation for rate purposes as follows:

- *over a period of time equivalent to a particular contract term related to the subject facility (for example, the term of the power purchase agreement with the first generator to connect to a transmission or distribution facility);*
- *over a period of time equivalent to the useful life of one or more connecting facilities;*
- *a hybrid approach, under which: a) accelerated depreciation is allowed for a pre-determined period (e.g., up to the length of the incentive regulation plan term that the utility is entering) and b) at the end of that period, the depreciation reverts to a rate determined by the remaining expected life of the asset; or*
- *any other reasonable and generally accepted regulatory method for estimating the project-specific depreciation.*

The Board will allow the depreciation established on a shorter useful life to be recovered in rates, and the resulting lower asset net book value to be added to rate base in a future cost of service proceeding." (EB-2009-0152 Report of the Board, pages 16-17)

The Board also addressed accelerated depreciation rates in the EB-2010-0207 (Union's Dawn to Dawn-TCPL transportation service), decision dated August 12, 2010.

Board Findings – Rate Design

[30] The Board finds that the proposed rate design for the Dawn to Dawn-TCPL transportation service is appropriate. Given the uncertainty regarding the demand beyond the initial 5-year term, the Board agrees with Union that the capital costs of $3.3 million should be recovered entirely over the 5-year term of the contract and therefore approves the depreciation methodology proposed by the Applicant. The Board also

agrees that any capital costs in excess of the $3.3 million estimated by Union should be paid by Union's shareholders and not its ratepayers.

The NEB has also approved accelerated depreciation for the existing Northern Ontario Line (NOL) recognizing the Economic Planning Horizon of each segment is influenced by unique factors. With respect to the usage of the NOL segment, TransCanada submitted that flows across the NOL segment have declined by roughly 70% over the past ten years and that the market demand along the NOL is also limited. TransCanada determined that a relatively short Economic Planning Horizon for the NOL, in the range of 2020 to 2030, would be appropriate. Similarly, the NEB approved accelerated depreciation rates for the Prairies Line with an Economic Planning Horizon.

TransCanada noted in the Energy East application that the accelerated depreciation for the NOL is due to the lack of perceived economic life of the asset.

The NEB also agreed with accelerated depreciation for the NOL:

"There is also no disagreement with TransCanada's proposition that the EPH of the NOL should lie somewhere between 2020 and 2030. We note TransCanada's intent to shorten the EPH of the NOL if the Restructuring Proposal is not implemented. In light of the approximately 70 per cent decline in NOL volume over the past decade and TransCanada's forecast of flat to declining NOL throughput, we are of the view that it would be appropriate for TransCanada to depreciate the NOL over a shortened time frame. Accordingly, we approve the EPH of the NOL to be 2020." (RH-003-2011 Reasons for Decision, page 54)

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 3, p. 7

If the OEB does not approve the 20-year depreciation rate will Union still go ahead with the project? Please explain.

Response:

It will depend on the nature of the Board's Decision. Union will evaluate a Decision relative to the risk, and considering the immediate need of customers.

The benefit of reducing the depreciation period now to 20 years is that it recovers the investment from as many customers as soon as possible which will minimize the rate impact to customers.

The uncertainty and risk caused by the introduction of Cap and Trade and the Climate Change Action Plan extends beyond the new Panhandle System investment to Union's entire asset base. Union plans to review alternatives, including depreciation rates from a system-wide basis, to address this risk as part of its 2019 rebasing application.

11

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Exhibit A, Tab 3, p.8

a) Please explain why the rate impacts for Union Gas south customers appear to be different depending on whether or not a rate class has Panhandle demands.

b) Please explain which Union south rate classes do not have Panhandle demands.

c) Why is there no rate impact shown in Table 3.1 for rate M5? Is it because there is no Panhandle System design day demand allocated to this rate class?

Response:

a) The Union South rate impacts vary based on each rate class' proportion of 2013 Board-approved and incremental Project-related Panhandle System Design Day demands, and the increase in the revenue requirement of the rate class related to the Project costs relative to the revenue requirement of the rate class prior to adding the Project costs.

b) The Union South in-franchise rate classes that do not have Panhandle System Design Day demands include Rate M9, Rate M10 and Rate T3.

c) Rate M5 is not shown in Table 3-1 as the bill impact is negative. Included in Union's proposed allocation factor is a small allocation to Rate M5A based on Panhandle System Design Day demands included as part of the 2013 Board-approved allocator. There is no incremental firm Rate M5 Panhandle System Design Day demands related to the Project.

   Please see Exhibit A, Tab 8, Schedule 6, p.2 for the estimated rate impact for Rate M5 for Union's proposal using 20-year depreciation rates and Exhibit A, Appendix B, Schedule 6, p.2 for the estimated rate impact for Rate M5A for Union's proposal using 2013 Board-approved depreciation rates.

12A

Filed: 2016-09-19
EB-2016-0186
Exhibit B.LPMA.24
Attachment 1

UNION GAS LIMITED
Proposed Delivery Charges and Annual Bill Impacts for Typical Small and Large Customers

Line No.	Particulars	Delivery Charges EB-2016-0040 Approved 01-Apr-16 (1) ($)	Delivery Charges EB-2016-0186 Proposed 01-Jan-18 ($)	Delivery Charge Impact ($)	Delivery Charge Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Union North				
1	Rate 01 - Small	435	434	(1.11)	-0.3%
2	Rate 10 - Small	4,232	4,217	(14.51)	-0.3%
3	Rate 10 - Large	13,579	13,541	(37.62)	-0.3%
4	Rate 20 - Small	73,272	72,937	(334.73)	-0.5%
5	Rate 20 - Large	281,495	280,472	(1,022.33)	-0.4%
6	Rate 25 - Average	62,814	62,598	(216.15)	-0.3%
7	Rate 100 - Small	260,184	259,444	(739.80)	-0.3%
8	Rate 100 - Large	2,106,720	2,101,477	(5,242.80)	-0.2%
	Union South				
9	Rate M1 - Small	346	354	8.03	2.3%
10	Rate M2 - Small	3,297	3,503	205.71	6.2%
11	Rate M2 - Large	10,642	11,462	820.27	7.7%
12	Rate M4 - Small	37,374	46,440	9,065.95	24.3%
13	Rate M4 - Large	277,378	351,384	74,006.01	26.7%
14	Rate M5 - Small	30,596	30,512	(84.11)	-0.3%
15	Rate M5 - Large	169,794	169,431	(362.18)	-0.2%
16	Rate M7 - Small	656,550	767,507	110,957.22	16.9%
17	Rate M7 - Large	2,513,626	2,997,803	484,176.96	19.3%
18	Rate M9 - Large	384,526	384,883	357.04	0.1%
19	Rate M10 - Average	5,570	5,536	(33.36)	-0.6%
20	Rate T1 - Small	132,068	150,193	18,124.88	13.7%
21	Rate T1 - Average	201,822	231,696	29,874.43	14.8%
22	Rate T1 - Large	445,903	516,897	70,993.82	15.9%
23	Rate T2 - Small	511,030	602,656	91,625.96	17.9%
24	Rate T2 - Average	1,186,197	1,417,724	231,526.53	19.5%
25	Rate T2 - Large	1,936,196	2,322,811	386,614.64	20.0%
26	Rate T3 - Large	3,552,739	3,565,851	13,112.16	0.4%

Notes:
(1) Reflects Board-approved rates per Appendix A in Union's April 2016 QRAM filing (EB-2016-0040).

12B

UNION GAS LIMITED
Delivery Charges and Impacts for Typical Small and Large Customers
Based on Board-Approved Cost Allocation Updated for the Project and Proposed 20 Year Depreciation Rates

Line No.	Particulars	Delivery Charges: EB-2016-0040 Approved 01-Apr-16 (1) ($)	Delivery Charges: EB-2016-0186 Proposed 01-Jan-18 ($)	Delivery Charge Impact ($)	Delivery Charge Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Union North				
1	Rate 01 - Small	435	434	(1.11)	-0.3%
2	Rate 10 - Small	4,232	4,217	(14.51)	-0.3%
3	Rate 10 - Large	13,579	13,541	(37.62)	-0.3%
4	Rate 20 - Small	73,272	72,937	(334.73)	-0.5%
5	Rate 20 - Large	281,495	280,472	(1,022.33)	-0.4%
6	Rate 25 - Average	62,814	62,598	(216.15)	-0.3%
7	Rate 100 - Small	260,184	259,444	(739.80)	-0.3%
8	Rate 100 - Large	2,106,720	2,101,477	(5,242.80)	-0.2%
	Union South				
9	Rate M1 - Small	346	349	3.79	1.1%
10	Rate M2 - Small	3,297	3,399	102.65	3.1%
11	Rate M2 - Large	10,642	11,055	413.62	3.9%
12	Rate M4 - Small	37,374	40,768	3,394.38	9.1%
13	Rate M4 - Large	277,378	305,085	27,706.42	10.0%
14	Rate M5 - Small	30,596	30,512	(84.11)	-0.3%
15	Rate M5 - Large	169,794	169,431	(362.18)	-0.2%
16	Rate M7 - Small	656,550	692,051	35,501.40	5.4%
17	Rate M7 - Large	2,513,626	2,668,541	154,915.20	6.2%
18	Rate M9 - Large	384,526	384,883	357.04	0.1%
19	Rate M10 - Average	5,570	5,536	(33.36)	-0.6%
20	Rate T1 - Small	132,068	154,055	21,987.38	16.6%
21	Rate T1 - Average	201,822	238,053	36,231.50	18.0%
22	Rate T1 - Large	445,903	531,984	86,080.88	19.3%
23	Rate T2 - Small	511,030	682,281	171,251.08	33.5%
24	Rate T2 - Average	1,186,197	1,618,258	432,060.83	36.4%
25	Rate T2 - Large	1,936,196	2,657,380	721,183.96	37.2%
26	Rate T3 - Large	3,552,739	3,565,851	13,112.16	0.4%

Notes:
(1) Reflects Board-approved rates per Appendix A in Union's April 2016 QRAM filing (EB-2016-0040).

12c

UNION GAS LIMITED
Delivery Charges and Impacts for Typical Small and Large Customers
Based on Union's Proposed Cost Allocation and Board-Approved Depreciation Rates of Approximately 50 Years

Line No.	Particulars	Delivery Charges: EB-2016-0040 Approved 01-Apr-16 (1) ($) (a)	Delivery Charges: EB-2016-0186 Proposed 01-Jan-18 ($) (b)	Delivery Charge Impact ($) (c) = (b - a)	Delivery Charge Impact (%) (d) = (c / a)
	Union North				
1	Rate 01 - Small	435	433	(2.03)	-0.5%
2	Rate 10 - Small	4,232	4,205	(27.23)	-0.6%
3	Rate 10 - Large	13,579	13,504	(74.43)	-0.5%
4	Rate 20 - Small	73,272	72,659	(612.86)	-0.8%
5	Rate 20 - Large	281,495	279,512	(1,983.10)	-0.7%
6	Rate 25 - Average	62,814	62,409	(405.28)	-0.6%
7	Rate 100 - Small	260,184	258,790	(1,394.52)	-0.5%
8	Rate 100 - Large	2,106,720	2,096,428	(10,292.52)	-0.5%
	Union South				
9	Rate M1 - Small	346	351	5.15	1.5%
10	Rate M2 - Small	3,297	3,441	144.01	4.4%
11	Rate M2 - Large	10,642	11,224	582.48	5.5%
12	Rate M4 - Small	37,374	43,475	6,100.85	16.3%
13	Rate M4 - Large	277,378	327,180	49,801.44	18.0%
14	Rate M5 - Small	30,596	30,440	(155.83)	-0.5%
15	Rate M5 - Large	169,794	169,031	(763.06)	-0.4%
16	Rate M7 - Small	656,550	725,798	69,248.52	10.5%
17	Rate M7 - Large	2,513,626	2,815,801	302,175.36	12.0%
18	Rate M9 - Large	384,526	383,685	(841.18)	-0.2%
19	Rate M10 - Average	5,570	5,490	(79.29)	-1.4%
20	Rate T1 - Small	132,068	144,975	12,907.02	9.8%
21	Rate T1 - Average	201,822	223,132	21,310.75	10.6%
22	Rate T1 - Large	445,903	496,624	50,720.74	11.4%
23	Rate T2 - Small	511,030	577,949	66,918.71	13.1%
24	Rate T2 - Average	1,186,197	1,356,166	169,968.86	14.3%
25	Rate T2 - Large	1,936,196	2,220,402	284,206.07	14.7%
26	Rate T3 - Large	3,552,739	3,555,805	3,066.36	0.1%

Notes:
(1) Reflects Board-approved rates per Appendix A in Union's April 2016 QRAM filing (EB-2016-0040).

12D

UNION GAS LIMITED
Delivery Charges and Impact for Typical Small and Large Customers
Based on Union's Proposed Cost Allocation and Proposed 20 Year Depreciation Rates
Updated to Include an Allocation Change for the St. Clair System

Line No.	Particulars	Delivery Charges EB-2016-0040 Approved 01-Apr-16 (1) ($) (a)	EB-2016-0186 Proposed 01-Jan-18 ($) (b)	Delivery Charge Impact ($) (c) = (b - a)	(%) (d) = (c / a)
	Union North				
1	Rate 01 - Small	435	434	(1.11)	-0.3%
2	Rate 10 - Small	4,232	4,217	(14.51)	-0.3%
3	Rate 10 - Large	13,579	13,541	(37.62)	-0.3%
4	Rate 20 - Small	73,272	72,937	(334.73)	-0.5%
5	Rate 20 - Large	281,495	280,472	(1,022.33)	-0.4%
6	Rate 25 - Average	62,814	62,598	(216.15)	-0.3%
7	Rate 100 - Small	260,184	259,444	(739.80)	-0.3%
8	Rate 100 - Large	2,106,720	2,101,477	(5,242.80)	-0.2%
	Union South				
9	Rate M1 - Small	346	354	8.34	2.4%
10	Rate M2 - Small	3,297	3,510	213.13	6.5%
11	Rate M2 - Large	10,642	11,491	849.63	8.0%
12	Rate M4 - Small	37,374	46,654	9,280.09	24.8%
13	Rate M4 - Large	277,378	353,133	75,754.46	27.3%
14	Rate M5 - Small	30,596	30,512	(84.11)	-0.3%
15	Rate M5 - Large	169,794	169,431	(362.18)	-0.2%
16	Rate M7 - Small	656,550	768,978	112,428.36	17.1%
17	Rate M7 - Large	2,513,626	3,004,222	490,596.48	19.5%
18	Rate M9 - Large	384,526	384,883	357.04	0.1%
19	Rate M10 - Average	5,570	5,536	(33.36)	-0.6%
20	Rate T1 - Small	132,068	149,966	17,898.38	13.6%
21	Rate T1 - Average	201,822	231,323	29,501.49	14.6%
22	Rate T1 - Large	445,903	516,011	70,108.30	15.7%
23	Rate T2 - Small	511,030	598,575	87,545.29	17.1%
24	Rate T2 - Average	1,186,197	1,407,447	221,249.52	18.7%
25	Rate T2 - Large	1,936,196	2,305,665	369,468.61	19.1%
26	Rate T3 - Large	3,552,739	3,565,851	13,112.16	0.4%

Notes:
(1) Reflects Board-approved rates per Appendix A in Union's April 2016 QRAM filing (EB-2016-0040).