EB-2016-0186

ONTARIO ENERGY BOARD

IN THE MATTER OF The Ontario Energy Board Act, 1998, S.O. 1998, c.15, Schedule B, and in particular, S.90.(1) thereof;

AND IN THE MATTER OF The Ontario Energy Board Act, 1998, S.O. 1998, c.15, Schedule B, and in particular, S. 36 thereof;

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders granting leave to construct natural gas pipelines and ancillary facilities in the Township of Dawn Euphemia, Township of St. Clair and the Municipality of Chatham-Kent;

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders for approval of recovery of the cost consequences of all facilities associated with the development of the proposed Panhandle Reinforcement Pipeline Project.

Final Submissions

Of

Association of Power Producers of Ontario (APPrO)

December 14, 2016

A. Association of Power Producers of Ontario

1. The Association of Power Producers of Ontario (**APPrO**) is a non-profit organization representing more than 100 companies involved in the generation of electricity in Ontario. APPrO members produce power from co-generation, hydro, gas, nuclear, wind and solar energy, waste wood and other sources. APPrO's members produce the majority of the electricity generated in Ontario and own and operate power generation capacity in the province. APPrO’s membership includes generators, marketers, contractors, equipment suppliers, consultants, local distribution companies, fuel suppliers, service providers and financiers. APPrO’s goal is to facilitate an economically and environmentally sustainable electricity sector in Ontario that supports the business interests of electricity generators, ratepayers and the provincial economy.

B. Executive Summary

2. APPrO respectfully submits that the evidence does not support the approval of the proposed Panhandle Pipeline facilities (the **Proposed Facilities**) at this time given that:

    a. The forecast demand is unrealistically optimistic.

        i. The vast majority of the proposed capacity addition is targeted at contract customers, yet no contract customers have made any binding commitments for capacity.

        ii. Union has not accounted for the reduction in design day load requirements from their ongoing and newly funded demand side management (**DSM**) programs. The capacity that will no longer be required as a result of these programs is more than sufficient to allow for continued general service market growth with no other capacity additions.

        iii. Union has not considered the effects of the Climate Change Action Plan (**CCAP**) and regulated cap and trade system (**CT System**) under *Ontario’s Climate Change Mitigation and Low-carbon Economy Act,* S.O. 2016 c.7 and related regulations (the **Climate Change Law**) on market demand as of January 1, 2017. This includes the impact of reduced demand that is likely to result from higher burner tip prices, and the impact of financial incentives for customers to reduce their carbon footprint and energy demand.

    b. Union has not adequately considered reasonable alternatives to the Proposed Facilities.

i. Union's request for proposal (**RFP**) to solicit commercial alternatives was conducted in a non-commercial and impractical manner. The RFP was only open for a few days that occurred over a major U.S. holiday weekend and effectively prevented most entities from submitting a proposal. Union also did not include the Rover shippers - the very shippers that Union claims control most of the capacity to Ojibway - in the RFP. The service requirements were poorly specified and the stipulated effective date was one year earlier than the start date of the Proposed Facilities.

ii. Union imposed unrealistic constraints on the import capability at Ojibway that biased the outcome in favour of the Proposed Facilities. Union claims that the import limitation is 115 TJ/d at Ojibway. This artificial constraint is not supported by the preponderance of the evidence and requires any upstream transportation capacity to be used at 100% load factor. The evidence indicates that 187 TJ/d of firm capacity is reliably available in peak winter months in order to meet the market requirements if this artificial constraint is relaxed.

iii. Union did not consider the potential to introduce a Demand Response program, similar to the program used in the electricity industry to incentivize customers to reduce their design day loads.

iv. Union did not reasonably negotiate a 'must nominate' or similar delivery obligation with its recently executed C1 contract for 35 TJ/d for receipts at Ojibway.

v. Union did not consider modifying the terms and/or conditions of its existing interruptible distribution service, which may mitigate the degree and the financial impact of a potential interruption. This may make the service more palatable to customers and thereby reduce the demand for new firm design day loads.

c. The rate implications for existing customers are not consistent with a just and reasonable outcome and cost causation. Existing customers will pay for approximately 95% of the 2018 revenue requirement of the Proposed Facilities. T2 customer rates will increase 20% as a result of the Proposed Facilities and thereby result in a rate shock for T2 customers. This will also have a significant and detrimental financial impact on the business and economics of T2 customers in a manner that is inconsistent with the Board's obligations to protect the interests of consumers pursuant to s. 2 of the *Ontario Energy Board Act, 1998,* as amended (the **OEB Act**).

3. In the event that the Board authorizes the construction of the facilities, APPrO:

   a. is strongly opposed to the proposed changes in the depreciation rate from the usual 50 years to 20 years for the Proposed Facilities and submits that such a change is prohibited by the terms of the EB-2013-0202 Settlement Agreement (the **Settlement Agreement**);

   b. supports Union's cost allocation changes; and

   c. hereby requests that the Board impose a 50 TJ/d threshold commitment by contract customers before any construction is approved and/or commences.

C. Introduction

4. Union has applied to the Board for approval to replace 40 km of its NPS 16 Panhandle pipeline system with a similar length of NPS 36 pipeline, along with modifications to several regulator stations at a combined capital cost of $264.5 million.[1] If approved, Union is proposing to construct the new facilities with a November 1, 2017, in-service date.[2] A schematic of the newly Proposed Facilities and the Panhandle system is shown in Exhibit KT.1.1 as outlined in Figure 1 below:[3]

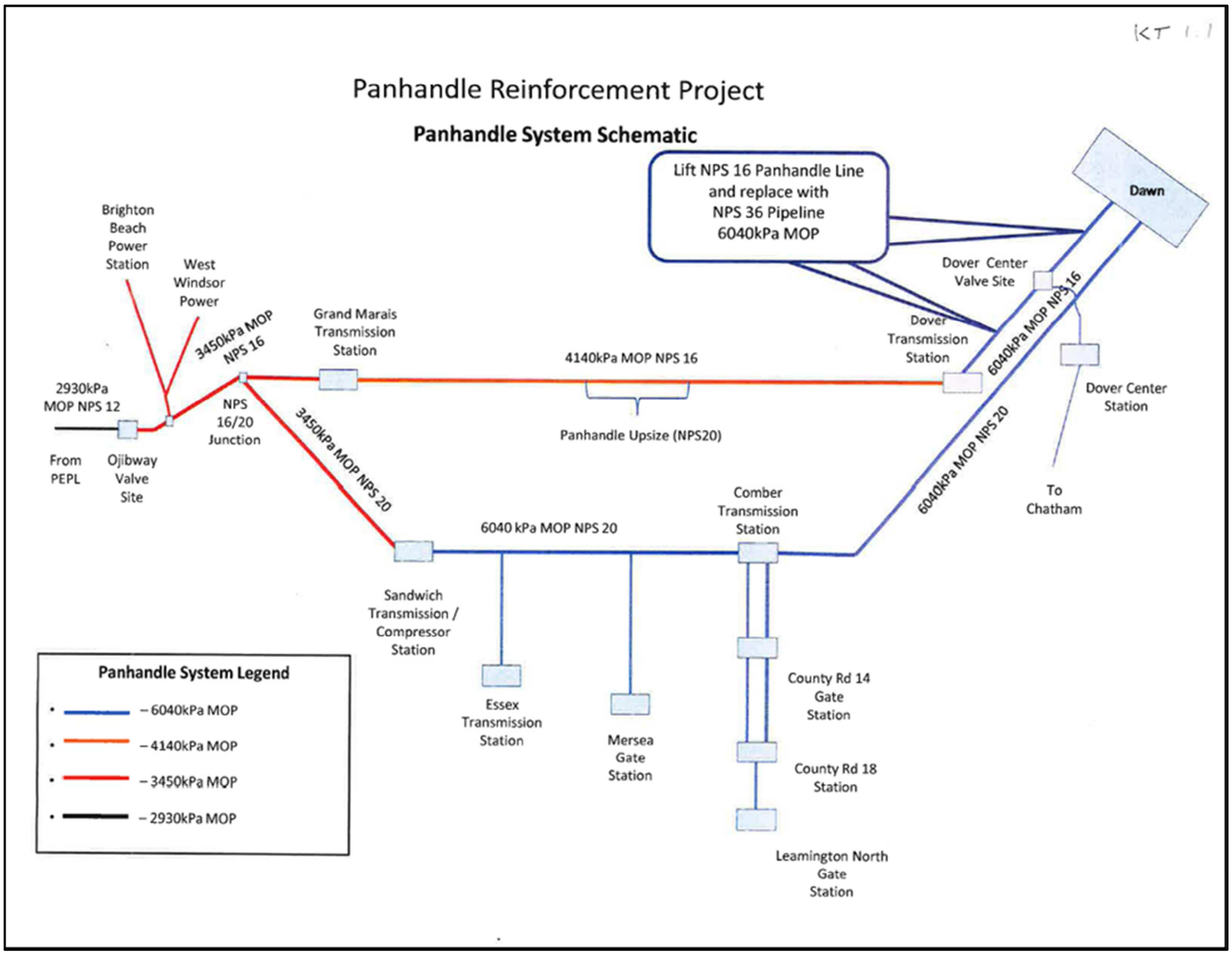

Figure 1. Proposed Facilities and Union's Current Panhandle System

5. Union's application provides additional capacity to accommodate a further increase of 106 TJ/d in design day demand. Union confirmed that it has received express feedback from

[1] Exhibit A Tab 3
[2] Application June 10, 2016 cover letter
[3] Exhibit K1.1

existing interruptible customers (representing a design day load of 2 TJ/d) indicating that they no longer wish to switch to firm service.[4] For the balance of this submission, APPrO will therefore proceed on the basis of 104 TJ/d as Union's formal five year 'adjusted' forecast as illustrated in Table 1 below. This table has been prepared by APPrO from the information on the record. This is also an excerpt from the larger table that can be found attached as Appendix 1 to these submissions.

(TJ/d)	W16/17	W17/18	W18/19	W19/20	W20/21	W21/22	Source
Union's Projected Incremental Design Day Demand Forecast							
Conversion of Interruptible to Firm Service	25	46	0	0	0	0	APPrO.2a
Growth in General Service Classes	3	2	2	3	2	4	APPrO.2a
New Contract	9	10	13	10	8	6	APPrO.2a
Total New Growth	37	58	15	13	10	10	Sum lines 20-22
Reduction in Conversion from Interruptible to Firm		(2)					Transcript Volume 2 page 60
Net New Growth		56	15	13	10	10	
Cumulative Net Incremental Growth		56	71	84	94	104	

Table 1. Five Year Market Growth - Panhandle System

6. Union has proposed to deviate from the Board approved depreciation period for the Proposed Facilities from approximately 50 years to 20 years, largely on the basis of the Climate Change Law and related regulatory impacts.

7. Union has also proposed to make certain changes to the cost allocation of its Panhandle system relating to the cost recovery for the Proposed Facilities.

8. The 2018 annual revenue requirement from the Proposed Facilities is $27.2 million.[5] The incremental revenue contributed from new customers is $1.6 million and the remaining $25.6 million[6] shortfall in revenue requirement is to be borne by all other rate payers in a manner that is not supported by cost causation principles.

9. Union's evidence confirms that the $25.6 million shortfall in the revenue requirement will result in significant rate increases for many rate classes. All APPrO members purchase T2 service in Union South territory. Many are classified as "large T2 customers". None of the projected capacity addition is being developed for, or at the request of, APPrO members and will largely serve other customers on Union's supply. Nonetheless, the evidence confirms that the rate increase for T2 customers is projected to be very significant and in the range of 20%.[7] This, in turn, is expected to result in an annual bill increase of approximately $386,000 for a large T2 customer.[8]

[4] Transcript Volume 1 page 53
[5] Exhibit A Tab 8 page 5
[6] Exhibit A Tab 8 page 5
[7] Exhibit A Tab 8 page 22
[8] Exhibit A Tab 8 Schedule 3 page 3 line 36

10. APPrO submits that the magnitude of rate increase for customers with no commensurate demand or service benefit is entirely inconsistent with the Board's mandate to protect the interests of consumers with respect to prices and the reliability and quality of gas service as set out in s. 2(2) of the OEB Act.

D. Market Need

11. The evidence indicates that Union's proposed market forecast for natural gas illustrated in Table 1 is overly optimistic in light of the lack of proposed firm commitments that Union has received from customers to date. Further, Union's ongoing and expanded DSM program is likely to also decrease demand. Moreover, both the CCAP customer incentives to reduce dependence on fossil fuels, and the higher burner tip prices for natural gas that are likely to result from the CT System and Climate Change Law that come into effect on January 1, 2017 are likely and intended to decrease the demand for natural gas from existing customers. Specifically:

    a. Table 1, indicates that is the projected increase in design day demand for contract customers is 54 TJ/d (updated from the market witness). This volume represents over one-half the total five year forecast load growth. Forty-four (44) TJ/d of this first year load is from customers that are existing interruptible customers of Union. According to Union, these interruptible customers are interested in obtaining firm service. However not a single one of these customers has signed a binding contract for firm service, or even a contract that is conditional on approval of the Proposed Facilities.[9] These customers have existing operations and are already customers of Union, and therefore they presumably should be the easiest customers for Union to obtain contractual commitments from. The Proposed Facilities have been under consideration by Union for a significant period of time and, consistent with regular business practice it is reasonable to expect that Union would have all or a significant proportion of contract commitments for the first year load at this point in time. Union acknowledged that *"prior to and at the time of the Leamington Projects (EB-2012-0431 and EB-2016-0013), Union had identified the need for reinforcement of the upstream portion of the Panhandle System".*[10] The EB-2012-0431 project was filed in 2012, and the EB-2016-0013 application was filed on January 14, 2016. Union started formal public consultation meetings for the Proposed Facilities on February 3, 2016[11] and subsequently filed this application on June 10, 2016. As of the oral hearing on November 22, 2016, almost a year after the facility proposal was crystallized, no customer had made any written binding commitments for capacity. Union suggests that some of these customers

[9] Transcript TC page 73, and Transcript Volume 1 page 61
[10] Exhibit B.Staff.1
[11] Exhibit A Tab 10 page 1

have provided a verbal commitment. APPrO submits that given that these verbal indications fall far short of a binding commitment, the Board should consider them to be verbal expressions of interest, at best. APPrO therefore submits that there is clearly insufficient commitment from contract customers for the Board to approve the Proposed Facilities at this time. APPrO further submits that if the Board were to approve the Proposed Facilities, it would put unfair burden on the remaining customers who would be responsible for the additional 2018 revenue requirement of $27.2 million.

b. While Union believes Union's forecast is "very robust,"[12] Union is not prepared to accept any revenue shortfall risk.[13] Instead Union proposed that the market risk is borne, not by the prospective customers for whom the capacity is intended, nor by Union that receives the benefit of the investment, but entirely by existing customers. This is inequity and deviation from cost causation principles is exacerbated by the fact that Union is the only party that can manage the market risk, and, in fact, directly influences the risk profile based on the accuracy of its forecast.

c. While Union has forecast incremental load growth for the region, it has not accounted for the reduction in design day demand that can be expected from Union's ongoing DSM programs. Union indicates that the historical average annual reduction in consumption for this region is 920 TJ.[14] A reduction in annual consumption from the existing DSM programs has a direct effect on the design day demands. APPrO submits that it is both illogical and inaccurate to suggest that annual demand reductions will occur without any reduction in the design day requirements. For heat sensitive markets, improvements in equipment efficiency, increases in the efficiency of the building envelope, or other changes to lifestyle permanently reduce the demand for gas on all heating days especially on design days. Similar changes to industrial markets, that operate equipment year round, can also result in reductions. Union expressly acknowledges this fact:

> *MR. WOLNIK: And this 920 tJs a day of annual reduction, you would think that would be positively correlate, or at least with -- to a large degree with heating degree days? In other words, a greater portion would be on colder days than warmer days.*
>
> *MR. ISHERWOOD: To the extent it is in the core market, the residential market, that would be true. If it is the industrial market, it may be smoother than that.* [15]

[12] Transcript Volume 1 page 78
[13] Transcript Volume 1 page 79
[14] Exhibit A Tab 5 page 14
[15] Transcript Volume 1 pages 68-69

i. While Union has been offering DSM programs for 20 years, it is remiss in not studying the effects of DSM programs on the design day demand and not accounting for such effects in its future demand forecast for its existing customer base.[16] APPrO has estimated the impact assuming that the entire savings from DSM programs is evenly spread out over the entire year as if the reductions were all in the industrial markets. The annual design day demand reduction from DSM measures would be 920 TJ ÷ 365 days = 2.5 TJ/d. Since Union has an approved DSM program through to 2020, these annual reductions in design day demand should occur each year and the benefits would be cumulative over the forecast period. APPrO submits that this estimated annual savings is very conservative for the following reasons:

- Much of consumption used by the smaller volume rate classes is heat sensitive (M1/M2 and greenhouses that are in the M4, M5 and M7 category) and this represents over 50% of the current design day demand.[17] The resulting design day demand reduction would be much greater in the heat sensitive markets due to the higher proportion of heating degree days that occur on the design day.

- Union also indicates:

  The majority of the customers served by the Panhandle System are heat sensitive and their maximum demands occur during the coldest day. [18]

- The reduction of 920 TJ/d in design day load was based on its historical budget amounts. Union's budget for DSM measures has recently doubled, so reductions in design day demand should also increase with these higher budget amounts.

Incorporating these conservative design day reduction estimates from DSM programs indicates that the annual need for incremental capacity should be adjusted downward each year to reflect the capacity freed up from existing markets. In this case the net fifth year demand for incremental capacity is reduced to 91 TJ/d as illustrated in Table 2.

[16] JT1.1
[17] Exhibit A Tab 5 Table 5-1
[18] Argument in Chief paragraph 8

(TJ/d)	W16/17	W17/18	W18/19	W19/20	W20/21	W21/22	Source
Union's Projected Incremental Design Day Demand Forecast							
Conversion of Interruptible to Firm Service	25	46	0	0	0	0	APPrO.2a
Growth in General Service Classes	3	2	2	3	2	4	APPrO.2a
New Contract	9	10	13	10	8	6	APPrO.2a
Total New Growth	37	58	15	13	10	10	Sum lines 20-22
Reduction in Conversion from Interruptible to Firm		(2)					Transcript Volume 2 page 60
Net New Growth		56	15	13	10	10	
Cumulative Net Incremental Growth		56	71	84	94	104	
Annual Reduction in Demand from DSM Programs		2.5	2.5	2.5	2.5	2.5	
Cumulative Reduction from DSM		2.5	5	7.5	10	12.5	
Cumulative Net Growth with DSM Effects		53.5	66	76.5	84	91.5	

Table 2. Cumulative Net Growth Including Estimated Effects of DSM Programs on Existing Markets

ii. An alternative way of considering the benefits of this DSM program is that the reduction in design day demand from the existing market is similar in size to the projected organic growth in the general service market. Therefore without any incremental supply into the region the general service market can continue to grow at the projected levels.

iii. Union has suggested that despite its DSM measures, they continue to see an increase in design day demand.[19] APPrO submits that the Board should not be persuaded that DSM has no impact on design day demand. These statements merely suggest that total annual growth in all markets is greater than design day reductions from DSM. APPrO does not dispute that net growth has likely occurred. However, it is inconsistent with the rationale for additional DSM recently approved by the Board to ignore the ongoing design day demand reductions from the existing base of customers from the implementation of DSM measures and it results in overstating future demand from existing markets.

d. Union also acknowledges that the CCAP is expected to result in incentives to retrofit to increase customer energy efficiency:

"The CCAP allocates almost $4 billion (nearly half of the entire plans' funding) in new grants, rebates and other subsidies directed toward energy retrofits and efficiency measures aimed at helping homeowners reduce their carbon footprints by supporting additional choice. In fact, as stated at page 27 of the CCAP, the government intends to help homeowners "purchase and install low-carbon energy technologies…"""[20]

Union further estimates that 4% of the $4 billion incentives could be targeted for this region, if these funds were allocated on the basis of population. This amounts to $160 million in potential incentives for this region. While the details of

[19] Transcript Volume 1 page 74
[20] Exhibit A Tab 3 page 6

these incentives are not yet finalized, it is inevitable that these incentives will further lower both the annual demand and the design day demand for the region served by the Panhandle system. Given that these programs are also targeting the installation of low-carbon technologies, the effects of CCAP incentives on decreasing design day loads could also be much greater than the design day effects of DSM programs.

While the magnitude of the CCAP incentives demand reductions could be substantial, APPrO recognizes that it is premature to quantify the specific design day reductions that could result from such incentive plans. Therefore any plans to increase capacity into the region should be as flexible as possible to be able to adjust to the ultimate effects of CCAP, reduce the risk of stranded assets, and minimize customer rate increases.

e. The Climate Change Law and associated CT System will come into full effect on January 1, 2017. Natural gas rates are therefore likely to increase significantly on and/or after January 1, 2017 as a result of the need for utilities to acquire emission allowances and other compliance units in accordance with the CT System and the Climate Change Law. Union proposes to increase its rates for all customers, due the cost of acquiring emission allowances and other compliance units. In its EB-2016-0296 application Union indicates that rates will increase by 3.3181¢/m3[21] to comply with customer related GHG obligations and a further 0.0115-0.0297¢/m3[22] to meet Union's facility related GHG obligations. Union has not estimated or otherwise analyzed the impact these costs will have on existing customers' demand and new customer additions.

Union has received feedback from some customers indicating that their future demand forecast could decline:

> *Some customers have indicated a revision to their natural gas needs or expansion plans as a result of Cap and Trade and the CCAP.* [23]

APPrO appreciates that the customers that have provided this specific feedback are not on the Panhandle system; however this feedback is significant in that it is a very predictable response from customers, especially commercial and industrial customers, operating in a highly competitive environment facing a significant cost increase. APPrO submits that it is reasonable to predict that Union will receive similar responses from other customers, including those on the Panhandle system.

[21] EB-2016-0296 Exhibit 7 Schedule 1
[22] EB-2016-0296 Exhibit 7 Schedule 1
[23] Exhibit B.Staff.2c

12. In summary on this point, contract customers that intend to use the new capacity resulting from the Proposed Facilities have yet to make any binding commitments for the capacity. This, in and of itself, suggests that the project is not yet mature enough for the Board to approve it. Moreover, Union has not taken into account the effects of existing and proposed financial, DSM, and CCAP incentives targeted to reduce customers' dependence on natural gas. Nor has it considered the burner tip implications of increased gas costs resulting from the CT System and Climate Change Law compliance costs. CCAP incentives will further reduce the design day loads from existing customers. Union's forecast of both new demands and existing demand is therefore overstated.

E. <u>Facility Alternatives</u>

13. In its evidence, Union indicated that, in addition to the Proposed Facilities, it evaluated three other alternatives including a liquefied natural gas (LNG) option, and a combination of incremental reduced facilities along with incremental deliveries at Ojibway. Union also conducted an open season with existing distribution customers served by the Panhandle system to assess if any of these customers were interested in returning their firm capacity. APPrO submits that there were other feasible alternatives that were not considered, which would offer a partial solution to meeting the overall market needs. The alternatives that were considered were either not evaluated appropriately or had unreasonable constraints applied to them, which materially biased the outcome to favour the Proposed Facilities.

14. First, the Board may wish to examine more generically the capacity availability on the Panhandle Eastern system to deliver firm US gas to Ojibway and Union's ability to receive and use that gas to meet design day demand. These issues were the source of some confusion over the course of the proceeding, until the last day of the oral hearing. This Panhandle Eastern route represents a significant and viable option, so it is important to understand the details. APPrO has summarized these capacities in Schedule 1, of this Final Argument. All of the details in Schedule 1 originate from the record in this proceeding.

    a. The maximum amount of gas that can be exported by Panhandle Eastern is 195 MMCFD or approximately 208 TJ/d. This is illustrated in Line 1 of Schedule 1. This volume is governed by their 'Presidential Permit'. While this is the current limit, it could potentially be changed over time. However for this purpose, it is not the limiting factor. It is worthwhile to note while this is a constraint today, it is a constraint that may be able to be changed in the future.

    b. Line 2 in Schedule 1 sets out Panhandle Eastern's firm capacity limitation which is 175 MMCFD or 187 TJ/d.

    c. Lines 4 through 11 set out Union's firm contracted capacity to Ojibway on Panhandle Eastern.

d. Line 12 sets out the remaining firm capacity on Panhandle Eastern after accounting for Union's contracted capacity.

e. Line 13 through 16 set out the capacity that third parties have contracted on Union as C1 capacity. It is assumed that these parties have equivalent contracted capacity on Panhandle Eastern. It is likely that these parties have similar firm capacity commitments on each side of Ojibway. Union has indicated that some Panhandle Eastern capacity was reserved for Rover. We know as of November 22, 2016, that Rover has contracted for 35 TJ/d on Union, so it is likely that they adjust their upstream commitments to match their downstream obligations.[24] Even if Rover maintains a greater amount of capacity on Panhandle Eastern, there is no reason to think that they would not make a delivered service available at Ojibway. This excess Rover capacity could also be assigned through the pipeline's standard capacity release arrangements, so this capacity is accessible either as raw transportation capacity or as a delivered service.

f. Line 18 sets out the remaining uncontracted capacity on Panhandle Eastern.

g. Lines 19 through 26 set out Union's adjusted annual load forecast.

h. Line 27 shows the net difference between the available capacity from Panhandle Eastern at Ojibway and the Load forecast.

APPrO therefore submits that the evidence supports the view that there is sufficient capacity to accommodate the first two years of growth without the Proposed Facilities.

15. Schedule 2 of this Final Argument shows a similar compilation of the evidence, however it incorporates reduced design day market demand resulting from DSM programs. This also shows that Union can comfortably meet the first two years of growth, and much of the third year demand as well without the Proposed Facilities.

16. With the proposed CCAP incentives, the impact of higher prices from CT System and Climate Change Laws, and the potential to pursue other commercial alternatives to meet the market growth (as further described below), the projected market growth could be accommodated and the Proposed Facilities deferred well beyond two years.

17. Union has repeatedly constrained its ability to receive gas at Ojibway to 115 TJ/d. This constraint is the major factor in driving the proposed $264.5 million reinforcement. This

[24] Exhibit K2.1 Attachment 1 page 25

constraint is artificial, unwarranted, and by its very nature eliminates other reasonable commercial and facility options.

a. The 115 TJ constraint has been set at the maximum amount of firm gas that Union can accept in Windsor in the summer months.[25] This constraint is then applied by Union to all other days of the year, regardless of the need or the ability of the distribution system to accept greater volumes:

> *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).*

i. Union chooses this 115 TJ/d constraint as it prefers to purchase firm gas supplies on a 365 basis and cycle the excess summer supplies through storage. APPrO acknowledges that purchasing gas supplies on a 365 day basis is one way to acquire gas supplies, but it is by no means the only way that gas can be acquired. Many gas utilities in North America have no access to local underground gas storage near their market area, and purchase the required upstream transportation and source gas as necessary throughout the year. The transportation is better utilized in the winter than summer. Centra Manitoba and Fortis BC are two good examples where they need to maintain year round firm transportation levels to meet the design market need as they have no local storage. Even Enbridge maintains large amounts of transportation from Dawn to its market areas, much of which is only used during the winter months. APPrO submits that by lifting this artificial summer constraint, and purchasing gas in the winter based on the need, much more gas can be brought in to meet the actual winter demand requirements. Union has not considered buying gas other than at 100% load factor at Ojibway, which limits imports to 115 TJ/d and reasonable alternatives.

ii. If Union contracted for 71 TJ/d of capacity on Panhandle Eastern (from Schedule 1) from Defiance Ohio (the point where the 3.1 BCFD Rover pipeline will connect with Panhandle Eastern) to Ojibway commencing in the winter of 2017/18, this would meet the market needs for at least two years. The fixed demand charges associated with this capacity are C$0.1381/GJ.[26] The annual costs for this capacity therefore would be:

[25] Exhibit A Tab 4 page 4
[26] Exhibit J2.6(A)

71,000 GJ/d X $0.1381/GJ/d X 365 days = $3.579 million.

$3.579 million represents a mere 13% of the $27.2 million of the 2018 revenue requirement associated with the Proposed Facilities. The Panhandle Eastern route from Defiance to Ojibway is illustrated in Figure 2.

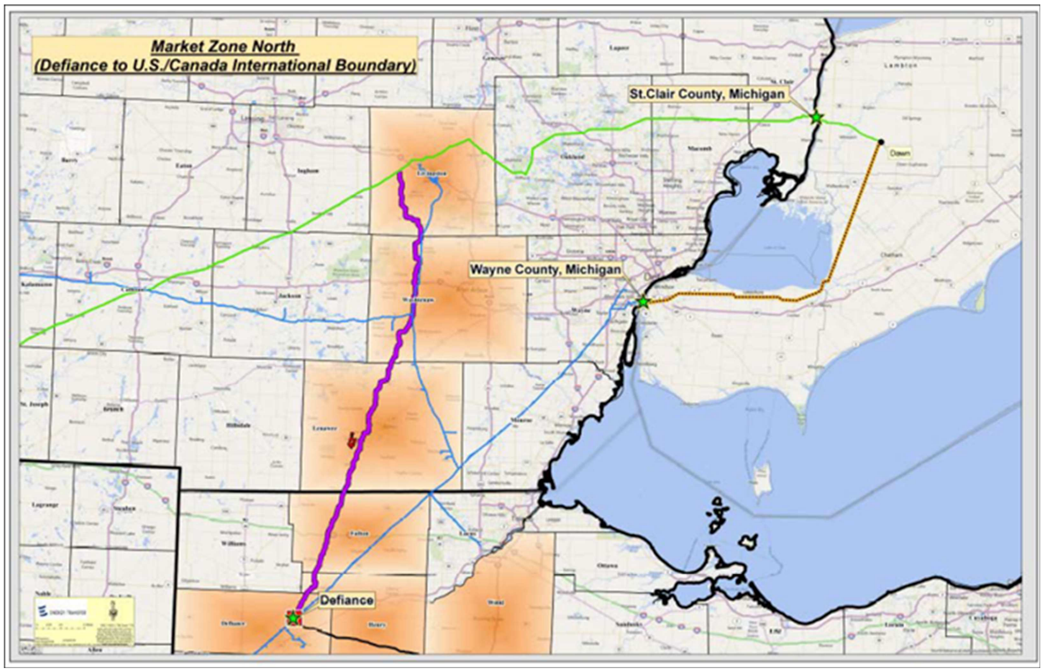

Figure 2. Panhandle North Route Defiance to Ojibway

iii. Union has tried to summarily discount Defiance as a reasonable place to purchase gas for the following reasons: Defiance has not been a liquid point, there could be volatility in pricing, and buying gas at this point could upset Union's overall system supply arrangements. APPrO submits that this is not supported by fact and evidence.

- Defiance has been an interconnection between two major pipelines (ANR and Panhandle Eastern) for decades. With the addition of the Rover pipeline scheduled for November 1, 2017, it will add 3.1 BCFD of new capacity. In addition, NEXUS will be developing its 1.5 BCFD pipeline that, while it may not directly interconnect at Defiance, will displace other loads that these existing pipelines are now serving and thereby result in increased supply availability at Defiance. Rover will bring significant quantities of gas arriving in 2017. Producers are in the business of selling their gas without having to incur downstream additional fixed cost unless necessary. It is therefore likely that producers would actually prefer to sell a portion of their gas at Defiance.

- Even if gas is not actively traded at Defiance today, the Rover and NEXUS pipelines will significantly change the dynamics in this region at this point. If Union were genuinely concerned about buying gas that didn't have an active spot market today, they would not have contracted for NEXUS capacity in the illiquid Utica supply area. Moreover, in this proceeding Union also raised concerns about Ojibway being an illiquid point.[27] Nonetheless, Union entered into a commercial arrangement for 21 TJ/d at Ojibway.[28]

- Union also had concerns about the impact that buying additional gas would have on their existing support portfolio. This concern assumed Union would purchase gas on a firm 365 day basis. If this supply were only purchased in the winter months it would have substantially less impact on the existing supply portfolio. Further, this incremental supply is for an incremental market. Buying incremental supply to meet the incremental market should not alter Union's existing supply arrangements. In the event that Union has somehow already pre-purchased supply to accommodate this incremental market growth, then Union may have already overbought their gas supply.

b. Union has also suggested that 140 TJ/d is the maximum amount of gas that it can purchase in the winter time. Like the 115 TJ/s summer constraint, APPrO submits that this is an artificial and unwarranted constraint. It only is relevant if Union chooses to buy this gas on a firm basis on each day of the winter at 100% load factor and wants to take gas in excess of the local market requirements back to Dawn for storage injection on the warmer winter days. As indicated above, the opportunity cost associated with the UDC is only $0.1381/GJ, less than the fully allocated costs to transport and store the gas at Dawn. APPrO submits that Union can readily use the incremental capacity on Panhandle Eastern (up to the firm capacity limitations), purchase the amount of gas in each of the winter months that reflects the market requirement and supplement this with its existing transportation capacity from Dawn in to this region to balance the total regional needs. One would expect that in months like January and February Union would fully use this capacity, but in months like March or November it may

[27] One examples is at Exhibit B.APPrO.3c)
[28] Transcript Volume 2 page 152

be able to adjust its purchases accordingly. The capacity would always therefore be at Union's disposal to meet it firm market demands.

18. In order to help assess potential commercial alternatives to the Proposed Facilities, Union conducted an RFP on May 26, 2016 to investigate the potential to secure a long term (greater than 3 years) commercial alterative to the Proposed Facilities:[29]

> *Union issued an RFP on May 26, 2016 to secure incremental firm long-term transportation capacity on PEPL or to secure firm delivered supply at Ojibway through the PEPL system. The RFP was issued to a broad range of market participants, including current pipeline capacity holders, marketers and PEPL. Please see Attachment 3 for RFP details. Union received no interest from market participants in providing incremental firm long-term transportation on the PEPL system to Ojibway. Only one market participant responded to the RFP to provide a firm delivered service at Ojibway. This is not surprising given the number of counterparties holding transportation capacity to Ojibway on the PEPL system.*

While on the surface it appears that Union was genuinely seeking third party commercial alternatives to the Proposed Facilities, APPrO submits that the RFP was not undertaken on a commercial basis and at a time to encourage response.

a. The RPP Process was unnecessarily short and did not allow parties reasonable time to respond. It targeted an earlier start date than what was necessary and was not sent to the very shippers that were in the best position to accommodate the request. The RFP was issued May 26, 2016, a Thursday afternoon. Responses were due back on May 31, 2016 the following Tuesday at 1:00 pm. Monday May 30, 2016 was the very popular US Memorial Day holiday weekend. Most of the likely respondents would be American. Even without the holiday weekend, this is an extremely short period of time to have someone develop a comprehensive long term proposal and obtain the necessary internal approvals to supply gas at Ojibway. Doing this over the holiday weekend exacerbates the situation and decreases the likelihood of response. APPrO submits that the timing also is suspect, occurring only a few days before this application was filed with the Board.

b. APPrO submits that Union should have issued the RFP well in advance of public consultation for this project, and it is unclear why Union waited until May 26, 2016 to issue the RFP. Public consultation for this project formally began on February 3, 2016.[30] APPrO is of the view that it would have been more appropriate to properly investigate the alternatives prior to engaging the public on Union's Proposed Facilities.

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[29] Exhibit B.Staff.3
[30] Exhibit A Tab 10 Page 1

c. Union claimed that all the remaining capacity on the Panhandle Eastern system was reserved for Rover, yet Union did not include all Rover shippers in its RFP. In fact Union sent the RFP to only 1 of the 7 Rover shippers with capacity on the PEPL North system[31] (i.e. between Defiance and Ojibway).[32] Union claims that they may not have known who all the shippers could be and further indicates that:

> *One of the requirements we have of doing business with various parties, especially if we are going to be buying supply, is to have a NAESB, or North American Energy Standards Board, agreement, so that in many cases is your foot in the door. So you have to have a NAESB agreement with Union to be included on many of our RFP lists, et cetera.* [33]

Energy Transfer, the owner of both Panhandle Eastern and Rover, indicated in its letter of November 17, 2017,[34] that it has been willing to work with Union by providing the avenue for Union to work with Rover shippers for some time. Union therefore had a clear avenue to access Rover shippers.

d. This application is to seek the Board's approval for Union to construct facilities that would come into service on November 1, 2017. The RFP issued was for service to commence *"as early as November 1, 2016".*[35] Granted this does not exclude a party submitting a proposal for service to commence sometime in the future, but Union provided no direction to potential respondents on the timing of their actual needs, nor the amount of capacity they were looking to secure. There is no possible way that a respondent, like a Rover shipper who had capacity becoming available November 1, 2017, would know the actual timing of first deliveries from the RFP.

e. Notwithstanding that the RFP suggests that it was prepared to entertain delivered services, it was only really seeking a transportation service. Exhibit B.Staff.3 indicates *"Union issued an RFP on May 26, 2016 to secure incremental firm long-term transportation capacity on PEPL or to secure firm delivered supply at Ojibway through the PEPL system".* While Union suggests that it was open to a delivered service, it is crystal clear that Union strongly preferred a transportation service and did not want a delivered supply. This is evident in that:

[31] Exhibit 2.3 page 15
[32] Transcript Volume 2 page 155
[33] Transcript Volume 2 page 156
[34] Exhibit K2.1 Attachment 1 page 4
[35] Exhibit B.Staff.3

i. The RFP document[36] directs respondents to provide many details on the transportation option, yet Union asks for no details about a supply option including asking for any pricing details.

ii. Union confirms that this was its intention all along:[37]

I take it that you really wanted the transportation as opposed to the delivered arrangements. Is that –

MR. SHORTS: That's correct.

By excluding a delivered supply, the RFP effectively prejudiced potential Rover shippers from submitting a delivered gas proposal.

f. Union suggests that Rover did not offer an Ojibway delivery point thus preventing Rover shippers from even submitting a proposal. Union obviously knows that US pipeline tariffs, like Canadian tariffs are living documents and evolve over time based on the needs of the parties. New delivery points can be added to meet the needs of shippers. By conducting this RFP over the holiday weekend, it effectively prevented any potential Rover shipper from contacting Rover or Panhandle Eastern to discuss the possibility of obtaining an Ojibway delivery point prior to submitting a proposal.

19. There are several other commercial proposals that Union did not consider. APPrO submits that these in combination with other alternatives could further defer the timing of the Proposed Facilities:

a. Union has been aware of pending need for reinforcement for this region since 2012.[38] In 2015 Union sought and received approval for recovery of the cost consequences of contracting for 150,000 Dth/d (approximately 158 TJ/d), for contracts associated with the Spectra/DTE NEXUS Project.[39] The NEXUS project like the Rover project originates in the Marcellus/Utica regions and they parallel one another seeking to serve several markets including those in the mid-west US and Dawn. Both of these pipelines cross the Panhandle Eastern system in and around Defiance, Ohio.[40] Union was asked in the Technical Conference if they considered the option of having NEXUS deliver a portion of Union's 150,000 DTH/d to a new Panhandle Eastern interconnect and subsequent contracting with Panhandle Eastern for delivery of these volumes to Ojibway. Union indicated

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[36] Exhibit B.Staff.3 Attachment 3 3rd paragraph
[37] Transcript Volume 2 page 153
[38] Exhibit B.Staff.1
[39] EB-2015-0166
[40] Exhibit K2.3 page 18

that NEXUS had not offered an interconnection with Panhandle Eastern. Union also never asked if it could have a portion of its contracted capacity delivered along this route:[41]

> *MR. WOLNIK: I think -- I acknowledged at the time, didn't know the number, but knew there was a pending need.*
> *So it seems to me you had the opportunity to forego a portion or delay this build by contracting -- recognizing there is limitations at Ojibway.*
> *But you could have shifted some of those Nexus volumes for delivery through your system and saved some upstream costs, because it is using your own system.*
> *You had the opportunity to do that, but failed.*
>
> *MR. REDFORD: The connection at St. Clair is using our own system as well. So we came in through DTE into the St. Clair line and that goes back to Dawn; its Union's system. So I would say that, you know, Panhandle is not advantageous to the arrangement that we made.*
>
> *MR. WOLNIK: You didn't consider it?*
>
> *MR. REDFORD: No, we didn't.*

Had Union been able to acquire capacity along this NEXUS-PEPL-Ojibway route, the Proposed Facilities perhaps could have been delayed several years. If Union overlooked an efficient opportunity at that time, it begs the question how many potential opportunities is Union they overlooking now?

Even though Union overlooked a potential opportunity when negotiating the NEXUS contracts, it may be possible now to go back and negotiate an interconnection at this time. If so, Union could use its existing gas supply arrangements on NEXUS along with incremental capacity on Panhandle Eastern (as described earlier) and use this capacity as needed in the Windsor area. On days when the supply was not needed in the Windsor area, Union could still use it primary NEXUS route back to Dawn to store the gas. APPrO submits that while there may be a cost associated with this interconnection, at least this alternative would not impact Union's existing gas supply arrangements.

b. On November 21, 2016, on the eve of the oral hearing, Union entered into a long term C1 letter agreement with Energy Transfer[42] for 35,000 GJ/d of Ojibway to Dawn firm transportation capacity to transport Rover volumes to Dawn. Union indicates that it did consider a must nominate service as an alternative the Proposed Facilities:

[41] Transcript Volume 2 pages 165-166
[42] K2.1 page 25

4. Union evaluated other commercial alternatives including:

> *i. Seeking an amendment to the existing firm C1 transportation contract still in effect at November 1, 2017 to obligate deliveries at Ojibway by negotiating a "must nominate" service - This is not currently a condition of Union's C1 firm transportation service. As a result of the RFP described above, Union secured 21 TJ/d of Ojibway deliveries from the sole remaining holder of firm C1 Ojibway to Dawn transportation capacity at November 1, 2017.* [43]

This IR response suggests that the only reason not to pursue a must nominate service is that it was not a current condition in Union's transportation contract. If this is the case, then Union missed yet another opportunity to secure firm deliveries at Ojibway to defer the Proposed Facilities in their recent negotiations with Rover/Energy Transfer.

It is clear that Rover shippers are very interested in selling their gas at Dawn. Union emphasizes this:

> *MR. REDFORD: They're moving a Bcf to Dawn, to Bcf to the Gulf. So I am not sure Rover would consider obligating 75 MMCFD a day at Ojibway as significant.* [44]

It is hard to imagine that if Rover shippers are eager to get their gas to Dawn that they would not want to consider perhaps receiving a premium to obligate their deliveries it via Ojibway.

Energy Transfer, the owner of Rover, was also of the view that getting Rover shippers to commit to delivering to Ojibway was possible:

> *Further, if a delivery commitment is required for the supply on the 75,000 Dth/d, Rover would be happy to pursue such, including by providing the avenue for Union to work with Rover shippers to accommodate that. We stand ready, as we have for the last 18 months, to discuss this with you.* [45]

Despite all the opportunities over the last 18 months to pursue a must nominate service or similar service, Union did not investigate this option even for the 35 TJ/d of new C1 capacity entered into on November 21, 2016.[46] Conveniently in their opening statement on the first day of the oral hearing and contrary to their interrogatory responses, Union now suggests that the only way to obligate the supply at Ojibway is for Union to either directly hold capacity on Panhandle Eastern or buy the gas at Dawn:

> *The only way to truly obligate supply at Ojibway is for Union to control the supply, similar to how Union controls 90% of the supply for the Panhandle Transmission*

[43] Exhibit B.Staff.3a
[44] Transcript Volume 2 page 70
[45] Exhibit K2.1 page 4-5
[46] Exhibit K2.1 page 25

> *System that comes from Dawn. Union can control supply to Ojibway by contracting for firm transportation capacity on Panhandle Eastern or through a firm delivered service - such as a delivered supply service.*
>
> *Union has discussed the issue of obligated flow through Ojibway with Rover Pipeline and while Rover Pipeline would consider such an arrangement for up to 35 TJ/d, Union would still be required to control the supply by purchasing from Rover shippers at Dawn.* [47]

APPrO does not dispute that either of these two options can result in obligating the supply. It appears that Union was not even open to exploring commercial solutions that could provide the same result. Energy Transfer in its November 17, 2016 letter to Union certainly believed that such an option was possible, and offered to assist Union in this regard. Union acknowledged that this mechanism had been successfully used by TransCanada to meet its firm obligation requirements[48] at Dawn. Perhaps it is not too late to approach Rover shippers to negotiate such a provision.

c. Union conducted a reverse open season to see if existing distribution customers would be willing to turn their firm capacity back to reduce the overall need to build facilities:

> *In an attempt to promote the most efficient expansion of the Panhandle System, while minimizing the overall cost to ratepayers, for the first time Union conducted a reverse open season for its in-franchise contract rate customers. The reverse open season was targeted at customers who hold firm capacity on the Panhandle System to determine if any of those customers wanted to reduce their firm contract demand ("Firm CD") and/or convert their Firm CD to interruptible distribution service before the end of their contract term. Union conducted the reverse open season to promote the most efficient expansion of the Panhandle System by ensuring that customers who may hold excess firm capacity had the opportunity to return that capacity to the system. Union issued the reverse open season to customers on May 11, 2016 with responses due back to Union on May 18, 2016. Union did not receive any responses to this reverse open season. The reverse open season letter is attached at Exhibit A, Tab 5, Schedule 1.* [49]

Under this arrangement a customer could turn back capacity and no longer have to pay the associated fixed costs associated with having firm distribution capacity so that Union could then use this capacity for higher valued markets. These customers would likely become interruptible customers of Union, assuming that they still had a demand for gas. While Union goal to make better use of existing facilities is commendable, they should not be surprised that they did not get any

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[47] Exhibit K1.4 page 4
[48] Exhibit B.FRPO.5a)
[49] Exhibit A Tab 5 page 17

responses.

i. First Union only provided one week for customers to evaluate whether they could turn capacity back. Only customers that had no further need for their current contract would be in a position to respond to this request in such a short time frame. Customers that may have been interested in converting to interruptible would need time to assess both the risk of interruption, the cost of alternate fuels and potentially the need to change equipment to accommodate alternate fuels. Doing all this and having to seek all the necessary management approvals in one week is clearly unrealistic. Union commenced public consultations on this project on February 3, 2016.[50] Exploring potential alternatives should have been completed prior to engaging the public on a new facility build; the Reverse Open Season ought to have been issued prior to Feb 2016 with reasonable timelines to allow customers to respond.

ii. In the electricity industry the independent electricity system operator (IESO) offers demand response programs whereby to encourage customers to reduce their design day usage.[51] They compensate these customers to reduce their on-peak demand. According to the IESO's website:

> *Demand response allows the electricity system to tap into existing infrastructure, such as factories or hospitals, making demand response an efficient approach to meeting energy needs.*

iii. Union acknowledged that the customers that currently have firm service might incur some costs to move to interruptible[52] so just being relieved of the fixed cost of the distribution capacity may be insufficient incentive for them to offer capacity back to the system. Under the proposed facility option in front of the Board, Union is prepared to spend $264.5 million to create 106 TJ/d of capacity. The 2018 revenue requirement associated with this facility option is $27.2 million. On a unitized basis this is about $0.70/GJ/day.[53] Implementation of a targeted demand response program would give existing customers the option to offer capacity back to the utility at a price that would reflect their opportunity cost to reduce their design day demand. This could result in capacity being offered back to the utility at a marginal price lower than the alternatives. The utility could then compare these market signals to its facility alternatives, and decide which is the most cost efficient and effective. This could create efficient

[50] Exhibit A Tab 10 page 1
[51] http://www.ieso.ca/Pages/Ontario's-Power-System/Reliability-Through-Markets/Demand-Response.aspx
[52] Transcript Volume 2 page 149-150
[53] Transcript Volume 2 page 144

pricing signals for the utility to determine the most efficient way of serving incremental needs. Union did not consider such a program.[54] APPrO does not suggest that a Demand Response program on its own would be sufficient to meet the total projected market, but in combination with other alternatives could meet the load growth while providing for a further delay of the facilities.

d. Finally, Union has not considered encouraging interruptible customers to stay interruptible customers rather than converting these customers to firm. Interruptible customers receive a lower rate than customers with firm service, but they do incur the costs associated with having the ability to switch to an alternate fuel when the natural gas system nears its peak. Union could work with this pool of customers and seek to obtain both upstream interruptible capacity on the Panhandle Eastern system and gas supply and stream these costs to these customers in lieu of an interruption. Schedule 1 illustrates that there is still 21 TJ/d of interruptible capacity on Panhandle Eastern and subject to Union's ability to transport such volumes it may be an economic alternative that could mitigate the alternate fuel costs to interruptible customers. While it would not completely reduce the chance of interruption it may be sufficient to encourage some customers to remain as interruptible. Union does consider this an option as noted below, but seems to again discount it again because Ojibway is not a liquid spot:

> *MR. WOLNIK: So for some of those interruptible customers in the Leamington and Windsor area, is it -- it is an option, as I hear you saying, for them to bring additional gas in, in lieu of being interrupted?*
>
> *MR. ISHERWOOD: We would definitely -- if they had the Request, we would definitely look at it. The challenge is Ojibway is not a liquid spot, so they can't really buy gas at Ojibway. They would have to be buying gas upstream of Ojibway and that is hard to do on a day, on a peak winter day.*[55]

Even if Ojibway is not a liquid spot today, Schedule 1 shows that there is upstream interruptible capacity to Defiance. Also effective November 2017, Rover shippers will have 35 TJ/d passing through Ojibway.

F. <u>Rate Impacts to Existing Customers</u>

20. APPrO's view is that both the short and long term rate impacts and the related risks are not just and reasonable and consistent with the Board's customer mandate. The Board should not therefore approve the Proposed Facilities.

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[54] Transcript Volume 2 page 150
[55] Transcript Volume 1 page 80

a. New customers will only pay a very small fraction of the 2018 revenue requirement:[56]

Total Revenue Requirement	$27.179
Incremental Project Revenue	$1.572
Net Subsidy from Other Customers	$25.607

Existing customers cross subsidize new customers and cover 94% of the incremental cost to supply this new load. This significant rate increase is not consistent with cost causation principles, the Board's recent decision on natural gas expansions, and AprO submits that it is threatening the economic viability of existing customers.

b. The $25.6 million shortfall in revenue requirement will result in significant rate increases to many rate classes. APPrO members all purchase T2 service in Union South. Many of these are classified as 'large' T2 customers. None of the projected capacity additions is being developed for APPrO members. The projected rate increase in the T2 delivery rate is 20%,[57] which will result in annual increases of approximately $386,000.[58] In the event that the Board rejects Union's proposed changes to cost allocation, the rate impact to T2 customers could be as high as 37%.[59] This would represent over a $700,000 increase for these customers that receive no benefit from service.

c. Notwithstanding the potential to meet these incremental loads in the short term and defer the Proposed Facilities, the sheer rate impact to these large customers indicates that the project is not in customer interests or otherwise just and reasonable unreasonable.

d. In the response to JT1.14, Union calculated the cost of alternative fuel to those customers contracting for interruptible service over the prior four winters. Adding the annual figures and dividing by four to get the average impact reveals the following:

    i. The average annual volume interrupted was 74,634 GJ.

    ii. The annual number of days that service was interrupted was 6.6.

    iii. The net cost of alternative fuel for these customers to accommodate this interruption was $5.9 million.

[56] Exhibit A Tab 8 Schedule 1
[57] Exhibit A Tab 8 page 22
[58] Exhibit A Tab 8 Schedule 3 page 3 line 36
[59] Exhibit B.LPMA.21b)

A substantial portion of the proposed capacity addition (44 TJ/d) is intended to improve the service to interruptible customers, as well as provide service to new customers over time. It is noteworthy that the financial benefit ($5.9 million) to such existing interruptible customers is small relative to the financial burden that existing customers incur to have this capacity made available ($25.6 million).

21. APPrO submits that the Board should also be cognizant of the fact that the rate impact for the proposed facility does not occur in isolation. The cumulative effects of other increases driven by other facility applications, CCAP, the CT system and the Climate Change Law result in continued upward cost pressure on industry. A few examples:

    a. Union's T2 distribution rate will increase by over 16% on January 1, 2017.[60]

    b. Union rates will increase on January I, 2017 by 3.3296 ¢/m3 due to the CT System and Climate Change Laws. A large T2 customer consuming 250 $10^6 m^3$/yr. (9.45 PJ/yr.) will see an annual increase of approximately $8 million annually.

G. Depreciation

22. In the event that the Board approves Union's Proposed Facilities, it should reject Union's proposal to change the depreciation period.

    a. First, the Settlement Agreement expressly prevents changes in depreciation rates during the current IRM and no changes to the Settlement Agreement are severable or otherwise permitted.[61] Specifically, the Settlement Agreement indicates that:

       *In this Agreement, the term "net delivery revenue requirement impacts" is used in a number of places. As used in this Agreement, that term means the **annual costs of a project** or initiative including operating costs, **depreciation**, costs of incremental debt, return, and related taxes, net of any incremental delivery revenues arising from, associated with, or enabled by the project or the initiative* (emphasis added).[62]
       …
       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.[63] …

[60] EB-2016-0245
[61] EB-2013-0202 Settlement Agreement ("Settlement Agreement") p.2 and 3
[62] Settlement Agreement p.6
[63] Settlement Agreement p. 19

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*** (emphasis added)***;***[64] ***…***
- ***Union agrees to make no changes to these parameters during the IRM term*** (emphasis added);[65]

The express wording of the Settlement Agreement therefore confirms that no change from the 50 year depreciation rate is permitted. This interpretation is also supported by the numerical schedules that accompany the Settlement Agreement at its Appendix B. Specifically, p.1 of the LPMA Questions in Appendix B confirm that Depreciation is at 2013 Board-approved rates. The Schedules outlining the Burlington to Oakville Project Revenue Requirement similarly confirm that depreciation expenses for each and all of 2015, 2016, 2017 and 2018 years are at 2013 Board approved depreciation rates. APPrO therefore submits that Union's proposed change in the depreciation rate for the Project Facilities is clearly prohibited by the Settlement Agreement. Any deviation from this agreed Settlement would bring the enforceability of the entire Settlement Agreement into question, and jeopardize the Board's longstanding settlement processes.

b. Second, the Board normally requires utilities to complete a comprehensive study examining all the factors that affect the economic lives of assets, and Union has not conducted any formal studies to support the change in depreciation rate. The extent of their analysis seems to be that it happens to be a date roughly mid-point between the province's 2030 and 2050 dates to reach certain emission reductions:[66]

MR. ISHERWOOD: I am not sure about that. So if you go to the climate-change action plan which came out in June of this year, the Ontario government made it very clear what the targets are for CO_2 reduction or greenhouse gas reduction. And by 2020 it is a reduction of 15 percent, by 2030 a reduction of 37 percent, and by 2050 a reduction of 80 percent.
So when we add 20 years on to 2017, that takes it out to 2037. So it is actually between the 2030 target of 37 percent reduction and the 2050 target of an 80 percent reduction.

Union further explains their view on the test that should be used to assess whether the assets should be included in rates:[67]

Union submits the question should be worded to ask under what conditions of deteriorating demand would Union's proposed asset fail to be used or useful, rather than

[64] Settlement Agreement p. 19
[65] Settlement Agreement p. 20
[66] Transcript Volume 1 page 44
[67] Exhibit B.Staff.3c)

> *used and useful. Assets settle to rate base and are included in rates when they are used or useful. An asset does not have to be used to be included in rates.*

Union does not appear to be suggesting that these assets would not be used or useful in 2037 suggesting that their economic lives would continue on.

c. Third, Union relies upon the implementation of CCAP to support its proposed depreciation change. APPrO suggests that there are a number of innovative alternatives to the Proposed Facilities that Union could pursue to meet both the short term demand for gas and potential demand long into the future. APPrO submits that efficient alternatives are far preferable to adding to rate base at a time of declining demand and investing in an expensive asset that increases rates, which in turn further contributes to the decline in demand for pipeline capacity.

H. Cost Allocation

23. Union is proposing to allocate the Panhandle System demand costs related to the proposed project in proportion to the firm Union South in-franchise Panhandle System Design Day demands, updated to include the incremental Project Design Day demands. This allocation methodology is consistent with how the Panhandle system is used. If the project is approved APPrO supports this proposal.

I. Other Comments

24. The Union Gas Conditions of Service require Union to offer service to new customers only if it is economic feasible:

> *1.3 Gas Distribution Services Gas distribution services will be made available to all residential, commercial and industrial customers in all communities served by us:*
>
> - *When we have determined transportation, distribution and/or storage capacity is available.*
> - *When we determine that the installation of gas piping (and related gas equipment) to serve you is economically feasible.*[68]

In light of postage stamp rate making, APPrO contends that the impact on existing customers must be considered in determining economic feasibility. In this case, this project requires existing customer to pay almost 95% of the related 2018 revenue requirement. This project is not economically feasible due the impact on existing customers.

25. This has been a challenging proceeding in trying to understand the operation of the system, including the upstream component of the Panhandle Eastern system, the reasonableness of

[68] Union Gas Conditions of Service June 1, 2016

some of the constraints, the available physical and commercial alternatives considered and how these alternatives were evaluated. We are left with some concerns about the veracity and the timing of the information that was made available. As an example, Union regularly indicated that all the remaining upstream capacity on Panhandle was reserved for Rover, specifically:

> *MR. SHORTS: Mr. Wolnik, I think we answered in a number of spots that there isn't any capacity available. We have gone to the market. We've gone to the open seasons that Panhandle has, and we have attempted to get incremental firm capacity. And we've tried to get incremental firm supply and whatever we had received, we bought. But we were not provided anything in addition to that.*[69]

Union filed Exhibit K2.1, which was filed late the evening of November 22, 2016, included a letter from Energy Transfer (owner of Panhandle Eastern) dated November 17, 2016, that made it clear that Energy Transfer was concerned about some of the information that Union was providing to the Board and specifically indicated:

> *…we have expressly made proposals from 57,000 to 95,000 Dth/d of capacity to Ojibway.* [70]

(Note that 57,000-95,000 Dth/d is equivalent to 59 – 100 TJ/d). Contrary to Union's assertions, capacity has been available on the Panhandle Eastern; a pipeline that is in place today and represents a viable alternative to at least meet the near term demand forecast. Having this information come to light effectively on the last day of the oral hearing does not provide sufficient time to review, understand and prepare additional cross examination questions. The Board needs to ensure that ratepayer interests are reasonably protected.

26. These types of projects naturally require the utility to develop evaluation criteria for projects and any alternatives. It is important that these criteria be open, transparent and applied on a consistent fair and reasonable basis to ensure that bias is not introduced. On one hand the utility is rewarded for investing in new facilities. On the other hand, contracting for commercial services from a third party may just be a cost pass-through with no benefit to the utility. Each project has its own set of long term costs, risks and rewards. The current process to evaluate these types of projects may not fully assess these costs and risks. On the eve of CCAP, CT System and Climate Change Law it is more important than ever to ensure that ratepayer dollars are spent with care to avoid facilities that may become redundant in the future. This may require an updating of the guidelines utilities use for transmission expansion.

[69] Transcript Technical Conference page 69 and Exhibit B.7d)
[70] Exhibit K2.1 Attachment 1 page 4

J. Conditions of Approval

27. While APPrO does not agree that the Proposed Facilities are required, if the Board is inclined to approve this project, 30 days prior to the commencement of construction Union should be obligated to demonstrate to the Board that:

    a. They have been able to obtain long term binding contract commitments for at least 50 TJ/d. This represents approximately 75% of the proposed contract load that has been forecasted in the first two years.

K. Conclusion

28. APPrO requests that the Board does not approve the Proposed Facilities at this time. There is insufficient market commitment by the contract customers to support the new capacity that is being proposed. Moreover, the reduction in design day demand from ongoing DSM programs is more than sufficient to meet the organic growth in the regular rate market.

29. The Proposed Facilities could potentially be deferred even further if the effects of CCAP are taken into account as the burner-tip price of gas increase which will suppress demand for gas. The associated CCAP incentives will further encourage customers to reduce their dependence on carbon based fuels. CCAP will have the effect of reducing design day demands on the natural gas system. This reduction can be used to accommodate the growth of additional new customers, thus further delaying the need of the new facilities.

30. Should the contract market materialize, the projected market demand can be met for at least two years as illustrated in Schedule 1, by utilizing the remaining firm year round capacity on the Panhandle Eastern System thereby foregoing the need to construct the Proposed Facilities at this time. This requires Union to deviate from its desire to only buy gas at 100% load factor and buy gas in the winter months.

31. In addition to utilizing the remaining capacity on the Panhandle Eastern system, Union could deploy other strategies to either rationalize existing capacity including implementing a targeted Demand Reduction incentive program, and programs to work with existing interruptible customers to offer alternative supply sources using upstream interruptible capacity to further defer the need for the Proposed Facilities.

32. Lastly Union could work with current C1 shippers to incent these shippers to commit to delivering their volumes at Ojibway during peak times. This could further defer the need for the Proposed Facilities.

33. By deferring the build of the Proposed Facilities, it provides time to determine first if the contract market does in fact mature to the levels forecasted by Union, and second the degree to which new CCAP incentive programs reduce the design day loads.

34. More efficient use of existing assets will not only eliminate or defer the need to construct the Proposed Facilities but it will also mitigate the significant and unfair rate increase that will be imposed on T2 and other customer classes. Making better use of existing assets is consistent with the Board's objectives:[71]

> *To facilitate rational expansion of transmission and distribution systems.*

35. APPrO opposes the change in depreciation rates for the reasons noted herein.

36. APPrO supports Union's cost allocation changes as it better aligns the cost responsibility.

[71] OEB Act Section 2.3

Schedule 1

EB-2016-0186

Comparison of Capacity Availability from Ojibway and Union's Panhandle System Market Growth Forecast

Line	(TJ/d)	W16/17	W17/18	W18/19	W19/20	W20/21	W21/22	Source
1	PEPL's Presidential Permit Limit	208	208	208	208	208	208	Tr Vol 2 p 62 (195 MMCFD converted to 208 TJ/d)
2	PEPL's Maximum Firm Export Capacity	187	187	187	187	187	187	Tr Vol 2 p 62 (175 MMCFD converted to TJ/d)
3	PEPL's Interruptible Capacity	21	21	21	21	21	21	Line 1-line 2
4	Current Union Contractual Commitments on PEPL							
5	Union-PEPL Contract 19605	26	26	26	26	26	26	Ex J2.8 Attachment 1 line 1 and 7
6	Union-PEPL Contract 43059	11	11	11	11	11	11	Ex J2.8 Attachment 1 line 2 and line 8
7	Union-PEPL Contract 36203	2						Ex J2.8 Attachment 1 line 3
8	Union-PEPL/Trunkline	21						Ex J2.8 Attachment 1 line 4
9	Existing 3rd Party Delivered Service	21	21	21				Ex J2.8 Attachment 1 line 5
10	New Nov 21, 2016 Union-PEPL Contract				23	23	23	Ex J2.8 Attachment 1 line 6
11	Union Firm Commitments	81	58	58	60	60	60	Sum lines 5-10
12	Remaining PEPL Firm Capacity to Ojibway	106	129	129	127	127	127	Line 2 - line 11
13	Union C1 Contracts							
14	Third Party C1 Contract C10106	21	21	21	21	21	21	Ex B.APPrO.3
15	Rover C1 Contract Ojibway to Dawn		35	35	35	35	35	Ex J2.8 Attachment 1 line 9
16	Subtotal 3rd Party C1 Capacity	21	56	56	56	56	56	Sum lines 14-15
18	Net Remaining PEPL Firm Capacity to Ojibway[1]	85	73	73	71	71	71	Line 12-line 16
19	Union's Projected Incremental Design Day Demand Forecast							
20	Conversion of Interruptible to Firm Service	25	46	0	0	0	0	APPrO.2a
21	Growth in General Service Classes	3	2	2	3	2	4	APPrO.2a
22	New Contract	9	10	13	10	8	6	APPrO.2a
23	Total New Growth	37	58	15	13	10	10	Sum lines 20-22
24	Reduction in Conversion from Interruptible to Firm		(2)					Transcript Volume 2 page 60
25	Net New Growth		56	15	13	10	10	
26	Cumulative Net Incremental Growth		56	71	84	94	104	Sum lines 24-25
27	**Surplus/(Shortfall) if Demand Served from Ojibway**		**17**	**2**	**(13)**	**(23)**	**(33)**	Line 18-line 26

Notes

1 This assumes that the C1 shippers have the equivalent amount of capacity on PEPL upstream of Ojibway. In the event that these parties contract for more volume on PEPL than their C1 contracts, the volume representing the difference between the their PEPL and C1 contract could be either acquired under a standard 'capacity release' arrangement or supplies could simply be purchased delivered to Ojibway.

Schedule 2

EB-2016-0186

Comparison of Capacity Availability from Ojibway and Union's Panhandle System Market Growth Forecast

Line	(TJ/d)	W16/17	W17/18	W18/19	W19/20	W20/21	W21/22	Source
1	PEPL's Presidential Permit Limit	208	208	208	208	208	208	Tr Vol 2 p 62 (195 MMCFD converted to 208 TJ/d)
2	PEPL's Maximum Firm Export Capacity	187	187	187	187	187	187	Tr Vol 2 p 62 (175 MMCFD converted to TJ/d)
3	PEPL's Interruptible Capacity	21	21	21	21	21	21	Line 1-line 2
4	Current Union Contractual Commitments on PEPL							
5	Union-PEPL Contract 19605	26	26	26	26	26	26	Ex J2.8 Attachment 1 line 1 and 7
6	Union-PEPL Contract 43059	11	11	11	11	11	11	Ex J2.8 Attachment 1 line 2 and line 8
7	Union-PEPL Contract 36203	2						Ex J2.8 Attachment 1 line 3
8	Union-PEPL/Trunkline	21						Ex J2.8 Attachment 1 line 4
9	Existing 3rd Party Delivered Service	21	21	21				Ex J2.8 Attachment 1 line 5
10	New Nov 21, 2016 Union-PEPL Contract				23	23	23	Ex J2.8 Attachment 1 line 6
11	Union Firm Commitments	81	58	58	60	60	60	Sum lines 5-10
12	Remaining PEPL Firm Capacity to Ojibway	106	129	129	127	127	127	Line 2 - line 11
13	Union C1 Contracts							
14	Third Party C1 Contract C10106	21	21	21	21	21	21	Ex B.APPrO.3
15	Rover C1 Contract Ojibway to Dawn		35	35	35	35	35	Ex J2.8 Attachment 1 line 9
16	Subtotal 3rd Party C1 Capacity	21	56	56	56	56	56	Sum lines 14-15
18	Net Remaining PEPL Firm Capacity to Ojibway[1]	85	73	73	71	71	71	Line 12-line 16
19	Union's Projected Incremental Design Day Demand Forecast							
20	Conversion of Interruptible to Firm Service	25	46	0	0	0	0	APPrO.2a
21	Growth in General Service Classes	3	2	2	3	2	4	APPrO.2a
22	New Contract	9	10	13	10	8	6	APPrO.2a
23	Total New Growth	37	58	15	13	10	10	Sum lines 20-22
24	Reduction in Conversion from Interruptible to Firm		(2)					Transcript Volume 2 page 60
25	Net New Growth		56	15	13	10	10	
26	Cumulative Net Incremental Growth		56	71	84	94	104	Sum lines 24-25
27	Annual Reduction in Demand from DSM Programs		2.5	2.5	2.5	2.5	2.5	
28	Cumulative Reduction from DSM		2.5	5	7.5	10	12.5	
29	Cumulative Net Growth with DSM Effects		53.5	66	76.5	84	91.5	Line 26 - line 32
30	**Surplus/(Shortfall) if Demand Served from Ojibway**		**20**	**7**	**(6)**	**(13)**	**(21)**	Line 18-line 26

Notes

1 This assumes that the C1 shippers have the equivalent amount of capacity on PEPL upstream of Ojibway. In the event that these parties contract for more volume on PEPL than their C1 contracts, the volume representing the difference between the their PEPL and C1 contract could be either acquired under a standard 'capacity release' arrangement or supplies could simply be purchased delivered to Ojibway.

ROVER PIPELINE
An ENERGY TRANSFER Company

November 17, 2016

VIA EMAIL

Chris Shorts
Director, Business Development
and Upstream Regulation
Union Gas Limited
50 Keil Drive North
Chatham, ON N7M 5M1
Canada

Re: Union Gas Limited's Panhandle Reinforcement Project (the "Project")

Dear Chris:

I am sending this letter as a follow-up to our phone conversation yesterday concerning Union's comments at the October 4, 2016 Technical Conference held with respect to the Project. To the point, the transcript of the Technical Conference reveals that Union made comments that mischaracterizes our discussions and negotiations for capacity on Union. As you know, we have been attempting to obtain C1 capacity on Union from Ojibway to Dawn for over 18 months. Indeed, we have submitted formal proposals in pursuit of that capacity. However, Union representatives have made comments on the record suggesting that, for example, Rover is "still wondering" about contracting for Union capacity [Transcript at p. 72]; or that Union has had conversations with "Energy Transfer, the Panhandle folks", but not with, "quote-unquote, Rover" [Transcript at p. 117] -- though Rover is part of Energy Transfer. We also see where Union refused on the record to discuss with us other service options to Dawn on the Ojibway line. [Transcript at p. 118] Further, contrary to Union's contention that it has not been provided any incremental capacity option by us [Transcript at p. 69], we have expressly made proposals from 57,000 to 95,000 Dth/d of capacity to Ojibway (for as short as 10 years) – as evidenced by the documents Union recently produced in the subject proceeding.[1]

We are concerned that Union has not been dealing in good faith with us and that Union is misleading the Ontario Energy Board ("OEB"). Accordingly, let me reiterate that we have been and continue to be seriously desirable of obtaining C1 capacity from Ojibway to Dawn for up to 75,000 Dth/d effective from the Rover in-service date (currently expected to be 11-1-2017) for a period of up to 15 years. Further, if a delivery commitment is required for the supply on the 75,000 Dth/d, Rover would be happy to pursue such, including by providing the avenue for

up to
15 yrs

[1] These examples are not comprehensive of the inaccuracies we are finding in the Technical Conference Transcript.

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capture for

Union to work with the Rover shippers to accommodate that. We stand ready, as we have for the last 18 months, to discuss this with you.

In addition, we request that Union make a filing with the OEB correcting its mischaracterizations of our efforts to obtain the subject capacity, and provide Rover with a copy of that filing. We realize that a hearing is scheduled for November 22-24, 2016; therefore, your immediate attention in this regard is required. In the event Union fails or refuses to formally correct the record by Monday, November 21, 2016, please be advised that we may pursue other avenues to inform the OEB of the mischaracterizations, including directly providing a copy of this letter.

Sincerely,

John Reid
Sr. Director – Business Development
Rover Pipeline LLC

cc: Jim Redford