K1.2

EB-2015-0029
EB-2015-0049

Green Energy Coalition

Cross-examination Compendium

For Union Panel 1

GTA Segment B1	$200	−10%					
Corrected							
without B1	$348	8,376	$41,508	7.7%	$3,196	$415	$3,611
with B1	$548	9,423	$58,121	7.7%	$4,475	$581	$5,057

The corrected nominally-levelized values are about 3.4 to 4.7 times the Enbridge estimate. In real-levelized terms, the total costs would be about \$2,900–\$4,100/yr/10^3m^3 of peak-day throughput, or 2.7–3.8 times Enbridge's nominally-levelized estimate in 2015, and would rise with inflation.

Q: Did Navigant develop higher estimates of avoided distribution costs than those presented in Enbridge's filing?

A: Yes. In its second workshop for Enbridge, Navigant reported an avoided distribution cost of \$1,165/10^3m^3 savings on the peak day (Exhibit JT1.23, Attachment 2, at 11).[35] In its third workshop presentation, Navigant reported an avoided distribution cost of \$1,523/10^3m^3 savings on the peak day (Exhibit JT1.23, Attachment 3, at 6). These values are about 10% and 40% higher than the \$1,065/10^3m^3 reported by Navigant in Exhibit C, Tab 1, Schedule 4 and apparently used by Enbridge in screening DSM programs.

2. Union

Q: How did Union estimate its avoided distribution costs?

A: Union did not develop T&D avoided costs based on its own system, but borrowed the work from Navigant based on Enbridge's system and adapted them for its use. Specifically, Union took the Enbridge estimates of avoided distribution costs by load shape, weighted those values by the share of Union's estimated DSM savings in 2015 for each of the load shapes, and

[35]Navigant does not appear to have used design-day loads in its analyses.

derived a distribution adder of 2% (Union Exhibit A, Tab 1, Appendix D, at 3, footnote 1), which it applied to all DSM.

Q: Is this computation appropriate?

A: No. The avoided distribution costs vary among the load shapes because a given annual load reduction of heating DSM saves much more gas on the design peak than the same reduction in base load. Union estimates that Enbridge's estimate of avoided distribution costs average 4.3% of Enbridge's estimates of avoided supply costs for space heating and 1.3% for water heating and baseload, over 30 years.

At the very least, Union should have used Enbridge's percentages or dollars per cubic metre for each load shape. The 2% value was computed by weighting industrial savings 85.5%, water-heating 3.2%, and space-heating only 11.3%. Assuming that savings for some period of time will include much lower industrial savings, the average avoided distribution adder would be closer to the space-heating 4.3% than to Union's 2%.

Correcting the errors and understatements in Enbridge's avoided-distribution estimates would produce an even larger average adder, on the order of 12% to 20%. In any case, Union should be using separate $\$/m^3$ values for each load shape, rather than an average value or percentage adders.

Q: Has Union provided any estimates of avoided distribution costs?

A: Yes. In Exhibit JT2.5, Attachment 1, at 75, Union provides an estimate developed in 1998. It is $\$30.64/m^3$ of design-hour load, or about $\$1.53/m^3$ of design-day load. Including inflation to 2015, this value would be $\$2,153/10^3m^3$ of design-day load, about twice the value that Enbridge used in this proceeding. The results of the older Union study would bring the avoided distribution cost to about \$0.024/m^3 of space-heat load saved, or about 11% of Union's estimate of avoided supply costs.

E. Utility Refusal to Allow Review of Avoided Cost

Q: Have the Companies provided adequate documentation of the avoided cost analysis?

A: No. Neither of the Companies provided the documentation (including inputs, calculations and workpapers) necessary to allow full independent review of their avoided costs.

Q: Why is access to this documentation essential to review?

A: When data, calculations, model inputs and outputs, and electronic spreadsheets are provided, intervenors are able to check the utility's calculations for errors or omissions, weigh in on the judgments on which experts may reasonably disagree, confirm their understanding of methodologies, and gauge the effect of alternative inputs and assumptions on the results. Without this information, avoided cost numbers cannot be evaluated or independently verified. As can be seen from the discussion above of the distribution component of avoidable costs and the numerous errors I was able to identify with only limited access to information, such errors or controversial methodological choices are not unusual and not insignificant.

1. Enbridge

Q: What is the basis for the Enbridge's refusal to provide adequate documentation of its avoided costs?

A: Enbridge provides a number of reasons, but its underlying position is that the DSM planning process in Ontario permits it to select the avoided costs

Enbridge (EGD) avoided cost data	EGD Water Heating			EGD Space Heating			EGD Industrial Processing		
	EGD 2013 avoided costs w/o T&D costs (EB-2014-0277)	EGD Avoided T&D costs (EB-2015-0049)	%	EGD 2013 avoided costs w/o T&D costs (EB-2014-0277)	EGD Avoided T&D costs (EB-2015-0049)	%	EGD 2013 avoided costs w/o T&D costs (EB-2014-0277)	EGD Avoided T&D costs (EB-2015-0049)	%
2015	0.16810	0.00328	2.0%	0.17452	0.01206	6.9%	0.16786	0.00345	2.1%
2016	0.14875	0.00328	2.2%	0.15623	0.01206	7.7%	0.14922	0.00345	2.3%
2017	0.16355	0.00328	2.0%	0.17324	0.01206	7.0%	0.16431	0.00345	2.1%
2018	0.17566	0.00328	1.9%	0.18442	0.01206	6.5%	0.17674	0.00345	2.0%
2019	0.19522	0.00328	1.7%	0.20490	0.01206	5.9%	0.19657	0.00345	1.8%
2020	0.21475	0.00328	1.5%	0.22592	0.01206	5.3%	0.21604	0.00345	1.6%
2021	0.24218	0.00328	1.4%	0.27799	0.01206	4.3%	0.24430	0.00345	1.4%
2022	0.24683	0.00328	1.3%	0.26316	0.01206	4.6%	0.24859	0.00345	1.4%
2023	0.25285	0.00328	1.3%	0.26957	0.01206	4.5%	0.25465	0.00345	1.4%
2024	0.25475	0.00328	1.3%	0.27160	0.01206	4.4%	0.25657	0.00345	1.3%
2025	0.25984	0.00328	1.3%	0.27703	0.01206	4.4%	0.26170	0.00345	1.3%
2026	0.26504	0.00328	1.2%	0.28257	0.01206	4.3%	0.26693	0.00345	1.3%
2027	0.27034	0.00328	1.2%	0.28822	0.01206	4.2%	0.27227	0.00345	1.3%
2028	0.27575	0.00328	1.2%	0.29399	0.01206	4.1%	0.27772	0.00345	1.2%
2029	0.28126	0.00328	1.2%	0.29987	0.01206	4.0%	0.28327	0.00345	1.2%
2030	0.28689	0.00328	1.1%	0.30586	0.01206	3.9%	0.28894	0.00345	1.2%
2031	0.29263	0.00328	1.1%	0.31198	0.01206	3.9%	0.29471	0.00345	1.2%
2032	0.29848	0.00328	1.1%	0.31822	0.01206	3.8%	0.30061	0.00345	1.1%
2033	0.30445	0.00328	1.1%	0.32459	0.01206	3.7%	0.30662	0.00345	1.1%
2034	0.31054	0.00328	1.1%	0.33108	0.01206	3.6%	0.31275	0.00345	1.1%
2035	0.31675	0.00328	1.0%	0.33770	0.01206	3.6%	0.31901	0.00345	1.1%
2036	0.32308	0.00328	1.0%	0.34445	0.01206	3.5%	0.32539	0.00345	1.1%
2037	0.32954	0.00328	1.0%	0.35134	0.01206	3.4%	0.33190	0.00345	1.0%
2038	0.33613	0.00328	1.0%	0.35837	0.01206	3.4%	0.33853	0.00345	1.0%
2039	0.34286	0.00328	1.0%	0.36554	0.01206	3.3%	0.34530	0.00345	1.0%
2040	0.34971	0.00328	0.9%	0.37285	0.01206	3.2%	0.35221	0.00345	1.0%
2041	0.35671	0.00328	0.9%	0.38030	0.01206	3.2%	0.35925	0.00345	1.0%
2042	0.36384	0.00328	0.9%	0.38791	0.01206	3.1%	0.36644	0.00345	0.9%
2043	0.37112	0.00328	0.9%	0.39567	0.01206	3.0%	0.37377	0.00345	0.9%
2044	0.37854	0.00328	0.9%	0.40358	0.01206	3.0%	0.38124	0.00345	0.9%
Average			1.3%			4.3%			1.3%

Union Gas (UGL) data			UGL Res/Com baseload net gas TRC benefits			UGL Res/Com weather-sensitive net TRC gas benefits			UGL Industrial Net TRC gas benefits	UGL Total net gas TRC benefits
UGL 2013 post-audit net gas TRC benefits			$12,300,238			$44,030,563			$331,826,041	$388,156,841

Estimated UGL T&D avoided costs	2%

2015 Avoided Costs

Union B.T8.GEC.44 Excel Attachment 1

Inflation Factor	1.68%
Discount Rate	4.00%

Gas Avoided Costs												
	Residential				**Commercial**				**Industrial**			
	Baseload (m3)		Weather Sensitive		Baseload (m3)		Weather Sensitive		Baseload (m3)		Weather Sensitive	
	Rate	NPV	Rate	NPV	Rate	NPV	Rate	NPV	Rate	NPV	Rate	NPV
1	0.21378	0.21378	0.22071	0.22071	0.21378	0.21378	0.22071	0.22071	0.20537	0.20537	0.20537	0.20537
2	0.19684	0.40304	0.20449	0.41734	0.19684	0.40304	0.20449	0.41734	0.20114	0.39878	0.20114	0.39878
3	0.19620	0.58444	0.20266	0.60471	0.19620	0.58444	0.20266	0.60471	0.19798	0.58182	0.19798	0.58182
4	0.20730	0.76873	0.21387	0.79484	0.20730	0.76873	0.21387	0.79484	0.20911	0.76772	0.20911	0.76772
5	0.23174	0.96682	0.23841	0.99864	0.23174	0.96682	0.23841	0.99864	0.23358	0.96739	0.23358	0.96739
6	0.25035	1.17259	0.25714	1.20999	0.25035	1.17259	0.25714	1.20999	0.25222	1.17470	0.25222	1.17470
7	0.24863	1.36908	0.25553	1.41194	0.24863	1.36908	0.25553	1.41194	0.25053	1.37270	0.25053	1.37270
8	0.25157	1.56025	0.25859	1.60844	0.25157	1.56025	0.25859	1.60844	0.25350	1.56534	0.25350	1.56534
9	0.26925	1.75699	0.27639	1.81040	0.26925	1.75699	0.27639	1.81040	0.27122	1.76351	0.27122	1.76351
10	0.25862	1.93870	0.26588	1.99720	0.25862	1.93870	0.26588	1.99720	0.26063	1.94663	0.26063	1.94663
11	0.27435	2.12404	0.28173	2.18753	0.27435	2.12404	0.28173	2.18753	0.27639	2.13334	0.27639	2.13334
12	0.27612	2.30340	0.28363	2.37177	0.27612	2.30340	0.28363	2.37177	0.27819	2.31405	0.27819	2.31405
13	0.29855	2.48987	0.30618	2.56300	0.29855	2.48987	0.30618	2.56300	0.30065	2.50184	0.30065	2.50184
14	0.30166	2.67104	0.30941	2.74883	0.30166	2.67104	0.30941	2.74883	0.30380	2.68429	0.30380	2.68429
15	0.32465	2.85851	0.33253	2.94086	0.32465	2.85851	0.33253	2.94086	0.32682	2.87302	0.32682	2.87302
16	0.32743	3.04032	0.33545	3.12712	0.32743	3.04032	0.33545	3.12712	0.32964	3.05606	0.32964	3.05606
17	0.33257	3.21788	0.34072	3.30904	0.33257	3.21788	0.34072	3.30904	0.33482	3.23482	0.33482	3.23482
18	0.33925	3.39205	0.34755	3.48746	0.33925	3.39205	0.34755	3.48746	0.34154	3.41016	0.34154	3.41016
19	0.35307	3.56633	0.36150	3.66591	0.35307	3.56633	0.36150	3.66591	0.35540	3.58559	0.35540	3.58559
20	0.36264	3.73846	0.37122	3.84210	0.36264	3.73846	0.37122	3.84210	0.36501	3.75884	0.36501	3.75884
21	0.37758	3.91078	0.38630	4.01840	0.37758	3.91078	0.38630	4.01840	0.37998	3.93226	0.37998	3.93226
22	0.38851	4.08127	0.39738	4.19278	0.38851	4.08127	0.39738	4.19278	0.39096	4.10383	0.39096	4.10383
23	0.39977	4.24996	0.40878	4.36527	0.39977	4.24996	0.40878	4.36527	0.40225	4.27356	0.40225	4.27356
24	0.41135	4.41685	0.42052	4.53588	0.41135	4.41685	0.42052	4.53588	0.41388	4.44148	0.41388	4.44148
25	0.42328	4.58198	0.43260	4.70465	0.42328	4.58198	0.43260	4.70465	0.42585	4.60762	0.42585	4.60762
26	0.43556	4.74537	0.44503	4.87159	0.43556	4.74537	0.44503	4.87159	0.43817	4.77198	0.43817	4.77198
27	0.44820	4.90703	0.45783	5.03673	0.44820	4.90703	0.45783	5.03673	0.45086	4.93460	0.45086	4.93460
28	0.46121	5.06699	0.47101	5.20008	0.46121	5.06699	0.47101	5.20008	0.46392	5.09550	0.46392	5.09550
29	0.47461	5.22526	0.48457	5.36167	0.47461	5.22526	0.48457	5.36167	0.47736	5.25468	0.47736	5.25468
30	0.48840	5.38187	0.49853	5.52153	0.48840	5.38187	0.49853	5.52153	0.49120	5.41219	0.49120	5.41219

Annual savings   Value / m3

75,000,000   * $ 3.00   = $225 million

2% is $4.5 million

12% is $27 million

20% is $45 million

8.0 Avoided Costs

Avoided costs represent the benefits in TRC calculations (i.e. the benefits of not having to provide an extra unit of supply of natural gas, electricity, water, heating fuel oil and/or propane) and are thus integral to Program screening.

Since 2007, Union and Enbridge have used the same methodology in calculating avoided gas costs. In late 2014, Union contracted ICF International to review Union's use of this methodology. The ICF International report, "Evaluation of Union Gas Avoided Costs", can be found at Exhibit A, Tab 2, Appendix C. The purpose of this review was to ensure that the methodology remains an accurate reflection of Union's franchise area and gas supply management policies and practices.

The review concluded that Union's use of this methodology is reasonable and appropriate. ICF's report provides four refinements to the methodology:

1. Account for avoided fuel losses across Union's system
2. Account for avoided storage costs
3. Incorporate a long term gas commodity price forecast when forecasting avoided cost estimates beyond the initial modeling period
4. Account for avoided, deferred or delayed infrastructure (T&D) costs

We developed separate supply option weights for residential/commercial demand and for industrial demand. For residential/commercial demand, the bulk of the reduction in design day supply in response to a reduction in peak gas demand would come from the storage option, since Union relies heavily on low cost storage as its primary means of supplying winter gas requirements. The load factor for industrial demand is much flatter than for residential/ commercial demand, and a majority of the reduction in design day demand comes from the pipeline option.

As noted earlier, for the "baseload" load segment the situation is much simpler, since firm gas supplies delivered by TCPL, purchased at 100% load factor, is assumed to be the gas supply option used to satisfy avoided baseload gas demands. Hence, there is no need to derive the mix of different types of supply options avoided for the baseload load segment.

4.6 Transmission Capacity Costs and Impact of DSM on Capacity Requirements

As noted earlier, our estimates of avoided transmission costs are based on the assumption that any change in expected in-franchise load due to potential DSM programs could impact transmission capacity requirements. Since transmission capacity planning is based on design day demand requirements, DSM programs which might alter design day demand volumes can potentially affect transmission capacity needs. Using numbers from the capital budgets and from a long term expansion scenario for the Trafalgar system, we calculated the time-valued, average cost per volume unit of capacity additions projected over a 30 year time horizon, extrapolating beyond the last year (2001) covered in the capital budget. In effect, we are using as our estimate of avoided cost per unit the "average" cost of an entire future transmission capacity expansion program.

This analysis included costs for all planned Union transmission lines (not just Dawn-Trafalgar). Avoided transmission costs were calculated for three categories of Union transmission:

- **Trafalgar Transmission**: Capacity expansion on the Trafalgar system to meet incremental demand growth served by the Trafalgar system.
- **Trafalgar Branch Transmission**: Other transmission originating from the Trafalgar system, such as the Owen Sound transmission line, and

- **Non-Trafalgar Transmission:** Other transmission capacity not originating from the Trafalgar system, such as the Panhandle and Sarnia lines.

The distinction is important since demand growth in areas served by the Trafalgar system also requires branch transmission, hence Trafalgar costs and branch transmission costs must be added to arrive at a total Trafalgar system avoided cost. In contrast, for demand not served by Trafalgar, costs are based on other "non-Trafalgar Transmission" projects. The Trafalgar system avoided cost is averaged with the avoided cost of the non-Trafalgar system based on volume to determine the weighted average avoided cost for Union's overall transmission system.

In estimating avoided transmission costs, we also had to account for how Trafalgar transmission requirements and costs might change if only in-franchise demand were to decrease or increase by 1 m^3/design day in response to future DSM programs. This adjustment is necessary since the projection of future increases in Trafalgar delivery capacity and associated costs is based on the sum of both in-franchise and M12 demand growth. An adjustment is necessary since the costs per m3 of design day delivery capacity are different to serve in-franchise growth in comparison to M12 growth.[13] Consequently, Union staff calculated two adjustment factors which were applied to adjust projected Trafalgar costs (based on serving both in-franchise and M12 customers) to reflect how Trafalgar costs would change when only in-franchise demand was altered. Two adjustment factors needed to be calculated, one to reflect service for Weather Sensitive loads and another to reflect Baseload service (constant year round demand), since transmission services are provided differently for these two load segments.

13 This is simply because gas service to Parkway requires, on average, gas to be moved over longer distances on the Trafalgar system than gas delivered to in-franchise customers. Hence, costs per unit of "delivered gas" at Parkway are higher.

TABLE A-8
UNION AVOIDED FACILITY COSTS
FOR NEW DSM ACTIVITIES IN 1997

Type of Facility	Average Levelized Cost/Unit (97$)	Average Annualized Cost/Unit (97$)
Transmission ($/m^3/design day)		
Weather Sensitive Load	$4.34	$0.44
Baseload	$0.58	$0.06
Distribution ($/m^3/design hour)	$ 30.64	3.13
Storage Deliverability ($/m^3/design day)		
1998 -2007	na	1.02
2008 - END	$ 14.71	1.51
Storage Space ($/10^{3}m^3)		
1998 - 2007	na	9.77
2008 - END	$ 72.00	7.37

TABLE B-4

CENTRA AVOIDED FACILITY COSTS FOR NEW DSM ACTIVITIES IN 1998

Type of Facility	Average Levelized Cost/Unit (97$)	Average Annualized Cost/Unit (97$)
Transmission ($/m³/design day)	$ 20.69	$2.12
Distribution ($/m³/design hour)	$ 107.68	$11.02

Notes On Table B-4

1. Table represents the avoided volume related facility costs applicable to DSM activities initiated in the 1998 DSM program year.

2. Average levelized avoided facility costs reflect the average investment cost per unit for new facilities accounted for in the year of the facility investment.

3. Annualized facility costs represent the average real investment cost per year of a facility investment where the costs are spread over the life of the investment. The levelized costs have been annualized using an annualization factor of 10.23 percent per year, reflecting the 10 percent TRC discount rate, and a facility life of 30 years.

Economics Inc., 2013). Avoided local distribution system infrastructure costs are achieved when reduced natural gas demand enables delays in the timing of new projects, or reductions in the size of these projects. The avoided transmission and distribution costs vary by utility service territory, but are typically driven by the level of gas demand in the winter heating season (National Action Plan for Energy Efficiency, 2008).

2.2.4 Market Price Suppression Effects (DRIPE)

Market price suppression effects represent a potential decrease in natural gas prices resulting from efficiency programs reducing the total demand for natural gas. Also known as the Demand-Reduction-Induced Price Effect (DRIPE), this is a measure of the value of efficiency measures in terms of the reductions in the wholesale market prices of gas seen by all customers (Synapse Energy Economics Inc., 2013). A reduction in the quantity of gas used in one region will reduce the overall demand for gas and therefore reduce the market price for gas supply in all regions supplied by the same natural gas producers. DRIPE will have little impact on the market price of energy, but very small impacts on market prices can result in large absolute dollar amounts when applied to all energy being purchased in the market.

DRIPE can be more significant in isolated markets, as it depends on the supply and demand situation of a specific region, and supply-constrained regions are more vulnerable to spikes in natural gas prices. For example in a region like New England, where natural gas shortages drive up prices during the winter, DRIPE impacts would be important to quantify.

2.2.5 Non-Energy Benefits

Conservation measures often have additional benefits beyond energy savings, potentially including improved comfort, health, convenience, aesthetics (National Action Plan for Energy Efficiency, 2008) and carbon emission reductions. The appropriateness of inclusion of non-energy benefits in the avoided costs typically would be based on policy decisions at the provincial level.

2.2.6 Differentiated Customer Costs

While not a type of avoided cost on its own, it is important to note how the other cost categories are typically broken down to account for different customer types. Costs are typically established separately for residential, commercial, and industrial customers, since these sectors can have different load profiles. Avoided costs can also be calculated separately for different types of natural gas end-uses, as the load profiles for different types of equipment can also vary significantly. End-uses will typically be grouped according to whether their gas demand is relatively constant through-out the year (eg. non-heating loads) or if demand changes through-out the year (eg. heating loads).

2.2.7 Seasonal Price Adjustments

As mentioned in several of the preceding sections, seasonal variations in natural gas use have a large impact on delivered gas costs. In northern regions where gas is used as a heating fuel, gas distributors need to have supply plans in place to meet the significant demand increases of this winter peak demand. This uneven demand results in uneven capacity and distribution costs, based on each individual gas distributor's supply arrangements. The variation in gas demand throughout a year can be represented by a load curve.

Ministry of Energy

Office of the Minister

4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
Fax: 416-327-6754

Ministère de l'Énergie

Bureau du ministre

4e étage, édifice Hearst
900, rue Bay
Toronto ON M7A 2E1
Tél. : 416 327-6758
Téléc. : 416 327-6754

Ontario

FEB - 4 2015

Ms Rosemarie T. Leclair
Chair & Chief Executive Officer
Ontario Energy Board
PO Box 2319
2300 Yonge Street
Toronto ON M4P 1E4

Dear Ms Leclair:

Re: Natural Gas Demand Side Management (DSM) Framework

I am pleased that the Ontario Energy Board (OEB) has released its final DSM Framework (2015-2020) in support of the government's Conservation First policy. Conservation is the cleanest and most cost-effective energy resource and it offers consumers a way to reduce their energy bills while contributing to a sustainable future.

I am particularly pleased that natural gas distributors will be expected to ensure that DSM is considered in infrastructure planning at the regional and local levels, consistent with the government's March 26, 2014 Directive to the OEB, and that a 15 per cent non-energy benefit adder will be applied to the benefit side of the Total Resource Cost Test in recognition of the environmental, economic and social benefits of DSM.

I note that as part of the expectation that natural gas distributors consider DSM in infrastructure planning, each distributor will be studying the potential role of DSM in reducing or deferring infrastructure investments in future system planning efforts. I expect that the natural gas distributors will work with stakeholders, including environmental organizations, to help inform the approach for these studies. I understand that they plan to initiate this work in the near future and complete the studies as soon as possible and no later than in time to inform the mid-term review of the DSM Framework.

The March 26, 2014 directive also requires an achievable potential study for natural gas efficiency in Ontario be conducted every three years with the first study completed by June 1, 2016. Building on the principle of the non-energy benefit adder, I request that the Board consider, in that study, how such potential DSM benefits as carbon reduction and natural gas price suppression may be used to screen prospective DSM programs and inform future budgets.

.../cont'd

I look forward to the OEB's continued support in implementing the government's Conservation First policy.

Sincerely,

Bob Chiarelli
Minister

Table 3: Efficiency Benefits that Put Downward Pressure on Rates

Benefit	NPV of Lifetime Benefits per Annual m^3 Saved[36]		Average Annual Value from Utilities'2016-2020 DSM Plans (millions $)[37]		Benefits as a % of Average Annual (2016-2020) DSM Plan Budget[38]	
	Enbridge	Union	Enbridge	Union	Enbridge	Union
1 Avoided carbon regulation costs[39]	$0.98	$0.98	$73.2	$73.9	101%	129%
2 Price suppression effects[40]	$0.08	$0.08	$6.2	$6.3	9%	11%
3 Reduce purchase of most expensive gas[41]	$0.10	$0.18	$7.2	$13.3	10%	23%
4 Avoided distribution system costs[42]	$0.38	$0.24	$28.1	$18.2	39%	32%
Total	**$1.54**	**$1.49**	**$114.7**	**$111.7**	**158%**	**195%**

[36] Assumes an average measure life of 16 years. All values in 2015 Canadian dollars (CDN).
[37] This is NPV of benefits per annual m3 saved multiplied by the average incremental annual m^3 savings forecast for the 2016-2020 period by Enbridge (74.4 million m^3) and Union (75.1 million m^3).
[38] Enbridge's average annual budget is $72.3 million; Union's is $57.4 million (both in 2015 dollars).
[39] Valued at Mr. Chernick's estimate of avoided costs of carbon emission regulations. As noted above, Mr. Chernick suggests such values would start at approximately $20 (2014 USD) per ton of CO_2 or $1.18 USD per MBtu of natural gas in the first year of a regulatory scheme. The values per m^3 of reduction are the same for both Enbridge and Union as the market clearing price unit of emissions is likely to be a provincial price.
[40] Mr. Chernick estimates that a 1 billion m^3 reduction in annual gas demand would produce a $0.00027 reduction in price per m^3. Over the 2016-2020 period, I assume that average annual gas sales in Ontario will be approximately 27 billion m^3. Thus, the price reduction benefit to Ontario gas users from a 1 billion m^3 reduction in gas demand would be worth approximately $7.2 million. That equates to a benefit of approximately $0.0072 for one year's worth of a single m^3 of demand reduction. That, in turn translates to a benefit of approximately $0.083 for 16 years (the average measure life) of one m^3 of demand reduction. The magnitude of this benefit is assumed to be the same (per m^3 of savings) for both utilities.
[41] For Enbridge, Mr. Chernick estimates that this benefit is equal to approximately $0.013 per m^3 of space heating gas saved per year and $0.011 per m^3 of combined space heating and water heating energy saved per year; there are essentially no such savings from baseload measures (industrial and water heating). For Union, I used the average of the differences Mr. Chernick reports for 2015 and 2016 (Chernick p. 28): $0.015 for baseload and $0.017 for space heating measures. Data on the mix of end use gas saved in the utilities' proposed plans were not included in their filing. Thus, I have assumed that the mix (in percentage terms) will be the same as in 2014 for Enbridge and the same as in 2014 for Union excluding the T2/Rate 100 savings. To the extent that the utilities will get more of their savings in future years from space heating these estimated benefits will be conservatively low."
[42] Enbridge used estimates of avoided distribution system costs developed for the Company by Navigant Consulting (Exh. C/T1/S4). The magnitude of those avoided costs varied by a factor of 4, depending on whether the savings were from space heating or from baseload measure end uses like water heating or industrial process efficiency improvements (See Navigant Table 7). Mr. Chernick has found that Enbridge's avoided distribution costs are actually three to five times higher than Navigant estimated for the Company. I have used the mid-point (factor of four) of that range. In this case, I estimated the lifetime NPV of an annual savings of an m^3 using a nominal discount rate (i.e. the 4% real discount rate adjusted for an assumed annual inflation rate of 1.68%) because Navigant estimates were expressed in constant nominal dollars. A weighted average value for the entire Enbridge portfolio was estimated based on the Company's 2014 distribution of savings by end use. Absent better information, the values for Union were assumed to be the same as for Enbridge per end use. However, because Union's savings are assumed to be more baseload heavy and less space heating focused, the weighted average value per m^3 is estimated to be lower for Union.

NGI NATURAL GAS INTELLIGENCE

TransCanada, Customers Squabble Over Costs of Mainline Conversion

Gordon Jaremko
July 31, 2015

TransCanada Corp. is digging in for a fight with its natural gas customers, calling their protest against costs that they blame on its Energy East plan to switch part of its Mainline into oil service a "patent and extreme" attack on its ability to manage the system.

The pipeline said the gas shippers created their own problem -- up to C$600 million (US$480 million) in costs of maintaining service after the conversion -- by failing to book enough delivery capacity to satisfy their needs during the planning stage of the project.

The pipeline company insists the gas grievance belongs in the law courts because the arena chosen by the protesters, the National Energy Board (NEB), has no authority to intervene against commercial contracts that impose the extra costs.

In a lengthy reply to the complaint lodged with the NEB by Enbridge Gas Distribution Inc. and Union Gas Ltd. (Spectra), TransCanada on Wednesday urged the board just to dismiss the affair as beyond its limited jurisdiction over pipeline tariffs and tolls.

The Ontario and Quebec energy ministries support the complaint (see *Daily GPI*, July 24). Enbridge and Union are Canada's largest gas distributors, with a combined total of 3.4 million customers in the Toronto region and southern and eastern Ontario. Their networks and the Mainline tie Quebec into the continental market spanning Canada and the United States.

Along with the Ontario and Quebec governments, Enbridge and Union enlisted support by Gaz Metro in Quebec, Centra Gas in Manitoba, Utilities Kingston in eastern Ontario, Northland Power in Toronto, the Canadian Industrial Gas Users Association, fabric and building materials manufacturers Morbern Inc. and Iko Industries Ltd., Ontario Power Generation, TransAlta Corp., and three customers of TransCanada gas export services in the U.S.: New York State Electric and Gas Co., St. Lawrence Gas Co. and Alberta Northeast Gas, a supply procurement agency of distribution companies in New England, New York and New Jersey.

Energy East ranks high on the economic agenda of the national Conservative government in Ottawa as a path to widening Canada's oil exports beyond the United States, as well as on official wish lists in the western oil-producing provinces and the Atlantic region.

Enbridge and Union said, "Gas shippers should not be required to backstop the enormous development costs of these facilities." They cite repeated promises by TransCanada to replace all gas delivery capacity lost due to the partial Mainline switch to carry 1.1 million b/d of oil.

Forecast costs add up to C$13.5 billion (US$12 billion): C$12 billion (US$10.7 billion) for the pipeline conversion and an extension to an East Coast tanker port, plus C$1.5 billion (US$1.2 billion) to build a new gas Eastern Mainline for Ontario and Quebec.

TransCanada said the gas portion of the scheme was based on the market for pipeline capacity as shown by firm service bookings.

During planning stages of Energy East, the pipeline said gas shippers' responses to contract offers during capacity open seasons showed their losses from the oil conversion would only be about 215 MMcf/d.

Demand has since risen to nearly 550 MMcf/d. The contested costs are for developing "incremental" expansion facilities not covered by the Energy East guarantee to replace lost gas capacity, TransCanada said. Much of the new traffic would be imports of U.S. shale production into Ontario and Quebec.

In rejecting the gas customers' grievance, TransCanada insists it is not in a business of maintaining excess delivery capacity in case they might want it at some future time.

"The Mainline is a contract carrier," TransCanada said. "It is not obliged to transport volumes for which no contracts have been signed, nor is it obliged to retain capacity that is uncontracted.

"It is also to be remembered that shippers on the Mainline, including Enbridge and Union, have not through payment of Mainline tolls acquired any right to Mainline capacity for which they choose not to contract. TransCanada is free to seek to repurpose facilities that provided uncontracted capacity."

After collecting another round of replies to each other by the participants in August, the NEB said it will determine whether to hold hearings and make a decision on the dispute. Effects on the Energy East and Eastern Mainline plans remain unknown. The board has not yet accepted the project applications as complete, a step that will trigger a legislated 15-month deadline for approval decisions.

Scope: Sectors and Emissions

What sectors should be covered by the cap and trade program?

What types of emissions should be covered?

Sectors Covered

- An economy-wide approach ensures the maximum environmental benefit and supports market stability
- Quebec and California started with electricity and industry and expanded to cover heating and transportation fuels in 2015
- An Ontario program is proposed to cover:
  - Large emitters (>25,000 t): industry, institutions, waste management, utilities
  - Electricity generators and importers
  - Liquid petroleum fuel distributors and importers
  - Natural gas distributors

Combustion Emissions

- Emissions from burning fuel for heating or industrial furnaces

Process emissions

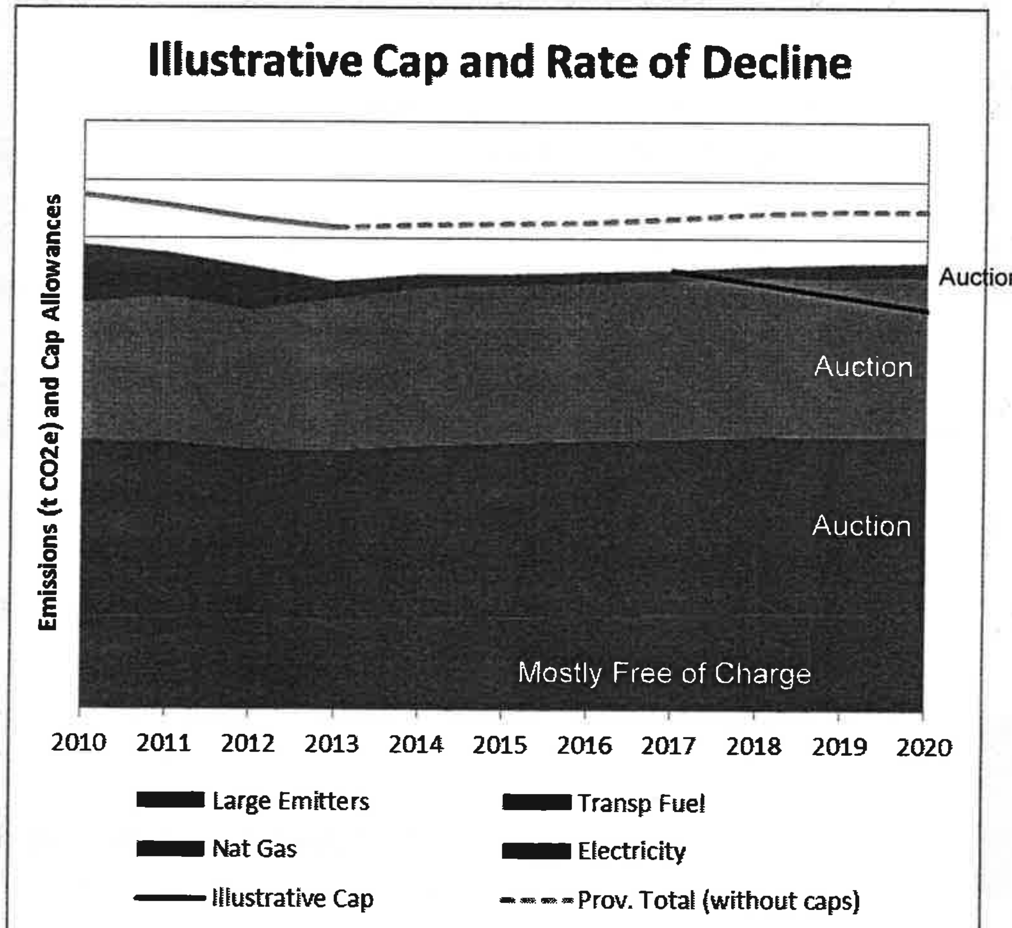
- Emissions from chemical or physical reactions as part of production
- California and Quebec cover both combustion and process emissions.
- Alberta covers only combustion emissions.

- An Ontario program is proposed to cover both types of emissions to create and maintain an incentive to reduce emissions from all sources

Cap Stringency and Rate of Decline

What should be the rate of decline towards 2020?

- An economy-wide cap decline between 2-3% per year could put Ontario on track to meet its 2020 emissions target (exact figures to be confirmed)
- Caps in Quebec and California programs decline at more than 3% per year
- Other climate critical elements included in Ontario's Climate Change Strategy will also support achievement of provincial targets



Ontario

Proposed Key Timelines

Spring/Summer 2015:

- Consultations on program design, focussing on allowance allocations methods and common understanding of any competitiveness implications

Fall 2015:

- Regulatory proposal posted on the Environmental Registry for comments

Summer 2016:

- Final regulation posted on the Environmental Registry

Qualified Bid Summary Statistics

All Qualified Bid Summary Statistics are determined in USD including all bids submitted in USD and CAD. The CAD equivalent of the USD Qualified Bid Summary Statistics is based on the Auction Exchange Rate. USD statistics are converted into CAD in whole cents to be able to compare statistics on a common basis.

Qualified Bid Price Summary Statistics	Current Vintage		2018 Vintage	
	USD	CAD	USD	CAD
Auction Reserve Price	$12.10	$14.78	$12.10	$14.78
Settlement Price	$12.29	$15.01	$12.10	$14.78
Maximum Price	$45.21	$55.21	$18.59	$22.70
Minimum Price	$12.10	$14.78	$12.10	$14.78
Mean Price	$13.93	$17.01	$12.46	$15.22
Median Price	$12.50	$15.27	$14.52	$17.73
Median Allowance Price	$12.63	$15.42	$12.18	$14.87

Auction Exchange Rate (USD to CAD)	1.2212

Ontario

NEWS

Ministry of the Environment and Climate Change

Ontario Names Board Members to Western Climate Initiative

Province Moving Forward On Cap and Trade System

August 5, 2015 1:00 P.M.

Ontario is moving closer to becoming part of North America's largest carbon market by naming two members to the board of the Western Climate Initiative, Inc., a non-profit, corporation that helps provinces and states deliver cap and trade programs.

Two assistant deputy ministers from the Ministry of the Environment and Climate Change--Rob Fleming and Jim Whitestone--are the new members.

Naming these directors signals Ontario's intent to use the Western Climate Initiative's services and trading infrastructure, including its platform for auctioning emissions allowances and a system for tracking emissions allowances, for Ontario's cap and trade program.

A strong, effective cap and trade program will help ensure Ontario curbs greenhouse gas pollution while rewarding innovative companies, providing certainty for industries and creating more opportunities for investment in Ontario.

Fighting climate change while keeping industries competitive is part of the government's plan to build Ontario up. The four part plan includes investing in people's talents and skills, making the largest investment in public infrastructure in Ontario's history, creating a dynamic, innovative environment where business thrives and building a secure retirement savings plan.

QUICK FACTS

- Ontario intends to link its cap and trade program with Quebec and California, two other member jurisdictions of Western Climate Initiative.
- Cap and trade effectively reduces the amount of greenhouse gas pollution going into the atmosphere by setting a limit on emissions. The “cap” sets a maximum limit on the amount of greenhouse gas pollution that can be emitted by facilities included in the program. Over time, the cap is lowered, reducing greenhouse gas pollution.
- The “trade” creates a market for pollution credits where facilities that do not use all their credits can sell or trade with those that are over their limit.
- The Western Climate Initiative, Inc., was established in 2011 to provide administrative and technical support for member states and provinces setting up cap and trade programs.

- According to the Conference Board of Canada, each $100 million invested in Ontario's climate-related technologies is estimated to generate a gain of $137 million in GDP, $25 million in tax revenue and 1,400 new jobs.

LEARN MORE

- Western Climate Initiative, Inc.
- Climate Summit of the Americas Retrospective
- Climate Change Discussion Paper
- Ontario Climate Change Update 2014

Lucas Malinowski Minister's Office
lucas.malinowski@ontario.ca
(416) 212-7307
Kate Jordan Communications Branch
kate.jordan@ontario.ca
(416) 314-6666

Available Online
Disponible en Français