K6.4

EB-2016-0004

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Schedule B;

AND IN THE MATTER OF an Application under the Ontario Energy Board's own motion to consider potential alternative approaches to recover costs of expanding natural gas service to communities that are not currently served

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CROSS-EXAMINATION COMPENDIUM OF THE SCHOOL ENERGY COALITION
(Union Gas Panel)

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UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference: All

a) Please produce a table which shows and contrasts the proposal of Union with the proposal of Enbridge.

b) Please provide a column in the above table with Union's comment as to the reason for any differences in the two proposals.

c) Specifically comment on the impact to Union's proposal if the Board were to accept Enbridge's proposal for a System Expansion Surcharge.

d) Specifically comment on Enbridge's proposal for a differentiated Community Expansion Portfolio and how, if the Board were inclined to accept this proposal, how this would impact Union's proposed projects.

e) Enbridge has proposed that community expansion projects should be treated as a "Y-factor" with the incremental revenue requirement of community expansion addressed as part of the annual rate setting process. Please comment on this proposal and contrast it to Union's position.

Response:

a) Please see Attachment 1.

b) Please see Attachment 1.

c) Please see the response at Exhibit S15.Union.SEC.9 for further comments.

d) Enbridge proposes that Community Expansion Projects be Exempted from the Investment Portfolio requirements of E.B.O. 188, which is consistent with Union's proposal.

With respect to the Rolling Project Portfolio (RPP), Enbridge proposes that Community Expansion Projects be exempted from the traditional RPP and instead that a separate RPP consisting of only Community Expansion Projects be maintained with a minimum RPP PI of 0.5. This Community Expansion RPP would vary from the 12 month rolling timeframe set by E.B.O. 188, and instead allow the timeframe to extend for the length of time (approximately 7 years) that Enbridge would be undergoing Community Expansion Projects.

This approach in isolation of other elements of Enbridge's proposal would limit the number of Projects that Union could undertake. Union could accept a similar proposal if the minimum PI of the RPP was set at 0.4.

e) Enbridge's proposal is similar to Union's in that it proposes that the capital costs of Community Expansion Projects be included in rates once the Projects have entered service. Union supports this concept.

Attachment 1: **Comparison of Union and Enbridge Community Expansion Project (CEP) Proposals**

Feature	Enbridge Proposal	Union Proposal	Rationale for Differences
Program Summary			
Project Eligibility	A natural gas system expansion project which will provide first time natural gas system access where a minimum of 50 potential customers in homes and businesses already exist, for which minimum economic feasibility guidelines permit a Profitability Index ("PI") of less than 1.0.		Same
Gross Capital	$410 million	$135 million; > $135 million if government funding becomes available	PI's of first 2 projects in Enbridge portfolio enable additional projects
Capital Pass Through to Rates	Yes		Same
Projects	39	29, additional projects if more if government funding is available	
Potential Customers	20,490	18,373	
Forecast Customers	16,246	9,107	
Forecast Penetration	79%	50%	
Gross Capital per Forecast Customer	$25,200	$14,800; unknown if government funding is available	
Profitability Index (PI) Treatment			
Project Minimum PI	No minimum	0.4 after including TES	
CEP Rolling Project Portfolio (RPP) Minimum PI	0.5	CEPs excluded from RPP (0.4 implied by min Project PI)	PI's of first 2 projects in Enbridge portfolio enable all other projects. Union's first few projects would not support many other projects.
CEP RPP Portfolio Term	*Full term of a multi-year expansion program	N/A	Enbridge: Traditional 12 month Rolling Portfolio approach would not enable other projects to occur after year 1. Union: manage portfolio through adherence to maximum rate impact/residential customer as opposed to managing to a minimum Portfolio PI.
Investment Portfolio PI	CEP's excluded from Investment Portfolio		Same
Average Residential Rate Impact Ceiling	$2.00/month		Same

Feature	Enbridge Proposal	Union Proposal	Rationale for Differences
SES or TES (New Customer Surcharge Mechanism)			
Type	Volumetric		Same
Applicability	All CEP customers	All CEP general service customers; contract rate customers have no TES	Enbridge and Union have differing contract customer offerings suited to their specific areas of operation.
Value	$0.23/m^3$		Same
Term	Lesser of 40 years, or when Project reaches a PI of 1.0	Minimum 4 years, maximum 10 years	
Treatment	Revenue	Revenue to deferral account for disposition to ratepayers	
ITE (Municipal Financial Support)			
Term	10 years	Minimum 4 years, maximum 10 years	
Optionality	Mandatory for any projects with PI >1.0	Mandatory for any projects with PI >0.8	
Basis	Incremental annual property tax value on assets installed		Same

* indicates an assumed or interpretation of the Enbridge proposal based on other components of their submission.

Both Enbridge and Union have defined similar proposals for small main extension projects that do not meet the definition of a CEP with two differing features. Enbridge will include these projects in its CEP RPP and include them in the "Y factor" to pass the capital through to rates, whereas Union proposed that these projects remain in its traditional RPP and not be subject to a capital pass through.

Opportunity Assessment Summary - Updated

											Including TES/ITE					
											Min PI= 0.4		Min PI= 0.5		Min PI=0.6	
Row	Community Name	Communities	Potential Customers	Forecast Customers	Distance From Source (km)	Annual Volume (million m3)	Gross Capital Cost (millions)	Gross Capital/ Potential Customer	Natural PI*	Potential Annual Savings** (millions)	TES/ITE Months	CIAC Required (millions)	TES/ITE Months	CIAC Required (millions)	TES/ITE Months	CIAC Required (millions)
1	Milverton	1	818	526	21	1.64	$4.77	$5,827	0.32	$1.31	48		48		50	
2	Prince Township, Sault Ste Marie	1	375	242		0.48	$2.72	$7,243	0.38	$0.60	48		48		82	
3	Lambton Shores, Kettle Point First Nation	2	496	281	6	1.65	$1.79	$3,615	0.44	$0.79	48		48		48	
4	~~Walpole Island First Nation- main commercial area~~	Removed from application														
5	Moraviantown First Nation- main commercial area	1	70	61	5	0.10	$0.49	$7,011	0.35	$0.11	48		48		50	
6	Lagoon City (Orillia)	1	2,556	1,150	19	2.61	$14.19	$5,553	0.42	$4.09	48		48		63	
7	Hidden Valley/Huntsville	1	100	46		0.10	$0.65	$6,452	0.38	$0.16	48		48		72	
8	Santa's Village/Beaumont Dr, Bracebridge	1	133	60	6	0.14	$0.86	$6,470	0.36	$0.21	48		49		84	
9	Canal, Gravenhurst	1	166	74	2	0.17	$1.17	$7,070	0.33	$0.27	48		63		98	
10	Northshore Rd / Peninsula Rd North Bay	1	333	150		0.34	$2.34	$7,030	0.33	$0.53	48		73		109	
11	Hornby	1	115	64	1	0.05	$1.22	$10,640	0.16	$0.18	77		111		120	$0.23
12	Oneida First Nation	1	466	210	5	0.48	$2.20	$4,720	0.28	$0.75	48		72		96	
13	Auburn	1	108	49	8	0.11	$0.53	$4,878	0.27	$0.17	48		61		86	
14	Cedar Springs	1	175	79	1	0.18	$0.90	$5,121	0.25	$0.28	48		74		98	
15	Astorville	1	467	210	5	0.48	$3.71	$7,951	0.29	$0.75	49		87		120	$0.21
16	***Brenman Line, Servern Twp (Gravenhurst)	1	33	14	2	0.03	$0.24	$7,396	0.29	$0.05	56		108		120	$0.02
17	Nipissing First Nation / Jocko Point	1	467	210		0.48	$3.92	$8,383	0.28	$0.75	60		97		120	$0.44
18	***Munsee Delaware First Nation	1	42	19		0.04	$0.27	$6,412	0.21	$0.07	63		96		120	$0.02
19	Chippewa of the Thames First Nation- phase 3 & 4	1	110	50		0.11	$0.72	$6,556	0.21	$0.18	64		97		120	$0.06
20	Sheffield	1	120	54	3	0.12	$0.78	$6,496	0.20	$0.19	70		99		120	$0.07
21	Turkey Point	1	541	244	12	0.65	$3.65	$6,749	0.20	$0.87	83		118		120	$0.69
22	Rockton	1	125	57	4	0.13	$0.88	$7,072	0.19	$0.20	79		112		120	$0.16
23	Chippewas of the Saugeen	1	120	54	5	0.12	$0.87	$7,290	0.19	$0.19	83		119		120	$0.17
24	Washago	1	405	182	6	0.41	$4.14	$10,232	0.23	$0.65	88		120	$0.48	120	$1.25
25	E Floral (T Bay area)	1	100	46	2	0.10	$1.08	$10,835	0.21	$0.16	84		120	$0.08	120	$0.29
26	Haldimand Shores	1	150	68	6	0.15	$1.80	$12,011	0.20	$0.24	105		120	$0.16	120	$0.37
27	Latchford, Tri Town	1	200	90	6	0.20	$2.34	$11,702	0.20	$0.32	111		120	$0.58	120	$0.95
28	Belwood	1	768	346	17	0.78	$5.79	$7,538	0.18	$1.23	95		120	$0.61	120	$1.71
29	Kincardine. Tiverton, Paisley, Chesley	4	8,331	4,250	87	13.31	$66.25	$7,952	0.23	$15.12	84		120	$1.90	120	$15.74
30	***Little Longlac	1	14	7	1	0.02	$0.25	$17,882	0.16	$0.02	120		120	$0.07	120	$0.11
31	Swiss Meadow	1	108	49	1	0.11	$1.02	$9,422	0.15	$0.17	111		120	$0.24	120	$0.40
32	Boblo Island	1	300	136	1	0.31	$2.66	$8,875	0.15	$0.48	117		120	$0.72	120	$1.14
33	Village of Warwick	1	150	69	13	0.30	$1.48	$9,896	0.14	$0.24	120		120	$0.41	120	$0.64
34	~~Mohawks of the Bay of Quinte (Tyendinaga FN)~~	Removed from application														
35	Garden Village (Promenade-de-lac)	1	133	60		0.14	$1.80	$13,560	0.18	$0.21	120	$0.11	120	$0.57	120	$0.83
36	Sioux Narrows / Nester Falls	2	1,044	470		1.07	$14.11	$13,519	0.17	$1.67	120	$1.84	120	$5.19	120	$7.09
37	Wroxieter/Gorrie/Fordwich	3	810	364	26	0.82	$8.06	$9,948	0.14	$1.30	120	$0.93	120	$2.88	120	$3.99
38	Moose Creek	1	319	143	12	0.32	$5.48	$17,182	0.14	$0.51	120	$2.06	120	$2.99	120	$3.52
39	Long Lake Phase 3, Sudbury	1	100	46		0.10	$1.80	$18,050	0.14	$0.16	120	$0.52	120	$0.87	120	$1.07
40	Gores Landing	1	239	108	9	0.24	$4.32	$18,057	0.13	$0.38	120	$1.85	120	$2.52	120	$2.90
41	***Emsdale Muskoka	1	33	14		0.03	$0.56	$16,979	0.13	$0.05	120	$0.24	120	$0.33	120	$0.37
42	Consecon- Ameliasburgh, Rossmore	3	1,650	744	33	1.77	$30.00	$18,184	0.13	$2.64	120	$12.01	120	$16.94	120	$19.73

Opportunity Assessment Summary - Updated

Row	Community Name	Communities	Potential Customers	Forecast Customers	Distance From Source (km)	Annual Volume (million m3)	Gross Capital Cost (millions)	Gross Capital/ Potential Customer	Natural PI*	Potential Annual Savings** (millions)	Including TES/ITE — Min PI= 0.4 TES/ITE Months	Min PI= 0.4 CIAC Required (millions)	Min PI= 0.5 TES/ITE Months	Min PI= 0.5 CIAC Required (millions)	Min PI=0.6 TES/ITE Months	Min PI=0.6 CIAC Required (millions)
43	Keast and South Bay Rd, Sudbury	1	100	46		0.10	$1.90	$19,044	0.13	$0.16	120	$0.64	120	$0.99	120	$1.18
44	Neustadt	1	209	94	9	0.21	$2.52	$12,053	0.12	$0.33	120	$0.76	120	$1.25	120	$1.52
45	Wabauskang First Nation	1	161	72		0.16	$3.12	$19,302	0.12	$0.26	120	$1.30	120	$1.80	120	$2.08
46	Cherry Valley	1	161	72	7	0.16	$3.12	$19,398	0.12	$0.26	120	$0.39	120	$0.75	120	$1.11
47	St Charles, Sudbury	1	427	192	11	0.44	$8.54	$19,992	0.12	$0.68	120	$3.99	120	$5.22	120	$5.92
48	Spencerville	1	317	142	13	0.32	$6.32	$19,935	0.12	$0.51	120	$3.07	120	$3.96	120	$4.46
49	Alderville, Roseneath (Incl Alderville FN)	2	265	119	13	0.27	$5.95	$22,458	0.11	$0.42	120	$3.38	120	$4.07	120	$4.47
50	Augusta Township	1	95	42	5	0.10	$2.15	$22,623	0.11	$0.15	120	$1.14	120	$1.41	120	$1.57
51	Nobel (Parry Sound)	1	221	100	4	0.23	$5.99	$27,096	0.09	$0.35	120	$1.23	120	$1.91	120	$2.60
52	Remi Lake area - north of Moonbeam	1	444	200		0.45	$12.43	$27,992	0.09	$0.71	120	$8.39	120	$9.49	120	$10.11
53	Chukuni Subdivision (Red Lake area)	1	97	43	0	0.10	$2.74	$28,229	0.09	$0.16	120	$1.81	120	$2.06	120	$2.21
54	Ripley,Lucknow	2	916	480	31	1.57	$21.67	$23,655	0.05	$1.66	120	$18.80	120	$19.57	120	$20.00
55	Redbridge	1	100	46	6	0.10	$3.19	$31,867	0.09	$0.16	120	$0.65	120	$1.02	120	$1.39
56	Sydenham, Harrowsmith, Verona	3	1,117	502	28	1.14	$35.06	$31,386	0.08	$1.79	120	$25.88	120	$28.37	120	$29.77
57	Gillies (outside Thunder Bay)	1	75	33		0.07	$2.34	$31,246	0.08	$0.12	120	$1.72	120	$1.89	120	$1.98
58	Inverary	1	200	91	8	0.25	$7.10	$35,511	0.07	$0.32	120	$5.58	120	$5.99	120	$6.22
59	Thomasburg	1	140	63	10	0.14	$4.93	$35,181	0.07	$0.22	120	$3.74	120	$4.06	120	$4.25
60	Loon Lake (outside of Thunder Bay)	1	175	79		0.18	$6.49	$37,112	0.07	$0.28	120	$5.16	120	$5.52	120	$5.73
61	Webbwood and McKerrow + Massey	3	524	236	35	0.53	$20.82	$39,724	0.07	$0.84	120	$5.15	120	$7.55	120	$9.96
62	Centenial Cres, North Bay	1	100	46	4	0.10	$4.44	$44,367	0.07	$0.16	120	$3.65	120	$3.86	120	$3.98
63	Thunder Lake & Meadows (Dryden area)	1	206	92		0.21	$9.01	$43,760	0.06	$0.33	120	$7.83	120	$8.15	120	$8.33
64	Charlton NW of Englehart	1	63	29	7	0.07	$2.85	$45,174	0.06	$0.10	120	$0.72	120	$1.05	120	$1.38
65	Goulais River and Goulais Bay	2	333	150	22	0.34	$15.06	$45,225	0.06	$0.53	120	$3.96	120	$5.70	120	$7.44
66	Westport	1	1,188	536	54	1.33	$55.79	$46,963	0.06	$1.90	120	$49.32	120	$51.05	120	$52.03
67	Bancroft	1	1,896	854	70	1.98	$89.32	$47,109	0.06	$3.04	120	$78.99	120	$81.77	120	$83.33
68	King Kirkland, Larder Lake, Virginiatown, Kearns	4	1,014	458	38	1.05	$48.33	$47,682	0.06	$1.62	120	$43.08	120	$44.48	120	$45.27
69	Sioux Lookout, Hudson, Lac Seul FN, Fisherman's Head	4	2,814	1,268	132	2.88	$134.40	$47,756	0.06	$4.51	120	$119.52	120	$123.51	120	$125.75
70	Roblin, Marbank	2	204	92	19	0.21	$9.76	$47,829	0.06	$0.33	120	$8.70	120	$8.98	120	$9.14
71	Red Rock First Nation - Lake Helen	1	100	46	3	0.10	$5.10	$50,984	0.06	$0.16	120	$2.02	120	$2.61	120	$3.20
72	Back Rd- Timmins area	1	126	57	9	0.13	$6.78	$53,771	0.05	$0.20	120	$6.13	120	$6.30	120	$6.40
73	Lac St-Therese (north of Hearst)	1	119	54	12	0.13	$6.97	$58,542	0.05	$0.19	120	$6.45	120	$6.59	120	$6.67
74	Field	1	100	46	15	0.10	$6.02	$60,214	0.05	$0.16	120	$1.67	120	$2.36	120	$3.06
75	Slate River (outside Thunder Bay)	1	300	136		0.31	$18.11	$60,380	0.05	$0.48	120	$17.25	120	$17.47	120	$17.60
76	Hagar	1	70	31	1	0.07	$4.17	$59,611	0.05	$0.11	120	$1.18	120	$1.66	120	$2.14
77	Rosseau (Parry Sound)	1	100	47	20	0.71	$6.54	$65,447	0.05	$0.16	120	$1.85	120	$2.61	120	$3.37
78	Wahnapitae First Nation	1	130	59	17	2.13	$8.28	$63,682	0.05	$0.21	120	$2.36	120	$3.32	120	$4.28
79	Lavigne	1	66	30	13	0.07	$4.47	$67,678	0.05	$0.11	120	$1.29	120	$1.81	120	$2.32
80	Town of Wabigoon, Wabigoon First Nation	2	254	114	39	0.26	$18.09	$71,239	0.04	$0.41	120	$5.44	120	$7.54	120	$9.64
81	O'Connor (Outside Thunder Bay)	1	275	123	6	0.28	$21.15	$76,916	0.04	$0.44	120	$6.44	120	$8.89	120	$11.35
82	Terrace Bay, Schrieber, Marathon	3	3,109	1,400	200	3.18	$243.97	$78,471	0.04	$4.98	120	$73.95	120	$102.25	120	$130.56
83	Conmee (outside Thunder Bay)	1	150	68		0.15	$12.01	$80,045	0.04	$0.24	120	$3.60	120	$5.00	120	$6.39
84	Algoma Mills, Spragge, Serpent River, Spanish	4	413	189	53	7.43	$35.16	$85,142	0.04	$0.66	120	$10.75	120	$14.83	120	$18.91

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Enbridge Evidence

If the Board were to adopt Enbridge's community expansion project methodology, including allowing projects with PI's below 0.4, how many additional communities would Union be able to connect, how many additional forecast customers would be added, and what would the additional capital costs be?

Response:

If Union applied a maximum 40 year temporary Expansion Surcharge (TES) to the Projects in order to achieve a minimum PI of 0.5, approximately 5 additional projects would become feasible. This would result in an incremental 1,100 forecast customers and add $31 million of incremental capital cost for those Projects.

If Union applied a maximum 40 year TES to the Projects in order to achieve a minimum PI of 0.4, approximately 15 additional projects would become feasible. This would result in an incremental 2,600 forecast customers and add $93 million of incremental capital costs for those Projects.

Table 6
Impact of Enabled Community Expansion Projects on Rolling Project Portfolio[13]
($ millions)

	Union South				Union North				Corporate			
	Inflow	Outflow	PI	NPV	Inflow	Outflow	PI	NPV	Inflow	Outflow	PI	NPV
Most Recent 3 year Average	$31.5	$20.5	1.54	$11.1	$13.6	$10.1	1.35	$3.5	$45.2	$30.6	1.48	$14.6
Incremental Investments (50% of 30 Projects)	$22.3	$55.7	0.40	-$33.4	$7.8	$19.5	0.40	-$11.7	$30.1	$75.2	0.40	-$45.1
3 Year Average Plus Incremental Projects	$53.8	$76.2	0.71	-$22.4	$21.4	$29.6	0.72	-$8.2	$75.2	$105.8	0.71	-$30.5

Stage 2 Economic Test

Consideration of the public interest by the Board can be aided by reviewing the results of a Stage 2 economic analysis of the effects of a broader community expansion program.

The Board's E.B.O. 134 decision, which was a precursor to E.B.O. 188, provided for use of further economic analysis to better understand the public benefits of expansion. This could take the form of both a Stage 2 and a Stage 3 analysis. Stage 2 generally refers to the energy cost savings that potential customers could achieve relative to their existing fuel usage. Stage 3 addresses public interest quantifiable and non-quantifiable benefits associated with a project. With the portfolio approach adopted in E.B.O. 188, the public benefits under the former Stage 2 and Stage 3 criteria of E.B.O. 134 are typically not reported in a facilities filing. They are not necessary because the PI of the IP and RPP exceed 1.0, indicating a positive NPV on cash flows attributed to Union.

Whereas a Stage 1 analysis includes only cash flows attributed to Union, Stage 2 and Stage 3 include cash flows not attributed to Union. These include customer cash flows attributed to

[13] Table represents a simplified analysis where capital expenditures constitute 100% of cash outflows.

energy savings, and non-cash factors both of which provide an understanding of the broader public interest perspective that the Board can consider in its evaluation of Union's proposal.

Union's Stage 2 analysis estimates that potential customers could have net energy savings of approximately $324 million if they had access to natural gas. This is derived as follows:

- Projects included are the 30 eligible projects at a minimum PI of 0.4, listed in Appendix D.
- The attachment rate is 80% of the market potential over an attachment term of 25 years. The 10 year forecast period attachment rate is 47% with the remaining 33% occurring over the following 15 years.
- Net energy savings include existing fuel cost less cost of new natural gas equipment, and less the cost of natural gas including the TES. These figures are then summed for the number of customers and the NPV for a 40 year period is determined using a 5% discount rate.

Alternative scenarios modelled to determine Stage 2 sensitivity include the following:

- Limiting the savings period to 30 years results in an NPV of $262 million;
- A market attachment rate of 60% results in an NPV of $ 278 million;
- Market attachment limited to 47% results in an NPV of $248 million.

All ranges of scenarios indicate several hundred millions of dollars are available to be reinvested in goods and services by customers. This will have a multiplier effect on the GDP in Ontario's economy. This impact would be considered in a Stage 3 analysis; however, given the significant benefits from Stage 2, Union has not attempted to quantify a Stage 3 analysis in this application.

In relative terms, Union's capital investment for the above Stage 2 figures is approximately $150 million. Although this figure is not used in the Stage 2 calculation it has been noted here to provide perspective to the Stage 2 NPV figures.

Potential Rate Impact Implications for Existing Customers

Union's proposals are expected to result in modest rate increases for existing in-franchise ratepayers. The following section provides the revenue requirement, cost allocation and rate impacts associated with the 30 potential Community Expansion Projects.

The annual revenue requirement associated with the 30 potential Community Expansion Projects ranges from approximately $4.4 million in 2016 to $13.0 million in 2018. The revenue requirements represent the costs associated with the 30 Community Expansion Project facilities assuming the projects are in service from 2016 to 2018. The calculation of the annual revenue requirement in 2016 to 2018 and the underpinning assumptions are provided at Appendix J.

i) To calculate rate impacts, Union added the largest revenue requirement directly attributable to the Project (rate base, return, interest, tax, depreciation and O&M) between 2016 and 2018 of $13.0 million to Union's 2013 Board-approved cost allocation study (updated per EB-

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

With regards to risks and benefits of Union's proposed community expansion methodology:

a) provide a list of all benefits and risks borne by each of the following:

v) Existing customers

vi) New customers

vii) New communities (i.e. municipalities)

viii) Union

b) Please explain why Enbridge believes the allocation of benefits/risk is appropriate.

Response:

a)

v. Existing Customers

Benefits: Positive Gross Domestic Product ("GDP") impacts as annual energy savings from those converting flow back into the provincial economy; economies of scale reflected in rates as future attachments occur; potential earnings sharing benefits in accordance with IRM.

Risks: Capital cost risk for constructed facilities; TES deferral credits may be higher or lower related to forecast achievement or consumption being more or less than forecasted.

vi. New Customers

Benefits: Annual savings available from switching to natural gas, and same benefits as existing customers.

Risks: Annual savings may be more or less than estimated at the time of conversion; same risks as for existing customers once attached.

vii. New Municipalities

Benefits: Ability to retain or attract new residents and businesses due to competitive energy costs, future incremental property taxes on pipeline systems installed, and to the extent they own buildings the same benefits as new customers.
Risks: None

viii. Union:

Benefits: Growth in earnings resulting from return on equity for the increased level of investment.

Risks: All risks inherent in the operation of a natural gas distribution company for the new attachments and distribution systems; traditional weather risk on new attachments.

b) Union believes the allocation of risk in its proposal is appropriate because the rate impacts for customers provided at Exhibit S15.Union.IGUA.6 and peak at $2.91 per year (an average of $0.24 per month) for a typical residential customer, in comparison to Stage 2 economic benefits in the range of $300 million as provided in EB-2015-0179 at Exhibit A, Tab 1 Updated, p. 39. Union believes utility risk is appropriate as noted at EB-2015-0179 Exhibit A, Section Exhibit B.CPA.11 (c) and Exhibit B.CPA.16.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, p. 56

a) Please explain to which "customers" the surcharge revenue would be disposed of annually.

b) Please explain why the surcharge revenue would not be considered an aid to construction and used to reduce the capital cost of the projects included in rate base.

c) If the surcharge revenue were treated as an aid to construction, thereby reducing rate base and associated costs with the projects, what would be the impact on the overall costs of the projects proposed in this application? Please provide all assumptions and calculations.

Response:

a) The surcharge revenue would be disposed to all current ratepayers in the rate classes listed in Exhibit 1, Tab 1, Appendix K, at the time of its disposal.

b) A contribution in Aid-to-Construction ("CIAC") is an amount collected and recorded at the time of construction. The proposed Temporary Expansion Surcharge ("TES") is a rate for service charged to customers in new communities as service is provided. Amounts earned as a result of providing service are accounted for as revenue consistent with generally accepted accounting principles ("GAAP"). The recovery of amounts from the municipality while not based directly on service provided are proposed to be recovered over time and will also be recorded as revenue. Treating some portion of the recovery of incremental costs as revenue and other amounts as a reduction in plant is unnecessarily complicated.

   It is Union's position that the proposal to treat the amounts recovered from customers and municipalities as revenue better reflects the economic reality, is less complicated than the treatment as CIAC, and results in an improvement of the P.I. using the E.B.O. 188 financial methodology. Each of these is discussed below.

   Treatment as revenue reflects economic reality of the transaction:

   - Under Union's proposal the incremental cost of expansion is rolled into rate base reflecting the real incremental cost incurred to provide service. Under the CIAC option, the incremental cost to construct reflected in rate base is adjusted down by the amount of the CIAC and the resulting average cost of service understates the actual average cost. In the CIAC case, the financial barrier for any pipeline addition whether it is for a new community, or for a new housing subdivision within an existing serviced area, continues to grow as actual costs increase while the revenue test, based on historical costs, does not.

- The revenue surcharge (TES/ITE) paid by the new Community Expansion customers offsets a portion of the additional rate increase attributed to the expansion. This is a hybrid approach between rolled in tolling, where all customers pay the same rate, and an incremental tolling approach, where incremental costs are the basis of the rate. The hybrid approach is reasonable in this limited circumstance as a means to respond to the Province's desire and the Board's request for proposals.

Reduced complexity

- Union's proposal is to:
  - Record capital as plant included in rate base;
  - Record billing of surcharge to customers as revenue; and,
  - Adjust rates to existing customers to recover any revenue deficiency (the difference between the additional revenue requirement and the revenue from the surcharge).

- The CIAC option would require additional process:
  - Record aid as a reduction to plant and a receivable up front (GAAP requirement);
  - Request Board approval to include CIAC receivable in rate base (to earn a return on investment);
  - Record an adjustment to revenue and receivable for the amount of CIAC collected. This would be a continuous monthly process as the TES/ITE is collected; and,
  - Request Board approval to include any uncollected CIAC receivable at the end of term in plant (regulatory asset).

P.I. Implications

- Under Union's proposal the P.I. is higher than it would be under a different proposal whereby a CIAC is collected. Milverton is the largest of the four projects Union is seeking approval for in this Application.[1] The P.I. for Milverton is 0.57 as proposed and would be 0.38 under a CIAC proposal.

c) The TES and ITE treated as revenue is a foundation of Union's proposal and if treated as an aid, an alternative financial proposal would be required.

Treatment as an aid would slightly decrease the 40 year assessment of the revenue requirement relative to Union's proposal although this would not occur until 20 plus years after in service.

[1] The Walpole Island First Nations Project, is proceeding with the support of Federal funding, under E.B.O. 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

To illustrate Union's proposal, Union has prepared an example using Milverton (Exhibit A, Tab 2, Section 2). Attachment 1 is the revenue requirement for Milverton over a 40 year term under Union's proposal and an alternative proposal whereby a CIAC mechanism is created and applied. Both cases use the same capital costs, attachments, use per customers, etc. The only difference is the TES and ITE treatment.

Milverton is based on the four year minimum term for the TES and ITE. Figure 1 below is a graph showing the annual revenue requirement as proposed and an alternative proposal where the equivalent amount is collected as an aid.

As shown in Figure 1, Union's proposal reduces the revenue requirement over the term the TES/ITE is in place. In the Milverton example the term is four years, but for other projccts the term can be as long as 10 years. Exhibit A, Tab 1, Appendix D lists the terms of the TES/ITE for other potential projects. When the TES/ITE term expires the revenue collection from the expansion customers served by that Project ceases and the annual revenue requirement relative to an aid reverses.

Figure 2 illustrates the NPV of the cumulative revenue requirement under both methods. The advantage of Union's proposal stays in place for 23 years before the cross over point. The significant early year impacts reduce the revenue requirement that would be paid by ratepayers. Other projects would have similar patterns. Since Milverton has a 4 year TES/ITE term, examples for other projects would have a cross over point sometime after year 23 because the TES/ITE revenue stream would be in place for terms as long as 10 years.

Figure 1: Revenue Requirement Annually

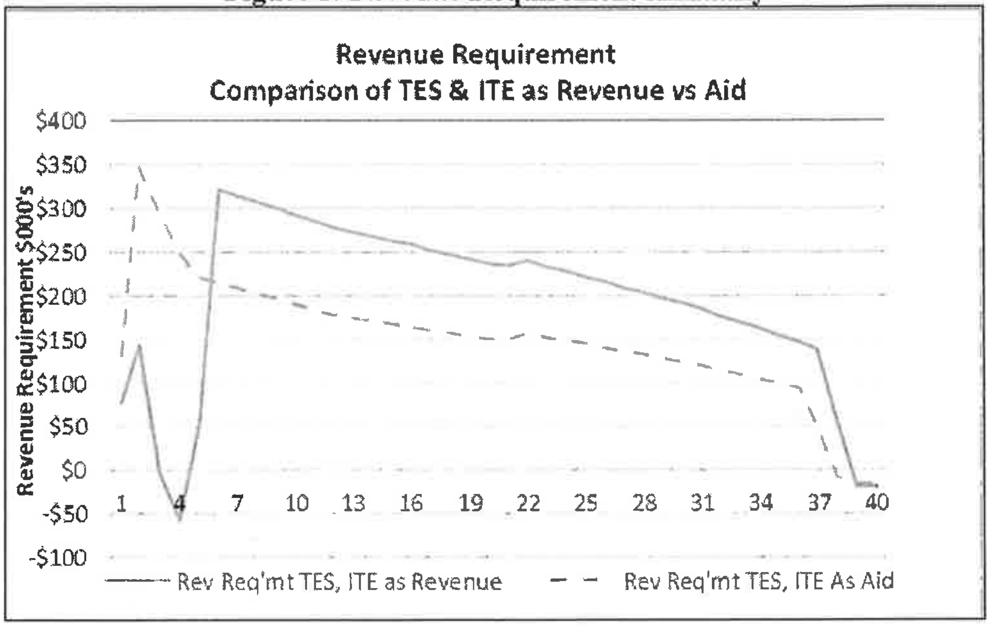
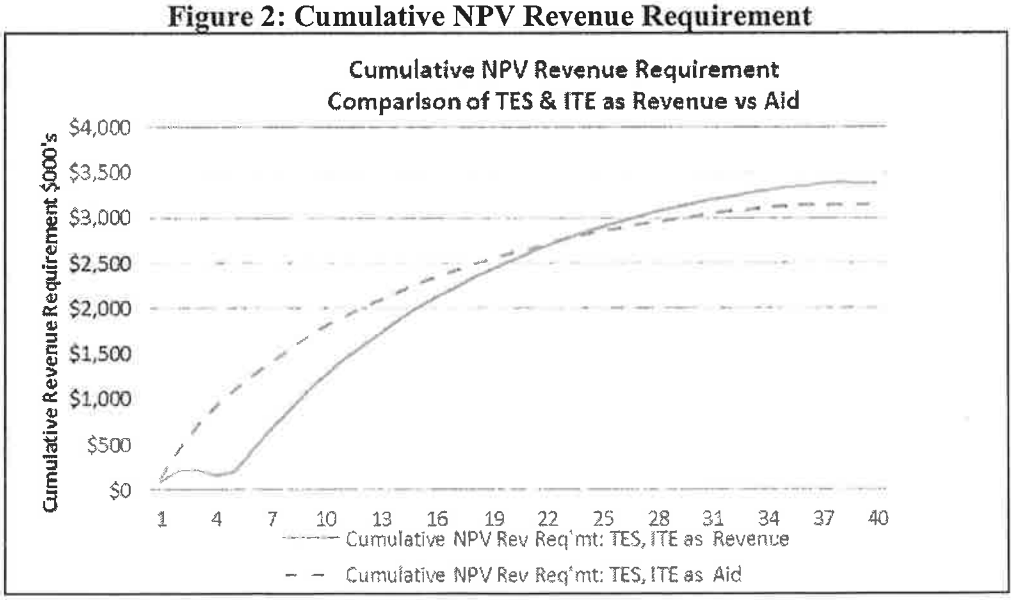


Figure 2: Cumulative NPV Revenue Requirement



Notes

Figure:

- Year 1 is based on a September 1st in service (four months) and Year 2 and thereafter are 12 months. As is normal the partial year revenue requirement skews the ongoing pattern.

Readers should be looking at the relative starting point of Year 2 for full year impact of each line.

- The line representing TES/ITE as revenue rises at Year 5, and the dashed line showing the TES/ITE as aid flattens at the same time because the term of the TES and ITE expires after 4 years for Milverton.
- There is a change in slope at Year 21. This is the result of the revenue assumption for the commercial/industrial customers which are based on a revenue term of 20 years. The revenue for the first year commercial attachment drops off at Year 21 and the last commercial attachment in Year 31.

The change in slope near the end of the line (Year 38) is the result of a reduction in depreciation expense as a portion of the asset becomes fully depreciated.

The data used to plot the graphs can be found in Attachment 1, lines 3, 4, 9 and 11.
The data in Attachment 1 is drawn from Attachment 2 (TES, ITE as Revenue), and Attachment 3 (TES, ITE as aid). Attachments 2 and 3 are the revenue requirements by year under each alternative.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 2, Section B, p. 4, para. 18-22

Union completed a telephone survey for the Milverton area and based on the results it has forecasted a total of 375 existing residential, 100 new residential, 45 existing medium and small commercial, 5 existing large commercial and one existing seasonal customers to be attached by the tenth year of the project.

Based on experience of attachment rates with past projects, Union has taken a conservative approach and reduced the attachment forecast from 74% (respondents extremely likely, very likely and likely to convert) to 59% (extremely likely, very likely, 50% of likely) for the existing residential, small commercial and medium commercial customers.

a) What is Union's forecast for the 100 new residential customers and what is the basis for the forecast?

b) Union has based its forecast for existing customer conversions on experience with past projects. Please provide details of the past projects that Union is referring to and the forecast and actual attachments.

c) Did Union conduct a similar survey for the Red Lake Project? If yes, please provide the forecast attachments, the basis of the forecast and the actual attachments to-date.

Response:

a) Union based its forecast of 100 new residential customers on the discussions with Municipal officials in Milverton and draft plan subdivisions which have been submitted to the Municipality.

b) Please see the response at Exhibit B.Staff.12, Attachment 1.

c) Yes. Union did conduct a similar survey for the Red Lake Project. In the EB-2011-0040 proceeding, Union identified that there were 1,265 private dwellings in the Municipality of Red Lake. Please see Attachment 1 for the attachment forecast and actual attachments to date.

Red Lake - Current Customer Attachments (Services) vs Original Forecast
Nov 20, 2015 vs Feb 8, 2011 Phase II Submission

	2012 Year 1			2013 Year 2			2014 Year 3			2015 Year 4		
	Original Forecast	Actual Attachmts	% of Actual vs forecast	Original Forecast	Actual Attachmts	% of Actual vs forecast	Original Forecast	Actual Attachmts	% of Actual vs forecast	Original Forecast	Actual Attachmts	% of Actual vs forecast
Conversion Residential	359	332	**92%**	225	272	121	162	188	**116**	85	127	**149**
New Construction Res	33	1	**3%**	26	3	12	17	3	**18**	17	1	**6**
TOTAL	392	333	**85%**	251	275	**110**	179	191	**107**	102	128	**125**
Commercial R-01	68	36	**53%**	44	28	**64**	30	13	**43**	16	9	**56**
New Construction R-01 comm	3	0	**0%**	3	2	**67**	2	2	**100**	2	0	**0**
TOTAL	71	36	**51%**	47	30	**64**	32	15	**47**	18	9	**50**
OVERALL TOTAL	463	369	**80%**	298	305	**102**	211	206	**98**	120	137	**114**

	2016 Year 5	2017 Year 6	2018 Year 7	2019 Year 8	2020 Year 9	2021 Year 10	2012-2021 TOTAL	
	Original Forecast	Original Forecast	Original Forecast	Original Forecast	Original Forecast	Original Forecast	Original Forecast	Actual Attachments (2012-2015)
Conversion Residential	60	55	45	30	25	25	1071	919
New Construction Res	17	8	8	8	8	8	150	8
TOTAL	77	63	53	38	33	33	1221	927
Commercial R-01	12	7	4	4	3	3	191	86
New Construction R-01 comm	2	1	1	1	0	0	15	4
TOTAL	14	8	5	5	3	3	206	90
OVERALL TOTAL	91	71	58	43	36	36	1427	1017

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: pp. 8-11

Which of the proposed clarifications and adjustments to the economic assessment factors in EBO 188 did Union include in its application and evidence in EB-2015-0179? If it did not include all, please provide a revised P.I. for each of its proposed 29 projects which does so.

Response:

With respect to costs, Union has included upstream reinforcement and minimum design costs in its EB-2015-0179 project applications. With respect to revenues, Union has used existing rates with a proposed Temporary Expansion Surcharge (TES). With respect to time periods, Union has not incorporated proposed changes to reflect either the commercial/industrial revenue time period or customer forecast time period.

Minnesota[73]
Throughout Minnesota, gas utilities have developed a New Area Surcharge (NAS) for new customers in previously un-serviced locations. This program was developed based on policy concerns that individual contributions could be so high that prospective customers may decide not to switch to natural gas, despite the fuel being the most cost- beneficial from a lifecycle perspective. To calculate the yearly surcharge, gas utilities take the present value of the annual difference between the expected and required revenue for a line extension and then divided it and charge it across the rate base. This provides for a gradual and affordable repayment of the capital and additional operating costs incurred to develop a new line[74].

Nebraska
Nebraska has passed legislation facilitating the expansion of gas lines into new areas, an initiative that was promoted as being about economic development. The legislation streamlines the regulatory review process and allows utilities to spread the costs of line extensions to all of their ratepayers. It requires the creation of line extension plans examining the economic effect on the area, economic feasibility, and other options that would better advance the public interest.

The legislation allows for several mechanisms to pay the cost of the line extension, including cost recovery from all of the utility's customers if the plan promotes economic development in an un-served or underserved area. The legislation also allows remote municipalities fund line extensions for the purpose of economic development.

North Carolina
North Carolina legislation authorizes the issuance of bonds for natural gas extensions that are not economically feasible. It also allows for the creation of expansion funds for the extension of gas service to un-served areas. Gas utilities can apply the funds only to economically infeasible expansions.

This legislation facilitates the development of natural gas infrastructure in remote areas of the state where the economics would otherwise preclude development. Funds can come from a surcharge imposed on existing ratepayers, supplier refunds, or other sources approved by the regulator.

Connecticut
On June 14, 2013, Connecticut's three gas distribution companies filed a plan to expand service to about 280,000 new customers over the next 10 years. The Plan is part of an effort to meet the gas expansion plans proposed in Governor Dan Malloy's Comprehensive Energy Strategy (CES). Recognizing that "conversion to natural gas promises a cheaper, cleaner, and more reliable fuel for heating, power generation, and perhaps transportation", the CES calls for an expansion of Connecticut's natural gas distribution infrastructure to increase access to natural gas to potential new residential and commercial customers across the state over the expansion period.

To allow for this expansion, the CES includes consideration of societal benefits in economic modelling and a unique system expansion rate to recover a portion of the expansion driven revenue requirements from existing customers. New customers as of January 1, 2014 will be placed on a different rate schedule that, in effect, will have all its distribution rates increased by a pre-determined percentage amount. The percentage will be set in order to allow each class of customers to retain the majority of the differential between oil and gas prices. In this manner, the proposal allows new customers to recoup their initial investment over time, while still contributing a significant amount towards the cost of the necessary expansion of the gas system.

ONTARIO CAN ENSURE THE CONNECTION OF THOUSANDS OF ONTARIANS WITH THE STROKE OF A PEN

The Ontario government should examine options and implement time limited solutions (for a period of five years) appropriate to specific circumstances to allow rural communities to be supplied with natural gas. This rural community economic development will benefit the entire economy as communities become more self-sustaining. A barrier to local economic development would be removed, and annual energy savings of up to $40 million would be injected into the local economies. It is also a province-building strategy, providing energy choice for all Ontarians. Options include a combination of the following measures:

Direct Government Capital Contribution
The province could provide a direct financial contribution to the projects recognizing the economic development potential that the pipeline would bring to the community. For example, a commitment of $200 million over 5 years would enable expansion to as many as 40,000 homes and businesses in over 40 towns and villages.

Provide direction to the OEB
The Ontario government could direct the Ontario Energy Board to treat new natural gas connections as network assets to allow for some greater level of cross-subsidization of expanding the network from existing utility gas customers to new customers in rural regions. This would be consistent with practices observed in jurisdictions such as Minnesota and Nebraska, where expansions can be bundled and funded through the full rate base. Any cross-subsidization model should keep impacts on existing customers minimal (approximately 1% or $3.50/year for residential customers).

A tax based approach
The province could make a change in tax regulations that would allow municipalities to voluntarily forego pipeline related property taxes until such time as total economic contributions required for a project have been collected.

Extension of Local Improvement Charges
The province could support and promote the use of Local Improvement Charges in order to help municipalities finance their contribution to the expansion project even though the community and the customers would not own the pipeline asset. This mechanism could be used to fund both a municipal and a customer contribution to the projects.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: p. 12

Considering a significant reduction in natural gas usage is going to be required to meet the GHG reduction targets set out in Bill 172, please explain why it is appropriate to expand natural gas service when consumption is going to need to be reduced dramatically.

Response:

It is appropriate to expand natural gas service because customers and municipalities are requesting it, the Provincial government supports it and because expansion of natural gas service is not inconsistent with reducing GHG emissions.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: p. 35

Please provide Union's forecast of annual natural gas consumption for each of the next 40 years, on a per customer basis for the average:

a) Residential customer

b) Commercial customer

c) Industrial customer

Response:

Union does not have a 40 year forecast of annual natural gas consumption. The longest forecast Union has is three years. Please see the table below for Union's 2016-2018 forecast consumption on a per customer basis for the general service rate class.

General Service
Annual Normalized Average Consumption (NAC)
(m^3)

	Residential	Commercial	Industrial
2016	2,262	18,309	97,090
2017	2,233	18,295	98,208
2018	2,214	18,341	99,816

Notes:
- NAC is at the 2016 Board-approved 50:50 weather normal.
- Includes DSM assumption as filed in 2015.

UNION GAS LIMITED

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

Reference: pp. 26-28

Why does Union think that the Board should become more heavily engaged in an RFP process to choose a new supplier for an unserved community? If so, please explain the process Union would envisage.

Response:

Any RFI or RFP process should not usurpt the Board's authority to set rates.

The Board should be engaged in any RFI or RFP process because the Board has the sole jurisdiction to grant Franchises, Certificates of Public Convenience and Necessity (CPCN), and Leave-to-Construct approval. In the absence of Board involvement, a municipality could conduct an RFI or RFP process only to discover that after the process has been completed and the selected project proponent applies for Leave-to-Construct approval from the Board, it could be denied or granted with conditions that the proponent could not or is not willing to meet.

At a minimum the Board's engagement should include setting specific parameters that the municipality should address in its evaluation of RFI or RFP responses. These parameters would include an assessment of the factors that Union has identified in its response to Issue 8 at Exhibit A, Tab 1, pp. 25-30. Since a primary component of the Board's mandate is setting just and reasonable rates, the rates that will be charged to customers in new communities should be a key factor in the assessment of RFI's or RFP's.

UNION GAS LIMITED

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

Reference: p. 21, Issue 4 f)

Union states in its evidence that it has only used EBO 134 in applications to expand the Dawn Parkway and Ojibway transmission systems. Does Union agree that EBO 134 remains a construct to facilitate expansion of these high pressure, long line transmission systems are essential to the operation of the Union integrated transmission/distribution business, and was not designed to be used for distribution system expansion projects? However, for distribution expansions to connect additional communities, EBO 188 is a well-developed test, which Union supports. Why is Union purporting to use the EBO 134 Guidelines for distribution expansion? Why is it appropriate to use these tests to support a project-specific assessment of distribution expansion projects. Does Union agree that using these second stage benefits could be used to justify any expansion to unserved communities in the province, no matter how remote the communities are from existing gas infrastructure.

Response:

The question misstates Union evidence. The question states "Union states in its evidence that is has only used E.B.O. 134 in applications to expand the Dawn Parkway and Ojibway systems". Union's EB-2016-0004 evidence at Exhibit A, Tab 1, p.16 states…"In Union's case, the current transmission pipeline system subject to E.B.O. 134 Guidelines are limited to the Dawn Parkway and Panhandle transmission system"

E.B.O. 134 applied to both transmission and distribution projects prior to the development of the E.B.O. 188 Guidelines in 1998. As such, E.B.O. 134 was developed for use with both types of projects, which included expansions to connect to additional communities. With the E.B.O. 188 Decision, in-franchise expansions to connect additional communities were subject to the E.B.O. 188 Guidelines rather than the previous E.B.O. 134 Decision.

The minimum Portfolio PI requirement identified in E.B.O. 188 was put in place as a means to ensure existing ratepayers were held harmless from the cost of new connections or projects[1]. Because existing ratepayers were being held harmless, there was no reason to consider economic assessments that included the broader public benefits of the projects. Union, however, has proposed that limited levels of subsidization from existing ratepayers are in the public interest. If limited levels of cross subsidization from existing ratepayers are acceptable, either the E.B.O. 188 Guidelines related to minimum Portfolio and Project PI's need to be relaxed, or those projects will need to be exempted from E.B.O. 188.

[1] Board Letter, dated February 18, 2015, and provided at EB-2015-0179 Exhibit A, Tab 1, Appendix A, p. 3.

Union has proposed the use of the Stage 2 and 3 Assessments identified in the E.B.O. 134 Decision as a means for the Board to assess the public interests in these cases. Union supports the use of a Stage 2 assessment for the analysis of any project where existing ratepayers will be impacted. However, whether that assessment would justify expansion to very remote communities would depend on the specific costs of the project being proposed. Union does not agree that every possible project is expected to be justified.

UNION GAS LIMITED

Undertaking Response
To Mr. Rubenstein

To provide charts for this project.

Union's Community Expansion Project Proposal is a direct response to the government's desire to complete the maximum number of expansion projects without the need for government funding and, the Board's invitation to propose plans to support that objective. The need for such a proposal was unknown at the time of Union's current IRM framework approval. Although the intent may be similar, the capital pass-through mechanism proposed in this Application does not, nor was it intended to, meet all of the specific criteria of the IRM capital pass-through mechanism.

Capital Pass-through Mechanism Criteria

Criterion		Applicability
i)	A minimum increase, or a minimum decrease, of $5 million in net delivery revenue requirement for a single new project (the "Rate Impact Threshold").	No specific Community Expansion Project proposed in this Application meets this criterion.
ii)	The capital cost of the project must exceed $50 million.	No specific Community Expansion Project proposed in this Application meets this criterion.
iii)	The project is outside the base rates on which the IRM is set.	Union's Community Expansion Project proposal was not included in 2013 base rates.
iv)	The project must be needed to serve customers and/or to maintain system safety, reliability or integrity, and cannot reasonably be delayed, and is demonstrated to be the most cost effective manner of achieving the project's objective relative to the reasonably available alternatives.	The need behind Union's Community Expansion Project Proposal is in response to the Ontario Energy Board's ("the Board") initiative to address the Ontario government's desire to expand natural gas distribution systems to communities that do not have access to natural gas as soon as possible.
v)	The project will be identified to stakeholders and the Board as soon as possible, including in that year's IRM stakeholder review session where practical.	Union identified the potential for a Community Expansion Program in the IRM stakeholder meetings held on April 9, 2014 and April 8, 2015.
vi)	The project will be subject to a full regulatory review; for any project that requires leave-to-construct approval of the Board, the full regulatory review in which the applicant must demonstrate need, safety or reliability purposes, and economic viability prior to inclusion in rates will be conducted in that proceeding. For any project that does not require Leave-to-Construct approval of the Board, Union commits to filing its annual rate adjustment application with the Board by July 1 of the year prior to the rate impacts of the project going into effect, to allow sufficient	This Application involves a full regulatory review of Union's Community Expansion Project Proposal. This review includes the rate recovery of the net revenue requirement for the four proposed expansion projects as well as leave to construct ("LTC") for those projects that meet the Board's LTC criteria. Union will file LTC Applications for future Community Expansion Projects including requests for approval of the net revenue requirement associated with these Projects. Union will also apply for franchise and certificate applications for future Projects, if necessary. For future Projects that do not require LTC approval, Union will seek Board approval of the forecast net revenue

	time for a full regulatory review of the project in its rates application.	requirements.
vii)	Union will allocate the net revenue requirement using EB-2011-0210 Board-approved cost allocation methodologies. Any party, including Union, may take any position with respect to the proposed allocation for any particular capital project during review of the project, or its rate impacts, by the Board.	Union has allocated the net revenue requirement using EB-2011-0210 Board-approved cost allocation methodologies.
viii)	The project will include a deferral account request to capture any differences between the forecast annual net delivery revenue requirement and the actual net delivery revenue requirement for each year of the IRM for which the project is included in rates.	This Application includes a request for a "Community Expansion Project Costs" deferral account. Please see Exhibit A, Tab 1, Appendix G, p.1.