K1.2.

Ontario Energy Board

FILE No. EB-2016-0061

EXHIBIT No. K1.2

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SCHOOL ENERGY COALITION

CROSS-EXAMINATION MATERIALS

EB-2016-0061

CANADIAN NIAGARA POWER

	Distributor	Benchmarking Results						
		2010	2011	2012	2013	2014	2015	3 Year
1	Hydro Hawkesbury	-61.8%	-59.4%	-55.8%	-51.1%	-64.3%	-68.1%	-61.2%
2	Wasaga Distribution	-46.8%	-46.3%	-37.8%	-41.6%	-41.6%	-45.6%	-42.9%
3	E.L.K. Energy	-28.2%	-26.2%	-25.4%	-33.2%	-44.9%	-34.7%	-37.6%
4	Northern Ontario Wires	-38.5%	-35.7%	-25.8%	-25.1%	-32.6%	-42.2%	-33.3%
5	Halton Hills Hydro	-27.2%	-24.9%	-27.5%	-35.7%	-31.3%	-28.2%	-31.7%
6	Cooperative Hydro Embrun	-19.3%	-16.9%	-26.4%	-18.7%	-29.7%	-33.2%	-27.2%
7	Haldimand County Hydro	-27.6%	-24.1%	-18.7%	-23.7%	-23.6%	-21.4%	-22.9%
8	Espanola Regional Hydro	-22.6%	-21.8%	-15.5%	-19.3%	-25.4%	-20.4%	-21.7%
9	Hearst Power	-26.3%	-30.1%	-28.4%	-33.1%	-22.4%	-7.4%	-21.0%
10	Kitchener-Wilmot Hydro	-22.9%	-22.8%	-20.7%	-19.3%	-19.0%	-22.3%	-20.2%
11	Newmarket-Tay Power	-14.6%	-21.0%	-19.5%	-19.5%	-18.6%	-19.3%	-19.1%
12	Welland Hydro	-19.6%	-16.2%	-10.4%	-15.2%	-17.3%	-18.7%	-17.0%
13	Grimsby Power	-23.1%	-18.6%	-9.6%	-16.9%	-17.3%	-17.0%	-17.0%
14	Oshawa PUC	-21.7%	-18.0%	-14.5%	-17.4%	-18.1%	-14.9%	-16.8%
15	Entegrus Powerlines	-13.1%	-13.4%	-10.9%	-14.7%	-16.7%	-17.3%	-16.3%
16	Lakefront Utilities	-14.7%	-12.5%	-18.7%	-7.4%	-16.0%	-22.1%	-15.2%
17	Essex Powerlines	-17.0%	-17.1%	-12.6%	-17.2%	-12.7%	-13.5%	-14.5%
18	COLLUS PowerStream	-8.2%	-9.5%	-1.2%	-12.3%	-14.2%	-14.2%	-13.6%
19	London Hydro	-16.8%	-10.1%	-11.1%	-11.0%	-12.8%	-9.9%	-11.3%
20	Enersource Hydro Mississauga	-9.5%	-16.1%	-9.5%	-10.7%	-13.9%	-8.2%	-11.0%
21	Burlington Hydro	-7.6%	-7.1%	-9.0%	-7.5%	-9.4%	-10.3%	-9.0%
22	Kenora Hydro	-11.5%	-4.6%	-5.2%	-11.2%	-11.0%	-3.9%	-8.7%
23	Hydro 2000	-14.8%	-12.2%	-0.8%	-1.0%	-15.3%	-6.2%	-7.5%
24	St. Thomas Energy	-6.4%	-4.5%	6.8%	-4.6%	-6.3%	-10.3%	-7.1%
25	Rideau St. Lawrence Distribution	-10.6%	-13.8%	-6.7%	-7.2%	-8.1%	-4.8%	-6.7%
26	Orillia Power	-3.5%	-1.9%	-3.7%	-4.7%	-5.3%	-8.0%	-6.0%
27	Whitby Hydro	0.4%	-3.0%	-7.0%	-5.7%	-6.8%	-2.6%	-5.0%
28	Horizon Utilities	-13.0%	-13.7%	-6.9%	-5.5%	-5.3%	-2.1%	-4.3%
29	Hydro One Brampton	-5.8%	-7.4%	-9.2%	-5.7%	-3.3%	-2.9%	-4.0%
30	Ottawa River Power	-2.9%	2.7%	0.0%	4.3%	-6.9%	-9.3%	-4.0%
31	Brant County	15.6%	22.4%	11.5%	5.5%	-3.6%	-13.6%	-3.9%
32	Orangeville Hydro	-2.7%	1.6%	0.8%	0.1%	-4.0%	-7.6%	-3.8%
33	Niagara-on-the-Lake Hydro	7.6%	6.5%	2.7%	-1.1%	-2.8%	-6.6%	-3.5%
34	Lakeland Power	na	na	-6.4%	-0.9%	-1.9%	-7.6%	-3.5%
35	Brantford Power	3.8%	-2.5%	4.7%	0.7%	-3.6%	-6.1%	-3.0%
36	Westario Power	-3.1%	-0.2%	-1.4%	2.2%	-4.2%	-6.0%	-2.6%
37	Guelph Hydro	12.4%	14.7%	-2.0%	0.8%	-4.8%	-3.8%	-2.6%
38	Centre Wellington Hydro	-8.7%	-4.9%	0.4%	-3.2%	-3.1%	-1.2%	-2.5%
39	Veridian Connections	-4.7%	-4.5%	2.4%	-1.3%	-3.0%	-2.7%	-2.3%
40	Milton Hydro	-4.1%	-3.0%	-37.6%	-4.6%	-4.0%	2.7%	-2.0%
41	Cambridge and North Dumfries	-10.1%	-7.8%	-3.3%	0.5%	-1.9%	-3.6%	-1.7%
42	Kingston Hydro	0.1%	2.2%	2.4%	3.7%	-3.6%	-3.1%	-1.0%
43	Innpower	-7.1%	-6.2%	-2.4%	-2.8%	-2.8%	8.5%	1.0%
44	Sioux Lookout Hydro	0.6%	-1.4%	7.2%	2.9%	6.2%	-4.3%	1.6%
45	Bluewater Power	-3.2%	1.7%	6.4%	5.9%	0.3%	0.8%	2.3%
46	Norfolk Power	-1.8%	-2.6%	6.0%	1.2%	6.5%	NA	3.9%
47	Niagara Peninsula Energy	5.4%	5.2%	10.2%	1.1%	7.7%	4.5%	4.5%
48	Atikokan Hydro	14.9%	7.7%	32.9%	10.3%	-4.9%	9.7%	5.0%
49	PowerStream	-7.4%	-6.4%	1.2%	3.0%	5.6%	8.1%	5.6%
50	Fort Frances Power	14.8%	10.5%	11.7%	6.4%	5.6%	5.1%	5.7%

51	North Bay Hydro	3.6%	5.5%	5.8%	5.4%	8.2%	7.0%	6.9%
52	Erie Thames Powerlines	14.9%	14.4%	3.9%	7.9%	7.0%	7.0%	7.3%
53	Tillsonburg Hydro	13.5%	10.7%	12.2%	19.5%	4.4%	-0.5%	7.8%
54	Thunder Bay Hydro	9.6%	8.0%	-2.8%	8.1%	7.4%	8.6%	8.0%
55	Greater Sudbury Hydro	-2.4%	14.1%	16.7%	4.8%	14.9%	8.0%	9.3%
56	Oakville Hydro	7.6%	12.4%	10.6%	13.8%	8.7%	6.9%	9.8%
57	Waterloo North Hydro	-3.1%	6.4%	4.3%	10.6%	11.0%	8.2%	9.9%
58	EnWin Utilities	17.8%	16.8%	23.9%	10.3%	10.9%	9.9%	10.3%
59	Hydro Ottawa	-0.1%	-2.6%	7.8%	8.5%	12.7%	15.2%	12.1%
60	Renfrew Hydro	15.3%	18.3%	18.3%	15.7%	10.4%	10.6%	12.2%
61	Canadian Niagara Power	16.4%	15.6%	10.0%	11.0%	12.9%	13.0%	12.3%
62	Peterborough Distribution	14.0%	15.6%	13.2%	14.5%	14.5%	11.0%	13.3%
63	Wellington North Power	7.4%	18.0%	12.8%	17.7%	14.2%	11.8%	14.6%
64	Midland Power	16.4%	17.0%	19.6%	18.7%	15.2%	13.8%	15.9%
65	Festival Hydro	20.5%	18.0%	20.2%	19.6%	16.6%	14.0%	16.8%
66	PUC Distribution	-8.5%	-5.2%	13.4%	22.7%	14.6%	16.2%	17.8%
67	Woodstock Hydro	33.5%	32.9%	29.0%	25.9%	23.0%	19.5%	22.8%
68	Chapleau Public Utilities	17.5%	14.8%	24.0%	20.5%	27.7%	23.9%	24.0%
69	Hydro One Networks	58.6%	57.3%	58.7%	27.6%	30.0%	20.3%	26.0%
70	West Coast Huron Energy	14.4%	16.0%	34.8%	41.4%	32.8%	33.5%	35.9%
71	Toronto Hydro	41.7%	47.7%	45.1%	48.4%	49.9%	51.5%	49.9%
72	Algoma Power	62.0%	68.1%	66.4%	69.1%	68.1%	70.6%	69.3%

Annual Distribution Bill Comparison - All LDCs 2016 Rates
(monthly charge and volumetric rate)

	Utility	Residential		GS<50		GS>50		Overall	Number of
		800 kwh	% of Avg	2000 kwh	% of Avg	250 KW	% of Avg	Ranking	Customers
1	Hydro Hawkesbury	$188.16	55.3%	$332.04	50.0%	$7,352.88	61.9%	55.73%	5,499
2	E.L.K.	$219.48	64.5%	$309.24	46.6%	$6,994.14	58.8%	56.65%	12,398
3	Hearst (2015)	$264.12	77.6%	$368.40	55.5%	$5,923.44	49.8%	60.99%	2,718
4	Hydro 2000	$334.92	98.5%	$495.84	74.7%	$5,247.90	44.2%	72.43%	1,221
5	Lakefront	$266.16	78.2%	$493.92	74.4%	$11,315.46	95.2%	82.62%	9,996
6	Peterborough	$272.64	80.1%	$584.76	88.1%	$10,045.44	84.5%	84.25%	36,058
7	Kingston	$301.20	88.5%	$521.64	78.6%	$10,222.14	86.0%	84.38%	27,356
8	Westario	$311.88	91.7%	$563.28	84.9%	$9,177.84	77.2%	84.58%	22,822
9	Rideau St. Lawr. (2015)	$302.28	88.9%	$587.04	88.4%	$9,351.60	78.7%	85.32%	5,858
10	Brantford	$281.28	82.7%	$483.12	72.8%	$11,965.86	100.7%	85.38%	38,789
11	Orangeville	$316.20	93.0%	$621.48	93.6%	$8,625.90	72.6%	86.38%	11,685
12	Ottawa River	$292.08	85.9%	$564.24	85.0%	$11,289.00	95.0%	88.61%	10,820
13	Burlington	$305.52	89.8%	$635.28	95.7%	$9,559.32	80.4%	88.65%	66,366
14	Thunder Bay	$276.00	81.1%	$661.68	99.7%	$10,248.78	86.2%	89.01%	50,482
15	Entegrus	$301.68	88.7%	$597.60	90.0%	$10,832.64	91.1%	89.95%	40,503
16	COLLUS	$311.88	91.7%	$576.60	86.9%	$10,861.38	91.4%	89.97%	16,426
17	London	$313.20	92.1%	$636.60	95.9%	$9,780.00	82.3%	90.08%	152,544
18	Welland	$325.92	95.8%	$557.16	83.9%	$10,761.24	90.5%	90.09%	22,470
19	Hydro One Brampton	$285.12	83.8%	$690.84	104.1%	$9,862.32	83.0%	90.29%	149,618
20	Northern Ontario Wires	$409.08	120.3%	$718.44	108.2%	$5,052.30	42.5%	90.33%	6,062
21	Guelph	$365.40	107.4%	$524.76	79.1%	$10,215.66	85.9%	90.80%	52,963
22	Essex	$310.32	91.2%	$697.56	105.1%	$9,260.58	77.9%	91.41%	28,640
23	Veridian	$313.68	92.2%	$600.36	90.4%	$11,112.06	93.5%	92.05%	117,494
24	Halton Hills	$300.48	88.3%	$567.72	85.5%	$12,231.00	102.9%	92.25%	21,534
25	Milton (DRO)	$329.76	96.9%	$616.20	92.8%	$10,612.26	89.3%	93.02%	35,111
26	Renfrew (2015)	$306.84	90.2%	$703.80	106.0%	$9,870.54	83.0%	93.09%	4,246
27	Cambridge North Dumfries	$305.76	89.9%	$506.52	76.3%	$13,666.32	115.0%	93.72%	52,684
28	Tillsonburg	$354.72	104.3%	$749.04	112.8%	$7,764.18	65.3%	94.15%	6,935
29	Oshawa	$270.84	79.6%	$569.04	85.7%	$14,048.40	118.2%	94.51%	54,731
30	Powerstream (DRO)	$292.08	85.9%	$659.40	99.3%	$11,854.74	99.7%	94.98%	353,284
31	Woodstock	$367.44	108.0%	$650.28	98.0%	$9,412.62	79.2%	95.06%	15,745
32	Erie Thames	$366.00	107.6%	$606.48	91.4%	$10,671.30	89.8%	96.25%	18,265
33	Embrun	$320.76	94.3%	$558.84	84.2%	$13,229.16	111.3%	96.59%	1,985
34	St.Thomas	$330.60	97.2%	$669.84	100.9%	$11,455.02	96.4%	98.16%	16,918
35	Niagara-on-the-Lake	$346.80	101.9%	$737.28	111.1%	$9,801.18	82.5%	98.49%	8,672
36	WestCoast Huron	$425.28	125.0%	$642.72	96.8%	$8,964.00	75.4%	99.09%	3,797
37	Kenora	$371.52	109.2%	$611.04	92.1%	$11,550.00	97.2%	99.48%	5,558
38	Wasaga	$292.20	85.9%	$534.72	80.6%	$15,692.16	132.0%	99.49%	12,985
39	North Bay	$330.48	97.1%	$721.08	108.6%	$11,086.02	93.3%	99.68%	23,975
40	Midland	$382.92	112.6%	$663.60	100.0%	$10,390.74	87.4%	99.98%	7,035
41	Festival	$350.52	103.0%	$746.04	112.4%	$10,267.44	86.4%	100.60%	20,362

42	Brant County	$338.76	99.6%	$640.32	96.5%	$12,952.86	109.0%	101.67%	9,971
43	Centre Wellington	$325.20	95.6%	$671.40	101.1%	$12,968.82	109.1%	101.95%	6,729
44	Kitchener-Wilmot	$283.32	83.3%	$626.88	94.4%	$15,819.06	133.1%	103.60%	91,143
45	Innpower	$431.64	126.9%	$611.16	92.1%	$11,158.80	93.9%	104.28%	15,790
46	Sioux Lookout	$460.20	135.3%	$708.72	106.8%	$8,557.26	72.0%	104.68%	2,779
47	Horizon	$341.76	100.5%	$748.92	112.8%	$12,147.66	102.2%	105.16%	240,076
48	Enersource	$286.92	84.3%	$788.04	118.7%	$14,064.18	118.3%	107.13%	201,359
49	Greater Sudbury	$312.84	92.0%	$708.48	106.7%	$14,822.28	124.7%	107.80%	47,187
50	Niagara Peninsula	$396.72	116.6%	$790.20	119.0%	$11,383.86	95.8%	110.48%	51,824
51	Lakeland	$392.40	115.4%	$753.72	113.5%	$12,245.22	103.0%	110.64%	13,264
52	Hydro Ottawa	$340.80	100.2%	$725.16	109.2%	$14,611.80	122.9%	110.79%	319,536
53	PUC Distribution	$290.28	85.3%	$687.24	103.5%	$17,432.34	146.7%	111.84%	33,487
54	EnWin	$329.28	96.8%	$727.68	109.6%	$15,800.34	132.9%	113.12%	86,662
55	Whitby	$362.88	106.7%	$749.40	112.9%	$14,935.92	125.7%	115.08%	41,488
56	Orillia	$334.08	98.2%	$845.04	127.3%	$14,834.70	124.8%	116.77%	13,340
57	Grimsby (proposed)	$387.48	113.9%	$858.36	129.3%	$12,982.86	109.2%	117.48%	11,038
58	Oakville (interim)	$334.80	98.4%	$807.48	121.6%	$15,749.28	132.5%	117.52%	66,530
59	Newmarket-Tay	$323.28	95.0%	$834.72	125.8%	$15,794.52	132.9%	117.89%	34,871
60	Haldimand County	$438.96	129.0%	$779.28	117.4%	$12,805.02	107.7%	118.06%	21,323
61	Bluewater	$397.80	116.9%	$799.32	120.4%	$14,722.08	123.9%	120.40%	36,115
62	Wellington North	$434.52	127.7%	$930.12	140.1%	$11,205.30	94.3%	120.71%	3,731
63	Waterloo North	$384.36	113.0%	$765.12	115.3%	$16,627.26	139.9%	122.71%	54,674
64	Norfolk	$455.64	133.9%	$974.16	146.8%	$14,827.20	124.7%	135.15%	19,559
65	Canadian Niagara	$427.20	125.6%	$891.12	134.2%	$21,888.06	184.1%	147.99%	28,627
66	Toronto Hydro	$461.87	135.8%	$1,052.70	158.6%	$21,534.03	181.2%	158.51%	744,252
67	Algoma	$605.76	178.1%			$16,876.98	142.0%	160.03%	11,650
	AVERAGE	$340.18		$663.79		$11,886.16			

can certainly do that for the next survey.

MR. SHEPHERD: Okay. So my next question is on 1 Staff 16, and I have some handouts which I sent to you.

MR. BEHARRIELL: Yes.

[Mr. Shepherd passes documents out to intervenors and witness panel.]

MR. SHEPHERD: So we are not singling you out. Everybody gets this table. Some people look better than others on it.

MS. DJURDJEVIC: In the meantime let's make this an exhibit. So it will be KTC1.2.

EXHIBIT NO. KTC1.2: HANDOUT.

MR. SHEPHERD: And I want to start with the benchmarking results. So we have six years of benchmarking results here. These are all from the PEG studies.

MR. BEHARRIELL: Yes.

MR. SHEPHERD: First of all, have you checked to see whether these appear to be accurate to you?

MR. BEHARRIELL: They appear to be accurate, yes.

MR. SHEPHERD: All right. And so -- and then you have admitted your benchmarking isn't that good, right? You are not benchmarking well relative to your peers. Fair?

MR. BEHARRIELL: I think the benchmarking model benchmarks us relative to ourselves in terms of what the model expects our costs to be and what it calculates our actual costs to be, and so that --

MR. SHEPHERD: You think this compares you to yourself? Because that is not what PEG said. What PEG said is that they're creating a standard for the Ontario industry.

MR. BEHARRIELL: Yes.

MR. SHEPHERD: They're comparing you to that standard. Expect it is the standard, right?

MR. BEHARRIELL: And it produces an expected cost for each utility and a calculated actual cost for each utility, yes.

MR. SHEPHERD: Okay. So you have been well above expected costs for years, right?

MR. BEHARRIELL: According to the model, yes.

MR. SHEPHERD: Well, okay. So is the model wrong?

MR. BEHARRIELL: I think the model was developed in the context of benchmarking to put utilities into cohort groups for IRM ratemaking.

It has just recently been introduced as a filing requirement in the cost of service, in terms of, you know, filling out the OEB's benchmarking forecast model.

So I am not saying the model is right or wrong. I'm saying it provides a predicted cost and it calculates an actual cost, which isn't, you know -- doesn't tie in any way to our revenue requirement. Some portions of it are actual costs. Some portions of it are calculated capital actual costs. And this is the result that it produces.

MR. SHEPHERD: So you're not saying you're asking for -- for example, you're forecasting 16.2 percent above expected. So you're not saying -- if I understand what you're saying, you're not 16.2 percent above what you should be on revenue requirement?

MR. BEHARRIELL: That's correct.

MR. SHEPHERD: So why do you think that?

MR. BEHARRIELL: Because the costs calculated by the model, even though they're labelled as actual costs in the model, they don't tie specifically to the revenue requirement.

MR. SHEPHERD: So then what can you learn from this benchmarking comparison? You as a utility. What can you learn from it?

MR. BEHARRIELL: From the comparison that you provided us --

MR. SHEPHERD: Well, the comparison I provided and the comparison that you've done yourself for 2017.

MR. BEHARRIELL: So I think what we can learn from that comparison is that, you know, the model produces a result, and we have to look at whether we have justifiable cost drivers that maybe aren't captured by the model that have influenced our application, and whether those cost drivers are meaningful and justified and appropriate in the context of this cost-of-service application.

MR. SHEPHERD: That doesn't -- sorry, maybe I misstated my question. I am trying to understand how you can take information from the benchmarking data that the Board has stipulated --

MR. BEHARRIELL: Right.

MR. SHEPHERD: -- take that information and improve how you run your utility.

MR. BEHARRIELL: Well, I don't think we make budgetary decisions based on the results of this benchmarking model, specifically for the reason that, A), it doesn't capture all the cost drivers, and B), it doesn't calculate costs that ties to revenue requirement.

MR. SHEPHERD: So you just ignore it when you do budgets?

MR. BEHARRIELL: I never said we ignore it.

MR. SHEPHERD: You said you don't take it into consideration. I am just trying to understand.

MR. BEHARRIELL: Sorry, so we don't let it be the sole influence of our budgeting process. So if it produces a result and we're still in the fourth cohort group with these results, the results are up and down historically over certain years --

MR. SHEPHERD: Well, that's why we gave you the six years. And now of course we have eight years, because we have -- or we have seven, because we have 2017, because you were improving from 2010 to 2012, and then you sort of slowly are starting to get worse and worse, and now you are as bad as you were in 2010.

MR. BEHARRIELL: When we looked at the PEG report, they specifically mention that in 2012, a lot of distributors looked like they were improving. There were data quality issues, I believe, related to certain Smart Metering costs associated with that model.

So again, there are flaws in the model, and while we accept the accept the results of the model for core and group assignment for IRM benchmarking, we don't believe that the model is an appropriate tool to run our business by.

MR. SHEPHERD: So how do you use the model in doing budgeting? Like, do you use it as sort of a target in any way?

MR. BEHARRIELL: No, we do not.

MR. SHEPHERD: No?

MR. KING: No.

MR. SHEPHERD: All right. The Board appears to be going in the direction of giving more weight to benchmarking, right?

MR. BEHARRIELL: Right, and I would expect - yes, sorry, yes.

MR. SHEPHERD: And so I guess a lot of people in the sector -- and maybe not you, but a lot of people in the sector think that at some point, your budgets are going to have to be constrained by benchmarking results.

I guess my question is -- and I am not asking you to agree with that. But my question is, do you have a plan to get your benchmarking results more closer to your expected costs?

MR. BEHARRIELL: Well, I think what you have suggested is a fundamental change in the industry, if the Board expects budgets to be tied to benchmarking results.

And I would expect that in that case, that there would have to be significant stakeholder consultation. We would have to potentially engage consultants to review, you know, the model as a whole, and how it relates specifically to our utility, whether the values that are statistically significant on the province as a whole are in fact appropriate to a utility.

You're talking about a fundamental change in process.

MR. SHEPHERD: Okay. And that's why I didn't ask that part of the question. But that's fine, that's useful.

But what I am asking is about your planning. You have the Board telling you that your costs are too high relative to where they should be.

Do you have a plan to get them back in line -- not back in line, but in line for the first time with expected costs?

MR. KING: Jay, when we do our budgeting, we are aware of where we stand with regard to cohorts, but it is not a driver.

You know, we look at our costs and we look for efficiency improvements. We look for reliability improvements in customer service, but it doesn't -- this PEG report doesn't drive our business decisions. We are aware of it. We would like to get there. It is a bit of a mystery, some of the numbers that come out of it. But in our budget, we are always looking for efficiencies.

MR. SHEPHERD: All right. So then the other part of this is, of course -- and you have said the PEG results aren't comparable to your revenue requirement. But in fact, your rates are significantly higher than the averages in the industry, right?

We have given you a table of all of the 2016 approved rates to see what the distribution charge is for each category, and you appear to be higher on all of them, and among the highest in the province.

And so my question is: (a) is it reasonable to think that that is because your actual costs are higher than expected? Is there a tie between the two? And (b), do you have a plan to get your rates back down to industry averages?

MR. BEHARRIELL: I don't accept that there is necessarily a tie between the two, I guess, nor do I accept that the rates between all utilities in the province should be equal as a starting point.

Different businesses have different cost drivers, different customer counts, different throughputs, different cost pressures. That's what rates come from; they come from revenue requirement, customer accounts --

MR. SHEPHERD: I would understand if you were in the middle of the pack, but you are almost the worst. In terms of rates, you are almost the worst.

I mean, is only your affiliate and Toronto-Hydro, who nobody thinks has good rates, it's only those two that are worse than you. I guess I don't understand -- and if I am starting to get into cross-examination, I apologize. I am not intending to.

I am actually trying to give you an opportunity to explain how you view this data. How does this drive what you are doing?

MR. BEHARRIELL: So again, I think, you know, I mentioned where rates come from, from revenue requirement, from customers, from throughput.

And I think you know, to really answer your question, I would have to understand whether every one of these utilities on the list is investing capital at, you know, a sustaining pace; are they over investing, under investing? Simple differences between, you know, weighted average cost of capital, investment levels, things like that would all influence these rates.

So, you know, I can't tell you where we should be in relation to other utilities.

MR. SHEPHERD: All right. My next question is on -- oh, that's all of my questions on section 1.

MR. BEHARRIELL: Thank you.

MS. DJURDJEVIC: Okay. Anybody else have questions on Exhibit 1 or any follow up?

CONTINUED QUESTIONS BY MR. GARNER:

MR. GARNER: If I could follow up Mr. Shepherd's thing on the model.

The thing - and again, I don't want to belabour it, but the thing that I guess I'm trying to grapple with when you talk about that is, it would seem to me -- based on what you've said -- is you're describing that the model somehow is non-reflective of things that can happen at CNPI that don't happen somewhere else, or --

So wouldn't your next step be to discover what it is that you think makes those differences, why those

2-Staff-47

Ref: E2/Appendix E – CNPI 2014 OEB Performance Scorecard – Cost Control: Total Cost per Customer, pg. 5 of 8

At the above reference, it is stated that:

> Total cost is calculated as the sum of CNPI's OM&A costs, including depreciation and financing costs. This amount is then divided by the total number of customers that CNPI serves to determine Total Cost per Customer. The cost performance result for 2014 is $749
> /customer which is a 3.2% increase over 2013. However, CNPI's Total Cost per Customer has increased on average by only 1.3% per annum over the period 2010 through 2014. This compares favorably with the Consumers Price Index (CPI) over the same period.

Please provide calculations showing how the forecast operating expenditure increases of over 6% per annum in 2016 and 2017 will impact the reported Scorecard results on an overall and per customer basis.

RESPONSE:

The following table summarizes CNPI's 2015 through 2017 results from the output of the revised version of the OEB's Benchmarking Spreadsheet Forecast Model filed in conjunction with these interrogatory responses. Rows have been added to provide the forecast number of customers, as well as the forecasted Scorecard Total Cost per Customer.

	Cost Benchmarking Summary	2015 (Actual)	2016 (Bridge)	2017 (Test Year)
A	*"Actual" Total Cost*	*22,334,375*	*23,734,124*	*25,708,814*
B	*Predicted Total Cost*	*19,620,562*	*20,383,100*	*21,862,804*
C = A - B	***Difference***	***2,713,813***	***3,351,025***	***3,846,011***
D = LN (A / B)	**Percentage Difference (Cost Performance)**	**13.0%**	**15.2%**	**16.2%**
E	Three-Year Average Performance	13.2%	13.7%	14.8%
F	Number of Customers	28,713	28,788	28,863
G = A / F	Scorecard Total Cost per Customer	778	824	891

OM&A CALCULATIONS

(Includes Property Taxes and LEAP)

		2013 BA	2013	2014	2015	2016	2017
SECTION 1	**ADJUSTMENTS TO OM&A**	2013 BA	2013	2014	2015	2016	2017
Total OM&A - Exhibit 4 - Table 4.1.1.1 & 1-Staff-17		9,835,961	8,864,063	9,434,813	9,518,933	10,130,816	10,574,723
Vehicle Depreciation - Exhibit 4, Table 4.2.2.1 & 4-EP-15		0	351,000	0	0	0	0
Adjusted Total		**9,835,961**	**9,215,063**	**9,434,813**	**9,518,933**	**10,130,816**	**10,574,723**
% Increase per Year			**-6.31%**	**2.38%**	**0.89%**	**6.43%**	**4.38%**
% Average Annual Compound Increase 2013 to 2017							**3.50%**
SECTION 2	**CUSTOMERS**	2013 BA	2013	2014	2015	2016	2017
Customers -Exhibit 4 - Appendix 2-L		28,438	28,584	28,627	28,670	28,705	28,781
Customer Growth			**0.51%**	**0.15%**	**0.15%**	**0.12%**	**0.26%**
% Average Annual Compound Increase 2013 to 2017							**0.17%**
SECTION 3	**ESCALATORS**			2014	2015	2016	2017
Inflation (1)				1.70%	1.60%	2.10%	1.90%
Base Productivity				0.00%	0.00%	0.00%	0.00%
Stretch Factor				0.45%	0.45%	0.45%	0.45%
Sub-Total (lines 20 - 21 - 22)				1.25%	1.15%	1.65%	1.45%
Customer Growth - PEG Customer Elasticity		**0.4448**		0.07%	0.07%	0.05%	0.12%
Total Escalator (lines 20 - 21 - 22 + 24)				**1.32%**	**1.22%**	**1.70%**	**1.57%**
SECTION 4	**OM&A GROWTH AT ESCALATOR**		2013	2014	2015	2016	2017
Adjusted OM&A Growth - Based on Escalator (line 25) - 2013 BA Start			9,835,961	9,965,492	10,086,753	10,258,662	10,419,494
Test Year Forecast (line 8)							10,574,723
Test Year Reduction							**-155,229**
Adjusted OM&A Growth - Based on Escalator (line 25) - 2013 Start			9,215,063	9,336,417	9,450,024	9,611,081	9,761,760
Test Year Forecast (line 8)							10,574,723
Test Year Reduction							**-812,963**
Adjusted OM&A Growth - Based on Escalator (line 25) - 2014 Start				9,434,813	9,549,617	9,712,371	9,864,638
Test Year Forecast (line 8)							10,574,723
Test Year Reduction							**-710,085**
Adjusted OM&A Growth - Based on Escalator (line 25) - 2015 Start					9,518,933	9,681,164	9,832,942
Test Year Forecast (line 8)							10,574,723
Test Year Reduction							**-741,781**
Adjusted OM&A Growth - Based on Escalator (line 25) - 2016 Start						10,130,816	10,289,644
Test Year Forecast (line 8)							10,574,723
Test Year Reduction							**-285,079**
Average							**-541,027**
Average (excluding Bridge)							**-605,014**
Average (excluding BA)							**-637,477**
Average (excluding BA & Bridge)							**-754,943**

NOTES

(1) Inflation rates taken from OEB website for each year

2-Staff-25

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.2.1.2: Sources of Cost Savings Expected, pg. 28-29 of 163

At the above reference, it is stated that:

> Over the previous cycle, CNPI has undertaken many procedural and policy improvements to improve efficiency in the operation of the system that are expected to show positive results with respect to cost savings and efficiencies.
>
> CNPI has identified the following sources of cost savings and efficiencies expected to be achieved over the forecast period:
>
> - Targeted Asset Replacement Programs
> - Distribution Automation (DA)
> - Standardized Designs
> - Mobile Computing
> - Distribution System Line-Loss Reduction

a) Please quantify the expected annual operational savings that will result from implementation of the following cost saving sources:

   a. Targeted Replacement Programs
   b. Distribution Automation Programs
   c. Standardized Design Programs
   d. Mobile Computing Programs
   e. Distribution System Line-Loss Reduction

b) Are the trends in capital and O&M spending related to these cost savings being tracked?
   a. If yes, please provide this data.
   b. If no, please describe the steps being taken by CNPI going forward to ensure adequate tracking of O&M spending trends and cost savings trends.

RESPONSE:

a) See response below:

   a. Please see CNPI's response to 2-Staff-24 for a quantification of cost savings on a per-pole basis. CNPI expects a lag between the ramp-up of pole replacement levels and a definitive downward trend in pole failure rates and is therefore unable to quantify an expected annual operational savings in the short term.

   b. The Distribution Automation program is focused on enhancing reliability rather than economic savings.

   c. The Standardized Design Programs and Mobile Computing Programs are expected to provide labor-saving efficiencies for Planning staff and Line staff that will allow them to perform their required tasks more efficiently. There have been many process changes in recent years due to increased demands from safety, regulatory, legal, and environmental stakeholders that have significantly increased the effort required to design, plan and execute projects. Examples of process changes with upwards pressure on costs include, but are not limited to, the introduction of requirements for non-linear design in recent CSA standards updates and the introduction of Habitat Stewardship procedures driven by the requirement to ensure on-going compliance with environmental legislation such as but not limited to Species at Risk, Clean Water, Fisheries and Wildlife.

      Implementation of the Standard Design Programs are anticipated to allow CNPI to continue to meet all of its current and above noted increasing obligations without affecting Engineering staff levels.

There will be some direct savings, as the Mobile Computing Project is expected to save $12k per year in avoided processing and distribution costs of updates to Operating System Mapbooks.

d. See response to c) above.

e. Any savings associated with Distribution System Line-Loss Reductions would flow-through to CNPI's ratepayers through lower charges to the cost of power variance account. CNPI's operating costs will not be impacted as a result of line loss reductions.

b) No.

a. N/A.

b. CNPI is not intending on establishing any formal monitoring of O&M spending trends at a level of granularity sufficient to track the costs discussed above. This would require a substantial increase in effort for limited value. It is likely that establishment of such tracking measures would trigger the addition of one or more full-time clerical or analytical staff.

2-Staff-28

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.1.7: Expected System Development over the Planning Horizon – Smart Grid Developments, pg. 54-55 of 163

At the above reference, it is stated that:

> CNPI will continue to invest in the following technology-driven Smart Grid programs that are already underway at CNPI:
>
> 1) Distribution automation through the targeted installation of reclosers, automated switches and fault indicators. CNPI intends to continue with its efforts to integrate such facilities with its SCADA and Outage Management System (OMS) applications
> 2) Substation Protection Upgrades – CNPI will continue with its program to replace legacy fuse protection with relay-controlled reclosers to improve reliability and protection, and improve SCADA controllability of its feeders.
> 3) GIS / OMS – CNPI will continue to make select investments in its GIS and OMS systems to meet the needs of its external and internal stakeholders. The focus will be on improved operational efficiencies and improved customer communications.

Do new Information Technologies and Smart Grid developments improve CNPI's labour productivity and/or system reliability?

i. If yes, how does CNPI measure and track these impacts? Please provide detailed examples.

ii. If no, what are the key benefits of new Information Technologies and Smart Grid developments?

RESPONSE:

i. CNPI's deployment of "smart grid" technology is fundamentally focused on improving system reliability and outage response time. From the distribution system perspective, CNPI evaluates monthly feeder based outage statistics and targets areas of poor performance with protection and automation enhancements where feasible.

For example, in 2015, the 17L67 feeder, servicing approximately 5,422 customers in the Fort Erie service area, was least performant in terms of SAIDI and SAIFI. The Feeder-SAIDI (F-SAIDI) value was 0.83 and the Feeder-SAIFI (F-SAIFI) value was 1.77 for the period. CNPI completed the implementation of protection upgrades and introduced additional sectionalizing capability on the feeder to improve coordination and restoration capability. In the first six months of 2016, the F-SAIDI value is 0.00039 and the F-SAIFI value is 0.00062 for the 17L67 feeder. While the balance of 2016 will likely see some addition to these indices for the feeder, performance to date has demonstrated significant improvement.

CNPI continues to monitor feeder level performance to identify year over year trends in SAIDI and SAIFI performance. Feeders with diminishing performance are analyzed to determine if technology deployment would benefit reliability and response time.

CNPI's GIS system models electrical connectivity from transformer station breaker to the customer's meter. The GIS provides operational staff with a single point of interface to support map based workflows and to provide asset information. The GIS model also supports system planning processes with tools for spatial analysis, engineering analysis, and environmental management.

CNPI utilizes an Outage Management System (OMS) in day to day operations which leverages the GIS connectivity model. The OMS uses this electrical connectivity model to support outage prediction. The fundamental advantages of the deployed outage management capabilities are:

- Outage Prediction Functionality: The outage prediction engine performs real time analysis of incoming calls to determine the probable failed device. This functionality eliminates the requirement for operational staff to translate calls into an outage event which reduces the overall response time for outages. This is particularly advantageous during significant events, allowing for prioritization of outages by critical customers and customer count.

- Automatic Vehicle Location: Crew location is tracked in real time on the outage management dispatch console, allowing operators to make informed decisions regarding work allocation. This ensures that the crew most equipped and available are tasked with responding to outage events, improving overall outage response time.

- Web-Based Outage Portal: CNPI has deployed a web-based outage portal which provides real time outage information to internal staff. This tool is used by customer service and operational staff for a depiction of outage status. This functionality significantly reduces verbal interaction between the control room and customer service staff, ultimately providing improved accuracy and timeliness of information to customers.

In addition to the aforementioned reduction in outage response times in this environment, the OMS is also integrated with CNPI's SCADA system. This integration combines real time device status input with inbound customer call data, as inputs to the prediction engine. The result is rapid prediction of outage events on the distribution system. Again, this is a significant, positive impact, to overall response time as

CNPI operational staff are immediately provided detailed information on outage scope and location.

ii. N/A

are going to save because of these things?

MR. BEHARRIELL: We don't really have a good history on, you know, how many after-hours outages would avoid a truck roll. So it's -- you know, I gave you that hypothetical example. As we get into this, you know, we can start quantifying that and have some history to --

MR. SHEPHERD: There is no dollars in your budget for --

MR. BEHARRIELL: No.

MR. SHEPHERD: -- those savings?

MR. HAN: No, before -- okay.

MR. SHEPHERD: Thanks.

Then I wanted to turn to 2 Staff 25. And Board Staff quoted your comment that you've undertaken many procedural and policy improvements to improve efficiency and -- et cetera that result in cost savings.

So I want to look at your response (c), and you have a bunch of examples of upward pressure on costs, but I didn't see you identifying where the savings are coming from.

It appears that what you're saying is that it's going to cost you just as much as before, but you are going to be able to do more.

MR. BEHARRIELL: We're going to be able to meet those increased cost drivers without adding staff as a result of, you know, a sum total of these marginal cost-efficiency improvements, you know -- none of those items on their own reduce a whole FTE. But they may make a task that previously took an hour, say, take 50, 55 minutes, and over the course of a month that adds up, and these other cost pressures are taking that same task that would have taken an hour and making it take, you know, hour and ten minutes, an hour and 15 minutes, so the two are offsetting.

MR. SHEPHERD: So from the customer's point of view they're spending more money and they're not getting anything more, but the reason they're not getting anything more is because of government or regulatory policy decisions that are requiring you to do more.

So the customers are getting something more from a policy point of view but not from a distribution point of view; is that fair?

MR. BEHARRIELL: That's correct, yes.

MR. SHEPHERD: My next question is on 2 Staff 28. We talked a little bit about this already. You have talked about the fact that your GIS gives you better information and your new outage management system is drawing on the capabilities of the GIS, right?

MR. BEHARRIELL: Yes.

MR. SHEPHERD: So there is going to be a bunch of savings there, but you haven't costed any of those yet. You don't know what those savings are going to be?

MR. BEHARRIELL: Correct, yes.

MR. SHEPHERD: The outage prediction functionality, are you doing that yet? Are you predicting outages yet?

MR. KILFOIL: We're not predicting outages. Once an outage occurs we're predicting the extent of the outage and how to respond to it. It is a triaging (sic) tool. It doesn't guess when an outage is going to happen sometime in the future. It makes for much more rapid identification of the extent of any given outage, so --

MR. HAN: Here is how it works, just a simplified answer. I have got one call on an operator. I have one call. You called me and say you have no power. I know where you are on my map. Okay. This is my GIS. Okay. You're there. And then I am going to send a truck to you. But where? It can be your house, the device above you, or device above that.

Now, meanwhile I am sending a truck to you, I get another call, and he is calling -- your neighbour call, so I look at you and your neighbour, oh, both of you are sending -- supplied from the same transformer. Potentially it is a transformer problem.

And then the third the customer call is a different transformer.

MR. KILFOIL: But same street.

MR. HAN: On the same street. Now it is a line problem.

So I can save the outage time by sending my crew to the problem now. It is not 100 percent right.

MR. SHEPHERD: Now, part of this -- and I take it this is not the same system, but it is a related system, is you now know where all your vehicles are too, right?

MR. HAN: Oh, sure. We can.

MR. SHEPHERD: Is that part of your GIS or is that part of a different system?

MR. HAN: It requires the equipment -- the vehicle equipped with a GIS before we know where they are.
MR. SHEPHERD: Which not all of them are yet?
MR. BEHARRIELL: Correct, yes.
MR. SHEPHERD: And that saves you money too, right? Because you can identify where the problem is --
MR. BEHARRIELL: I don't know if it saves us money, but in a mass outage scenario when you have vehicles all over the place and you have outages all over the place, you can more efficiently decide which crews respond to which outage by knowing where the vehicles are with certain crew components and in relation to those outages.
At the end of the day in a mass scenario like that when you have tonnes of crews out on overtime, if they get everything wrapped up half an hour early then, yes, maybe there is a marginal savings, but --
MR. SHEPHERD: And then the last component of this is -- that I am -- from this example is -- I am on page 3 -- is the web-based outage portal, which is not so much for your customers. This is internally, right?
MR. BEHARRIELL: Right.
MR. SHEPHERD: This is giving you internal information on outages.
MR. BEHARRIELL: Yes.
MR. SHEPHERD: Again, that saves you money, right? The more information you have the more efficiently you can respond, right?
MR. KILFOIL: It is more of an increase in available

information than a money savings. We make a better decision, not necessarily cheaper decisions.

MR. SHEPHERD: Better decisions save you money, right?

MR. BEHARRIELL: Well, but I think when you talk about that outage portal, so a customer-service staff that's taking the calls during the outage during regular hours, they now have information on the extent of that outage.

So, yes, they might be able to minimize the call time with a customer during that outage. Are we reducing an FTE because of that? No, we're not. So there is no direct cost savings. We have better information to supply to our customers.

MR. SHEPHERD: None of these things are reflected in cost saving in your budgets right now? Right? They may be in the future, but not right now.

MR. BEHARRIELL: True.

MR. SHEPHERD: Okay. My next question is on 2 Staff 34. 2 Staff 34, you talk about these two major projects that you are going to be doing. They're both delta to Y conversions, I guess, are they? Yes?

But what you said is that even though they're two big Projects, you are actually going to split them into a number of sub projects. Can you describe how that works?

MR. KILFOIL: Well, when we assign jobs to planners who go out there and plan specific work to be gone by line Crews, we don't say here's five million dollars go do it. We break it down into much more manageable pieces to be planned, and staked, and performed more efficiently.

However, we do believe we have some savings, because we use the same manpower level, a combination of a lot of requirement over the last five years or four years, without increased staff level.

MR. WALSH: Okay.

MR. HAN: Does that make sense?

MR. WALSH: Yes, thank you.

Let me just quote from the same question -- in here -- let me just read the quote. It said that 2 percent inflation is a reasonable balance between inflationary pressures and the offsetting nature of productivity improvements and additional cost drivers.

Is there somewhere in your, either in the DSP or in the filing, where you have your inflation assumption?

MR. BEHARRIELL: I will have to find that reference, but I believe it is somewhere in Exhibit 1.

MR. WALSH: Do you know what it is offhand?

MR. BEHARRIELL: I will have to look for that to find that reference for you.

MR. WALSH: I guess the question is, if it is different than 2 percent, then I guess the question is, then is there any productivity that's bringing that number down?

I am imagining that inflation goes up, productivity pushes it down, and consequently this 2 percent number would be below the inflationary number, but I am just trying to seek clarification on that.

MR. BEHARRIELL: So we do have productivity improvements. We will also have cost drivers that are in excess of inflation. So our assumption 2018 forward is that 2 percent is a reasonable balance between those two items.

MR. WALSH: Okay. Thank you.

MR. SHEPHERD: So I have a follow-up on that as well. I had the same thing. It looks like it is zero productivity, right? The net of the additional cost drivers and the productivity benefits is zero.

MR. BEHARRIELL: That's what we have assumed for the purpose of presenting O&M costs 2018 forward, yes.

MR. SHEPHERD: But then you have things like these additional programs that you are saying are additional cost drivers. And they're not offset by productivity benefits, right? You have a list of additional cost drivers that you are saying are pushing your costs up and you are adding those.

MR. BEHARRIELL: Yes, we are.

MR. SHEPHERD: But I thought you said they are offset by productivity improvements.

MR. BEHARRIELL: That is our forecast for 2018 forward.

MR. SHEPHERD: Okay. So 2016 and 2017, that is not true?

MR. BEHARRIELL: For 2016 and 2017 we have identified additional programs, such as the emerald ash borer, missed metering, et cetera, pole testing, that are additional cost drivers for various reasons that are not offset by productivity improvements.

MR. SHEPHERD: Okay, thanks.

MR. WALSH: I just have a clarifying question. On the emerald ash borer program, how many years do you expect that is to last, and does it dissipate over -- are the costs higher in the initial years? Or is it sort of a five years and -- what does the anticipated spend on addressing that issue look like?

MR. HAN: We hired a consultant. They did a study on that. And my understanding is, once a tree is infected, it is predicted in three years the tree will be dead. But whether the tree owner decides to remove the tree or not is up to the tree owner. That's one piece of information.

The other piece of information, there is a projection of the next seven years -- seven to eight years most of the trees in the Niagara region will be dead, in the -- you know, emerald ash tree will be dead.

So we're thinking it is a prudent -- we don't really know. This is a new program. We really don't know what it is going to cost us if we go into this field at the end of the day. But we feel it is providing the tree owner a safety working zone for them to remove tree or improve public safety, because this is not a one-person or two-persons issue. This is a system-wide issue. It is similar to underground locates. We do not charge people for underground locates, but this is a safety issue. If we charge them, they may not report. They may not ask. So this is a similar thing.

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Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2013

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Senior Unsecured Notes	Life insurance comp	Third-Party	Fixed Rate	14-Aug-03	15	$ 30,000,000	7.092%	$2,127,600.00	
2	Senior Unsecured Notes	n/a	Third-Party	Fixed Rate	14-Aug-03	15			$ 32,028.00	Debt issue costs amort.
3	Promissory Note	FortisOntario Inc.	Affiliated	Fixed Rate	1-Jan-13	Demand	$ 20,000,000	4.030%	$ 806,000.00	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 50,000,000	5.93%	$2,965,628.00	

Year 2014

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Senior Unsecured Notes	Life insurance comp	Third-Party	Fixed Rate	14-Aug-03	15	$ 30,000,000	7.092%	$2,127,600.00	
2	Senior Unsecured Notes	n/a	Third-Party	Fixed Rate	14-Aug-03	15			$ 32,028.00	Debt issue costs amort.
3	Promissory Note	FortisOntario Inc.	Affiliated	Fixed Rate	1-Jan-13	Demand	$ 20,000,000	4.030%	$ 806,000.00	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 50,000,000	5.93%	$2,965,628.00	

Year 2015

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Senior Unsecured Notes	Life insurance comp	Third-Party	Fixed Rate	14-Aug-03	15	$ 30,000,000	7.092%	$2,127,600.00	
2	Senior Unsecured Notes	n/a	Third-Party	Fixed Rate	14-Aug-03	15			$ 32,028.00	Debt issue costs amort.
3	Promissory Note	FortisOntario Inc.	Affiliated	Fixed Rate	1-Jan-13	Demand	$ 20,000,000	4.030%	$ 806,000.00	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 50,000,000	5.93%	$2,965,628.00	

Year 2016BY

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Senior Unsecured Notes	Life insurance comp	Third-Party	Fixed Rate	14-Aug-03	15	$ 30,000,000	7.092%	$2,127,600.00	
2	Senior Unsecured Notes	n/a	Third-Party	Fixed Rate	14-Aug-03	15			$ 32,028.00	Debt issue costs amort.
3	Promissory Note	FortisOntario Inc.	Affiliated	Fixed Rate	1-Jan-13	Demand	$ 20,000,000	4.030%	$ 806,000.00	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 50,000,000	5.93%	$2,965,628.00	

Year 2017TY

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Third Party Debt	Life insurance comp	Third-Party	Fixed Rate	14-Aug-03	15	$ 30,000,000	7.092%	$2,127,600.00	
2	Affiliated debt	FortisOntario Inc.	Affiliated	Fixed Rate	14-Aug-03	15			$ 32,028.00	Debt issue costs amort.
3	Affiliated debt	FortisOntario Inc.	Affiliated	Fixed Rate	1-Jan-17	Demand	$ 20,000,000	4.540%	$ 908,000.00	Updated deemed
4									$ -	interest rate
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 50,000,000	6.14%	$3,067,628.00	

Notes

1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.

2 Input actual or deemed long-term debt rate in accordance with the guidelines i*The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, or with any subsequent update issued by the Board.

3 Add more lines above row 12 if necessary.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Algoma Power Inc.
A FORTIS ONTARIO Company

September 22, 2016

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2700
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli:

RE: CONSULTATION ON THE REGULATORY TREATMENT OF PENSIONS AND OTHER POST EMPLOYMENT BENEFIT COSTS (EB-2015-0040)

In response to the Board's letter of August 10, 2016, please find accompanying this letter, the submissions of Canadian Niagara Power Inc. ("CNPI") and Algoma Power Inc. ("API"). In addition to the general submissions requested in the August 10 letter, CNPI and API have provided additional submissions relating to their respective unique circumstances and prior proceedings before the Board in relation to Pension and Other Post Employment Benefit Costs.

If you have any questions in connection with the above matter, please do not hesitate to contact the undersigned at (905) 871-0330 extension 3278.

Yours truly,

Original Signed by

Gregory Beharriell
Manager, Regulatory Affairs

Enclosure

Comments Specific to CNPI and API

Pension and OPEB History - CNPI

Prior to July 1999, all CNPI employees were eligible for participation in the CNPI Defined Pension Plan (the "DB Plan"). Beginning in July 1999, the DB Plan was closed to new entrants and remained available for only those active employees that, at that time, elected to remain in the DB Plan. All employees hired post July 1999 and those employees that elected to exit the DB plan are eligible for participation in the CNPI Defined Contribution Plan (the "DC Plan").

With the inception of the Port Colborne Hydro lease arrangement in April 2002, CNPI acquired employees who were active participants in the Ontario Municipal Employees Retirement System ("OMERS"). At that time, CNPI became an Associated Employer within OMERS accommodating the continued participation of the "acquired employees" in OMERS as well as recruited employees from an OMERS Employer. Otherwise, new employees are not eligible for OMERS enrolment.

CNPI also provides certain extended health and dental benefits, ("OPEB"), on behalf of its retired employees.

Pension and OPEB History - API

Effective July 1, 2009, employees of the distribution division of Great Lakes Power Limited ("GLPL") were transferred to a separate company, Algoma Power Inc. (formerly Great Lakes Power Distribution Inc.). These employees were members of the Retirement Plan of GLPL prior to July 1, 2009. The Retirement Fund of Algoma Power Inc. (the "DB Plan") was established for the employees transferred to Great Lakes Power Distribution and for future eligible employees. On January 27, 2011, the Financial Services Commission of Ontario approved the transfer of assets from the GLPL Plan to the DB Plan. Full time unionized employees are eligible to participate in the DB Plan. All full-time, permanent, non-unionized employees are eligible for participation in the API Defined Contribution Plan (the "DC Plan").

API provides certain extended health and dental benefits, ("OPEB"), on behalf of its retired employees.

Uniqueness of CNPI and API

As detailed in the previous section, CNPI currently administers three forms of pension and post-employment plans for its employees, namely the DB Plan, the DC Plan, and OMERS. Likewise, API administers both a DB Plan and a DC Plan.

In addition to administering multiple types of pension plans, CNPI's and API's treatment of their DB Plans and OPEB's is complicated by reporting under a different accounting standard, namely Part II of the CPA Canada Handbook – Accounting standards for private enterprises ("ASPE"), on an accrual basis. Impacts arising from differences in accounting standards have been discussed in the KPMG report and multiple stakeholder submissions. This has resulted in most stakeholders emphasizing recommendations that the Board retain the flexibility to decide on the appropriate treatment of pension and OPEB costs on a case-by-case basis. CNPI and API agree with this recommendation and further submit that in its circumstances, the OEB has already turned its attention to this issue as a result of the EB-2013-0368 and EB-2013-0369 proceedings, as summarized below.

The EB-2013-0369 (CNPI) and EB-2013-0368 (API) Proceedings

On October 21, 2013, both CNPI and API submitted applications to the Board for Deferral and Variance Accounts for Transitional & Annual Adjustments to its Pension and Other Post-Employment Benefits. The basis for these applications was the impact that would have been caused by the Canadian Accounting Standards Board's May 2013 issuance of Section 3462, Employee Future Benefits, in Part II of the CPA Canada Handbook, replacing Section 3461, effective January 1, 2014.

Section 3461 permitted the use of a "corridor approach" to allow the deferral of actuarial and other re-measurement gains and losses to future periods through the amortization of these costs over the remaining service life of current active employees. This approach provided a mechanism for smoothing pension and post-retirement expense that would otherwise be volatile. Section 3462 requires all re-measurement gains and losses be recognized immediately, resulting in significant volatility in the income statement. Other accounting standards (e.g. legacy Canadian GAAP, US GAAP, and IFRS) allow the re-measurement gains and losses to be amortized over multiple years, or recognized in Other Comprehensive Income.

CNPI and API requested to continue to use the corridor approach permitted under Section 3461, and to establish DVA's to track any differences between the Section 3461 and Section 3462 approaches. The Board's decision in these proceedings established the requested accounts, retroactive to January 1, 2013. CNPI expects that in the fullness of time, the account balances should work back to zero, as the amounts recorded simply reflect a timing difference between Section 3461 and Section 3462 accounting.

It should be noted that these proceedings apply only to the DB Plans and OPEB's. The DC and OMERS plans are recorded on an accrual basis based on actual contributions made.

General Submissions of CNPI and API

In its letter of August 10, 2016, the Board provided guidance with respect to the focus of stakeholder submissions. In particular, the Board expressed an interest in parties' views on principles for assessing costs, options for cost recovery, and views on whether a set-aside mechanism is necessary. The views of CNPI and API are summarized below.

Principles that the OEB Should Adopt for Assessing Pension and OPEB Costs in Rate Applications

CNPI and API submit that in considering the appropriate rate mechanism for cost recovery, the OEB should be guided by the principles of intergenerational equity, rate stability, predictability, and fairness.

CNPI and API believe that current filing requirements provide for sufficient information to be filed in support of cost of service or custom-IR rate applications to allow the OEB to assess the reasonability of an individual LDC's request for recovery of pension and OPEB related costs. CNPI and API appreciate the Board's desire to be able to benchmark LDC's, but re-iterate the significant concerns that have been brought forward regarding the fact that pensions and OPEB's represent only a portion of overall compensation. CNPI and API also submit that any proposal to benchmark these costs through changes to accounting methods and/or changes to filing requirements are likely to be administratively burdensome, and likely of limited value without consideration of the inherent difference in overall compensation. In short, it is quite likely that the costs to ratepayers of such an exercise will exceed the benefits.

Options for Rate Mechanisms for Cost Recovery

CNPI and API submit that the accrual basis currently in use by a majority of stakeholders is the method that best satisfies the above principles, with a minimum administrative burden. The assumptions used in expense calculations and the values resulting from those calculations are highly scrutinized by multiple parties, including independent auditors. In the case of CNPI and

API, this scrutiny applies to both the Section 3461 and Section 3462 approaches. Any deviation or change in accounting policy that the OEB may require may affect the level of review and the comfort gained over these numbers on a go forward basis.

Given the range of possible combinations of pension plan type, OPEB's, and accounting standards, CNPI and API submit that a universal approach is neither practical, nor desirable. In providing any direction or guidelines related to pension and OPEB cost recovery, the OEB should retain the flexibility to address LDC-specific issues on a case-by-case basis.

Views on Set-Aside Mechanism

As requested in the Board's letter of August 10, 2016, CNPI and API views are focused on the latter two options for a set-aside mechanisms proposed by KPMG (reduction to rate base and a tracking account).

CNPI and API do not support the inclusion of any set-aside mechanism on the basis that it would expect little, if any, net benefit to ratepayers. As outlined by the EDA, the adoption of any set-aside mechanism is likely to negatively impact LDC's in terms of restricting funds and negatively impacting credit ratings. To the extent that this increases an LDC's cost of borrowing, or requirements to borrow, ratepayers will be negatively impacted.

In addition, the reduction to rate base and tracking account mechanisms as proposed do not satisfy the rate making principle of fairness. To the extent that excess recoveries reduce rate base or attract interest to the ratepayers benefit, then a counter-mechanism should be applied to situations where a shortfall exists.

Notwithstanding the above objections to a set-aside mechanism of any kind, CNPI and API submit that *if* the Board decides to adopt a set-aside mechanism, the tracking account option seems to be the only appropriate mechanism. CNPI and API submit however that the Board should seek further input on value-for-money of such a proposal, and should consider the merits of implementing this mechanism on a case-by-case basis, where objective evidence shows that the amounts are material and the benefits offset the costs, rather than mandating an industry-wide implementation.