BY EMAIL and RESS

Jay Shepherd
jay@shepherdrubenstein.com
Direct: 416-804-2767

March 8, 2018
Our File No. EB-2017-0269

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

Attn: Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: EB-2017-0269 – Newmarket-Tay/Midland MAADs

We are counsel for the School Energy Coalition. Pursuant to Procedural Order #2 in this proceeding, this letter constitutes SEC's submissions with respect to the Application.

Overall Position/Summary

SEC submits that the transactions meet the "no harm" test, support the Board's statutory objectives, and are a positive step toward the goal of rational consolidation of the electricity distribution sector. Therefore, SEC submits that the Board should approve the transactions, subject to certain conditions.

The proposed conditions are as follows:

1. The Applicants should be required to update their cost allocation models (including updated load shapes) within twelve months of completing the transactions. Those new models should be filed with the Board, together with a proposal to adjust over time any rates that are too high or too low relative to the Board's cost allocation policies.

2. The Applicants' commitment to file a consolidated DSP by the end of 2020 should be made a condition of approval.

3. The 10 year rebasing deferral period should be fixed, not optional at the discretion of the Applicants.

4. Any amount arising from the earnings sharing formula should be refunded annually to customers as part of the Applicants' annual IRM applications.

5. The impact of accounting changes due to IFRS conversion should be reported in the next IRM application of NT Power, and thereafter should be refunded annually to customers as part of the Applicants' annual IRM applications.

Background

NT Power seeks to acquire MPUC and amalgamate their service territories. The MPUC service territory is contiguous with the Tay component of the NT Power service territory. There are obvious efficiencies to be gained by the combination of the two utilities. Cost savings of up to $1.4 million are forecast. In addition, the Applicants are already thinking ahead to reducing line losses, and increasing reliability, through changes to their receipt of power from the IESO grid in the Midland and Tay area. While these plans have no guarantees, they are clearly promising.

Currently, MPUC has slightly higher residential distribution rates than NT Power, but has much lower small business and commercial/industrial rates. The Applicants agree that the rate comparison, using the most recent class volumes from MPUC, is as follows[1]:

NT Power vs. MPUC Annual Distribution Bills Comparison

MPUC Class and Average Load per Cust.	*Billing Component*	*MPUC 2017 Rates*		*NT Power 2017 Rates*	
Residential 628	Monthly	23.20	$278.40	21.25	$255.00
	Volume	0.0107	$80.64	0.0075	$56.52
	Annual Bill		$359.04		$311.52
GS<50KW 2518	Monthly	22.62	$271.44	30.55	$366.60
	Volume	0.0167	$504.61	0.0200	$604.32
	Annual Bill		$776.05		$970.92
GS>50KW 218.7	Monthly	63.93	$767.16	138.54	$1,662.48
	Volume	3.2581	$8,550.56	4.9127	$12,892.89
	Annual Bill		$9,317.72		$14,555.37

Generally, NT Power has relatively high rates compared to provincial averages, while MPUC has rates that are closer to average. Attached as Appendix 1 to this Final Argument is a table listing the 2017 distribution bills for all Ontario distributors (except Hydro One) for the residential GS<50 and GS>50 classes. The volumes used in the table are the same as those above.

[1] SEC IR #5, corrected for typo in the GS>50 volumetric rate.

What the rate comparison shows is that MPUC's rates are about 10% above average for residential, dead on for small business, and about 15% below average for commercial/industrial. By contrast, NT Power rates are about 5% below average for residential, but more than 25% higher for small business, and more than 30% above average for commercial/industrial. In fact, only three distributors have higher small business rates, and only five distributors have higher commercial/industrial rates.

In our comments below, we note the likely reasons for this problem, and a potential solution.

On the other side, NT Power has better efficiency benchmarking results than MPUC. While it is unusual for a utility to have higher rates, but better efficiency, in 2016 the NT Power actual costs were 16.7% below predicted costs. For MPUC, actual costs were 11.8% above predicted costs. This differential has been consistent for all of the years the Board has been benchmarking distributors using the PEG model.

Both distributors have reasonably good reliability and customer service results, and there is no reason to believe that their performance in either case will decline after a consolidation.

Subject to some specific comments, noted below, it would appear to SEC that the combination of these distributors will be in the long term interests of customers, and should be approved.

Rebasing Deferral

The Applicants have proposed that they be allowed a ten year deferred rebasing period, in keeping with the Board's MAADs policies.

Aside from problems with cost allocation and rate design, discussed below, the proposal is normal, but for two problems.

First, the Applicants propose that they be allowed to choose whether to continue on the 10 year deferral or not, in effect having an unfettered discretion to file cost of service at any time[2].

SEC believes that this would allow the Applicants to, in effect, game the system. If they can keep their expenses down, they benefit for a relatively long time from rebasing deferral. On the other hand, if they cannot control expenses, they can come back at any time for an increase in rates. The result is asymmetrical, and in our submission is not fair to customers.

SEC therefore submits that the Board's order should make clear that the ten year rebasing deferral, if allowed, is a fixed period, and cannot be shortened by the Applicants except under the normal rules for early rebasing.

Second, and much more important, the Applicants' have not had a Board review of their costs on the normal cycle. MPUC last rebased for 2013[3], and so would normally have been expected to rebase for 2017 rates. It did not, and now proposes to extend that period from four years to

[2] SEC IR #15 and Staff IR #16.
[3] SEC IR #20.

fifteen. NT Power last rebased in 2010 (EB-2009-0269)[4], and has deferred rebasing already for four years. Now they are seeking to move to eighteen years before the Board reviews their costs and operations.

One result of this is that the embedded assumptions in NT Power rates are much higher than the Board's current assumptions. As NT Power admits[5], embedded in their current rates are a cost of long term debt of 5.48%, a tax rate of 28.25%, an ROE of 9.66%, and a working capital allowance of 15%. While SEC has been unable to find a source for those figures (which are lower than we thought were the case), even with those figures revenue requirement is about 8% higher than it would be with the current Board deemed amounts for those items. The size of the differential is largely the result of the unusually long period since the last NT Power rebasing. To the extent that capital and operating costs have increased at a rate greater than the IRM formula, that could partially offset the abnormally high revenue requirement.

In SEC's submission, the Board should consider whether an adjustment to revenue requirement is appropriate to update the underlying basis of rates. While we have not included that as one of our recommendations, above, in our view it would be appropriate for the Board to consider whether the lengthy past rebasing deferrals for NT Power should influence how the Board applies its normal 10 year rebasing deferral (usually applied with no adjustments) in this case.

Another result of the lengthy deferral period is that cost allocation and rate design are also badly out of date, and corrections that should have been made have not yet been made. This is dealt with in more detail below.

A third result is that IFRS impacts have not yet been addressed, and the Applicants have refused to answer questions on how they plan to do so[6]. That is also dealt with below.

The fourth and most important impact of the lengthy deferral period is that the operations and management of the Applicants, and particularly NT Power, are today and will increasingly be opaque to the Board, its regulator. Although they will be required to report under the RRR annually, the Board's normal ability to do a thorough review of how they are serving their customers, and their plans for the future, will have an eighteen year hiatus. This lack of transparency creates an obvious risk for the regulator, and for the NT Power customers.

SEC therefore submits that the Board should consider whether to require additional reporting, or perhaps even a shorter deferred rebasing period, so that the Board's ability to regulate the Applicants effectively is not compromised by lack of timely and thorough information.

<u>Distribution System Plan</u>

NT Power last filed a DSP in December, 2015[7]. MPUC has never filed a DSP, and deferred the filing of their DSP for two years due to the possibility of the transactions in this Application[8].

---

[4] SEC IR #15.
[5] Staff Supp. IR #9 and SEC IR #14.
[6] SEC IR #13.
[7] SEC IR #15.
[8] SEC IR #20.

The Applicants first committed to file a DSP for the MPUC rate zone some time after completion of the transactions[9]. However, after follow-up by OEB Staff[10], the Applicants advised that they would file a consolidated DSP for the whole entity by the end of December, 2020.

SEC believes that the filing of that consolidated DSP by that date should be made a condition of approval by the Board, for two reasons.

First, it would solve the problem of the lack of DSP for MPUC. There would appear to us to be little value in asking MPUC to file a separate DSP, when a consolidated one is offered in a reasonable time frame, as here.

Second, the Applicants have an ambitious plan to change how they receive power from the IESO grid. That plan, if it is able to proceed, could have significant positive benefits for customers, but could also involve material changes to the configuration of the system in the MPUC and Tay service areas. It could also result in an ICM application[11]. The filing of a consolidated DSP by the end of 2020 will allow the Applicants to consider those IESO connection changes in the context of their overall system, and will give the Board and customers visibility as to the changes proposed.

<u>Cost Allocation and Rate Design</u>

The table presented earlier shows the substantial differences between rates for MPUC and NT Power. As shown in the attachment, NT Power has unusually high rates for small business and commercial/industrial customers (including schools).

The last time cost allocation and rate design was done for NT Power was in EB-2009-0269, and that cost allocation used the load shapes from Hydro One in 2004. The cost allocation is thus almost ten years old, and the load shapes are at least fifteen years old. Under the deferred rebasing proposal, cost allocation and rate design would remain out of date for a total of twenty years, and by then the load shapes would be twenty-five years old.

This is a particular problem for the GS>50 class, because while in EB-2009-0269 its revenue to cost ratio was within the Board's then maximum level, it would not be today. This is likely the main reason why GS>50 rates for NT Power customers are 32.5% above the averages across Ontario.

In the normal course, this problem would have been corrected in 2014 or 2015, when NT Power came in for rebasing. The customers reasonably expected that would be the case, based on the Board's regulatory policies. NT Power did not rebase, and so it did not correct the problem, and now it proposes to delay correction of this problem for a lengthy additional period.

For a school in Newmarket that has been paying at least $4,000 per year more than their share of costs for the last eight years (plus the impact of the out of date embedded assumptions in revenue requirement), a requirement to continue to overpay for another ten years is unreasonable. Add to this the fact that load shapes are likely much flatter today, meaning that

[9] SEC IR #20.
[10] Staff Supp. IR #14.
[11] Staff IR #9.

these same customers are probably overpaying for incorrectly allocated costs, and for transmission charges, and would continue to do so unless this is corrected.

SEC submits that it should be a condition of approval that the Applicants update their cost allocation model, including the load shapes, within twelve months of completing the transactions. While the problem only arises with respect to NT Power, it is likely better if the Applicants do a consolidated cost allocation model, so that they can see overall differences between the rate zones as well. The incremental amount of work is probably worth it for the substantial additional information provided.

SEC proposes that the Applicants be required to file their updated cost allocation with their 2020 IRM application, along with a proposal to rectify any material problems shown in the results. For example, if GS>50 customers in the NT Power rate zone continue to be outside of the Board's revenue to cost ratio ranges, as they likely will be, the Applicants should be required to propose a revenue-neutral adjustment, or series of adjustments, to rates to correct those problems. Not only will this deal with some of the existing unfairness, but it should assist the Applicants later when they are facing harmonization of their two rate zones.

IFRS Impacts

The NT Power 2016 financial statements[12] show a regulatory liability to customers of about $7.5 million relating to the accounting changes required by IFRS conversion. When SEC asked about that, the Applicants refused to answer[13]. When OEB Staff followed up on a related SEC question[14], which the Applicants also had refused to answer, the Applicants provided a response which indicated that at least some of the IFRS conversion impact, $1.5 million, was recorded as an addition to net income in 2016[15].

It is likely that some of this $7.5 million is a financial statement amount but not a regulatory amount. On the other hand, it is almost certain that a material amount will be owing to customers, as indicated on the financial statements. The Applicants are refusing to provide sufficient information for the Board to understand that issue, and should not be allowed to hide the explanation of these obligations to customers.

SEC submits that the Board should require the Applicants, as a condition of approval, to file with their next IRM application a full explanation of all IFRS conversion impacts, including a reconciliation of amounts owing to customers, and a proposal for the clearance of those amounts.

Further, since the lengthy deferral of rebasing means that OM&A and rate base may not have been adjusted fully for IFRS, and impacts continue to arise annually, the Applicant's filing should include forecasts of future impacts, and a plan for how to ensure that the customers receive annual reimbursement for any regulatory deferral credits relating to IFRS as they arise.

---

[12] Page 19.
[13] SEC IR #13.
[14] SEC IR #12.
[15] Staff Supp. IR #8.

SEC submits that it is inappropriate for NT Power to retain IFRS impacts equal to almost half of their annual revenue requirement for such a lengthy period of time.

Earnings Sharing

The Applicants have proposed that 50% of amounts 300 basis points above allowed ROE should be held in an interest-bearing deferral account, and then used on rebasing to mitigate any rate adjustments required on harmonization. The Applicants argue that use of these amounts to smooth the harmonization process is a practical answer that benefits everyone.

SEC believes that the deferral and redirection of these amounts is inappropriate.

The initial proposal, the deferral of payment, is justified only if the mitigation proposal is accepted. Otherwise, there would be no reason an overearning utility should simply keep the overearnings for up to five years. There is no rationale for delaying payment. It is just low cost financing for the utility on the backs of the customers.

The redirection of the amounts is more problematic. Rates are supposed to be set based on cost causality. ROE would normally be one of the costs that is allocated. What the Applicants are proposing is that cost causality should be ignored during the harmonization process. Instead, disproportionate amounts of the earnings sharing should be allocated to some customers at the expense of other customers. No principled reason for this has been offered. It appears to be solely pragmatic.

SEC submits that earnings sharing, as the name implies, should be reimbursed to customers annually after it is calculated, and should be allocated on the same basis as ROE. It should not benefit some customers more than others.

Conclusion

SEC therefore submits that the Board should approve the transactions, subject to the following conditions:

1. The Applicants should be required to update their cost allocation models (including updated load shapes) within twelve months of completing the transactions. Those new models should be filed with the Board, together with a proposal to adjust over time any rates that are too high or too low relative to the Board’s cost allocation policies.

2. The Applicants’ commitment to file a consolidated DSP by the end of 2020 should be made a condition of approval.

3. The 10 year rebasing deferral period should be fixed, not optional at the discretion of the Applicants.

4. Any amount arising from the earnings sharing formula should be refunded annually to customers as part of the Applicants’ annual IRM applications.

5. The impact of accounting changes due to IFRS conversion should be reported in the next IRM application of NT Power, and thereafter should be refunded annually to customers as part of the Applicants' annual IRM applications.

All of which is respectfully submitted.

Yours very truly,
JAY SHEPHERD P. C.

Jay Shepherd

cc: Wayne McNally, SEC (email)
Interested Parties

Annual Distribution Bill Comparison - 2017 Rates

(monthly charge and volumetric rate @ MPUC volumes)

	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	$181.23	55.5%	$369.96	47.9%	$6,584.03	59.9%	54.45%	5,499
2	Hearst (DRO)	$256.18	78.5%	$413.80	53.6%	$5,276.23	48.0%	60.03%	2,718
3	E.L.K. (Applied)	$248.73	76.2%	$502.60	65.0%	$7,537.95	68.6%	69.96%	12,398
4	Hydro 2000 (Applied)	$335.01	102.7%	$566.36	73.3%	$4,799.15	43.7%	73.21%	1,221
5	Lakefront	$249.27	76.4%	$535.29	69.3%	$9,863.69	89.8%	78.48%	9,996
6	Peterborough (2016)	$253.24	77.6%	$639.46	82.8%	$9,026.81	82.2%	80.84%	36,058
7	Westario (2016)	$286.91	87.9%	$632.28	81.8%	$8,371.88	76.2%	81.98%	22,822
8	Brantford	$270.87	83.0%	$600.39	77.7%	$10,146.06	92.4%	84.35%	38,789
9	Kingston	$284.28	87.1%	$631.34	81.7%	$9,428.14	85.8%	84.88%	27,356
10	Orangeville	$304.00	93.2%	$694.68	89.9%	$7,918.42	72.1%	85.05%	11,685
11	Ottawa River (DRO)	$272.25	83.4%	$652.18	84.4%	$10,160.13	92.5%	86.77%	10,820
12	Burlington (Applied)	$291.42	89.3%	$732.00	94.7%	$8,604.48	78.3%	87.45%	66,366
13	London (DRO)	$293.88	90.1%	$713.33	92.3%	$9,029.49	82.2%	88.19%	152,544
14	Entegrus (DRO)	$291.07	89.2%	$671.54	86.9%	$9,790.95	89.1%	88.41%	40,503
15	COLLUS (Applied)	$289.66	88.8%	$675.62	87.4%	$9,837.85	89.5%	88.58%	16,426
16	Hydro One Brampton	$271.97	83.3%	$806.05	104.3%	$8,953.84	81.5%	89.72%	149,618
17	Guelph	$342.17	104.9%	$619.08	80.1%	$9,349.96	85.1%	90.03%	52,963
18	Essex (Applied)	$303.73	93.1%	$784.99	101.6%	$8,609.53	78.4%	91.01%	28,640
19	Halton Hills (DRO)	$294.60	90.3%	$641.54	83.0%	$11,034.60	100.4%	91.25%	21,534
20	Milton (Applied)	$316.65	97.0%	$736.54	95.3%	$8,991.10	81.8%	91.40%	35,111
21	Tillsonburg (DRO)	$321.96	98.7%	$872.29	112.9%	$7,086.37	64.5%	92.02%	6,935
22	Veridian (Applied)	$299.79	91.9%	$716.83	92.8%	$10,058.26	91.6%	92.06%	117,494
23	Energy Plus (Applied)	$286.20	87.7%	$607.98	78.7%	$12,343.01	112.3%	92.91%	52,684
24	Rideau St. Lawr. (Applied)	$311.38	95.4%	$731.85	94.7%	$9,863.56	89.8%	93.31%	5,858
25	Oshawa	$252.78	77.5%	$681.36	88.2%	$12,631.11	115.0%	93.54%	54,731
26	Erie Thames (DRO)	$349.48	107.1%	$705.61	91.3%	$9,676.86	88.1%	95.50%	18,265
27	Renfrew	$294.26	90.2%	$837.30	108.4%	$9,786.47	89.1%	95.87%	4,246
28	WestCoast Huron	$395.22	121.1%	$718.42	93.0%	$8,175.23	74.4%	96.17%	3,797
29	St.Thomas	$310.45	95.1%	$783.54	101.4%	$10,293.62	93.7%	96.75%	16,918
30	Embrun	$316.70	97.0%	$662.00	85.7%	$12,092.40	110.1%	97.60%	1,985
31	Niagara-on-the-Lake (DRO)	$337.98	103.6%	$822.25	106.4%	$9,130.71	83.1%	97.70%	8,672
32	Wasaga (Applied)	$271.76	83.3%	$639.76	82.8%	$14,039.97	127.8%	97.96%	12,985
33	Welland (Applied)	$332.31	101.8%	$666.95	86.3%	$11,719.94	106.7%	98.28%	22,470
34	Kenora (DRO)	$356.97	109.4%	$657.98	85.2%	$11,050.63	100.6%	98.38%	5,558
35	Midland	$359.04	110.0%	$776.05	100.4%	$9,317.72	84.8%	98.42%	7,035
36	Festival	$329.70	101.0%	$853.83	110.5%	$9,464.69	86.1%	99.23%	20,362
37	North Bay (DRO)	$321.05	98.4%	$847.84	109.7%	$10,310.11	93.8%	100.65%	23,975
38	Thunder Bay	$298.08	91.3%	$875.94	113.4%	$10,878.81	99.0%	101.24%	50,482
39	Kitchener-Wilmot	$262.98	80.6%	$718.13	92.9%	$14,354.32	130.7%	101.39%	91,143
40	Grimsby	$319.89	98.0%	$871.10	112.7%	$10,409.71	94.7%	101.84%	11,038

41	Horizon	$317.12	97.2%	$820.35	106.2%	$11,245.60	102.4%	101.90%	240,076
42	Centre Wellington (Applied)	$308.49	94.5%	$801.91	103.8%	$11,805.72	107.5%	101.92%	6,729
43	Northern Ontario Wires (Applied)	$453.50	139.0%	$961.50	124.4%	$5,413.31	49.3%	104.23%	6,062
44	Sioux Lookout	$471.94	144.6%	$770.37	99.7%	$8,181.59	74.5%	106.26%	2,779
45	Enersource	$281.32	86.2%	$906.94	117.4%	$13,049.62	118.8%	107.46%	201,359
46	Greater Sudbury (DRO)	$304.40	93.3%	$837.98	108.5%	$13,449.90	122.4%	108.05%	47,187
47	Niagara Peninsula (Applied)	$380.47	116.6%	$893.83	115.7%	$10,296.14	93.7%	108.66%	51,824
48	Lakeland	$383.07	117.4%	$821.83	106.4%	$11,363.10	103.4%	109.06%	13,264
49	Powerstream	$320.09	98.1%	$897.83	116.2%	$12,723.83	115.8%	110.03%	353,284
50	EnWin (Applied)	$306.48	93.9%	$847.84	109.7%	$14,189.48	129.2%	110.93%	86,662
51	PUC Distribution (Applied)	$280.97	86.1%	$825.23	106.8%	$15,673.63	142.7%	111.86%	33,487
52	Hydro Ottawa	$312.99	95.9%	$900.58	116.6%	$13,749.22	125.1%	112.54%	319,536
53	Whitby	$352.11	107.9%	$891.22	115.3%	$13,585.33	123.7%	115.63%	41,488
54	Oakville (interim)	$325.20	99.6%	$921.60	119.3%	$14,183.83	129.1%	116.01%	66,530
55	Orillia (Applied)	$322.96	99.0%	$964.71	124.9%	$13,731.95	125.0%	116.27%	13,340
56	Newmarket-Tay	$311.52	95.5%	$970.92	125.7%	$14,555.37	132.5%	117.87%	34,871
57	Bluewater (DRO)	$372.44	114.1%	$934.26	120.9%	$13,316.86	121.2%	118.75%	36,115
58	Wellington North	$413.02	126.6%	$1,057.65	136.9%	$10,365.16	94.3%	119.26%	3,731
59	Waterloo North	$364.97	111.8%	$879.14	113.8%	$14,960.38	136.2%	120.60%	54,674
60	Innpower (Applied)	$542.36	166.2%	$887.88	114.9%	$12,806.03	116.6%	132.56%	15,790
61	Canadian Niagara (Applied)	$437.80	134.2%	$1,132.48	146.6%	$21,115.87	192.2%	157.64%	28,627
62	Algoma	$580.11	177.8%			$16,120.03	146.7%	162.24%	11,650
63	Toronto Hydro	$451.07	138.2%	$1,311.31	169.7%	$20,269.88	184.5%	164.15%	744,252
	AVERAGE	$326.34		$772.64		$10,986.50			