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EB-2008-0222/223

0224
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IN THE MATTER OF the *Ontario Energy Board Act, 1998*, **S.O. 1998, c.O.15, Sch. B;**

AND IN THE MATTER OF Applications by Canadian Niagara Power Inc. – Eastern Ontario Power/Gananoque and Canadian Niagara Power Inc. – Fort Erie for an Order or Orders approving just and reasonable rates for the delivery and distribution of electricity commencing May 1, 2009.

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ONTARIO ENERGY BOARD
OFFICE OF THE BOARD SECRETARY

FINAL SUBMISSIONS OF THE

SCHOOL ENERGY COALITION

Introduction

1. On August 15, 2008 Canadian Niagara Power Inc. ("CNP") filed rate applications for its franchise areas in Eastern Ontario Power/Gananoque ("EOP"), Board file #EB-2008-0223, and Fort Erie ("FE"), Board file #EB-2008-0222, both seeking new rates effective May 1, 2009. The applied for net revenue requirement for CNP-EOP was $2,223,812 with a deficiency of $317,166 and an average rate increase of 16.6%. The applied for net revenue requirement for CNP-FE was $9,252,464 with a deficiency of $313,352 and an average rate increase of 3.5%. The Applications also seek to harmonize rates between the two franchise areas, with resulting incremental rate impacts.

2. These are the Submissions of the School Energy Coalition on the FE and EOP rate applications.

3. CNP also made a rate application on August 15, 2008 for new rates for their Port Colborne franchise area (EB-2008-0224). All three rate applications were originally combined by the Board. However, after unique issues arose with respect to the Port Colborne Application, by Order of the Board on April 23, 2009 the proceeding relating to Port Colborne was separated from the FE and EOP proceeding. These Submissions do not deal with Port Colborne.

4. While SEC has been active on all issues in these Applications, these Submissions deal only with those issues that we feel are of significant concern. As there is no approved Issues List for these proceedings, these Submissions are organized instead by general subject headings.

Benchmarking

5. The costs in the FE and EOP franchise areas do not do well in the OM&A benchmarking analysis prepared for the Board by Pacific Economics Group. CNP quite properly dealt with this fact in their Applications [FE Ex. 1/2/1, p.4] and subsequently provided supplementary evidence at the hearing [Ex. K1.5]. They were questioned on this comparison at some length by both Energy Probe and SEC.

6. It is submitted that, in general, the comments of CNP questioning the comparability of their OM&A numbers with those of their peers have some merit, as any comparison that is not all-inclusive will have the potential for anomalies. As the Board is already aware from other proceedings, an OM&A benchmarking activity does not compare all costs, and so is only a first step in comprehensive benchmarking of utility costs. It gives an important part of the story, but not all of the story.

7. On the other hand, the criticisms of CNP's "adjustments", including those criticisms made by Energy Probe in their Final Argument, also have merit.

8. In our submission, the bigger question is not whether CNP can be compared to other LDCs on an OM&A basis, but rather "On what basis does the Applicant believe it can fairly be compared with other LDCs?" It is one thing to challenge a particular comparison. At the very least, offering a more legitimate method of comparison should form a part of that challenge. In this case, CNP has offered an OM&A comparison that they admit suffers from many of the same questions as the one they objected to.

9. It is submitted that one comparison that CNP cannot object to is a comparison of how much, relative to other LDCs, they charge similar customers for distribution service. While that comparison may still have flaws (there may be good reasons for disparities), it at least can fairly be said to compare apples to apples.

10. Attached as Appendix A to these Submissions is a table prepared by School Energy Coalition based on the final 2008 rate orders from the Board for about forty LDCs. (It does not contain all LDCs because the project to develop this table is not yet complete. However, it does contain about half, and the selection of that half is entirely random.)

11. In Appendix A, the total annual distribution charges (fixed charge and variable charges) for six typical general service customers are compared. All rates used are final 2008 rates from the Board's published rate order. Some of the utilities compared rebased in 2008, while others will be rebasing in 2009 and beyond. At the bottom of the table are arithmetic averages. We have then compared the EOP and FE distribution charges for those sample customers to the averages. For example, in the EOP franchise area a Residential customer using 1,000 kwhrs monthly pays about 86% of the sample average.

12. As can be seen, the amounts charged by the Applicant for distribution services in EOP and Fort Erie are at or below the sample averages for residential. However, for Non-Residential customers, charges appear to be significantly higher than the sample.

13. In our view, these publicly available figures do not have any independent probative value. That is, we agree that the Board should not, under its current policies, set rates for CNP based on this comparison of distribution charges. On the other hand, knowing that, even before these proposed rate increases are considered, the Applicant charges a relatively high amount for distribution, should cause the Board to consider on specific issues whether there is room for cost reductions to bring this utility more in line with its peers, or whether rate impacts of cost allocation or rate design issues are appropriate.

14. We note that, as with the PEG Benchmarking, the Applicant may well object to the particular comparison we have offered. They are welcome to propose different comparisons, either by adding more LDCs to the chart, or by suggesting appropriate cohorts or peer groups. There are ways of arranging this data to make EOP and FE look either better or worse, but in the end the Applicant should still, in our view, be able to explain to the Board why what it charges in Gananoque is so significantly different than its neighbour Kingston, and why what it charges in Fort Erie is so much higher than its neighbour Welland charges similar customers, and so on. As we will note in our discussion of Cost Allocation and Rate Design later, some of these disparities are inter class issues, but others are simply a more expensive operation.

Load Forecast

15. We have had an opportunity to review the Final Argument of VECC in these proceedings, and we agree with their reasoning on the load forecast and the normalized average uses on which that forecast is based. It is submitted that the adjustments proposed by VECC would produce a more reasonable basis for establishing the deficiency and new rates.

Rate Base and Capital Spending

16. ***Capital Program Proposed.*** The Applicant has spent, and is continuing to spend, at a relatively high rate for capital improvements. This rate is particularly noticeable given their low customer and load growth rates, suggesting a mature business that should not need unusually high amounts of capital spending.

17. However, the Applicant notes that parts of their system were in poor condition, and the spending is required essentially to bring it up to standard [e.g. Tr.3:22]. In fact, the Fortis companies appear to have a particular expertise in operating old, perhaps even outdated electricity distribution systems, and in their Ontario operations have some of the oldest in the province. It is perhaps not surprising that capital spending needs are high.

18. What does concern us is that the Applicant has not presented the Board with a plan for bringing their infrastructure into line. The Applicant was asked in SEC IR#5 to file their five year business plan, precisely so that we could look at how they are approaching the renewal of their system, but they refused to provide it. They provided only overall budget forecasts, which don't assist the Board in looking at capital renewal planning.

Further, when SEC pursued that in followup questions, both in writing and at the Technical Conference, they continued to decline to provide that information. Even on a motion, they argued that it was not useful to the Board.

19. Given that they had ample opportunity to provide their business plan, and declined to do so, we believe that the Board is now faced with a dilemma. On the one hand, they have asked for approval of aggressive capital spending, and substantial increases in rate base, but on the other hand that spending does not have any context for the Board to assess its value.

20. One option available to the Board is to decline approval of the spending plan until the Applicant provides a proper long term renewal plan. In our view that is unnecessarily Draconian. It is submitted that a better approach in this particular case is for the Board to require the Applicant to file with the Board, on the record, their current long-term capital spending plan, with all narrative, and with all backup analysis, prior to the end of this year. While that will not affect their current rates, the Board, as regulator, will have visibility on what CNP is doing to improve their system. If the plan is weak, Board Staff will have an opportunity to discuss improvements with the Applicant. Further, when the Applicant comes in on their next rebasing, asking for a substantial further increase in rate base, the Board will have a reference point with which to assess what has transpired.

21. ***Impact on Maintenance Costs.*** We have expressed our concern in the hearing, and continue to be concerned, that the Applicant does not expect reductions in maintenance spending, or increases in service quality indicators, resulting from its admittedly aggressive capital spending programs. Several discussions on that point arose in the course of Day 3 of the proceeding, of which one [pp. 56-67] includes clear statements to this effect.

22. Later, the Applicant admitted [Tr.3:75-76] that the revenue requirement is proposed to increase by about $2 million because of capital spending, but is unable to point to any savings that offset any of that impact.

23. While it is true that sometimes you just have to replace things when they get old, and it is true that new equipment sometimes is more technically complex, it is also true that strong capital spending should not result in <u>zero</u> operating savings.

24. It is also the case that the Applicant does not do formal analysis of cost savings that will arise as a result of capital programs [Tr.3:64], something that is commonly done by most utilities. The fact that they take a more intuitive, hands-on approach is not necessarily fatal to their capital budget. In smaller companies – utilities and otherwise – people with a lot of knowledge make judgment calls that don't appear to be very rigorous, but are in fact the result of years of experience. This cannot simply be discounted.

25. However, we believe that, where the results one would normally expect – reduced operating costs, and/or improved service quality metrics – are not apparent, the utility should have solid evidence of the appropriateness of the capital spending. In our

submission, there is insufficient support for the prudence of this level of capital spending in light of the lack of results. The solution, in our view, is not to reduce the capital spending, but to closely supervise the OM&A budget to ensure that some benefit from the spending program is obtained.

OM&A

26. ***Overall Levels***. We have noted above our concerns that capital spending does not appear to be translating into OM&A reductions, particularly in the area of maintenance. We also note the PEG Benchmarking results, and our own higher level distribution charges comparison, earlier in these Submissions. We thus have a concern that OM&A for this Applicant should be lower.

27. However, except for an adjustment to regulatory costs, set out below, we are not proposing any reductions in OM&A. While there are numerous areas in which small adjustments might be warranted, none of them are sufficiently material to be pursued.

28. This should not be the end of the matter, though. We believe the Board should be concerned that CNP continues to be a relatively high cost LDC, with a long term capital spending program that will exacerbate that disparity.

29. We therefore propose that the Board direct CNP, in their next rebasing application, to report on tangible OM&A savings they have achieved, through their capital spending initiatives and otherwise, and also report on their future plans to get their cost levels in line with comparable Ontario LDCs.

30. ***Regulatory Costs***. The Applicant has taken the position that it needs to recover substantial regulatory costs, $475,000 in total resulting in $158,333 in the revenue requirement [Ex. K1.2], in excess of what would be usually for a utility of this overall size. In our submission, 50% of these regulatory costs in the test year should be disallowed.

31. It would appear that there are three reasons why the regulatory costs for CNP are so high:

    a. The Applicant uses a complicated shared services system that makes it difficult for the Board and parties to review a substantial portion of their regulatory requirement, and in respect of which the Applicant has not demonstrated any net benefit to the ratepayers;

    b. The Applicant's corporate and business structure, with multiple franchise areas kept separate for many years, and complex business arrangements, increases the cost of regulation, yet it too does not appear to have any significant offsetting benefit; and

    c. The Applicant's consistent unwillingness to take an open, forthright approach to the regulatory process, with numerous refusals to provide information and a running battle to keep evidence from the Board, has resulted in wasted effort and ultimately a delayed process.

32. In our view, a utility of the size of CNP should normally not have regulatory budget of this magnitude. The incremental cost does not appear to be intervenors (who are in the budget for about $150,000), but is primarily for external legal and consulting costs.

33. It is submitted that a more appropriate maximum budget in these circumstances would be $300,000, which provides room for some of the costs resulting from corporate complexity, but does not allow ratepayer recovery for costs incurred in refusing to co-operate with the regulatory process. Spread over the appropriate period, four years, this would result in $75,000 being included in revenue requirement for all three franchise areas. We believe it is appropriate to allocate $40,000 of that to FE and EOP, leaving $35,000 to be allocated to Port Colborne when that proceeding continues.

34. ***Shared Services***. We have spent a considerable amount of time reviewing the shared services evidence of the Applicant, including the breakdowns of allocations, the external consulting study, and the underlying agreements.

35. This review has been made more difficult by two facts:

a. the actual amounts charged for shared services within the Fortis family have at all times been fully allocated costs, but the agreements have used fundamentally different - and inconsistent - concepts to describe the basis for inter-company payments [Tr.3:97-100];

b. several SEC IRs sought information on Cornwall and the Transmission business, so that inter-company payments could be assessed, but that information was not provided.

36. That having been said, in fact after our review we have not been able to identify any areas in which there appear to be material problems with the allocations. The allocation system, while complicated, does appear to be thorough and does appear to allocate costs in a fair manner, based the information available on the record.

Cost of Capital

37. CNP proposes to issue a new, $21 million demand promissory note to its shareholder FortisOntario, at the Board's current deemed rate of 7.62%. There is no evidence on the record of the Applicant seeking to obtain this financing at market rates, and most of this new note - $15 million - would replace an existing promissory note to its shareholder, issued coincidentally with the filing of these Applications, that has a rate of 6.13%.

38. This would appear to us to be an undisguised attempt to use the Board's policies to recover the maximum amount possible from ratepayers, without consideration of market rates or fairness as between ratepayers and shareholder. If allowed, it would it is

submitted be a indirect method of increasing the effective ROE on the shareholder's equity in the Applicant.

39. It is submitted that the Board should reduce revenue requirement by the proposed increase in the amount to be recovered on the existing $15 million indebtedness. The evidence is that CNP cannot repay that at will, so reduction of the interest rate recoverable to the original 6.13% is an approach that seems fair. As to the additional $6 million, in our submission the Applicant has not provided the evidence it should have provided as to market rates. In our view the Applicant should not be able to use their own failure to act prudently to justify recovering a high rate of interest from ratepayers in order to pay it to their shareholder. At most, the 6.13% the shareholder has already accepted recently should be used. Even at that, with demand debt being granted by banks at under 5%, the shareholder would still be over recovering for this loan.

40. It is therefore submitted that the maximum rate that CNP should be allowed to recover on all of its affiliate debt is 6.13%.

Cost Allocation

41. CNP has proposed revenue to cost ratios that:

a. Bring the GS<50KW class to within the Board's recommended range;
b. Leave Sentinel Lights, Street Lights, and USL well below the bottom of the Board's recommended ranges for those classes;
c. Leave Residential below the Board's recommended range by 2.12%; and
d. Move GS>50 KW even further away from unity, to 152.66%.

42. In our opinion, it is inappropriate to leave these disparities in place for a further period of several years during IRM. Instead, it is submitted that the Board should order the following:

a. Increase the revenue responsibility of the Residential Class by $165,679 to bring the revenue to cost ratio to 85%, the bottom of the Board's range. This has a 2.8% average impact on residential customers.
b. Increase the revenue responsibility of Sentinel Lights by $12,000 to bring the revenue to cost ratio to 70%, the bottom of the Board's range.
c. Increase the revenue responsibility of USL by $12,000 to bring the revenue to cost ratio to 70%, the bottom of the Board's range.
d. Increase the revenue responsibility of Street Lights by $88,000 to bring the revenue to cost ratio to about 37%, which is about one-third of the way to the bottom of the Board's range.
e. Apply the revenues shifted to the above classes to the GS>50KW class, to reduce the revenue responsibility by that total of approximately $278,000, reducing the revenue to cost ratio for that class to 142%, still far higher than any other class.
f. Further shift Street Lights by $88,000 in each of 2010 and 2011 to get its RTC to 70% by 2011, and apply those revenues to further reduce the revenue responsibility for the

GS>50 KW class, thus reducing its revenue to cost ratio to about 137% when that adjustment is complete.

43. It is submitted that, with the implementation of the changes proposed, the GS>50KW and GS<50KW classes, containing most of the enterprises that drive the local economy and provide local services, will still be overcontributing at a high level, and the Residential, Sentinel, Street and USL classes will still be undercontributing in substantial amounts, but the level of the cross-subsidy will have been narrowed slightly. A movement in that direction is fair to all parties, while still leaving a considerable difference to be dealt with in the future.

Rate Harmonization

44. CNP has proposed harmonization of the rates of FE and EOP in a single step, with the intention of harmonizing with Port Colborne at a future time. The Applicant advises [OEB Staff IR #65, p. 2] that the effect of the harmonization is to shift $129,000 of revenue from EOP to FE. That amounts to about 5.8% of the revenue requirement of EOP, and so represents on average a distribution bill decrease of 5.8% for EOP customers. It amounts to about 1.4% of the revenue requirement of FE, and represents on average a distribution bill increase of 1.4% for EOP customers.

45. However, the detailed breakdown on page 3 of that interrogatory response shows that the reallocation of revenue responsibility is not as simple as that. If each class revenue responsibility is looked at individually, the differences are more substantial:

a. For the GS>50KW class, harmonization reduces the revenue responsibility for EOP customers by $154,691, or 22.0% of revenue requirement. However, it increases the revenue responsibility for FE customers by $366,368, or 11.9% of revenue requirement. It appears from this data that the class revenue responsibility is increased by $211,677, an implicit 5.6% rate increase for this customer class. As noted elsewhere in these submissions, this customer class already suffers from a very high revenue to cost ratio, so an increase of this magnitude does not appear appropriate.

b. For the GS<50 KW class, harmonization increases the revenue responsibility for EOP customers by $21,177, or 5.3% of revenue requirement. However, it decreases the revenue responsibility for FE customers by $72,159, or 5.9% of revenue requirement. It appears from this data that the class revenue responsibility is decreased by $50,982, an implicit 3.1% rate decrease for this customer class. Given the current revenue to cost ratio, this would appear to be directionally sound.

c. For the Residential class, harmonization increases the revenue responsibility for EOP customers by $8,895, or 0.8% of revenue requirement. However, it decreases the revenue responsibility for FE customers by $157,747, or 3.2% of revenue requirement. It appears from this data that the class revenue responsibility is decreased by $148,852, an implicit 2.5% rate decrease for this customer class. If this analysis is correct, residential customers, already undercontributing, are moved in the wrong direction by harmonization.

46. The apparent effect of harmonization appears to be to transfer more than two hundred thousand dollars of revenue responsibility from already undercontributing residential customers and overcontributing small GS customers to the already heavily overcontributing large GS customers.

47. If this analysis of the data is correct, it would appear to us that, in addition to any cost allocation adjustment ordered by the Board, it is appropriate for the Board to require that, on harmonization, this reallocation amongst classes be reversed. Given that about 10% of this impact is a result of the increase in the FE fixed charge, and the balance is the result of the increase in the FE variable charge, the result should be to allocate the adjustment 10% to fixed and 90% to variable charge. While this will benefit the larger GS>50 KW customers (i.e. not schools) more than smaller ones, it is the fair result on the facts filed, and therefore it is submitted that it is appropriate.

Rate Design

48. No additional submissions.

Deferral and Variance Accounts

49. The Applicant is seeking establishment of an IFRS Deferral Account. In our submission, such accounts should not be established except as determined in EB-2008-0408, where the Board is considering IFRS issues in the proper context.

Effective Date

50. The Applicant was one of the very few utilities to file their 2009 rate applications on time on August 15, 2008. Those applications, while supplemented by substantial amounts of evidence in interrogatories, technical conference, and oral hearing, were nevertheless professionally done and thorough. In those applications, the Applicant has requested that new rates be made effective May 1, 2009.

51. On the other side, the primary reason for delay was the time involved in obtaining information from the Applicant necessary to the determination of the issues. Without those delays, it is reasonable to assume that new rates would already be in place, long before the requested date.

52. Notwithstanding those delays, it is our submission that the Applicant's new rates should be effective May 1, 2009. Although SEC is on record as opposing the retroactivity inherent in rates being set after the effective date, there are times when that is the fair result. We believe this is one of them.

53. From a process point of view, it is submitted that the Applicant should calculate new rates, designed to recover any deficiency determined by the Board, as if they had been in place on May 1, 2009, and then recover the difference between old rates and new rates through a rate rider for the period from the implementation date of new rates until April 30. 2010.

Costs

54. It is submitted that the School Energy Coalition has participated reasonably in this process with a view to assisting the Board. We therefore request that the Board order payment of our reasonably incurred costs of participation.

All of which is respectfully submitted on behalf of the School Energy Coalition on the 1st day of June, 2009.

SHIBLEY RIGHTON LLP

Per: ______________________
Jay Shepherd

APPENDIX A – 2008 Published Distribution Charges

UTILITY	RESIDENTIAL		GS<50 KW		GS>50 KW	
	1,000kwhr	1,500kwhr	2,000kwhr	10,000kwhr	60 KW	500 KW
Atikokan	$583.92	$666.12	$1,149.84	$2,081.04	$3,299.28	$7,877.04
Barrie	$363.84	$451.44	$595.32	$2,208.12	$6,155.16	$17,163.96
Bluewater	$307.20	$377.40	$612.24	$1,841.04	$5,139.19	$13,714.44
Brant	$405.48	$540.48	$667.44	$2,529.84	$4,405.92	$34,095.36
Burlington	$332.28	$427.68	$607.08	$2,018.28	$2,656.90	$16,341.60
CNP - EOP	**$283.44**	**$327.24**	**$764.04**	**$2.242.44**	**$11.716.44**	**$30.320.52**
CNP- Fort Erie	**$327.12**	**$370.32**	**$743.52**	**$2.874.72**	**$6.610.90**	**$44.837.04**
Centre Wellington	$342.96	$434.76	$592.32	$2,291.52	$2,652.65	$18,389.16
Chatham-Kent	$336.96	$420.36	$614.64	$1,497.84	$3,059.78	$11,339.88
Clinton	$248.64	$316.44	$480.72	$1,527.12	$3,256.82	$24,335.64
Collus Power	$335.04	$445.44	$464.64	$1,530.24	$1,692.12	$9,313.80
E.L.K.	$251.88	$308.88	$211.44	$509.04	$7,760.57	$25,894.20
EnerSource	$286.32	$356.52	$748.20	$1,842.60	$3,780.46	$25,451.16
EnWin	$357.12	$483.72	$664.56	$2,152.56	$6,264.48	$23,714.88
Erie Thames	$344.28	$430.08	$483.96	$1,501.56	$3,735.38	$13,045.08
Festival	$361.44	$456.24	$680.40	$2,043.60	$4,137.96	$16,044.36
Grimsby	$296.76	$352.56	$565.32	$1,582.92	$3,218.11	$12,221.04
Haldimand	$508.80	$696.60	$766.92	$2,955.72	$4,745.81	$36,567.84
Halton Hills	$316.56	$395.76	$580.92	$1,540.92	$3,632.26	$24,896.40
Hawkesbury	$171.36	$225.96	$241.20	$730.80	$943.13	$3,780.60
Hydro 2000	$243.12	$312.12	$614.16	$1,881.36	$3,579.91	$19,225.08
Hydro One Brampton	$325.80	$420.00	$689.88	$2,427.48	$2,929.30	$15,249.12
Hydro Ottawa	$360.48	$483.48	$627.24	$2,384.04	$5,136.46	$20,933.16
Innisfil	$420.24	$513.24	$731.64	$1,893.24	$6,738.07	$24,463.56
Kenora	$281.64	$340.44	$405.60	$789.60	$5,313.38	$11,787.72
Kingston	$276.48	$352.08	$525.48	$1,485.48	$4,128.91	$13,662.48
Kitchener-Wilmot	$265.32	$339.12	$521.04	$1,385.04	$5,325.74	$23,896.56
Lakefront	$298.32	$385.92	$557.04	$1,545.84	$5,450.69	$27,686.88
Lakeland Power	$409.44	$504.24	$737.16	$1,850.76	$8,228.38	$22,177.08
London	$297.00	$375.00	$619.80	$1,560.60	$3,775.10	$10,592.64
Middlesex	$383.28	$472.68	$385.08	$884.28	$1,744.08	$10,289.76
Midland Power	$374.04	$492.84	$487.32	$1,831.32	$1,835.26	$14,057.40
Milton	$351.84	$431.64	$588.24	$2,124.24	$2,689.42	$15,914.76
Newbury	$286.92	$358.32	$546.84	$1,689.24	$4,122.58	$11,260.08
Niagara Falls	$363.48	$446.28	$824.40	$1,803.60	$5,622.70	$21,783.72
Peninsula West	$369.12	$491.52	$596.16	$2,468.16	$5,452.54	$43,401.48
Niagara-on-the-Lake	$360.12	$433.92	$769.32	$1,921.32	$8,059.73	$26,357.04
Northern Ontario Wires	$329.52	$394.32	$506.40	$1,485.60	$3,992.02	$14,846.64
Powerstream	$195.96	$274.56	$632.52	$1,726.92	$5,336.42	$17,811.48
Thunder Bay	$300.24	$383.04	$507.96	$1,707.96	$3,004.10	$8,620.44
Welland	$313.80	$391.80	$393.60	$1,036.80	$2,884.46	$7,133.28
West Coast Huron	$269.88	$320.28	$526.32	$1,025.52	$5,600.76	$11,247.72
Westario Power	$290.16	$369.96	$443.28	$1,268.88	$4,481.76	$16,192.80
Averages	**$327.83**	**$411.85**	**$592.51**	**$1,753.89**	**$4,624.21**	**$19,085.65**
EOP - % of Avg.	86%	79%	129%	128%	253%	159%
Fort Erie - % of Avg.	100%	90%	125%	164%	143%	235%