# ONTARIO ENERGY BOARD

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

**AND IN THE MATTER OF** an Application by Canadian Niagara Power Inc. pursuant to the *Ontario Energy Board Act* for an Order or Orders approving rates for the distribution of electricity commencing January 1, 2017

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# FINAL ARGUMENT
# OF THE
# SCHOOL ENERGY COALITION

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# 1 GENERAL COMMENTS

## 1.1 *Introduction*

***1.1.1*** On July 13, 2016 the Applicant Canadian Niagara Power Inc. filed a complete application to set just and reasonable rates for the distribution of electricity for the period commencing January 1, 2017. The Application sought an increase of $2.4 million in its revenues, representing a 14.0% weighted average rate increase.

***1.1.2*** The parties settled most of the issues in this proceeding, and on January 5, 2017 the Board accepted the Settlement Agreement. As a result of the Settlement Agreement, the requested revenue increase was reduced to $1.7 million, and the requested weighted average rate increase to 9.4%.

***1.1.3*** Four issues remain to be determined:

***(a)*** OM&A in the test year.

***(b)*** The appropriate accounting treatment of Pension and OPEB costs, and a related issue of variance account treatment for those costs.

***(c)*** How the Board should deal with a substantial expected drop in the cost of long term debt in 2018.

***(d)*** Effective date of new rates.

***1.1.4*** An oral hearing was held on January 4, 2017, and undertaking responses were filed January 10, 2017. The Applicant's Argument-in-Chief was filed on January 12, 2017.

***1.1.5*** This is the Final Argument of the School Energy Coalition.

***1.1.6*** The ratepayer groups who intervened in this proceeding have worked together throughout the proceeding to avoid duplication, including exchanging drafts or partial drafts of their final arguments. We have been assisted in preparing this Final Argument by that co-operation amongst the parties.

***1.1.7*** We also note that the Final Argument prepared by OEB Staff was filed on January 20, 2017. Reviewing OEB Staff argument prior to finalizing these SEC submissions has been of assistance to us.

***1.1.8*** The numbering of Sections and Subsections in this Final Argument is not consistent with the numbering in the Issues List, as the issues that arose in the course of the proceeding, the ones left unsettled, and the development of this Final Argument made a different logical structure appropriate.

## 1.2 ***Summary of Submissions***

*1.2.1* ***CNPI Performance***. The context of this Application is the longstanding poor cost performance of CNPI relative to its peers. Whatever the original reasons for the Applicant's high costs, there has been no real improvement over a very long period of time. Further, the utility has no plan in place to reach a more reasonable cost level in the future, and appears to think it is not necessary.

*1.2.2* This is inconsistent with the RRFE goals of favourable outcomes for ratepayers, and continuous improvement. This utility needs clear direction from the Board, reflected both in words and in dollars, that CNPI must develop and implement a plan to improve its cost performance over time.

*1.2.3* ***OM&A.*** CNPI has consistently underspent the OM&A included in its current rates, yet still seeks a substantial increase. Any reasonable analysis of the data shows that their request is too high relative to past actual spending and expected cost drivers. SEC proposes that their OM&A be reduced by $813,000.

*1.2.4* ***Cost of Debt.*** In 2018 a material change in CNPI's circumstances is expected to occur (a reduction in the interest rate on third party debt), and revenue requirement will likely drop by several hundred thousand dollars or more. This should be treated as a Z factor, and CNPI should be expected to file an application in 2018 to reduce its rates to reflect this change.

*1.2.5* In the alternative, the Board should average the cost of debt over the five year IRM period, as it is clear that the amount included in revenue requirement in the rebasing year is not a representative cost of debt suitable for IRM purposes.

*1.2.6* ***Pension and OPEBs***. Consistent with other utilities, the pension and OPEBs costs included in rates for CNPI should be on a cash basis until the Board determines a generic policy going forward for this issue. Whether the Board includes cash or accrual in rates, it is appropriate to have a variance account to capture any difference between the method included in rates, and the method determined to be appropriate in the generic proceeding.

*1.2.7* ***Effective Date***. CNPI eventually filed a complete application for 2017 rates on July 13, 2016. If there is a deficiency as a result of the Board's decision in this matter, it should not be included in rates before the earlier of eight months after that date, i.e. March 13, 2017, or the month following the Board's rate order. A sufficiency should, of course, be implemented as of January 1, 2017, as effective date is inherently an asymmetrical issue. The Applicant controls the timing of its application, and should not benefit from its own delay.

# 2 RENEWED REGULATORY FRAMEWORK

## 2.1 *Introduction*

***2.1.1*** The Board has established that applications for new rates by electricity distributors should be viewed through the customer-centric lens of the Renewed Regulatory Framework for Electricity. That Board policy includes three key components:

*(a)* Planning and operating decisions should be driven by outcomes of benefit to the customers;

*(b)* Measurement of results should be employed, using objective metrics, including in particular benchmarking of costs to other distributors and to the Applicant's own history; and

*(c)* Continuous improvement should be demonstrated by regulated utilities so that, to the extent that they are not stellar cost performers, or are not achieving the best possible outcomes for their customers, they are shown to be striving to do so.

***2.1.2*** Canadian Niagara Power Inc. has had relatively poor cost performance for many years. This should by itself be of concern to the Board. However, of more concern, in our submission, is that the Applicant has no plan to improve from that unsatisfactory level, and does not even appear to see that as a necessary part of their responsibility as a regulated monopoly. As outlined below, SEC believes that the Board should be directing the Applicant, in a firm but fair way, to make incremental changes over time that will produce the necessary cost and other improvements[1] for the benefit of their customers. In addition, the Board's direction should be backed up by financial restrictions that will incent the Applicant to achieve better results, or penalize them for failing to heed the Board's direction.

## 2.2 *Outcomes vs. "Needs"*

***2.2.1*** The RRFE starts with the reasonable premise that rate increases should be driven by improved outcomes for customers. Just as in the competitive markets, companies should be striving to reduce their costs, not increase them, and when increases are proposed they should only be for improved outcomes for which their customers are willing to pay extra.

***2.2.2*** Embedded in this notion is the concept of "continuous improvement". Again, the analogy is to competitive companies. In a competitive environment, your competitors

[1] This Final Argument will focus on cost improvements, because most of the other issues have been settled and the issues remaining are essentially all cost-related issues.

are constantly seeking to improve on what they are doing, and therefore on what you are doing. The improvement can be in the form of reduced cost – price competition – or better products with increased functionality or quality – product competition. To compete, you have to either drive your costs down to keep pace with your competitors, or improve your products in ways that customers want to buy them.

***2.2.3*** All of this happens within the context of external factors – inflation, interest rates, etc. – that apply to all companies in the industry in the same manner. If inflation pushes all costs up by 10% (as has happened in the past), all companies can increase prices by 10% and stay competitive. The company that can be more productive, and increase only 9%, will have an "improvement" that will give them a better position in the market.

***2.2.4*** Aside from the common influences on competitive companies, though, the competitive markets are heavily driven by outcomes, and the RRFE imports that concept into the monopoly utility environment. The Applicant in this case must achieve price and cost competitiveness, because that is the outcome that the regulator, as the market proxy, requires for the Applicant's customers. If the Applicant cannot achieve price and cost competitiveness, it must deliver other outcomes (reliability, customer service, functionality, etc.) that are valued sufficiently by the Applicant's customers that they are prepared to pay the cost differential.

***2.2.5*** In this situation, the Applicant has high prices relative to other companies in the sector, and high costs whether compared head to head or using econometric benchmarking. It is not taking any significant steps to bring those high costs and prices down, and it is not proposing any substantial enhancements to its customer offerings – reliability, customer service, or anything else – sufficient to warrant the cost differential. Therefore, in our submission the Board's role as market proxy is engaged, and it should at least start to move the Applicant back to a reasonable price and cost level.

***2.2.6*** The Applicant instead focuses on how much it "needs" rather than how much the customers should pay for the outcomes the Applicant is delivering. We understand that, under the old view of cost of service, this was perfectly normal. Now that, under the RRFE, the Board has re-engaged its full market proxy role, SEC submits that the "needs" of the Applicant are of little or no relevance, except in considering how to transition to more appropriate outcomes.

***2.2.7*** That is, the Board can and should consider needs if it determines that a utility cannot get to reasonable cost levels overnight, and should have some time to transition. In our view, though, needs should only be considered in the context of a plan to get to outcomes that are reasonable.

***2.2.8*** SEC views the current Application as a classic example of a utility that wants to continue with the old, bottom-up, cost-driven approach to rates, rather than embracing the customer-focused approach in the RRFE.

***2.2.9*** The Applicant has concluded that it does not need to have a plan to improve its costs, or achieve better outcomes for its customers. Instead, the Applicant complains that comparing its costs and prices to other distributors is either not fair or not relevant, and admits that it has no plan to improve on those scores.

***2.2.10*** In this situation, SEC submits that the Board should be firm in its rejection of that approach. Unlike the competitive markets, which would force a company like that into bankruptcy pretty quick, the Board must, to achieve its mandate, take a more incremental approach. However, being incremental does not prevent the Board from being firm. Companies that offer services to the public must control their costs, compared to their peers and to the market. Utilities are no different. The only difference is the mechanism to do so.

## 2.3 ***Benchmarking***

***2.3.1*** There are several ways that the costs and prices of the Applicant can be benchmarked.

***2.3.2*** ***Rate and Bill Comparison.*** The prices of the Applicant can be compared to the prices of other electricity distributors in the province. In K1.2 SEC provided a table of 2016 bills for residential and general service customers. That table is reproduced in Appendix 1 to this Final Argument. The Applicant's rate levels are 65$^{th}$ out of 67 electricity distributors, on average about 148% of the simple average of the industry. Hydro One was excluded because it has different rate classes. It would perform worse than the Applicant as well.

***2.3.3*** The Applicant would likely prefer to compare its rates and bills to the industry on a weighted average basis, because Hydro One and Toronto Hydro would dominate the weighted average, thus making the Applicant look not as bad. Even if it did that[2], it couldn't hide the fact that its rates and bills are higher than pretty well every other electricity distributor in Ontario, except Toronto Hydro, Hydro One, and its affiliate Algoma Power. There is no way to make that relative price performance better than it is. It is bad.

***2.3.4*** ***Econometric Cost Benchmarking.*** The second way to compare is by costs. For this the Board has created a comprehensive econometric model that uses data from all utilities to create an expected total cost for a utility, given its business conditions. In K1.2 SEC has provided that comparison as well, reproduced at Appendix 2 to this Final Argument.

***2.3.5*** Although the Board's econometric model compares a utility to its own expected costs,

[2] Which the Board rejected in its own productivity analysis precisely because of the skewing of results by those two distributors.

those expected costs are derived from normalized standards from the entire Ontario distribution sector. The purpose of the model is to compare the utility to other utilities in the province, but with fair adjustments for differences in business conditions. Thus, it is not correct to say the model compares a utility to itself. What it does is compare a utility's costs to the costs it would have if it performed at the average level of utilities in the province.

***2.3.6*** The Board's model can be used two ways. First, it can be used to compare the Applicant on an absolute basis to the expected costs based on the rest of the industry. On this basis, the Applicant has always been a poor performer relative to the rest of the distributors. Using the average of 2013-2015, the Board's standard approach, the Applicant was 61st out of 72, with costs 12.3% above expected costs (i.e. industry average adjusted for local business conditions). The Applicant has always been in the double digits above expected costs, although from 2010 to 2015 it did show some marginal improvement.

***2.3.7*** We note that, for 2016 and 2017, the Board's model can be used to forecast the same comparison to expected costs. The Applicant has produced an updated Board model in J1.3, showing that for the test year it will be back up to 15.9% over expected costs, almost the same level as the 16.4% in 2010, and higher than any of the intervening years. If there was any improvement after 2010, the proposed increase for the test year would wipe it out.

***2.3.8*** While we do not have the 2017 numbers for all LDCs to do a straight-up comparison of performance, based on 2015 numbers the Applicant would go to 65th out of 72 with its forecast 2017 cost performance.

***2.3.9*** It is worthwhile noting that, if the Applicant's costs or prices are compared to the LDCs in its immediate geographic area, it is almost last in each case, and that is true year after year. Of the local LDCs, only Woodstock is worse on cost, but with a clear improving trend[3].

***2.3.10*** The evidence is thus overwhelming that the Applicant is, has been, and proposes to continue to be a very poor cost and price performer. In this context, the RRFE contemplates action by the Board to address those problems.

## 2.4 ***Alternative Benchmarking by the Applicant***

***2.4.1*** We note that, in J1.3, the Applicant has sought to cast doubt on the accuracy or usefulness of the Board's econometric cost comparison model. While emphasizing that it is not intending to criticize the model, the Applicant expresses concerns that the model does not fairly compare utilities in Ontario.

[3] Woodstock has since been bought out by Hydro One, which is why they don't show on the price comparison for 2016.

***2.4.2*** There are a number of technical reasons why the objections from the Applicant are not valid. They are addressed in the Energy Probe Final Argument, and we will not reiterate them here. We generally agree with those submissions.

***2.4.3*** We are more concerned, however, that the Applicant seeks, late in the process, to challenge the Board's model on a basis apparently never before raised. In doing so, the Applicant made no effort to arrange a discussion with the developers of the model, to see if their concerns were already dealt with in the model. The Applicant basically says that, since they don't understand how the model reflects differences in other income, the model must somehow be wrong.

***2.4.4*** The model doesn't deal with other income because it is a cost model, not a cost and revenue model. Thus, the step taken by the Applicant of arbitrarily adjusting its costs for the amount of its other income is obviously incorrect. Even if the Applicant is right that other income should have an impact on the model, at least to the extent of the related costs, it is patently clear that simply deducting that from costs does not correct the model.

***2.4.5*** In fact, this cherry-picking approach is likely wrong altogether. In developing the model, the Board's consultant looked at a number of potential variables to get the model specifications. Other income, or the costs associated with other income, did not end up as a material variable, just as many other factors in utility operations did not end up in the model. You can't adjust for everything, as the Applicant would certainly have learned if they took their concerns directly to the firm that developed the econometric model in the first place.

***2.4.6*** We note in passing that the Applicant's defence of their cost performance on the basis of this rewriting of the econometric model fails to deal with two important facts.

***(a)*** First, even if they were entirely right, which they're not, their own adjusted numbers still show them at almost 10% above expected costs. This is still poor performance, i.e. 56$^{th}$ of 72 instead of 65$^{th}$ of 72.

***(b)*** Second, the attack on the Board's model doesn't provide any explanation of the price comparison. Being almost dead last on price is still bad, no matter what the econometric model says.

## 2.5 ***SEC Position***

***2.5.1*** SEC submits that all of the evidence demonstrates that the Applicant is not delivering good outcomes to its customers at a reasonable cost. In our submission, the Board should take a step to correct this by considering the request for a large increase in OM&A in the context of a utility whose costs are demonstrably too high. A substantial reduction in those OM&A costs is thus indicated.

# 3 OM&A EXPENSES

## 3.1 *Overview*

***3.1.1*** The Applicant is proposing an increase of 7.8% in its OM&A spending from 2016 to 2017. This follows increases in actuals of 2.4% from 2013 to 2014 (after an accounting adjustment, discussed later), 0.9% from 2014 to 2015, and 3.1% from 2015 to 2016. Thus, the test year increase is not consistent with the Applicant's past pattern during IRM.

***3.1.2*** This is further complicated by the fact that, in its 2013 cost of service application, the Applicant sought and was granted an OM&A increase of about 12%[4], but had an actual increase[5] of about 4.9%. As a result, the Applicant collected $621,000 more in rates in 2013 than it actually spent on OM&A. This continued throughout the 2013-2016 period, i.e. rate recovery exceeding actual spending.

***3.1.3*** In its evidence, and the testimony of its witnesses, the Applicant has focused on the actual line items of spending it is proposing. Its evidence does not propose an empirical or envelope basis for determining a reasonable level of OM&A. Perhaps more important, the Applicant does not in its evidence explain how the customers are benefiting from the increased OM&A spending it is proposing.

***3.1.4*** SEC believes, consistent with the Board's decision in EB-2015-0089, that OM&A should be established on a prima facie basis using objective evidence of a reasonable level of OM&A spending for the Applicant. This is normally ascertained from past spending levels, modified by factors such as inflation, customer growth, and productivity. Then, the Board should explore whether any adjustments should be made to that prima facie level to reflect improved outcomes for customers, or external factors (government requirements, for example) requiring increased spending for electricity distributors in the position of the Applicant.

## 3.2 *The Energy Probe Model*

***3.2.1*** In the Final Argument filed by Energy Probe, a revised model devised by their consultant Mr. Aiken, providing an objective view of the reasonable level of the Applicant's 2017 OM&A, is filed as Appendix 1. That model, a version of which was filed in the hearing[6], shows that with appropriate adjustments to 2013 actuals, and appropriate indexing of costs from then until 2017, the OM&A in 2017 should be around $9.8 million. This is an increase from each of 2013, 2014, and 2015, and almost equal to 2016 Bridge year forecast.

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[4] Due almost entirely, in fairness, to the change from CGAAP to MIFRS.
[5] After adjustment for $351,000 for misclassified vehicle depreciation.
[6] Exhibit K1.2, p. 15.

***3.2.2*** The Aiken model escalates actual OM&A by the Board's inflation factor, plus a factor based on the Applicant's actual customer growth, less the Board's Applicant-specific stretch factor. Aside from the stretch factor, productivity is assumed to be zero.

***3.2.3*** The base year can be any year's actual spending, but clearly in an IRM period the appropriate base year is the earliest historical year available. However, it has to be adjusted for any material factors that make that year unrepresentative (just as in all IRM calculations). In this case, the model increases the 2013 actual spending by $351,000, to adjust for a misclassification of vehicle depreciation that understated the 2013 actual spending. Thus, the $8.864 million actually spent in 2013 is increased to $9.215 million, and the latter amount is the figure escalated annually by inflation, plus growth, less stretch. The end result is $9.762 million in 2017. Although that is actually 10.1% above the 2013 actuals, it is treated due to the 2013 adjustment as 5.9% above the 2013 actuals, which is the compound impact of inflation plus growth less stretch over four years[7].

***3.2.4*** Energy Probe has also provided an alternate view of the Aiken model, in which the stretch factor is removed, and the growth factor is increased. Productivity is still zero, and the adjustment and factors are unchanged. This produces a test year OM&A of about $9.973 million.

***3.2.5*** Based in part on this revised model, Energy Probe proposes a reduction in OM&A of $588,000 to $720,000 from the amount requested by the Applicant, i.e. OM&A of $9.853 million to $10.016 million.

## 3.3 ***SEC Position***

***3.3.1*** SEC agrees that the Aiken model provides a strong empirical basis for establishing a reasonable OM&A level for the Applicant in 2017 on a top-down basis. The methodology is sound, and accounts for all of the material elements that affect OM&A levels.

***3.3.2*** However, as with any model there is some judgement required in selecting the inputs. In this case, the range that is proposed by Energy Probe at one end assumes no productivity, continuous improvement, or economies of scale, and at the other end assumes that the above inflation increases in OM&A in 2014, 2015 and 2016 were reasonable. Neither is, in our view, an appropriate assumption.

***3.3.3*** On the first point, productivity, continuous improvement, and economies of scale, this Applicant has a history of poor cost performance. As we have noted earlier in this Final Argument, in our submission this is precisely the situation in which those

[7] i.e. a compound annual growth rate of 1.44% net of all of those factors.

factors should be taken into account. It is the utility with poor cost performance that should be expected to have the most improvement. This is in part because it has the most room to improve. It is also in part because it is that utility's customers that most need utility management to find ways to improve cost performance. It is those customers that have the most right to expect the regulator to step in when that doesn't happen.

***3.3.4*** On the second point, we see no reason to assume that OM&A increases in excess of inflation in 2014 and 2016 are any more acceptable than the proposed 7.76% increase in 2017. Just because the Applicant spent the money, doesn't mean it was a good idea. It only means the customers can't get it back.

***3.3.5*** Therefore, SEC believes that the appropriate OM&A for the test year is $9.762 million, a reduction of $813,000 from the amount ultimately being proposed by the Applicant. This is based on the adjusted actuals for 2013, escalated for inflation and growth (building in economies of scale), net of stretch factor.

***3.3.6*** SEC notes that the amount included in rates for 2013 was $9.836 million, but the Applicant did not actually spend that much in 2013, or any subsequent year. In fact, when that amount is escalated by the Board's IRM factor, the total collected from ratepayers for OM&A has been about $40.7 million over the four years 2013-2016. The actual OM&A spending over that period will be about $37.6 million, meaning that the Applicant will have collected about $3.1 million more than it actually spent over that period, or $775,000 per year on average.

***3.3.7*** SEC is aware that, once an empirical "target" OM&A level is set, it is appropriate to look at the actual spending plans for the year to see if there is anything unusual that requires an adjustment. We have reviewed the OM&A budgets of the Applicant for the test year. In our submission, there are no material amounts that are sufficiently out of the ordinary to require an adjustment. All planned spending is, in our view, within the range that management should normally be expected to manage with seeking further funding from customers.

***3.3.8*** Further, SEC notes that none of the planned spending by the Applicant is tied to improved outcomes for customers. In essence, the Applicant proposes that the customers provide the company with considerably more money, but to provide the same service they are already getting.

***3.3.9*** Thus, it is submitted that no adjustments to the empirically-determined reasonable level of OM&A are appropriate.

# 4 COST OF LONG TERM DEBT

## 4.1 *Background*

***4.1.1*** The Applicant has $30 million of third party debt currently outstanding at an interest rate of 7.092%, maturing August 14, 2018. As a result of this substantial high rate debt, the Applicant has a cost of long term debt of $2,979,961, and a weighted average cost of long term debt of 5.86%[8]. The Applicant expects that, when the debt is replaced, it will be at a lower rate.

***4.1.2*** This is a substantial issue. If the debt were to be refinanced at 4%, for example, which is a rough approximation of the current market, the Applicant's total cost of debt would be reduced to 4.22%, reducing the amount in the revenue requirement, and therefore the deficiency, by almost $800,000. Over the period from August 14, 2018 until the Applicant's next rebasing, the impact would be more than $2.5 million excess return to the Applicant.

***4.1.3*** This is not a normal situation. Most LDCs have non-arms-length debt, so their interest rate is adjusted at each rebasing. In those cases where high rate debt is being refinanced at lower rates, it is normally a smaller component of debt, and the impact is not sufficiently material to be a concern. Whether the impact is a lower cost, as here, or a higher cost, the impact is managed within the utility's overall budget. This is as it should be.

***4.1.4*** Here, the impact will be half the proposed deficiency, a rate impact of 4-5%. This is very unusual.

***4.1.5*** SEC believes there are two ways you could look at this. First, you could see the refinancing in 2018 as an event that qualifies for Z factor treatment, because it will be a result of a change in market conditions not within the utility's control, and it is material. Second, you could see the likely change in debt cost as reflective of the rebasing year not being a representative year. The Board could adjust the rebasing revenue requirement to make the year more representative of a normal year for this utility, while still allowing them to recover the higher cost until August 2018. The decision on whether to use one or the other depends on whether a Z factor must be a surprise to qualify.

## 4.2 *Z Factor Treatment*

***4.2.1*** A Z factor is an event that causes a material change in the costs of the utility, and is not one that is part of the normal course of business nor one that should be managed within the existing revenue envelope. It can be an increase or decrease in

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[8] All figures from Appendix 2-OB and Revenue Requirement Work Form filed with the Settlement Proposal.

costs, and in general the utility has a positive obligation to seek an adjustment if it is a reduction in costs, and an opportunity to seek an adjustment if it is an increase in costs.

***4.2.2*** To the best of our knowledge, no utility has sought Z factor treatment for a change in costs that is driven by a change in the interest rate on their long-term debt. This makes sense. Not only are most changes in debt costs not sufficiently material to justify Z factor treatment, but in most cases they are part of the normal ebb and flow of costs of the utility. Some costs go up, some costs go down, and management adjusts for these variations in the normal course of business.

***4.2.3*** This is the first time SEC has seen the maturity of a long-term (15 year) third party debt with a very large change in the interest rate on refinancing. This is not something that happens regularly, so it is not something that management would have to consider in the ordinary course of their day to day business.

***4.2.4*** To assess whether it is reasonable to consider the large savings on this refinancing a Z factor event, SEC looked at what would happen if the situation were reversed. What if, after fifteen years at a low interest rate, a utility had to refinance during IRM long term debt in a market that has higher interest rates? Would the utility seek rate relief, and would SEC oppose that relief?

***4.2.5*** Our conclusion was that, in most cases, utilities would not seek recovery, and if they did SEC would oppose that recovery. SEC's rationale would be that interest rates are a normal course market factor that should be part of management decision making. Most utilities would agree.

***4.2.6*** On the other hand, what would happen if the market took a sudden turn, and a utility had no choice but to finance almost all of its debt at much higher rates? In that situation, we could well see the utility seeking rate relief, and it is not as clear that we would oppose recovery. SEC might ask whether being locked into one maturity date was prudent for a large debt amount. We might ask whether there are other options rather than locking into new higher rates. However, we would see the situation as being different from the normal ebb and flow of interest rates.

***4.2.7*** Thus, in this case our view is that it is not unreasonable to consider this large decrease in interest costs, when it occurs, as a Z factor event. While we fully recognize that this suggestion is new and unique, and certainly not generalizable to all interest rate fluctuations, it would appear reasonable to consider extreme interest rate impacts as potentially eligible for Z factor treatment.

***4.2.8*** If the Board agrees, SEC proposes that the Board specifically decide not to adjust revenue requirement for the pending reduction in interest rates, but do so on the basis that it expects the Applicant to file for a Z factor rate adjustment when the event occurs. This would set the expectation for the Applicant to file in 2018, once the actual numbers are known, and would suggest a framework within which the rate adjustment could take place.

## 4.3 *Alternative Resolution*

*4.3.1* In the event that the Board is not comfortable applying the Z factor concept to an extreme change in interest rates (which we would certainly understand), in our view the alternative is to treat the change as a known change in costs, and adjust for it in the same way as the Board adjusts for one-time costs.

*4.3.2* In this alternative scenario, the Board would estimate the impact of the change in interest rates, average it over the five year IRM period, and reduce rates for the test year by the amount of that average. To reflect the uncertain nature of interest rates in 2018, a variance account could be established to capture the variance between the actual impact until the next rebasing, compared to the amount being included in rates. This would have the added benefit of capturing any additional differential resulting from any delay in rebasing.

*4.3.3* Again, in order to test this suggestion SEC looked at what would happen in a situation in which the utility faced a known one-time increase in costs. A utility is leasing premises at a very low rent, but knows that its lease ends next year, and the increase in cost – whether for the same premises or new - is going to be substantial (4-5% of rates). How would the Board reflect this in rates, if at all?

*4.3.4* Under IRM, it is not immediately apparent that the utility would be able to recover for this change, unless it filed a Custom IR application. Material future cost changes have been considered in the past, and generally rejected, but to the best of our knowledge none of them have been at the level of 4-5% of rates.

*4.3.5* In the real world, a utility in that situation would probably file a Custom IR application, seeking rates set in the same manner as 4th Generation IRM, but with an added adjustment for the increasing cost of premises. This kind of non-standard situation is one of the reasons Custom IR exists in the first place.

*4.3.6* In this case, the Applicant did not file a Custom IR application[9], and the customers are not in a position to file one on their behalf. This would appear to create a procedural Catch-22, and the question is whether the RRFE rate paradigm has that asymmetry built in.

*4.3.7* In our view, it does not, and if the Board does not want to deal with the large change in interest rates by way of a Z factor, the solution is to fashion a rate adjustment that accomplishes the same result as a Custom IR application would have done, so that both customers and utility are kept whole.

[9] Understandable, since it is not an <u>increase</u> in costs that is expected.

# 5 PENSION AND OPEBS

## 5.1 *Impact of Cash vs. Accrual Method*

***5.1.1*** The scope of the issue of whether Pension and OPEBs should be included in rates on a cash basis vs. an accrual basis is well understood by the Board. We will not reiterate the analysis here. The Board is considering this issue in EB-2015-0040, and will likely produce a generic policy on the question. The only issue in this proceeding is what to include in the rates of the Applicant while the generic proceeding is still going on. They would like to continue to include pension and OPEBs costs on an accrual basis, because that is what they have been doing in the past. SEC disagrees.

***5.1.2*** The impact of this issue appears to be the following[10]:

> ***(a)*** For pensions, OM&A on an accrual basis exceeds cash by $211,000, and capital on an accrual basis exceeds cash by $133,000, having a net revenue requirement impact of about $12,000.
>
> ***(b)*** For OPEBs, OM&A on an accrual basis exceeds cash by $88,320, and capital on an accrual basis exceeds cash by $55,680, having a net revenue requirement impact of about $5,000.

***5.1.3*** Thus, a reasonable estimate of the reduction in revenue requirement to move from accrual to cash is about $316,000.

***5.1.4*** As noted below, we agree with other parties that there should be a variance account established to capture the difference, on a forecast basis, between accrual and cash, so that if cash is included in rates, and the Board ultimately concludes that accrual is the appropriate policy standard, the Applicant can recover the $316,000 annuals difference from ratepayers. Thus, the choice of cash vs. accrual is neutral over the longer term.

***5.1.5*** SEC does believe, unlike some other parties, that the Board should order that cash basis be used until the Board policy is known. We have three reasons for that:

> ***(a)*** Most other utilities who have rebased since EB-2015-0040 started are using cash basis in the interim period, with the protection of a cash vs. accrual variance account.
>
> ***(b)*** At this particular time, when customers are more sensitive than usual to increases in electricity bills, every choice the Board can make to keep those rates lower is appreciated, and that is especially true for the most vulnerable

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[10] This is a summary of the analysis in the Energy Probe Final Argument, with which we agree.

customers.

*(c)* While SEC understands that it is perhaps cynical to view it this way, in our experience when a utility has to collect a variance account balance from customers, it will collect the full amount without offset. Conversely, when the utility has to refund a variance account balance to customers, that is sometimes seen as an opportunity to seek a rate increase for another purpose, knowing that the impact will be masked by the refund. If there is even a small amount of this factor when the cash vs. accrual account is to be disposed, the result is that the utility and customers are more likely to be made whole if the baseline is the cash basis, rather than the higher accrual basis.

***5.1.6*** For these reasons, SEC believes that the Board should include the cash basis for pension and OPEBs in the revenue requirement for the test year.

## 5.2 ***New Variance Account***

***5.2.1*** SEC agrees with other parties that a variance account to capture the difference between forecast cash and accrual pension and OPEBs should be established. If the Board in the generic proceeding concludes that the accrual method should be used, and the Applicant has had the cash method in rates, then the $316,000 annual difference would be recovered through the variance account. If the Board concludes that the cash method should be used, the variance account would be zeroed out, with no claim from the customers.

***5.2.2*** We note that this is intended to be forecast to forecast, not actuals, because the point is not to remove the normal IRM risk of cost differentials over time. It is only to adjust between what is included in rates in the test year, and what would have been included in rates had the other accounting approach been used when rates were set.

# 6 EFFECTIVE DATE

## 6.1 ***Principles***

***6.1.1*** SEC believes that it is the responsibility of a regulated utility to file an application for a rate change in sufficient time, and detail, to allow the Board, acting reasonably, to set rates by the target date in the application.

***6.1.2*** The converse of that is that, in the event that the Board is unable to issue a rate order until some later date, the only reason why the Board should give that retroactive effect is if the Board did not act reasonably and promptly in dealing with the application. For example, if the Board, for its own scheduling reasons, was unable to hear oral evidence until after a delay, that cannot be part of the responsibility of the utility. However, where the actions of the Board have not caused any unusual delay, the rate order should not have retroactive effect.

***6.1.3*** Based on that principle, it would appear to us that the Applicant did not make its Application complete until July, so the notice could not go out until August. In that situation, new rates would not be possible before mid-March. No delay resulting from Board actions appears to have occurred.

***6.1.4*** In our submission, unless there is an unreasonable delay by the Board between now and the rate order, any deficiency should be built into rates the month following the Board's rate order, with no retroactivity.

***6.1.5*** On the other hand, if the result of the Board's decision is a sufficiency, that should be implemented with an effective date of January 1, 2017. The Applicant is in control of the process. It should not get the benefit of higher rates after January 1, 2017 because it failed to seek a rate change in a sufficiently timely manner.

# 7 OTHER MATTERS

## 7.1 *Costs*

*7.1.1* The School Energy Coalition hereby requests that the Board order payment of our reasonably incurred costs in connection with our participation in this proceeding. It is submitted that the School Energy Coalition has participated responsibly in all aspects of the process, in a manner designed to assist the Board as efficiently as possible

All of which is respectfully submitted.

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Jay Shepherd
Counsel for the School Energy Coalition

## 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 | | | |

| | 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% |
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