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 Alectra Utilities Corporation pursuant to the *Ontario Energy Board Act* for an Order or Orders approving rates for the distribution of electricity commencing January 1, 2018

FINAL ARGUMENT
OF THE
SCHOOL ENERGY COALITION

January 16, 2018

SHEPHERD RUBENSTEIN
PROFESSIONAL CORPORATION
2200 Yonge Street, Suite 1302
Toronto, Ontario M4S 2C6

Jay Shepherd

Tel: 416-483-3300
Fax: 416-483-3305
jay@shepherdrubenstein.com

Counsel for the School Energy Coalition

TABLE OF CONTENTS

1 GENERAL COMMENTS

1.1 *Introduction*

1.1.1 On July 7, 2017 the Applicant Alectra Utilities Corporation filed an Application to set just and reasonable rates for the distribution of electricity for the period commencing January 1, 2018 for each of its four rate zones. Rates for the Horizon Rate Zone (HRZ) were proposed to increase on the basis of its Custom IR decision in EB-2014-0002. Rates for the Brampton Rate Zone (BRZ), Powerstream Rate Zone (PRZ), and Enersource Rate Zone (ERZ) were proposed to be set through a combination of a Price Cap IR escalator, plus ICM riders totaling $4,503,598 to "fund" incremental capital of $56.18 million.

1.1.2 The primary issues in the proceeding were:

(a) ***Incremental Capital.*** The extent to which the additional ICM amounts were appropriate.

(b) ***Accounting Policy Changes.*** A change in capitalization policy allowing for double counting of about $53 million of costs in rates, which the Applicant claims should go to their shareholders as a "benefit" of the Alectra merger.

(c) ***Enersource DSP.*** The appropriateness and impact, if any, of the Enersource Distribution System Plan, its first;

(d) ***Monthly Billing.*** The treatment of the savings the Applicant will enjoy by moving to monthly billing during the deferred rebasing period.

(e) ***Effective Date.*** The appropriate effective date for new rates arising out of the Board's decision in this matter.

While there are many other issues arising in the proceeding, SEC has limited its submissions to these five main concerns.

1.1.3 There was no oral hearing in this proceeding, but there was an extensive discussion of the issues orally in a two-day technical conference[1]. There was also substantial discovery, through which many of the issues were either raised or clarified. An ADR was unsuccessful.

1.1.4 Alectra's Argument-in-Chief was filed on May 3, 2017. This is the Final Argument of the School Energy Coalition.

[1] Unlike most technical conferences, the transcript of this one is well worth reading right through from front to back. There are numerous useful exchanges that have not been referred to directly in this or other final arguments.

1.1.5 The ratepayer groups who intervened in this proceeding have worked together throughout the hearing 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 parties. Where we are in agreement with the submissions of other parties, we have not repeated their arguments here, but have adopted their reasoning to the extent possible.

1.1.6 We did not in this proceeding have the benefit of seeing the final argument of OEB Staff in this proceeding, so we are unable to comment on OEB Staff positions on the issues.

1.1.7 SEC has not organized this Final Argument in accordance with the Issues List. Instead, we have grouped our submissions under the five headings above.

1.1.8 That means that we have provided no submissions on many of the other issues on the Issues List. Failure to make submissions on those issues should not be interpreted as acceptance of the evidence as filed. Where we agree with the Applicant's positions, we say so explicitly. Silence is just silence.

1.1.9 The one exception to that is in the case of the Metrolinx electrification project, which affects at least PRZ and ERZ. In our view, the appropriate way to deal with the uncertainties surrounding this potentially very large project is to establish a deferral account for incremental capital expenditures relating to this project.

1.2 ***Overriding Issues***

1.2.1 There are four overriding issues that exist as context for this Application. Rather than raise them in various places throughout this Final Argument, SEC believes it is more efficient to deal with them once at the outset.

1.2.2 ***Merger Savings***. The Board will be aware that the customer groups are still concerned with the $425 million of merger savings (at least[2]) going to the shareholders of Alectra over the next ten years, with none to the customers.

1.2.3 However, in fairness to the Applicant and the Board, we fought that battle in the MAADs application, and we lost[3]. SEC believes it doesn't help to keep complaining about it. To the extent that the Board believes the substantial savings arising from the

[2] We note that the Applicant has refused to file their 2017-2021 Financial Plan, so the Board can't even see what those savings will be in the most recent forecast: Tr.2:190. The Board may wish to consider requiring the filing of such a plan each year if the Applicant carries through on its intention to file for incremental rates each of the deferred rebasing years.
[3] Decisions with Reasons, EB-2016-0025, p.19.

merger should colour what the Board believes is appropriate incremental funding for capital, we leave that to the Board to consider[4].

1.2.4 ***Fair Hydro Plan.*** During the technical conference, PWU raised the question of whether the impact of this Application is really nothing due to the Fair Hydro Plan[5].

1.2.5 SEC urges the Board to reject any such argument. The intention of the government in promulgating the Fair Hydro Plan was most certainly not to allow the utilities to have more money to spend, and any suggestion that the Board can allow the Applicant higher rates because of this government action is simply inappropriate.

1.2.6 ***Customer Engagement.*** The Applicant claims that its customers think it should spend more money to maintain the current level of reliability[6].

1.2.7 That is not what the customers said. What the customers said is that they wanted lower rates[7]. Far and away the most pointed message in the customer engagement was lower rates. Not spend more. No customer suggested that the Applicant should spend more.

1.2.8 What the Applicant has done is to revert to the old, debunked style of customer engagement. In that approach, the utility tells the customers that if they don't spend some extra money, the whole system will fall apart[8]. Then they ask whether they should spend a little bit to "maintain reliability", without letting on to the customers that they already have money in their budget to maintain reliability. They just don't think it's enough, and they want more.

1.2.9 Further, both the Applicant[9] and their consultant[10] admit they did just that.

1.2.10 This is not what the RRF principle of outcomes is supposed to be about. The whole concept is that customers will pay more to get more. Except for inflation less productivity, or special cases, they should not have to pay more to get the same. The Applicant does not appear to understand this basic regulatory concept.

1.2.11 When you tell your customers that they have to pay more "or else", that is simply not the same as listening to your customers.

1.2.12 ***ICM Availability During Rebasing Deferral Period.*** "This application is about the

---

[4] It will come as no surprise to the Board that SEC agrees with the position of CCC on this point as set out in its Final Argument. SEC, however, has elected not to focus on this issue in this proceeding.
[5] See Tr.2:136.
[6] Argument-in-Chief, p. 5, and many places in the transcript and evidence.
[7] Tr.2:151 and many other places in the record. Also, see Argument-in-Chief, p. 23.
[8] Tr.1:43-4.
[9] Tr.1:44.
[10] Tr.2:152.

ICM funding", said the Applicant during the Technical Conference[11]. However, what it is really about, more than anything else, is whether this Board has a new rule that you can continue to add to capital at levels similar to your past spending (or even spend less), and with similar types of spending, but now get extra rate increases to pad your profit margins. Is the ICM after a merger a kind of stealth Custom IR, in which the utility recovers the extra costs, but gives no credit for the paybacks for those costs, including savings and other financial benefits?

1.2.13 As we will note later in this Final Argument, the Applicant thinks that the sole criterion for ICM funding is to spend more than the threshold on capital. SEC believes it is important for the Board to send a clear message that ICM funding is not supposed to be a back door way to increase rates. It is supposed to be an exception to the normal rule that you live within your IRM envelope. It is not an invitation to spend more. It is a relief valve where utilities have done everything they can to live within their means. This Applicant has made no attempt to do so (it doesn't think it has to), and therefore SEC submits they should be expected to live within the IRM envelope.

1.3 ***Summary of Submissions***

1.3.1 This section provides a brief summary of the positions taken and recommendations made by SEC in this Final Argument.

1.3.2 ***Enersource DSP.*** The Board should accept the DSP as filed, but give it little weight in assessing the planned capital spending of the Applicant in the ERZ

1.3.3 ***Incremental Capital.*** This ICM application is the first of a series, with the potential impact over the deferred rebasing period of $275 million or more of incremental rates.

1.3.4 None of the proposed incremental capital amounts should be approved as filed. The one project that might otherwise qualify, the YRRT, should be dealt with by way of a variance account, but only to the extent, if any, that it causes the Powerstream capital additions to go over the 2017 Board-approved level of $115 million.

1.3.5 ***Capitalization Policy.*** The Board-ordered deferral account for the impacts of these changes should remain open until rebasing to capture the forecast $60 million of newly capitalized OM&A, of which $53 million would be double recovered from customers under the Applicant's proposals.

1.3.6 Each year the Applicant should be required to clear the amounts in the account to the customers in the affected rate zones, so that the customers will be made whole and the rate base at the point of rebasing will not include any amount for double-counting. The amounts should be recalculated to ensure that the tax impacts of payments to or

[11] Tr.2:134.

from customers are reflected correctly.

1.3.7 ***Monthly Billing.*** The Board should order creation of deferral accounts to track the cumulative impact of monthly billing for each of the affected rate zones. Starting in 2019, whenever the cumulative net impact (savings less costs) is a credit, the accounts should be cleared by way of a refund to customers.

1.3.8 ***Effective Date.*** The Board should follow its normal practice of making new rates effective the month immediately following the Board's decision in this matter.

2 ENERSOURCE DSP

2.1 *Background*

2.1.1 The ICM application by Enersource in EB-2015-0065 was rejected by the Board largely because Enersource had not filed a DSP, only a draft that appeared to be a long way from being finished[12]. The Board never really got to the question of whether the projects and programs proposed (many of which are similar to those being proposed for ICM treatment in this Application) should be funded as ICM projects. The Board instead told Enersource that if they wanted to seek ICM funding, they would have to file a DSP[13].

2.1.2 Alectra has filed a DSP on behalf of its unit, Enersource. However, the Board is already aware that Alectra will be filing a new DSP for the entire utility in 2019 for 2020 capital and beyond. Further, asked to file its current financial plan, including the capital plan that covers 2018 and 2019, the Applicant refused to do so[14]. As a result, the Board really has very little idea how Alectra will actually manage the Enersource distribution system, and the capital spending that will arise, for the next five years.

2.1.3 The Enersource DSP was reviewed by a third party firm, Vanry Associates, that the Applicant refers to as "experts". In fact, the Argument in Chief quotes Vanry's "professional opinion"[15] with respect to the DSP. The Applicant also tries to strengthen it further, saying:

> *"Despite its report being filed as part of the Application, no party asked a single question of Vanry. It's conclusions were unchallenged."*[16]

2.1.4 With respect, the Vanry report is not an expert report, and SEC submits that as a matter of law the Board should not rely on it in any way. Vanry were never led as witnesses, either at an oral hearing before the Board (since at the request of the Applicant there was no oral hearing), nor at the technical conference. Lacking an oral hearing, the parties never had an opportunity to challenge the expertise of Vanry, and the Board never had an opportunity to determine if they are indeed experts. Further, no attempt was made by the Applicant to seek agreement from the other parties that Vanry was qualified as an expert. If the Applicant wanted to rely on this report as expert evidence, it was their responsibility to ensure that they qualified their experts as experts, one way or another. They did not.

---

[12] Which the Applicant appears to recognize: Tr.2:129.
[13] EB-2015-0065, Decision with Reasons, p. 7.
[14] Tr.2:190.
[15] P. 31.
[16] Ibid.

2.1.5 Had Vanry been offered as expert witnesses, SEC would certainly have challenged their independence. They were not offered as expert witnesses, so we didn't have any opportunity to do so. In our submission, the Applicant can thus not rely on any evidence presented by Vanry. Evidence is only fact evidence, or expert opinion evidence. This is neither.

2.1.6 We note in passing the Applicant's comment that intervenors did not ask any questions on the Vanry report. There are two reasons why an intervenor doesn't ask questions: a) because they accept the evidence, or don't believe it is susceptible to being challenged, or b) because the evidence is not material, useful or relevant on its face. SEC didn't ask any questions on the Vanry report because we did not feel it added any value to the process[17]. As we always try to do, we focused on the things that matter.

2.2 ***SEC Recommendation***

2.2.1 The Enersource DSP is an outdated pre-merger document that is not particularly helpful to the Board. SEC believes that the Board should accept the document, neither approving it nor rejecting it, but acknowledging that the Applicant has complied with the requirement in EB-2015-0065 to file a DSP.

2.2.2 In our submission, this DSP has no further value to the Board other than compliance with that requirement.

[17] And the Applicant admits that the Vanry work didn't influence the DSP at all: Tr.2:100-1.

3 INCREMENTAL CAPITAL

3.1 *Background*

3.1.1 The Applicant is seeking a total of $4,503,598 in incremental 2018 rate revenue on the basis of ICM requests for $56.18 million in capital spending that it says is incremental. The amounts are $6.8 million in the BRZ, $25.1 million in the PRZ, and $24.2 million in the ERZ. The Horizon Rate Zone is not eligible for ICM because it is still within its Custom IR framework.

3.1.2 Although Alectra seeks to avoid confirming the fact[18], the Board is well aware that it plans to file ICM applications for each year of the deferred rebasing period for each rate zone that it believes is eligible. The Applicant finally appears to have admitted this in the Argument in Chief[19].

3.1.3 This is important because the rate impact of this succession of ICM applications, over the nine years from 2018 to 2026[20], is exponential in nature. The $4.5 million per year for the 2018 application would last for 9 years, and total $40.5 million in incremental revenue. A similar application for 2019 would garner $36 million over eight years, and so on. Even if the ICM amounts are not increased, the incremental revenue from this sequence of ICM applications would be $203 million.

3.1.4 On the other hand, once Horizon is off Custom IR, the expected ICM threshold for Alectra, with about $120 million of depreciation (most recent Board-approved for each rate zone), would be about $200 million. If Alectra just continues its average capital additions from the past five years, with no increase, under Alectra's theory of the ICM they would be allowed extra funding for about $87 million per year of ICM projects. This would bring the cumulative ICM rate riders to $275 million[21] from 2018-2026. The decision of principle by the Board in this proceeding thus has the potential to increase rates for Alectra customers by $275 million. Small increments can lead to large totals[22].

---

[18] See Tr.1:18 and Tr.2-185-6, among the many examples.
[19] Where it says, at p. 4, "In the MAADs Decision, the OEB acknowledged that Alectra Utilities intended to file an ICM in each year for each rate zone under Price Cap IR during the rebasing deferral period."
[20] Assuming there are no further deferrals due to additional MAADs transactions.
[21] $4.5 million for each of 2018 and 2019 ($4.5 x 17 = $77 million), then $7 million on $87 million for 2020-2026 ($7 x 28 = $198 million).
[22] There was a time when every first year law student had the pleasure of learning about the 1663 British case James v. Morgan, 1 Lev. 111, said to be the foundation of the law on unconscionable bargains, but also a lesson in identifying cumulative impacts. James agreed to sell a horse to Morgan, a farmer, with the price to be paid in barleycorns. The price was one barleycorn for the first nail in the horse's shoe, two for the second nail, and so on, doubling each time. There were 32 nails in each shoe. James sued to receive 500 quarters of barley. A quarter is 6.9 bushels, and a bushel of barley is 21.8 kilos. Five hundred quarters is thus about 75 metric tonnes of barley, worth at the time about £300. The horse was worth £8 (which is what farmer Morgan was ordered to pay).

3.1.5 Two of the rate zone claims follow on failed attempts to get approval for capital spending from the Board.

(a) Enersource sought ICM rate recovery for 2016 in EB-2015-0065, but except for a payment to Hydro One the Board rejected its ICM request. Total capital additions of $75 million (excluding the Hydro One payment) were planned, of which $31 million was said to be dependent on the additional ICM funding in order to proceed[23]. The Board rejected the additional funding. Of the planned spending, $70.3 million was spent. In the result, 85% of the incremental capital that "needed" additional funding was spent without that funding.

(b) Powerstream sought Custom IR rate recovery for the five years 2016-2020. The Board rejected the Custom IR application, but allowed an IRM increase for 2016 (without ICM), and a cost of service increase for 2017, after reducing the 2017 capital budget from $131 million to $115 million.

3.1.6 The claim for the third rate zone, Brampton, is for a second true-up payment to its former affiliate, Hydro One Networks. That true-up was not forecast in the DSP dated March, 2014 filed in EB-2014-0083, Hydro One Brampton's last rebasing application[24]**.**

3.2 General Issues

3.2.1 The following general issues appear to arise in the context of these requests for ICM funding:

(a) ***Spending Levels.*** Should capital spending that is not actually incremental to past capital spending levels be provided extra rate recovery through the ICM?

(b) ***Projects vs. Programs.*** Are projects and programs somehow different, and is renaming a former program as a series of projects sufficient to qualify for ICM funding? When is a project "discrete" under the ICM policy? Put another way, does ICM spending have to be different from the routine annual spending of a utility in order to qualify?

(c) ***Context for Spending.*** Is it appropriate for the Board to authorize extra rate recovery for capital spending without the context of a long-term distribution system plan (or something similar, like a comprehensive multi-year business plan) applicable to the entity?

---

[23] EB-2015-0065, Supplemental ICM Evidence, Page 5 of 5.
[24] EB-2014-0083, Ex. 2, Tab 5, Schedule 6, p. 111 et. seq. See also Tr.1:114.

(d) ***RRF***. How should the Board balance its expectation that utilities live within their IRM envelope, and only exceed it to provide incremental outcomes that the customers value, against the ICM policy that sets a threshold well below the normal spending of many utilities?

3.2.2 ***What Capital is Incremental?*** Alectra has taken the position[25] that all capital is incremental if it exceeds the ICM threshold that is calculated using the Board's model. Whether or not the capital spending level proposed is similar to prior years is, in their view, not relevant.

3.2.3 There is an obvious conceptual issue here. Is ICM in fact designed to provide extra rate recovery for capital that is truly incremental to normal capital spending, or is it designed to boost rates for all utilities that spend more than a minimum amount on capital?

3.2.4 To analyze this, SEC looked at the past capital spending history of the four utilities that make up Alectra. That history is set forth in the table below[26].

Higher Rates to "Fund" Investing Less
Capital Spending 2012 to 2016 - Alectra Predecessors
(000's omitted)

	Historical Actuals from OEB Electricity Yearbook							*Compared to*	
	2012	***2013***	***2014***	***2015***	***2016***	***Totals***	***Average***	***2018***	***Threshold***
Powerstream									
Depreciation	$33,195	$34,930	$38,223	$42,259	$48,291	$196,898	$39,380	$52,272	
Capital Additions	$111,050	$114,771	$131,125	$140,709	$127,385	$625,040	$125,008	$109,774	
Percentage	335%	329%	343%	333%	264%	317%	317%	210%	160%
Enersource									
Depreciation	$31,560	$24,800	$29,225	$31,282	$33,306	$150,173	$30,035	$28,722	
Capital Additions	$67,481	$49,072	$53,158	$120,666	$70,314	$360,691	$72,138	$83,119	
Percentage	214%	198%	182%	386%	211%	240%	240%	289%	151%
Brampton									
Depreciation	$12,430	$17,288	$14,601	$17,379	$18,204	$79,902	$15,980	$15,227	
Capital Additions	$44,358	$30,789	$45,810	$51,143	$31,678	$203,778	$40,756	$38,069	
Percentage	357%	178%	314%	294%	174%	255%	255%	250%	203%
Alectra Totals (excluding Horizon)									
Depreciation	$77,185	$77,018	$82,049	$90,920	$99,801	$426,973	$85,395	$96,221	
Capital Additions	$222,889	$194,632	$230,093	$312,518	$229,377	$1,189,509	$237,902	$230,962	
Percentage	289%	253%	280%	344%	230%	279%	279%	240%	165%

3.2.5 What this table demonstrates is that Alectra is proposing to spend less than it spent for

[25] Argument-in-Chief, p. 12.
[26] Horizon RZ is excluded because it is on Custom IR, and so is not eligible for ICM. As a result, Alectra has refused to file the Horizon capital budget.

the last five years, on average, but insists it needs additional "funding" to do so. The 2018 proposed spending is below the average, and is either below or similar to three of the last five years. Further, the percentage of historical depreciation spent is significantly below the average.

3.2.6 These figures exclude Horizon because Horizon is on Custom IR, and as a result Alectra refuses to provide forecast information. However, based on the EB-2014-0002 forecasts, it is likely that this picture would look even worse if Horizon were included.

3.2.7 The situation is even more stark when one looks just at Powerstream. Alectra plans to spend less in the PRZ than in any of the last six years[27], Despite this, Alectra takes the position that under Board policies more than $25 million of their low 2018 capital spending qualifies as "incremental". Thus, they believe that while their past average capital spending is 317% of depreciation, they can treat anything above 160% of their last Board-approved depreciation amount as "incremental".

3.2.8 In the BRZ, Alectra proposes to spend less than the five year average (lower than three years, higher than two years), but still claim almost $7 million of that spend as incremental. Part of the reason for this is that the Board's threshold formula uses the last Board-approved depreciation level, which for Brampton is that in EB-2014-0083. If current depreciation levels were used in the formula, little if any of the Brampton capital spending would be considered incremental.

3.2.9 Some of the same problem arises in Enersource (using current depreciation would reduce the amount above the threshold by about $10 million), but at least with Enersource the spending is well above past levels. If you adjust for the extra $40 million in 2015 as a result of a true-up payment to Hydro One, Enersource is proposing capital spending of about $19 million above historical levels. While SEC has concerns about the reasons for this spending, at least it is "incremental" in the common use of the word.

3.2.10 Generally, the level of capital spending is built into the personnel and resourcing structure of the Applicant, so it is not surprising that Alectra wants to maintain past spending levels. The Applicant has people available to do the work, and doesn't want them to be idle. This mundane reality is shown in the following exchange[28]:

> *"MR. BRETT: [after quoting from the ERZ DSP]…I take it that's either/or subdivision or overhead rebuilds, "were completed to optimize usage of outside workers. This was necessitated by lower activity in subtransmission expansion," which is categorized as system service, "which led to unforeseen availability of workers and allowed more rebuild projects to be*

[27] Five years on the table, plus the reduced capital budget approved in EB-2015-0003.
[28] Tr.2:65-7.

completed."

So effectively, am I -- I mean, that seems relatively clear on its face. I'm inferring from that that what you do over in the company is if you have excess labour because of deferral of certain projects, you move them over to do other projects.

…You move people over to do other projects that can soak up the capacity, effectively?

MR. WASIK: I would categorize it the other way, Mr. Brett. We look at resource constraints as one of the pacing and prioritization constraints that we evaluate, and if resources are available, that removes that constraint in that we can move forward with specific investment needs that have been identified.

So we try to optimize work levels across the various different operational functions, and ensure that that constraint is appropriately managed.

MR. BRETT: …As I understand it, what happened is you had sort of a plan that you were going to do a certain amount of activity in the subtransmission area and, for various reasons, that didn't come about. So you had the people that you were going to use to do that work and you shifted them over, which allowed you to do more subdivision overhead renewal work, rebuild work, right?

MR. WASIK: That's correct. So having available resources lifted the constraint, and we were able to go and complete some of the other system renewal work.

MR. BRETT: Right. But your initial plan was not that you had the resources to use there. Your initial plan was to use the resources in the subtransmission area?

MR. WASIK: That's correct. We had constraints initially, and those constraints were lifted afterwards."

.

3.2.11 This is all part of running a utility properly. The utility is resourced to do a certain amount of work, both OM&A and capital, based largely on the capital and operating budgets approved by the Board for recovery in rates. If the Board approves $115 million of capital for Powerstream, for example, then absent any shift to OM&A for those people[29], the utility has to get them doing $115 million of capital each year, or it is forced to downsize its workforce.

3.2.12 There is nothing wrong with this. The question is whether building in the capacity to do a certain amount of work in a rebasing year should mean that high rate increases in future years are also built in.

3.2.13 SEC submits that, where capital spending is similar to historical capital spending, that

[29] And subject of course to the level of variable resources through outside contractors, etc., which in any case tends to stay constant.

does not justify the extraordinary remedy of incremental capital recovery. In this respect, the Board has established the basic starting point that utilities on Price Cap IR should live within their means. This is described various places, including the OEB's Applications Handbook[30]:

> *"<u>During the IRM period, it is expected that a utility should manage both its capital and operating expenses to service current and new customers while maintaining its financial viability and delivering productivity improvements, in line with the "inflation less productivity" Price Cap IR adjustment. However, capital investments can be "lumpy".</u> To preserve the efficiency of the IRM process and avoid early rebasing or inefficiently timed capital investments aligned with the cost of service rebasing application, the OEB has provided for capital tracker mechanisms (e.g. the Incremental Capital Module and the Advanced Capital Module developed for electricity distributors). These allow for approval and funding recovery of qualifying capital investments during the IRM period between cost of service rebasing where material capital investments that are beyond what is normally funded through rates can be reviewed and approved without requiring an early rebasing." [emphasis added]*

3.2.14 Alectra, on the other hand, has a completely different view of the purpose of incremental capital funding, expressed in the Argument-in-Chief as follows[31]:

> *"The ICM is intended to address the treatment of a distributor's capital investment needs that arise during the rate-setting plan which are incremental to a materiality threshold."*

3.2.15 If the sole criterion for whether capital spending is incremental is whether it exceeds the ICM threshold, then Alectra has exceeded that level in each of its rate zones in each of the last several years. Further, it can reasonably be expected to do so during the entire deferred rebasing period. That means that the average rate increase for Alectra customers over the next ten years can be expected to be well in excess of inflation, perhaps double that level. If this is what the Board intends with the ICM, then it should say so expressly. SEC believes that it is not what the Board intends.

3.2.16 SEC therefore submits that the Board should make clear that capital spending that tracks past spending levels is not in and of itself considered "incremental", and is not eligible for additional rate recovery through ICM unless it exhibits other attributes that make it unique or unusual.

3.2.17 Projects vs. Programs. The criteria for ICM treatment include the following

[30] Handbook to Utility Rate Applications, October 13, 2016, App. 3, p. i.
[31] Argument-in-Chief, p. 12.

requirement[32]:

> *"The Board is of the view that projects proposed for incremental capital funding must be discrete projects, and not part of typical annual capital programs."*

3.2.18 This creates a problem for the Applicant, because much of the work proposed for ICM funding is precisely that: part of typical annual capital programs. To get around this, Alectra has re-characterized its programs in several areas as "projects", and has said that it has changed its approach to those activities to make them more project-like[33]. This is a façade, and should be recognized as such[34].

3.2.19 The concept is described as follows[35]:

> *"MR. WASIK: Mr. Oakley, it might be helpful if we clarified what a project is. So in our view, a discrete project has a discrete driver. It has a specific purpose. It's also finite, meaning that it has a start and an end. And that differentiates between an ongoing recurring investment program.*
>
> *…Where our view of a program is that it's ongoing, it's recurring, it doesn't have an end, it's -- as long as we have a fleet of these particular assets or any other type of an asset, those types of programs will roll forward.*
> *And so that -- we're hoping -- that explanation we're hoping provides you a little bit more clarity in the sense of, what is the difference. One is specific. It's discrete. And the other one is ongoing and recurring."*

3.2.20 Thus, the difference between projects and programs is that projects are "discrete" – and thus qualify for ICM funding – whereas programs are "recurring" - and therefore do not qualify. Or, to rephrase, projects are spending for which the Applicant is seeking ICM funding. This is, of course, entirely circular.

3.2.21 This was pursued a number of times during the Technical Conference. In the following exchange, responding initially to a question from Ms. Grice, the Applicant provided still more context[36]:

> *"MR. MATTHEWS: So the distinction between the program structure and the project structure. The program was based on general high level estimates to do a certain amount per year. I believe we identified 25*

[32] ACM Report, September 18, 2014, p. 5.
[33] Tr.1:139-41.
[34] Even Alectra sometimes gets confused: see for example Tr.2:63 and the materials referred to in that exchange.
[35] Tr.1:23-4
[36] Tr.2:75-6.

> *kilometres per year of cable replacement. We've restructured that into specific projects and by doing so, we are able to develop more accurate estimates for those projects, with more specific schedules targeting specific areas.*
>
> *So it just provides more -- first of all, from an estimate point of view, the estimates are more detailed. We're doing preliminary designs and then detailed designs in determining what the budgets are. And then we can schedule more precisely our resources based on those detailed designs. So the whole process is more accurate than on a program basis, where you're just generally replacing a certain amount of cable on an annual basis and not determining exactly those locations.*
>
> *MR. SHEPHERD: That sounds -- sorry to interject, but that sounds like what you do normally. You have a program that says we have we're going to do 25 kilometres and then as the year comes up, you start to specify which kilometres are we going do, who is going to do it, how do we assign the people, what's the actual cost going to be. The that's what you normally do, right?*
>
> *MR. WASIK: Mr. Shepherd, what we identified in our response to PRZ-AMPCO-7 was we listened to the Board's decision. We recognized that unit pricing and generality in terms of approaching cable replacements was something that we wanted to look at, we evaluated how to properly manage this investment requirement.*
>
> *So what we did was we looked at each specific area and said we're going to treat it as a project, and let it stand on its own merit. And they're identified and ranked and prioritized based on their own project, as opposed to one program standing."*

3.2.22 The exchange then goes on for six pages in the transcript, with intervenors seeking to find out how this kind of work (in this case, cable replacements) was done in the past. That led to the following admission[37]:

> *"MR. GARNER: I'm sorry, can I just interrupt? I just got confused on this, just one -- there are projects, but there are still programs, aren't there? You still do it? Programs are now eliminated as a concept completely within the utility?*
>
> *MR. MATTHEWS: Programs with respect to cable replacement are not -- no longer the way we do it. It's each individual area is done as a specific project."*

3.2.23 Or, again to paraphrase: "We're doing the same things that we always did. We are just approaching it differently, and thus it now qualifies as discrete projects."

[37] Tr.2:83.

3.2.24 As was the case with cable replacements, normal road activity also represents recurring capital activities that have been morphed into "projects". The Applicant admits that the only difference between the road projects in the base budget and the ICM request is that the ICM project was identified later[38].

3.2.25 Perhaps the best example of a recurring capital program that is now ICM projects is subdivision renewals. The Applicant has ten planned in the ERZ for 2018; six are ICM projects, and four are not. They admit that the ones in the ICM are "not different in nature" from the ones that are not[39].

3.2.26 The truth is that the ICM "projects" are nothing different from the normal capital activities of the Applicant, year in and year out. The Applicant replaces cable every year, and will do so this year. The Applicant does subdivision renewals every year, and rebuilds feeders every year, and so on. These are annual capital renewal and expansion programs typical of any distributor.

3.2.27 The Applicant seeks to change these recurring capital programs into projects through nomenclature[40], and through cosmetic changes to how they are done. .

3.2.28 SEC submits that the Board should consider providing further guidance as to the meaning of "discrete project" in the ACM Report, and how it differs from the types of projects which make up the recurring annual capital programs of a distributor[41].

3.2.29 SEC also submits that most of the projects for which the Applicant is seeking ICM funding are not "discrete projects', as described in the ACM Report, but are part of the "typical annual capital programs" of the Applicant. As such, they should not qualify for ICM treatment.

---

[38] Tr.2:53-4.

[39] Tr.2:64-5 and JT2.6. Later they admit that the real difference is that they want additional budget to include some of the projects: Tr.2:127-8.

[40] Interestingly, the nomenclature is not really changing much, despite the increased emphasis on the work "project". As the Board can see from looking at the draft Enersource DSP filed in EB-2015-0065, even the form for the business cases had a box for "Program" and a box for "Project". This is because, like most distributors, Enersource organized its capital activity into broad programs (subdivision rebuilds, for example), and then the many projects within those programs, usually distinguished geographically (by subdivision, by street name, by feeder, etc.) There was good reason for the witness to avoid talking about how recurring annual capital work was done in the past [Tr.2-75-83]. It was essentially identical to how it is to be done in 2018.

[41] The Board attempted to do so in the ACM Report (p. 14), by distinguishing between the types of projects for which an ACM would be appropriate (i.e. "discrete" projects that fall in the ICM/ACM category), and the capital spending profile more suitable to a Custom IR application. For example, the Board said that an ACM is suitable for a utility that "is not seeking funding for a series of projects that are more related to recurring capital programs for replacements or refurbishments (i.e. "business as usual" type projects)". SEC thought it was pretty clear that the ICM/ACM category was not intended to cover "business as usual" any more, but the Applicant in this case appears to have interpreted the policy differently. Further clarification might therefore benefit all distributors.

3.2.30 ***Context for Spending.*** SEC has concerns with the framework within which this spending is being proposed.

3.2.31 The Board is looking at capital projects in this Application without a relevant distribution system plan. While the Board does have DSPs for all four of the former utilities, the Applicant is now consolidating its activities. It is not sensible – nor would it be prudent – for the capital spending of the Applicant to continue to be based on those separate DSPs[42]. In fact, this was discussed in the MAADs proceeding, and the Board accepted the proposal of the Applicants to file a consolidated DSP by 2019 for 2020 implementation[43].

3.2.32 In the meantime, it would have been useful to have at least the Business Plan of the Applicant for the next several years[44], to see how actual capital spending for the combined entity is likely to track – if at all – the capital spending in the four DSPs[45]. The Applicant refused to file that document, leaving the Board with no useful context for the proposed capital spending for 2018. The RRF is clear that capital spending should be considered in the context of a multi-year plan[46].

3.2.33 Related to this is the fact that the Applicant plans a series of one-year ICM applications. The Board has made clear, in the ACM Report and elsewhere, that it prefers to consider capital spending programs in a multi-year context, either by way of an ACM during rebasing (if it is a series of discrete projects), or by way of a Custom IR application (if it is high levels of "business as usual" spending). ICMs are intended to have more limited use under the ACM Report.

3.2.34 Of course, the reason the Applicant doesn't do either is that it wants to take full advantage of the deferred rebasing period to maximize profits from the merger. It is hard to imagine that they would do otherwise.

3.2.35 However, SEC submits that one of the implications of this is that the Applicant is limited to ICM claims for that more limited class of projects that is left to the ICM approach under the ACM Report. If Alectra seeks to build a transformer station, the ICM would be available. Similar treatment might be available for the Metrolinx Electrification project, if that project were more clearly defined.

---

[42] And it won't be: see Tr.2:153-5.
[43] EB-2016-0025, Decision with Reasons, p. 25-6. Also Tr.2:34.
[44] They admit they have 2017-2021, but state that they do not yet have an updated plan for 2018-2022, even though we are now into 2018: Tr.2:157.
[45] It would also allow the Board to see details of the rather rudimentary approach the Applicant has taken to allocation of costs and assets across the rate zones: see Tr.2:30-34.
[46] The Applicant implies that they don't plan to optimize capital spending across their entire service territory, but only within each service territory [Tr.2:97-8], but the filing of a consolidate plan might allow the Board to provide guidance in that regard.

3.2.36 But the Applicant should not be able to have their cake and eat it too. The Board has a mechanism for utilities with long-term, recurring capital programs that cannot be accommodated under Price Cap IR. Horizon is on that rate plan, Custom IR.

3.2.37 What Alectra is seeking, with this Application and with the plan for subsequent applications each year, is Custom IR without the comprehensive review of the entire program, and without returning the savings from the capital spending to the customers in rates.

3.2.38 It is a kind of back-door or stealth Custom IR, in which year by year Alectra gets approval for another year of Custom IR, but only the increase in rates that arises out of the capital spend. There are no new load forecasts or updated loss factors. Funding in rates is based on outdated depreciation levels. OM&A savings and other financial paybacks from capital spending are ignored. Pacing is never considered. New Board policies benefiting customers (like the lower working capital rate) are not applied. And, best of all, the utility doesn't even have to go to the trouble of filing a longer term plan. It can just ask for more money each year.

3.2.39 SEC submits that the Board should make clear that its intent, in the MAADs policy, is not to provide indirectly for a kind of creeping, asymmetrical Custom IR, in which high capital spending year after year will simply be given extra funding without the context of a DSP, a rebasing/ACM application, or a Custom IR application.

3.2.40 ***RRF.*** The Applicant is not offering its customers any improvements whatsoever for its increased capital spending. There are no positive outcomes. All capital spending is justified by reference only to avoidance of negative outcomes. In fact, in its customer engagement Alectra didn't even put to the customers the proposition of increased spending for improved outcomes[47]. It already knows that the customers are not willing to pay for that[48].

3.2.41 SEC understands the RRFE to work from the principle that prices should increase by a certain percentage (inflation less productivity, essentially), in the absence of a change in outcomes. If outcomes (such as reliability, customer service, etc.) improve, on the other hand, prices can go up more quickly. It works just like the competitive markets. To the extent that the utility delivers improved outcomes that customers value, the utility can charge higher prices for its services. If it doesn't deliver those outcomes, it should not be charging more (in real terms).

3.2.42 In this Application, Alectra seeks to recast that market proxy approach. For Alectra, it is enough that they keep reliability, for example, at current levels. If they do that, they are entitled to extra funding, over and above inflation less productivity. In their

[47] Tr.1:43, 130.
[48] Tr.1:131.

customer engagement, that's what they told their customers: agree to these extra rate increases, or we will let reliability decline[49].

3.2.43 We note that it appears the Applicant didn't even try to develop a plan that maintained reliability without incremental rate increases. There was some controversy about this, as the initial answer from the witness was unequivocal that no such plan had been attempted. After a break, the witness sought to walk that statement back[50]. However, when asked to show the work they had done, they provided only the analysis of the reliability impacts of each ICM project. SEC counsel harped on the question of whether there was a report to management in this regard, but the Applicant claims there was none[51].

3.2.44 SEC submits that, if a real attempt had been made to find a way to maintain reliability without getting extra money, there would have been documentation of that attempt, including a report to management or the Board of Directors explaining why it was not possible. Indeed, the Board of Directors or senior management of a utility with good governance should be demanding just that kind of rigour. If no-one is saying "Prove that we can't maintain our current reliability without getting extra money", that is a serious problem that should concern the Board.

3.2.45 . SEC submits that the Board should insist that high rate increases (for example resulting from incremental capital spending) should bring with them improvements in reliability, or future cost savings, or other positive outcomes valued by the customers. The Board should not accept high rate increases that are merely designed to achieve the status quo.

3.3 ***Brampton Rate Zone***

3.3.1 The sole capital project for which the Applicant seeks ICM treatment is a true-up payment to its former affiliate, Hydro One, of $6.8 million. The payment is required under the CCRA because the load that has materialized is about a quarter of what was originally forecast in 2006, i.e. 33.4 MW in 2017 as opposed to the original forecast of 122.4 MW. As a result, the Applicant is responsible for more of the original cost of the $40 million transformer station than the $4.1 million originally paid.

3.3.2 The issue with the true-up is not whether the payment has to be made. All parties appear to agree that it must be paid. The issue, instead, is the extent, if any, to which the customers of the Alectra should be required to pay for what it now appears was an unnecessary transformer station.

[49] Tr.1:43-4.
[50] See exchange at Tr.1:46-48.
[51] JT1.3 and JT1.9.

3.3.3 SEC submits that there are at least four reasons that the CCRA true-up of $6.8 million should not be recovered from the Applicant's customers:

(a) ***Unrealistic Load Forecast.*** The load forecast was wrong by so much that it raises a question whether it was carried out in a prudent manner. The original business case that justified the transformer station did not consider alternatives to meet a load in the range of what actually transpired[52].

(b) ***Non-Arms-Length Transaction.*** The agreement between the former Hydro One Brampton and Hydro One Networks dealt with a non-arms-length transaction between affiliates. The Applicant has not demonstrated that the terms of that agreement, and the transaction itself, were objectively fair and should now be treated by the Board as if they were arms-length.

(c) ***Liability of Acquired Company.*** The liability to make a payment to Hydro One is a liability of Hydro One Brampton, the shares of which were acquired by Alectra. The liability was not disclosed in the DSP or the financial statements of Hydro One Brampton (or in the Share Purchase Agreement), and the Applicant has led no evidence to demonstrate that Alectra did proper due diligence to identify this liability, nor that this material obligation was disclosed to the Board in EB-2016-0025.

(d) ***Within Past Spending Levels.*** This payment is not incremental to the historical spending levels of Hydro One Brampton, as discussed under "General Issues" above.

3.3.4 ***Unrealistic Load Forecast.*** The original load forecast was prepared by Hydro One Brampton[53]. It appears to be wrong for two main reasons:

(a) The absolute estimates of 27.6 kV demand growth at the new Pleasant TS were all optimistic.

(b) Hydro One Brampton assumed – improbably – that for every year that Pleasant TS was in service there would be zero unused capacity on its other 27.6 kV transformer stations[54]. That has not turned out to be correct.

3.3.5 The data for the original forecast, and the actual results, are contained in BRZ-Staff-5. They are summarized in the following table:

---

[52] This was debated, and the Applicant insists that the station was required even at the low load level: Tr.1:107-110. However, the original business case does not appear to be consistent with that conclusion today.
[53] Tr.1:95.
[54] Tr.1:101.

Pleasant TS Forecast and Actual Demand								
Anniv.	Year	New Load at Pleasant TS		Unused Capacity at Existing Stations		Net New Load for CCRA True-up		Percent Actual/ Forecast
		Forecast	Actual	Forecast	Actual	Forecast	Actual	
1	2009	26.0	20.9	0.0	19.6	26.0	1.3	5.0%
2	2010	42.6	21.5	0.0	16.5	42.6	5.0	11.7%
3	2011	56.4	33.7	0.0	14.7	56.4	19.0	33.7%
4	2012	68.9	45.5	0.0	20.9	68.9	24.6	35.7%
5	2013	80.5	52.1	0.0	17.0	80.5	35.1	43.6%
6	2014	92.4	57.7	0.0	24.0	92.4	33.7	36.5%
7	2015	104.7	61.2	0.0	30.5	104.7	30.7	29.3%
8	2016	116.2	57.9	0.0	31.2	116.2	26.7	23.0%
9	2017	122.4	61.6	0.0	28.2	122.4	33.4	27.3%

3.3.6 It can readily be seen that the net demand is not even up to the year 2 (2010) forecast level, and from the pattern there doesn't appear to be much likelihood it will ever get there. The figures show the two reasons for this. First, the load growth at the TS, expected to average almost 10% per year, has instead averaged under 4% per year. Second, the capacity available from other 27.6 kV stations, expected to be zero[55], has instead been substantial in every year, and shows no sign of letting up.

3.3.7 Using hindsight (see below for the relevance of this), it is clear that it wouldn't make sense to spend $40 million on a new TS of this size to serve a long term demand of 33.4 MW. That is precisely why payments have to be made to Hydro One; because the station's load does not justify its cost. At the very least, Hydro One Brampton should have considered alternatives (not seen in the original business case), such as sharing a new TS with another utility, or expanding the capacity of an existing station or stations, or reconfiguring the system to spread load more evenly, or some combination of options.

3.3.8 Instead, the Applicant is saying that the expected load did not materialize, so its customers have to pick up the tab for its overly optimistic forecast.

3.3.9 What the Applicant has said is that it was surprised at the housing crisis and economic downturn of 2008 and 2009[56], which was not factored into its forecast. It also did not expect the level of induced and natural conservation that in fact occurred[57].

[55] Actually, the assumption was that three of the stations would take less load by the in-service year, in aggregate 28.4 MW. See JT1.5, Table 2.
[56] Tr.1:99,102. Argument-in-Chief, p. 18.
[57] Tr.1:102.

3.3.10 However, no effort appears to have been made to demonstrate in the evidence in this proceeding the actual impact of the housing crisis and economic downturn on load (for example with a study of impacts on other LDCs). They also made no effort to provide details of the induced and natural conservation assumed in the original forecast, the reasons for those assumptions, how the reality unfolded differently, and why.

3.3.11 The whole explanation has an air of "Oh well", as if to say that it was a forecast, and everyone knows that forecasts will be wrong. Not our fault.

3.3.12 There was a time when utilities could insist that their past actions were presumed to be prudent, and they were held harmless if they didn't work out as planned. That principle has been rejected by the Supreme Court of Canada[58] in the only OEB appeal that court has ever considered. The law in Ontario, said the SCC, is that the onus is on the utility to prove that their past actions were prudent, and they cannot rely on any presumptions to get there.

3.3.13 SEC submits that, in this proceeding, the Applicant has not provided evidence that proves its original assumptions that a) Pleasant TS demand would grow by 10% per year, and b) at no time would any other 27.6 kV station have unused capacity, were prudent assumptions. The Applicant has not shown that the forecast was done with sufficient detail, and rigour, befitting the acceptance of a $40 million contingent liability for the capital cost of a new station.

3.3.14 ***Non-Arms-Length Transaction.*** SEC submits that, even if this had been an arms' length transaction, the Applicant would not have met its onus. However, in this case the situation is worse, because Hydro One Brampton was not dealing with an arms' length transmission company. They were dealing with their affiliate.

3.3.15 SEC submits that the onus to demonstrate a transaction is prudent is greater when the transaction is with an affiliate. When a transaction is at arms' length, the Board can assume that two entities, each with their own goals, and each with their own expertise, have reviewed the transaction and concluded that the transaction is appropriate. Further, where the parties have differing interests (as is the case here when it comes to risk allocation), the Board can assume that the parties would take appropriate steps – through due diligence, negotiations, or otherwise – to ensure that their interests are protected and the other side doesn't get the upper hand.

3.3.16 None of that is true in a non-arms-length transaction. There is essentially one review only, and the only parties with a differing interest – the customers of the distributor – are not at the table.

---

[58] Ontario (Energy Board) v. Ontario Power Generation [2015] 3 SCR 147.

3.3.17 The normal way to deal with this kind of situation is to enlist independent third parties to review the transaction, including the underlying assumptions and the terms of the deal, to assess whether it's fair. That is not just to prove prudence to a regulator later. It is also to satisfy the management and Board of Directors of each of the two companies that the decision is a good one. And, it is also to ensure that the lack of independence of the parties does not have a negative impact on the customers of either party.

3.3.18 None of that was done in this case. The transmission company ensured through the terms of the CCRA that it had no risk in the transaction. The distribution company, on the other hand, took no steps to minimize its risk.

3.3.19 SEC therefore submits that, even if the transaction would be considered prudent, despite the very different results, if it were arms' length, it cannot be considered prudent in the context of two companies with common ownership.

3.3.20 ***Acquisition of Hydro One Brampton by Alectra.*** The Share Purchase Agreement for the acquisition of the shares of Hydro One Brampton is Attachment 10 to the application in EB-2016-0025. In that agreement, Section 5.2(24) is a representation by Hydro One that there are no material liabilities (including commitments and other obligations) of Hydro One Brampton other than those disclosed in the financial statements or in the Confidential Disclosure Letter[59].

3.3.21 The obligation to make a payment to Hydro One of at least some material amount would have been known in 2015 when the share purchase agreement was signed, as can be seen by the forecast and actual loads detailed above. That obligation is not disclosed on the financial statements of Hydro One Brampton, either as filed in EB-2016-0025, or those filed subsequently. Further, the Applicant has filed no evidence that the CCRA obligation was disclosed to Alectra by Hydro One in the Confidential Disclosure Letter referenced in Section 5.2(24).

3.3.22 The representations and warranties in Section 5.2(24) survived the closing of the transaction for 18 months (Section 5.5). The Applicant has provided no evidence that it did not know of the CCRA obligation at the time of the expiry of the reps and warranties, nor any evidence that it did any due diligence on such liabilities prior to expiry.

3.3.23 Absent any express agreement to the contrary, the existence of an undisclosed material liability in Hydro One Brampton, especially one payable to Hydro One Networks, should result in a payment by the Vendor Hydro One to the Purchaser Alectra for breach of its representation and warranty. The Applicant has provided no evidence that it has made any attempt to seek recovery of this $6.8 million from Hydro One, the

[59] See Argument-in-Chief, p. 19, where the Applicant refers to the CCRA obligation as "conditional debt".

Vendor.

3.3.24 SEC therefore submits that the Applicant has failed to demonstrate that, under the terms of the Share Purchase Agreement, the Applicant is liable to pay the $6.8 million to Hydro One Networks, and is not entitled to reimbursement of that amount from Hydro One.

3.3.25 SEC is conscious that none of these points relating to the Share Purchase Agreement were raised by SEC during interrogatories or the technical conference. It would have been more helpful to the Board if we had raised this earlier, but we didn't. It would also be helpful if we had an excuse, but we don't. We just missed it as, apparently, did everyone else.

3.3.26 We therefore debated whether it was appropriate to raise this in Final Argument. Ultimately, we concluded that we had a responsibility to do so, and to leave it to the Board to determine the impact of the late "catch" on the weight it gives to this issue.

3.3.27 The onus is on the Applicant to demonstrate that it is obligated to make the payment. Material on the record suggests that it is not liable to make the payment due to Hydro One's misrepresentation or if liable it can recover the same money back under the Share Purchase Agreement, generating an offset. The Applicant therefore had a responsibility to discharge its onus, and it did not. The fact that it was not raised by any party prior to final argument does not change the Applicant's onus, nor its failure to provide evidence demonstrating that a fundamental requirement of its claim is correct.

3.3.28 SEC therefore submits that the failure to show that the $6.8 million must in law be paid to Hydro One, or if paid will not be reimbursed, is fatal to this ICM claim.

3.3.29 ***Is the Spending Incremental?*** As noted earlier, even if this payment were approved, test year capital spending in the BRZ would still be below the average capital spending by the predecessor company in its prior years. Thus, this spending is not actually incremental at all.

3.3.30 ***Result.*** SEC therefore submits that, for any one or more of those four reasons, recovery by way of ICM of the CCRA amount should be denied.

3.4 *Enersource Rate Zone*

3.4.1 The Applicant seeks to have an ICM rate rider to fund $24.2 million of capital that it says is incremental.

3.4.2 ***Is the Spending Incremental?*** As noted earlier, the proposed spending is $19 million above the average capital spending by Enersource in the previous five years (excluding the unusual incremental payment in 2015). Therefore, while not all of the proposed spending is incremental to average past spending, it is substantially so.

3.4.3 ***Projects vs. Programs/Routine Annual Spending.*** The projects for which ICM funding is sought are captured in the following table[60]:

Project Description	Capital Expenditures $
Road Widening Project - QEW (Evans to Cawthra)	$1,294,220
System Access	**$1,294,220**
Overhead Rebuild - Lake/John	$927,370
Overhead Rebuild - Church	$1,020,107
Leaking Transformer Replacement Project	$8,447,243
Subdivision Rebuild - Credit Woodlands Crt/Wiltshire	$1,548,270
Subdivision Rebuild - Glen Erin & Montevideo (Section 1)	$1,961,142
Subdivision Rebuild - Tenth Line Main Feeder	$1,135,398
Subdivision Rebuild - Folkway & Erin Mills Main Feeder	$1,032,180
Subdivision Rebuild - Glen Erin & Battleford	$2,064,360
Subdivision Rebuild - Walmart Cables	$1,548,270
System Renewal	**$19,684,339**
Substation Upgrade - York MS	$3,268,463
System Service	**$3,268,463**
Total Distribution Capital	**$24,247,022**

3.4.4 Each and every one of these "projects" are part of normal annual capital spending programs.

3.4.5 The first project is a road widening. The 2018 budget for "road projects" in System Access is $3,120,000[61], so this item is only 41% of the 2018 road projects. It is not unique relative to the other road projects.

3.4.6 Further, in each and every one of the past and future years cited or forecast, except one, the Applicant had road projects in the ERZ. As noted in the draft Enersource DSP filed in EB-2015-0065, the Applicant regularly has road projects required as a result of activity by the City of Mississauga, the Region of Peel, and the Ministry of

[60] Ex. 2/4/11, p. 30. Table 144.
[61] Ex. 2/4/11, p. 17. Table 132.

Transportation[62].

3.4.7 The next two projects are overhead rebuilds. These two projects make up $1.9 million of the $6.5 million budget for overhead renewals for 2018[63], or about 30%. There are many other overhead rebuilds in the System Renewal budget, and these are not unique in any way.

3.4.8 The six subdivision rebuilds totaling $9.3 million are part of a total of ten planned for 2018[64] with a total budget of $16.1 million[65]. Asked at the technical conference about these projects, the Applicant admitted that the ten projects are similar. The six in the ICM list are the ones that were not "funded" as determined by the threshold calculation[66].

3.4.9 Subdivision rebuilds have always been a substantial part of the annual capital program for Enersource[67]. The 2018 plan is not in any way dissimilar from past practice.

3.4.10 For road widening, overhead rebuilds, and subdivision rebuilds, these have always in the past been called projects. The Enersource approach, as seen throughout the 2014 draft Enersource DSP, has been to refer to the overall package of projects in a given area (overhead rebuilds, for example) as a program, but to assess whether work is done on any given part of the system as a project[68].

3.4.11 None of that appears to have changed. All of these projects appear to be nothing more than normal annual capital spending in programs that have existed in past years, and will continue in future years. None of these projects appears to be distinguishable from the similar projects, of the same type, being carried out side by side with the ICM projects in the 2018 year.

3.4.12 The biggest project proposed is portrayed as something different. Titled the "Leaking Transformer Replacement Project", this $8.4 million project is part of a multi-year plan to clear up the backlog of leaking transformers in the ERZ system. It is described by the Applicant as follows[69]:

> *"MR. WASIK: … the transformer replacement project is different from the transformer replacement program in that the project addresses a backlog of*

---

[62] EB-2015-0065, Supp-Staff-15, p. 22.
[63] Ex. 2/4/11, p. 19. Table 133.
[64] Tr.2:64-5
[65] Ex. 2/4/11, p. 19. Table 133.
[66] JT2.6.
[67] Ex. 2/4/11, p. 19. Table 133.
[68] This appears to SEC to be typical of most LDCs, but there does not appear to be evidence on the record dealing with normal practice in this area.
[69] Tr.1:10.

> *known transformers found to exhibit signs of leaking, where the transformer replacement program addresses immediate need to replace damaged, faulted, or rusted transformers that pose a safety hazard to employees and the public."*

3.4.13 This project was discussed in some detail at the technical conference. Based on the evidence, and the answers in the technical conference, SEC believes that the following statements are correct:

(a) Enersource regularly replaced leaking transformers in the past, and they will continue to replace them in the future, with no end in sight[70]. The ostensible reason for this project is to clear up a backlog, as replacements have gotten behind the rate of replacement the Applicant believes is optimal.

(b) As of the end of 2016, the Applicant had 2,084 leaking transformers in the ERZ, of which 1,768 had minor leaks (85%), 254 had moderate leaks (12%), and 62 had major leaks (3%)[71].

(c) Despite resistance to the concept at the technical conference by the Alectra witness[72], it appears clear that all of the PCB transformers, leaking and non-leaking, have been replaced in 2017, and all of the major leaks and most of the moderate leaks have also been replaced. Essentially, the Leaking Transformer Replacement Project is, in the Test Year, dealing entirely with transformers that have minor leaks. This is because the Applicant admits that they prioritize major leaks, and they prioritize PCB transformers. Since they replaced 543 in 2017[73], there should only be transformers with minor leaks left[74].

(d) The planned replacement rate for leaking and PCB transformers in 2018 is less than the actual levels in each of 2015 and 2016[75].

(e) The essence of this project appears to be the shifting of some of the transformer replacements to a "discrete" project, solely for the purposes of getting ICM funding[76].

---

[70] Tr.1:14.
[71] ERZ-Staff-24, p. 4.
[72] Tr.2:167-9.
[73] DSP, Appendix E, Business Case for this project. It says 775 leaking or PCB transformers were replaced in 2016, but that will go down in 2017 and beyond.
[74] The statement in the business case that the project is mandatory in order to comply with provincial regulations, which may have been correct in 2017, does not appear to be correct any longer.
[75] DSP, Appendix E, Business case, Fig. 3. The actual replacements of all transformers in each of 2017 and 2018 was forecast to be 752 [ERZ-AMPCO-6, App. B], but that included all transformer replacements, not just those that were leaking or had PCB.
[76] This can be seen in JT2.18. The table in that Undertaking response shows that 1237 total transformers were replace in 2016, and 923 total transformers were replaced in 2017. For 2018, the base budget includes the

(f) The Applicant provided no evidence that it is unique relative to other LDCs in its leaking transformer "problem", nor that it had done any investigations to determine if its planned replacement rate was faster than, slower than, or the same as other LDCs[77].

(g) The replacements do not have any reliability or customer service benefits[78].

3.4.14 All of these facts suggest that this is part of an ongoing capital program to replace leaky transformers, the most important parts of which are already done. What is left is by definition minor, and should be accommodated in the existing capital budget.

3.4.15 The final ICM project is the York MS station upgrade. This project for a municipal station, at $3.3 million, is less than half of the $7.4 million budget for Municipal and Substation Construction and Upgrades in 2018. Every year, in fact, there is a substantial budget in this category[79], because building and upgrading municipal stations is an ongoing annual function of a distributor like Enersource. Alectra describes it in the Application as follows[80]:

> *"The capital expenditures for municipal substation construction and upgrades are driven by the need for the renewal of substation assets (i.e. power transformers, high voltage and low voltage switchgear) that have reached the end of their useful life, and to meet growth needs in specific areas of the City. In particular, large capital investment is required to meet the projected growth in the downtown core. Alectra Utilities will also upgrade several substations that currently operate with end-of-life equipment (including replacement where the equipment is obsolete)."*

3.4.16 Each substation upgrade is, of course, a fairly substantial investment. However, every year a few of them have to be done, as part of the normal management of the system.

3.4.17 SEC therefore submits that the York MS project should not be given additional ICM funding.

3.4.18 ***Deferral of Custom IR.*** As can be seen from the nature of the ICM projects, and the

---

replacement of only 131 total transformers. A further 678 replacements are in ICM projects. The total transformer replacements in 2018 are 809, still well below each of 2016 and 2017. Total transformer replacements over the next four years 2019-2022 are forecast to be 630, 631, 500, and 293.

[77] The evidence on the record is that Powerstream, for example, replaces transformers at a much lower rates: PRZ-AMPCO-13. However, it is not clear that the information in that interrogatory is directly comparable to the Enersource figures.

[78] DSP, Appendix E, Business Case.

[79] Ex. 2/4/11, p. 20.

[80] Ex. 2/4/11, p. 21.

planned spending in future years outlined in the DSP and in Exhibit 2, Tab 4 of the Application, the Applicant plans aggressive capital spending in the ERZ, with a number of multi-year programs that will be similar, year after year.

3.4.19 Prior to the merger that formed Alectra, Enersource had advised the Board that it planned to apply for rates under Custom IR, mainly because it had substantial capital spending planned. This would have been consistent with the Board's principled approach to capital spending: utilities should make a comprehensive long-term plan, pacing spending and building in a) customer benefits from that spending and b) productivity improvements. The Board has made it clear that long term capital spending should be considered in the context of overall spending over a multi-year period. That is the only way the Board can properly protect the interests of the customers.

3.4.20 Enersource had a plan to do just that, but with the expectation of the merger, Enersource elected not to proceed. The only apparent reason for this was to avoid having to consider the operating and capital savings that would arise over the upcoming five year period of the Custom IR. Alectra has, instead, taken the approach that the same thing as could have been accomplished with the Custom IR can be accomplished with a series of ICM applications, without risking the windfall profits associated with the merger.

3.4.21 Enersource is a particularly good example where the question is put to the Board: Is a series of ICM applications sufficient in place of a Custom IR? SEC believes the answer to that question should be no.

3.4.22 In the case of Enersource, it is clear that the ICM "projects" are, in every case, just a ramping up of spending in all of the normal categories of capital. There is nothing unique or different. This is precisely what Custom IR was for. It is not what ICM is for.

3.4.23 ***Results.*** SEC submits that none of the projects proposed for the Test Year in the ERZ should be considered appropriate for ICM funding. In each case, the spending represents nothing more than current year projects that are part of normal annual capital programs. In each case, these are precisely the kinds of capital spending that are supposed to be handled by the utility within the price cap framework.

3.5 ***<u>Powerstream Rate Zone</u>***

3.5.1 SEC has reviewed the Final Arguments of AMPCO and VECC with respect to the ICM projects proposed in the Powerstream Rate Zone, and generally supports those submissions. We wish to add the following additional submissions.

3.5.2 The following table shows the PRZ ICM projects, plus those that were in its preliminary list in March, but were removed, and those that were not in the preliminary list, but added later[81]. The table also shows the reasons claimed by the Applicant for removal or addition of projects.

Project	CapEx ($) (E2/T3/S10/Pg19)	CapEx ($) CCC-1	Comment
Road Authority YRRT Yonge St	11,243,530	14,283,443	Reduced expenditure to reflect projected in-service additions for 2018.
Station Switchgear Replacement (ACA) 8th Line MS323	1,394,991	1,394,991	No change.
Rear Lot Supply Remediation - Royal Orchard – North	1,681,034		Project added to ICM proposed list as required for implementation in 2018.
Cable Replacement - (M49) - Steeles and Fairway Heights	1,842,953		Project added to ICM proposed list as required for implementation in 2018.
Cable Replacement - (MV08) - Steeles Ave and New Westminster	2,637,046		Project added to ICM proposed list as required for implementation in 2018.
Planned Circuit Breaker Replacement - Richmond Hill TS #1	1,186,729	2,341,642	Reduced expenditure to reflect projected in-service additions for 2018.
Rebuild 27.6kV pole line on Warden Ave into 4 ccts from 16th Ave to Major Mack	1,372,976	1,372,976	No change.
Mill Street MS835 TX Upgrade – Tottenham	1,298,572		Project added to the proposed ICM list as required for implementation in 2018.
Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Bayview Ave	1,202,306	1,202,306	No change.
Double Circuit existing 23M21 Circuit from Bayfield & Livingstone to Little Lake MS	1,276,180	2,148,044	Reduced expenditure to reflect projected in-service additions for 2018.
Radial Supply Remediation/Conversion - 13.8 to 27.6kV on Miller Ave		1,628,533	Removed as project was deferred beyond 2018 based on the City of Markham's revised schedule for work on Miller Ave.
Install Two 27.6kV ccts on 16th Ave from Hwy 404 to Woodbine Ave		1,187,653	Removed as project was deferred beyond 2018 based on delays relating to the closing of the Buttonville Airport which is now expected to stay in service in 2018. Construction of an overhead line on 16th is not permitted while the airport remains operational.
Vaughan TS #4 Feeder Integration		4,302,513	Removed as project was deferred to 2020 based on pacing of development and load growth in the area.

3.5.3 From the evidence, what appears to have happened is that:

(a) Three projects totaling $7.1 million had to be removed as they could not be

[81] JT1.10, p. 3-4.

completed in 2018.

(b) Three projects had reductions in the expected 2018 in-service amounts that could be achieved, totaling $5.1 million.

(c) Four projects totaling $7.5 million (one of the rear lot projects, two of the cable replacements, and one municipal substation upgrade) were, between March and May of 2017, determined to be "required for implementation in 2018".

(d) Three projects totaling $4.0 million survived the review unchanged.

3.5.4 In the result, there are ten projects with a combined in-service in 2018 of $25.1 million. They are:

(a) Two of its cable replacement projects.

(b) Two station switchgear replacement projects.

(c) Three of its overhead feeder rebuild projects.

(d) One rear lot supply remediation, part of its multi-year program to deal with rear lot supply[82].

(e) One station capacity upgrade.

(f) The continuing annual work on the York Region Rapid Transit relocations..

3.5.5 All of these projects are similar in type and scope of project to work done in 2017 and prior years. In addition, the overall capital budget for PRZ for 2018 is, as discussed earlier, down from 2017.

3.5.6 With respect to cable replacement projects, it is instructive to look at PRZ-AMPCO-18, Appendix A. In that table, the Applicant reveals that it replaced 32,657 meters of cables in 2016, and forecast 23,487 meters in 2017. For 2018, the plan is to replace 17,387 meters, less than either of the prior two years. However, only 8,223 meters is in the base budget. The remaining 9,164 meters are characterized as two "discrete" and incremental projects, to which the ICM is said to be applicable.

3.5.7 The same interrogatory response is instructive with respect to circuit breaker replacements. Eight were replaced in 2016, and six were replaced in 2017[83]. For 2018, the forecast is to replace none, but to have an ICM project that will replace ten[84].

[82] See JT1.11.
[83] Circuit breakers have been replaced by Powerstream in 13 of the last 17 years: JT2.31.
[84] The change appears to be solely about ICM funding: see Tr.2:145-6.

Four of those ten are in poor or very poor condition.

3.5.8 We also note that one of the cable replacement programs, Fairway Heights, appears to be part of a decade-long program to replace the John MS[85].

3.5.9 ***Results.*** For the reasons provided by AMPCO and VECC, and our additional analysis above, SEC believes that the Applicant should not be given additional ICM funding for any of the proposed projects. For all but the YRRT project, they are routine annual programs, no different from any prior year, or even other projects in the same year. They aren't even expansions of those programs.

3.5.10 The YRRT project is different because of is size, but it is in fact just the latest in many years of YRRT projects in a growing service territory. Further, even with that project the capital budget of Alectra in the PRZ is lower than all prior years.

3.5.11 Therefore, SEC believes that the YRRT project should also not be funded under the ICM rubric. Alectra should complete projects of this nature within the price cap amounts available to them.

3.5.12 SEC does agree with AMPCO, however, that if the YRRT project goes substantially over (or under) budget as a result of actions of the municipality, this inherent unpredictability justifies the creation of a variance account around the current budget, to capture that additional spending (or reduced spending, for that matter) that is outside of the control of the Applicant.

3.6 ***SEC Recommendations***

3.6.1 ***Specific Findings.*** SEC submits that none of the ICM requests qualifies for ICM treatment:

(a) For the BRZ, the CCRA payment should simply not be recoverable from ratepayers. It is based on a load forecast that has not been shown to be prudent (and on the face of it, was imprudent), and in any case the Applicant should be (or have been) able to recover the amount from Hydro One under the Share Purchase Agreement as a breach of Hydro One's representations and warranties.

(b) For the ERZ and the PRZ, the projects are not discrete projects, but are part of normal annual capital programs.

(c) The ICM requests are not actually incremental to the capital spending levels of the Applicant, and are not consistent with the purpose of ICM funding as set

---

[85] Tr.2:6-7.

out in the ACM Report.

(d) The Applicant should not have ICM funding until it comes back with a consolidated DSP, and even then the Board should consider whether some form of multi-year rate plan is a better approach if there are significant multi-year capital needs.

(e) At no point does the Applicant propose improved outcomes valued by customers arising out of the proposed projects. In each case in which there is any impact, it is to maintain current reliability, not to improve it. Generally speaking, customers are not willing to pay more to get the same. The Applicant has a budget to maintain reliability, That's what price cap allows. Absent any improvement in outcomes, additional funds should not be available.

4 CHANGES IN ACCOUNTING POLICIES

4.1 Background

4.1.1 As a result of the merger that formed Alectra, the capitalization policy of Powerstream (deemed for accounting purposes to be the acquirer) had to be made applicable to all of Alectra. The effect is to shift $60.2 million[86] of OM&A to capital over the deferred rebasing period. Similar to the changes to capitalization that brought in MIFRS, the result would be double counting, since the OM&A is included in rates, but the capital would remain in rate base and then – at least to some extent – be captured once more in future rates. This double-counting led to the Board's use of accounts 1575 and 1576 to adjust for this problem in the MIFRS situation.

4.1.2 Alectra alleges that the net impact is $25.9 million, but that calculation appears to be incomplete, as we show below.

4.1.3 Alectra submits that it is entitled to keep this impact, because it is a "benefit" from the merger transaction[87].

4.1.4 Alectra included very little information on this substantial change in the pre-filed evidence, which resulted in the Board commenting as follows:

> *"There was limited information in the application on the change to a common capitalization policy for Alectra Utilities. Through interrogatories, the magnitude of the change for the Horizon RZ was disclosed to be in excess of six million dollars per year. Alectra Utilities also indicated that there were changes to capitalize more costs for the Enersource RZ and less costs for the Brampton RZ.3 The magnitude of these changes is unknown. Furthermore, the exact date and specific details of the transition to the harmonized capitalization policy are not clear in the evidence."*[88]

4.1.5 The initial details came out in HRZ-SEC-6, which was limited to the Horizon impacts. The full details, with the incomplete impact calculation, have now been provided in JT-Staff-7.

4.1.6 As a result of the initial information, the Board required the establishment of deferral accounts (sub-accounts of 1508) to reflect the impact of these changes for each of the affected rate zones, BRZ, ERZ, and HRZ. The Board expressly asked parties to deal with the potential clearance of those accounts in final argument.

---

[86] JTStaff7, p. 4. This is the current estimate only.
[87] Argument in Chief, p. 45.
[88] Decision on Issues List, p. 3.

4.1.7 The Applicant has now confirmed[89] that the only accounting changes having any material impact are the changes in capitalization policy, which reduces OM&A in ERZ and HRZ, and increases OM&A in BRZ.

4.2 ***Capitalization Policy***

4.2.1 There are three issues relating to the accounting changes:

(a) Is this change in accounting policy a "benefit" arising out of the merger that should accrue to the shareholders?

(b) What is the correct calculation of the impact?

(c) How and when should the impact be collected from, or refunded to, customers?

4.2.2 ***The "Benefit" Argument.*** To understand the benefit argument, it is first necessary to understand what is actually happening here. There are certain expenditures that are being spent. They will continue to be spent. Right now, they are recovered through rates as part of the OM&A budget. After the change, they are being added to rate base, to be recovered through rates over time. They will still remain in rates as part of the OM&A budget as well.

4.2.3 Alectra makes quite a point of the fact that this is a non-cash transaction, saying[90]:

> *"The capitalization change had no impact on the underlying economics at any of Alectra Utilities' rate zones. It was (and is) a non-cash event. The cost of replacing a pole line on January 31, 2017 did not change the next day – it stayed the same. What changed was the relative share of the work that could be capitalized, nothing more. Regardless of the classification of any particular expenditure, be it as operating or capital, the expenditure must still be made in cash which is matched by rate-revenue cash flows."*

4.2.4 What they fail to note is that, as proposed by Alectra, they would collect the cash for these amounts in current rates, since they are part of the OM&A budget, but then they would have the right to collect 88.3% of that cash again after rebasing, when those same amounts are still part of rate base.

4.2.5 Alectra is proposing, in fact, to collect from customers twice a total of $53.2 million out of the forecast $60.2 million of additional capitalized OM&A. That is the amount

[89] JT-Staff-7.
[90] Argument in Chief, p. 43.

left in rate base at the end of the deferral rebasing period, so the actual amount of the double counting[91].

4.2.6 The Board has not generally allowed utilities to collect money twice from customers for the same expenditure.

4.2.7 SEC submits that the Board should respond to the "benefit" argument as what it is: an egregious attempt to double-count expenditures, under the guise of the MAADs policy. The Board should, in our view, make clear to the Applicant that the MAADs policy was never intended to allow double recovery of expenditures, and should not be so interpreted.

4.2.8 We note in this regard that the AIC seeks to characterize this as re-arguing the benefits issue from EB-2016-0025. The impacts of this capitalization policy change were not disclosed to the Board in that case. If they had been, perhaps this would have been argued there. However, as with the current case, the Applicant, despite having a detailed analysis in hand of the impacts of this change[92], elected not to provide that information to the Board[93].

4.2.9 ***What Are the Impacts?*** JT-Staff-7, Table 1 shows Alectra's calculation of the net impacts of the change in capitalization policy. That calculation shows the net, after-tax impact on Alectra if they are allowed to keep all of the double-counting. Since they have to pay tax on the windfall, the net is $25.945 million.

4.2.10 This is not, however, the impact on ratepayers. If the double-counting has to be refunded to customers, then the refund is tax-deductible for Alectra, and thus must be grossed-up if both the utility and the customers are to be kept whole.

4.2.11 The easiest way to see this is to look at one year, for one rate zone. Using the figures from JT-Staff-7, Alectra estimates the 2017 net impact in the Horizon rate zone to be $4.261 million. That is made up of the following components:

---

[91] The calculation can be done from the table in JT-Staff-7, and for each rate zone is simply the cumulative amount of extra OM&A amount that will be capitalized, less the cumulative depreciation until rebasing on those amounts. For ERZ, it is $15.570 million. For HRZ, it is $57.741 million. For BRZ, it is -$20.140 million.

[92] Tr.2:159 and JT2.32. SEC notes that this detailed information was only provided in response to a technical conference undertaking, despite the clear interest the Board and the parties had in this issue.

[93] The conclusion of the AIC is, frankly, offensive. The Applicant says, at page 46, "*The Board should see these arguments for what they are – a backdoor attack on the MAADs Decision and the MAADs policy itself that should be rejected. <u>No doubt this argument would not have been pursued by intervenors had the non-cash change resulted in an increase in operating expense for Alectra Utilities</u>." [emphasis added]* The Board will be aware, as Alectra and their counsel certainly are, of SEC's longstanding practice of arguing for the right answer, even when it is not in the short-term interests of schools. The consistent position of the schools has been that the right answer is always in their interests in the long term. The Applicant's argument is particularly offensive in the context of both the lack of information provided to the Board by the Applicant, and the bold nature of their basic position, i.e. double collection for expenditures is OK in a merger.

Reduction in OM&A	$6.280
Increase in depreciation	-.079
Increase in PILs	-1.598
Increase of cost of capital	-.343
Net Impact	$4.261

4.2.12 This is an after-tax amount. If the Board determines that this amount should be returned to customers, it must be grossed-up, since the refund is tax deductible. The total refund would thus be $5.797 million ($4.261/(1-.265)).

4.2.13 This can then be carried forward to all of the figures on the table with the following impacts to customers:

- ***(a)*** Horizon Rate Zone - $36.679 million refund to customers ($26.959/.735)
- ***(b)*** Enersource Rate Zone - $8.869 million refund to customers ($6.519/.735)
- ***(c)*** Brampton Rate Zone - $10.249 million from customers ($7.533/.735).

The aggregate impact, in the form of rate adjustments, is thus $35.299 million, but as noted it is significantly different for the customers in each of the rate zones.

4.2.14 ***Clearance of Accounts.*** The amounts for 2017 are already accrued in the accounts established by the Board. They total, after gross-up, a $5.797 million refund to the customers in Horizon rate zone[94], a $1.631 million refund to the customers in the Enersource rate zone, and a $2.110 million charge to the customers in the Brampton rate zone.

4.2.15 Given that these are material amounts that will matter to the customers, SEC submits that the 2017 amounts should be processed as rate riders in 2018, and the accounts cleared. However, the accounts should remain open to record the differences for 2018, which should be cleared when Alectra seeks its 2019 rates. This can continue through to the end of the deferred rebasing period.

4.2.16 The alternative is to hold onto the funds in the accounts until rebasing, whether in 2026 or at some later date. This was the process used for accounts 1575 and 1576, but we note that at that time the period before clearance was four years or less and as a practical matter deferral of the clearance was to be preferred to having seventy or eighty LDCs coming to the Board for special clearance applications. In this case, the period is almost ten years, and it affects one utility. There does not appear to be any principled reason to leave these accumulating balances in the hands of the utility for that extended period of time.

[94] This about 5% of Horizon's 2018 revenue requirement, as forecast in the EB-2014-0002 rate order.

4.3 ***SEC Recommendation***

4.3.1 SEC therefore recommends that the Board:

(a) Determine that the net impact of the capitalization policy change is not a "benefit" of the merger, and the MAADs policy does not apply.

(b) Order that the balances in the accounts, as of the end of 2017, be refunded to or charged to customers as a 2018 rate rider, with the appropriate gross-up to reflect the taxable or tax deductible nature of the clearance.

(c) Order that the deferral accounts remain open to record the accruing difference each year, and that the Applicant be required to clear each year's accrual to customers in the subsequent year.

5 MONTHLY BILLING

5.1 *Background*

5.1.1 Alectra went to monthly billing in the Powerstream rate zone in January 2017 and in the Horizon rate zone in June, 2017. It will transition in the Enersource rate zone in August 2018.

5.1.2 Alectra has refused to file its MergeCo Financial Plan 2017-2021[95], but it did file an excerpt. In that excerpt, Alectra estimates the impact on working capital of moving to monthly billing: a reduction in accounts receivable of $71.8 million[96].

5.1.3 At an average weighted average cost of capital of 7.5% for Alectra (including PILs gross-up on the ROE to reflect the rate impacts), the annual savings are $5.4 million. Over eight years, this is an additional $43.2 million paid by the customers for costs not actually incurred.

5.1.4 Challenged to explain this[97], Alectra refused to respond to whether the calculations are correct[98]. Instead, they took the position that they are entitled to the benefit of the reduced costs associated with monthly billing, because under the Board's MAADs policy they keep their base revenue requirement, including working capital allowance, throughout the deferred rebasing period.

5.1.5 SEC submits that the cause of this cost saving is not the merger, but rather a Board policy that requires distributors to move to monthly billing. Alectra wants the merger to somehow defer the time that they have to pass the monthly billing savings on to customers.

5.1.6 There is a certain irony in this. Customers have to pay sooner, so all have to incur costs associated with financing their earlier payments to Alectra (some at the rate of their savings accounts, some at the rate of their credit cards, and some in between). $71.8 million at a typical personal cost of funds of 10% is $7.2 million per year, or $57.2 million over eight years. Alectra, on the other hand, believes that their side of the same equation – their $43.3 million of savings from not having to finance that $71.8 million of A/R – should be pocketed by their shareholders.

5.1.7 SEC believes that this is not the intent of the MAADs policy. Under the MAADs policy, the shareholders get the <u>synergies</u> that arise from the merger, and pay the

[95] Tr.2:190
[96] HRZ-SEC-7, Attachment 5, p. 2.
[97] Using a lower cost of capital figure that produced $4.94 million per year.
[98] JT2.40.

costs to deliver those synergies and implement the merger. Implementing a mandatory Board policy like monthly billing is not a "synergy". The MAADs policy is not designed to give a windfall to shareholders when merged utilities implement Board policies and savings arise as a result of that implementation.

5.2 *SEC Recommendation*

5.2.1 SEC submits that the Applicant should be required to file a breakdown of the $71.8 million figure from their own financial plan, and calculate at the respective cost of capital rates (including PILs gross-up) the rate-related savings. Direct (not merger) related OM&A costs and benefits (such as implementation costs, higher call centre volumes, lower collection costs, and lower bad debt) associated with the move to monthly billing should then be deducted or added, as the case maybe.

5.2.2 In any year in which the cumulative benefits exceed the cumulative costs, SEC submits that the Board should require the Applicant to refund the cumulative net to customers through an appropriate rate rider.

5.2.3 In order to implement the tracking and disposal of net monthly billing benefits, SEC submits that a deferral account should be set up in each of the three affected rate zones, with the expectation that the deferral account will be cleared annually to ratepayers when it is a credit, in much the same way as the capitalization adjustment.

5.2.4 SEC notes that Alectra may prefer to do a lead/lag study, rather than accept their own internal estimate of the reduced A/R. SEC agrees that this is the preferred approach, but believes that this should be done only in the context of a rebasing application. A lead/lag study needs a reference point for the revenues and costs it is timing and measuring. Thus, whenever Alectra comes in for rebasing, they should be encouraged to do a lead/lag study.

6 EFFECTIVE DATE

6.1 *General*

6.1.1 Alectra filed this Application on July 7, 2017, giving the Board less than six months to consider its first in a series of ICM applications with the potential for $275 million of incremental rates.

6.1.2 Furthermore, at the time Alectra filed the Application it was aware that the bulk of the ICM requests were for Enersource and Powerstream, each of whom had experienced a refusal of capital funding from the Board in its most recent application. That coupled with the unusual nature of the Brampton claim, would have made it clear to Alectra that this was not a simple application, and would take some time.

6.1.3 The Board approved the MAADs application in EB-2016-0025 on December 8, 2016, seven months prior to the filing of this Application. While Alectra of course had a lot to do to complete its merger, and the acquisition of Hydro One Brampton, it does not appear to SEC that Alectra can point to the Board as a reason why this Application was not filed in a timely manner. Alectra knew the nature of its application, and most of the details, by March[99]. The delay subsequent to that appears to be because they had not done any customer engagement, particularly on the new Enersource DSP[100]. They were also changing the projects that they felt they could get approved on an ICM basis[101].

6.1.4 It also appears clear that Alectra at all times thought that the Board's processes could happen more quickly than would normally be the case. By way of example, as late as August 24th Alectra thought that new rates could be in place by February 24th, even if there was an oral hearing in this proceeding[102].

6.1.5 SEC submits that it is the responsibility of an applicant to make sure that they file their application in sufficient time for the Board to give it full consideration, and for rates to be in place at the date the applicant targets. In this case, Alectra did not do so, and they do not appear to have a reasonable explanation for that.

6.1.6 SEC therefore submits that the Board should follow its normal practice, and determine that new rates for Alectra arising out of this Application become effective on the first day of the month following the Board's rate order.

[99] CCC-1, Attach 1.
[100] CCC-1, Attach 2.
[101] See JT1.10.
[102] CCC-1, Attach 4.

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.

____

Jay Shepherd
Counsel for the School Energy Coalition