SEC-1

Reference: Exhibit 1, Tab 1, Schedule 2, p. 2

Please describe in detail the factors that caused the Applicant to file this Application, including $10.6 million of incremental capital spending proposals, on August 17th, with only four and a half months available until the proposed effective date, rather than on an earlier date, consistent with Chapter 3 of the Filing Requirements. Please identify specifically any delay caused by the Covid-19 pandemic and related lockdowns and/or work restrictions.

Response:

Alectra Utilities' 2021 electricity distribution rate ("EDR") application (the "Application") was filed on August 17, 2020. The Application is largely a mechanistic application, in which Alectra Utilities seeks IRM adjustments for all five rate zones, as well as clearance of variance accounts. Contrary to the assertion made in the preamble, the date on which Alectra Utilities filed the Application is consistent with the OEB's Chapter 3 Filing Requirements, which state the following at page 3, Section 3.1.1:

> *Distributors that are seeking rate adjustments effective January 1, 2021 under IRM will be required to file their application by August 17, 2020.*

In addition, the date of filing is consistent with the OEB's July 14, 2020 letter to distributors regarding the process for 2021 IRM applications. In that letter, the OEB explained that it established four filing dates for distributors so that it could issue decisions in time for January 1 or May 1 implementation dates. Alectra Utilities was assigned to Tranche 1, with a filing deadline of August 17, 2020. Tranche 1 is described in the letter as being for all distributors seeking a January 1, 2021 effective date for rates, with Tranches 2, 3 and 4 being for applicants seeking May 1, 2021 effective dates based on the expected levels of complexity of those applications. Please find attached SEC-1_Attachment 1, which is a copy of the OEB's July 14, 2020 letter.

Moreover, given the Application filing date of August 17, 2020, the OEB's issuance of a completeness letter for the Application on August 31, 2020, and the issuance of PO#1 on September 25, 2020, the Application is on track to be processed within the applicable timelines established by the OEB's updated Performance Standards for Processing Rate Applications.

In the Application, Alectra Utilities has included incremental capital module ("ICM") funding for three projects that are nondiscretionary: i) the Rutherford Road Widening project; ii) the Goreway Road Widening Project and iii) the Goreway CCRA True-Up payment to Hydro One. As a result of the COVID-19 pandemic, Alectra Utilities experienced delays in receiving confirmation from the municipal road authorities for the Rutherford Road Widening Project and the Goreway Road Widening Project.

In addition, the ten-year anniversary date for the Goreway Transformer Station expansion was at the end of May 2020. Given the time remaining in 2020, the process will not be completed until early 2021. However, notwithstanding those delays, Alectra Utilities was able to file the application by the required filing date.

As identified above, the three projects for which Alectra Utilities seeks ICM funding are mandatory and there is no discretion as to whether or not Alectra Utilities will incur the related costs. Given the straightforward nature of the projects and the mechanistic nature of the application before the OEB, Alectra Utilities anticipates that the OEB should be able to adjudicate the application and issue a decision with an effective date for rates of January 1, 2021.

SEC-1

Attachment 1 – 2021 IRM Tranche Assignment

Ontario Energy Board | Commission de l'énergie de l'Ontario

VIA E-MAIL AND WEB POSTING

July 14, 2020

To: Rate-regulated Electricity Distributors

Re: Process for 2021 Incentive Rate-setting Mechanism Distribution Rate Applications

Under the Ontario Energy Board's (OEB) incentive rate-setting mechanism (IRM) process, base rates are adjusted by a mechanism that is based on an inflation factor less a productivity or X-Factor. The formula includes an industry-specific inflation factor and two factors for productivity. One productivity factor is a fixed amount for industry-wide productivity and the other is a stretch factor, which is set each year based on the level of productivity the electricity distributor has achieved. The OEB will establish the final inflation factor and stretch factor to apply to distributors for the 2021 rate year in due course.[1] The rate generator will initially include rate-setting parameters from the 2020 rate year as a placeholder. OEB staff will adjust the rate generator once updated rate-setting parameters are available.

The OEB posted the rate generator model and other optional IRM models on July 14, 2020. The COVID-19 foregone revenue rate rider model will be posted following the IRM webinar that is planned for July 15, 2020.

The OEB has established four filing dates for distributors. The application filing deadlines for each group were determined so that, in the normal course, the OEB could process a large number of applications, and a decision on each application could be issued in time for a January 1 or May 1 implementation date. The OEB expects 46 IRM applications to be filed for 2021 rates representing 45 distributors.

The application groupings are as follows:

[1] Electricity distributors filing under the Annual IR Index method receive the highest stretch factor adjustment.

Tranche	Application Filing Deadline	No. of Applications
1	August 17, 2020	21
2	October 13, 2020	9
3	November 2, 2020	8
4	November 23, 2020	8
	Total Number of Applications	**46**

Tranche 1 is for those distributors applying for a January 1, 2021 effective date for rates. Applicants for May 1 rates have been assigned to one of three later filing dates based on the expected level of complexity of the application as reflected in distributors' responses to a survey conducted in May 2020. The attached table lists the assignment of electricity distributors to each of the tranches.

If a distributor in Tranche 3 or 4 contemplates a material increase in the complexity of its application relative to the information it provided in the survey, it should advise the OEB and is encouraged to file as part of Tranche 2.

Distributors that postponed the implementation of rates effective May 1, 2020 to November 1, 2020 should submit the foregone revenue rider spreadsheet by September 15, 2020. The forgone revenue riders will be reviewed and a new Tariff of Rates and Charges for 2020 rates will be issued in October 2020 that will serve as a revised starting point for all IRM applications. The review of the spreadsheet and issuance of the updated Tariff of Rates and Charges for 2020 rates will be conducted through an administrative process, outside of the 2021 IRM process. The OEB will issue further guidance regarding the process for implementation of 2020 rates shortly.

The OEB expects applicants to submit all filings with the OEB by 4:45 pm on the applicable filing deadline.

Yours truly,

Original signed by

Christine E. Long
Registrar and Board Secretary

Att: List of Distributors by Tranche

Attachment to Letter Dated July 14, 2020

Filing Deadlines
List of Electricity Distributors by Tranche

Company	EB Number	Tranche	Filing Deadline
Alectra Utilities Corporation	EB-2020-0002	1	Aug. 17
Algoma Power Inc.	EB-2020-0003	1	Aug. 17
Brantford Power Inc.	EB-2020-0006	1	Aug. 17
Canadian Niagara Power Inc.	EB-2020-0008	1	Aug. 17
Centre Wellington Hydro Ltd.	EB-2020-0009	1	Aug. 17
Cooperative Hydro Embrun Inc.	EB-2020-0011	1	Aug. 17
Elexicon Energy Inc. - Whitby service area*	EB-2020-0012	1	Aug. 17
Energy + Inc.	EB-2020-0016	1	Aug. 17
Entegrus Powerlines Inc.	EB-2020-0015	1	Aug. 17
ENWIN Utilities Ltd.	EB-2020-0017	1	Aug. 17
Festival Hydro Inc.	EB-2020-0022	1	Aug. 17
Grimsby Power Incorporated	EB-2020-0025	1	Aug. 17
Hydro Hawkesbury Inc.	EB-2020-0029	1	Aug. 17
Hydro One Networks Inc. - Norfolk, Haldimand, Woodstock	EB-2020-0031	1	Aug. 17
Innpower Corporation	EB-2020-0033	1	Aug. 17
Kingston Hydro Corporation	EB-2020-0034	1	Aug. 17
Kitchener-Wilmot Hydro Inc.	EB-2020-0035	1	Aug. 17
Lakefront Utilities Inc.	EB-2020-0036	1	Aug. 17
Oakville Hydro Electricity Distribution Inc.*	EB-2020-0045	1	Aug. 17
Renfrew Hydro Inc.	EB-2020-0052	1	Aug. 17
Westario Power Inc.	EB-2020-0062	1	Aug. 17
Atikokan Hydro Inc.	EB-2020-0004	2	Oct. 13
Elexicon Energy Inc. - Veridian service area	EB-2020-0013	2	Oct. 13
EPCOR Electricity Distribution Ontario Inc.	EB-2020-0018	2	Oct. 13
Fort Frances Power Corporation*	EB-2020-0023	2	Oct. 13
Greater Sudbury Hydro Inc.	EB-2020-0024	2	Oct. 13
Lakeland Power Distribution Ltd.	EB-2020-0037	2	Oct. 13
Newmarket – Tay Power Distribution Ltd.*	EB-2020-0041	2	Oct. 13
Niagara-on-the-Lake Hydro Inc.*	EB-2020-0042	2	Oct. 13
PUC Distribution Inc.	EB-2020-0051	2	Oct. 13
Welland Hydro Electric System Corp.	EB-2020-0060	3	Nov. 2
Chapleau Public Utilities Corporation	EB-2020-0010	3	Nov. 2
E.L.K. Energy Inc.*	EB-2020-0014	3	Nov. 2
Essex Powerlines Corporation	EB-2020-0021	3	Nov. 2
London Hydro Inc.	EB-2020-0038	3	Nov. 2
Orangeville Hydro Limited*	EB-2020-0046	3	Nov. 2
Tillsonburg Hydro Inc.*	EB-2020-0056	3	Nov. 2

Wasaga Distribution Inc.	EB-2020-0058	3	Nov. 2
Bluewater Power Distribution Corp.*	EB-2020-0005	4	Nov. 23
ERTH Power Corporation	EB-2020-0019	4	Nov. 23
Hydro 2000 Inc.	EB-2020-0028	4	Nov. 23
Hydro One Remote Communities Inc.	EB-2020-0032	4	Nov. 23
Milton Hydro Distribution Inc.	EB-2020-0039	4	Nov. 23
Northern Ontario Wires Inc.	EB-2020-0044	4	Nov. 23
Sioux Lookout Hydro Inc.	EB-2020-0054	4	Nov. 23
Synergy North Corporation	EB-2020-0055	4	Nov. 23
Total Applications	**46**		

***** These distributors have indicated in the IRM survey that they will be filing an Annual IR Index application.

SEC-2

References: Exhibit 2, Tab 1, Schedule 1, p. 1
Exhibit 4, Tab 1, Schedule 1, Attachment 4, 7

Please provide the full capital expenditures budget of the Applicant for all rate zones, in the form approved by the Board of Directors of the Applicant, or by the senior management of the Applicant if it has not been approved by the Board of Directors. In addition, please provide a full explanation of the $37.8 million General Plant budget of the Applicant for 2021.

Response:

Please see Alectra Utilities' response to AMPCO-1 for the capital expenditures budget provide to senior management.

A breakdown of the $37.8MM General Plant budget for 2021 is presented in Table 1, below. As shown, this budget includes eight material projects for which the budget is greater than $1MM, totalling $16.7MM. The remaining $21.1MM is comprised of 107 smaller projects, with budgets ranging from $10k to $900k, the majority being less than $500k. These smaller projects include $7.8MM in fleet-related investments; $6.0MM in Information Technology projects, and $3.0MM in facilities requirements.

Table 1 – 2021 Financial Plan – General Plant Material Projects List ($MM)

Project Description	2021 Plan
Goreway TS Expansion (CCRA) - 10 Yr True-Up Payment	5.7
Customer Service Strategy	3.5
ERP Continuous Improvement	1.7
CIS CC&B Enhancements and Modifications	1.3
Enterprise Information Protection	1.3
CIS CC&B Modifications(Regulatory Enhancements)	1.1
Enterprise System Access	1.1
Client - IT Infrastructure	1
Sub-Total Material Projects	**16.7**
Miscellaneous Projects (under materiality threshold)	21.1
Total General Plant	**37.8**

SEC-3

Reference: Exhibit 2, Tab 1, Schedule 1, p. 1

Please provide details of all changes to the capital expenditures budget of the Applicant in 2020 or 2021 that have been made as a result of the Covid-19 pandemic, the related lockdowns, and/or changes to the economic outlook as a result.

Response:

In 2020, Alectra Utilities reduced its planned capital by $26MM in response to the OEB's Decision on the M-factor included in the 2020 Electricity Distribution Rate Application (EB-2019-0018). Due to the COVID-19 pandemic, customers, developers and municipalities put their capital plans on hold for a brief period, thereby reducing the funding required for System Access investments. This allowed Alectra Utilities to redirect the funding to necessary and prudent investments in System Renewal. In addition, the computation and negotiation of the ten-year true-up CCRA payments for Goreway TS were deferred by Hydro One Networks Inc. due to its focus on the pandemic response. As a result, this funding was redirected to address immediate reliability issues. The Q2 forecast was approved at $256MM, a reduction of $0.7MM from the reduced capital forecast as a result of the M-Factor decision, or $26.7MM from the amount provided in Alectra Utilities' Distribution System Plan.

SEC-4

Reference: Exhibit 2, Tab 1, Schedule 1, p. 1

Please calculate the difference in interest cost related to the rate base for the Brampton RZ between the interest rates currently embedded in rates, and the forecast interest rates for the Applicant in 2021. Please provide the Applicant's most recent interest rate forecast for 2021.

Response:

Please see Alectra Utilities' response to SEC-11.

SEC-5

Reference: Exhibit 2, Tab 1, Schedule 1, Table 2

Please provide details of all changes to the 2020 and 2021 capital expenditures by category for the Brampton RZ that have been made since January 1, 2018.

Response:

The tables below provide the details of changes made to the 2020 and 2021 planned capital expenditures by category from the Distribution System Plan to the current plan.

Table 1 – Brampton RZ 2020 Capital Expenditures Comparison to DSP ($MM)

Investment Category	2020 DSP	2020 Current	Variance
System Access	8.9	11.4	2.5
System Renewal	17.4	17.3	(0.1)
System Service	5.4	2.5	(2.9)
General Plant	5.7	4.6	(1.1)
Total Brampton	**37.4**	**35.8**	**(1.6)**

The increase in System Access was a result of higher meter renewal requirements. System Renewal increased due to Reactive expenditures which were offset by the deferral of substation expenditures. The reduction due to deferral of capacity projects resulted in the System Service decrease. General Plant in 2020 decreased as a result of the deferral of the CCRA payment.

Table 2 – Brampton 2021 Capital Expenditures Comparison to DSP ($MM)

Investment Category	2021 DSP	2021 Current	Variance
System Access	8.6	13.2	4.6
System Renewal	15.8	21.9	6.1
System Service	3.9	1.6	(2.3)
General Plant	5.0	5.5	0.5
Total Brampton	**33.3**	**42.2**	**8.9**

The increase in System Access is a result of higher expected demand from developers and municipalities. System Renewal increased due to increased requirements for Voltage conversion project, and underground reliability issues. The reduction due to deferral of capacity projects resulted in the System Service reduction.

SEC-6

References: Exhibit 2, Tab 1, Schedule 1, p. 6
Exhibit 4, Tab 1, Schedule 1, Attachment 3, p. 5-8

The Applicant says "Alectra estimates a shortfall of revenue to HONI versus the forecasted demand". Please provide the full calculation of that shortfall, including all assumptions made in both the new forecast of demand, and the previous forecast of demand. Please identify and quantify the material variances. Please provide the results in live Excel format.

Response:

Please see Alectra Utilities' response to BRZ-Staff-21.

SEC-7

References: Exhibit 2, Tab 1, Schedule 1, p. 6
Exhibit 4, Tab 1, Schedule 1, Attachment 3, p. 5-8

Please provide details of any negotiations that took place between Hydro One and the Applicant (or its predecessor) with respect to the CCRA and the load and demand forecast that is the basis for the current financial obligation.

Response:

1 Please see Alectra Utilities' response to BRZ-Staff-21.

SEC-8

References: Exhibit 2, Tab 1, Schedule 1, p. 6
Exhibit 4, Tab 1, Schedule 1, Attachment 3, p. 5-8

Please provide details, including numerical impacts, of any part of the current load forecast that is assumed to be affected by the Covid-19 pandemic and related lockdowns and economic downturn.

Response:

Please refer to the response to BRZ-Staff-21 for a detailed explanation of the actual peak demand from 2010 to 2020 and the revised 2021-2035 peak demand forecast that underpins the ten-year true-up for the Goreway TS expansion. As explained in that response, the CCRA true-up for Goreway TS is based on an economic evaluation that considers the lower monthly average peak demand experienced for the Goreway Study Area between years 5 to 10 (which was a result of declining demand in the existing connection facilities at Bramalea 27.6kV TS, as well as stagnation of demand growth due to natural conservation), and a revised lower forecasted monthly peak demand for years 10 to 25. Relative to the 2015 forecast applied at the 5-year true-up, Alectra Utilities has reduced the forecast from an average annual growth rate of 2.9% to a revised average annual growth rate of 1.4% over the remaining 15-year period of the Goreway TS CCRA.

Alectra Utilities continues to monitor and assess the long term impacts of the COVID-19 pandemic on the Goreway 27.6kV Study Area and in general. As provided in response to BRZ-Staff 21, the main driver of growth in the Goreway TS Study Area is the residential developments that have continued. The long-term impact and duration of the COVID-19 pandemic is unknown at this time. Consequently, Alectra Utilities has not reduced the forecast for the Goreway 27.6kV TS Study Area for the 2021-2035 period as a result of the pandemic, at this time. The CCRA and TSC include provisions for a 15-year true-up for the Goreway TS that will reconcile any difference between the revised forecast and the actual average peak demand experienced over the 2020 to 2025 time period.

SEC-9

References: Exhibit 2, Tab 1, Schedule 1, p. 7
Exhibit 4, Tab 1, Schedule 1, Attachment 3, p. 1-4

With respect to the Goreway Road widening:

a. **Please confirm that the 2021 relocation project is the first of three segments of this road widening. Please provide the budget and timing for the full three segment project, and confirm that ICM treatment will be sought for all three segments.**

b. **The first two projects (p. 2 of Attach 3) appear to be the same stretch of road. Please explain.**

c. **Please provide any lifecycle analysis done to demonstrate that undergrounding the new assets under Option 2 would, on a lifecycle basis, be more expensive than the preferred option under Option 3.**

d. **Please provide all calculations that justify the conclusion that Option 2 is more expensive, and show the difference in cost.**

e. **Please provide any technical report or other analysis that shows "putting the system underground was not technically an option"(Attach 3, p. 3). Please explain why the technical limitations were in the Attachment, but not mentioned in Ex. 2/1/1.**

f. **Please provide any information in the possession of the Applicant that deals with whether further relocations of the new assets may be required before they have reached the end of their useful lives (for example by further road widening projects on the same stretch of road).**

Response:

a) Alectra Utilities confirms that the 2021 relocation project is the first of three projects related to the Goreway Road Widening Project. Provided in Table 1 below are the estimates for all segments of the Goreway Road Widening Project based on the information currently available. Alectra Utilities will seek ICM treatment for the other segments of the project if they meet the required ICM criteria as set out by the OEB.

Table 1 – Goreway Road Widening Project Costs

Description	Gross Cost	Contributions	Net Cost	Timing
Goreway: Cottrelle Boulevard to Countryside Drive	$3.2MM	$1.1MM	$2.1MM	2021
Goreway: Humberwest Parkway to Cotrelle Boulevard (Rough Estimated Cost)	$3.8MM	$1.3MM	$2.5MM	2022
Goreway: Countryside Drive to Mayfield Road (Rough Estimated Cost)	$0.7MM	$0.2MM	$0.5MM	2023

b) Please see Alectra Utilities' response BRZ-Staff-23 a).

c) Alectra Utilities did not complete specific lifecycle analysis as no reliability benefit exists based on a reliability analysis conducted from January 2015-October 2020 for the specific assets and project location. Without added reliability benefits, Alectra Utilities is not aware of a lifecycle costing model where underground is more cost effective then overhead infrastructure.

d) Alectra Utilities has provided a comparison of the estimated gross cost of Option 2 to Option 3 in Table 2, below. The estimated cost of Option 3 is $20.3MM or over 7 times higher than the cost of Option 3, which is Alectra Utilities' proposed option.

Table 2 – Goreway Gross Cost Option 2 vs. Option 3 Comparison ($MM)

Like for Like Rebuild Option 3	Underground Rebuild Option 2	Difference (Option 3 – Option 2)
$3.2	$23.5	$20.3

e) Alectra Utilities reviewed the option of placing the feeder underground and discovered that sufficient trench/duct space was not available in the municipal right-of-way. Therefore, if this option were to proceed, easements would be required which the utility cannot guarantee, and the depth of the trench would exceed the recommended design standards.

f) Based on the information from the City of Brampton and their 10-year Capital Plan, Goreway Road from Cottrelle Boulevard to Countryside Drive is not scheduled for any further road widening that would require Alectra Utilities to further relocate its distribution infrastructure.

SEC-10

Reference: Exhibit 4, Tab 1, Schedule 1, Attachment 4

In the event that the Applicant was required to keep its 2021 Brampton RZ capital budget within the $31.5 million threshold amount, which projects would be removed from the capital projects list?

Response:

Please see Alectra Utilities' response to 2-PWU-5.

SEC-11

Reference: Exhibit 2, Tab 1, Schedule 1, p. 14

Please calculate the difference in interest cost related to the rate base for the Powerstream RZ between the interest rates currently embedded in rates, and the forecast interest rates for the Applicant in 2021. Please provide the Applicant's most recent interest rate forecast for 2021.

Response:

This question is not relevant to the application. Alectra Utilities' rate zones are currently on Price Cap IR. Alectra Utilities does not have a reopener, nor an annual update for changes in interest rates or any other elements of the revenue requirement calculation that have changed since each predecessor utility last rebased. As such, neither the interest rate forecast for 2021 for the PowerStream RZ, nor the requested calculation, are relevant to the Application.

SEC-12

Reference: Exhibit 2, Tab 1, Schedule 1, Table 10

Please provide details of all changes to the 2020 and 2021 capital expenditures by category for the Powerstream RZ that have been made since January 1, 2018.

Response:

Tables 1 and 2 below, provide the details of changes made to the 2020 and 2021 planned capital expenditures by category from the Distribution System Plan to the current plan.

Table 1 – PowerStream RZ 2020 Capital Expenditures Comparison to DSP ($MM)

Investment Category	2020 DSP	2020 Current	Variance
System Access	30.0	27.0	(3.0)
System Renewal	52.1	42.2	(9.9)
System Service	15.7	14.8	(0.9)
General Plant	14.4	11.6	(2.8)
Total PowerStream	**112.2**	**95.6**	**(16.6)**

System Access decreased largely due to a reduction in Subdivision capital projects. System Renewal decreased as a result of deferral of projects, such as rear lots and substation renewal, in an effort to meet the reduced funding. This reduction also impacted System Service projects. General Plant in 2020 decreased as a result of the deferral of the CCRA payment.

Table 2 – PowerStream 2021 Capital Expenditures Comparison to DSP ($MM)

Investment Category	2021 DSP	2021 Current	Variance
System Access	30.0	28.7	(1.3)
System Renewal	52.2	50.2	(2.0)
System Service	14.9	9.0	(5.9)
General Plant	12.6	13.8	1.2
Total PowerStream	**109.7**	**101.7**	**(8.0)**

System Access decreased largely due to a reduction in subdivision capital projects. System Renewal and System Service reduction was a result of the deferral of projects due to reduced funding.

SEC-13

References: Exhibit 2, Tab 1, Schedule 1, p. 13-15
Exhibit 4, Tab 1, Schedule 1, Attachment 6

With respect to the Rutherford Road widening:

a. Please confirm that the 2021 relocation project is the last of three segments of this road widening. Please provide the budget and timing for the full three segment project, and confirm that ICM treatment has been sought for all three segments.

b. Please provide any lifecycle analysis done to demonstrate that undergrounding the new assets under Option 2 would, on a lifecycle basis, be more expensive than the preferred option under Option 3.

c. Please provide all calculations that justify the conclusion that Option 2 is more expensive, and show the difference in cost.

d. Please provide any information in the possession of the Applicant that deals with whether further relocations of the new assets may be required before they have reached the end of their useful lives (for example by further road widening projects on the same stretch of road).

Response:

a) Alectra Utilities confirms that the 2021 relocation project is the last of three segments in the Rutherford Road Widening project. Alectra Utilities did not seek ICM funding for the first two segments of the project. Alectra Utilities is seeking ICM funding for the 2021 segment of the project: Rutherford Road from Bathurst Street to Prince Rupert Avenue. Table 1 provides the net budget for each project and the timing of the project.

Table 1 – Rutherford Road Widening Projects ($/MM)

Description	Gross Cost	Contributions	Net Cost	Timing
Rutherford from Westburne Drive to Confederation Parkway	$2.8MM	$0.4MM	$2.4MM	Completed Oct 2019
Rutherford from Westburne Drive to Jane Street	$4.4MM	$1.5MM	$2.9MM	In Construction (completion by no later than the 1st week of Nov 2020)
Rutherford from Bathurst Street to Prince Rupert Avenue (Estimated Cost)	$4.4MM	$1.5MM	$2.9MM	To be completed in 2021

b) Alectra Utilities did not complete specific lifecycle analysis as no reliability benefit exists based on a reliability analysis conducted from January 2015-October 2020 on assets within the specific project area. Without added reliability benefits, Alectra Utilities is not aware of a lifecycle costing model where underground is cheaper than overhead without additional considerations to reliability and potential other factors.

c) Please see Alectra Utilities' response to PRZ-Staff-46 a).

d) Based on the information from York Region and their 10-year Capital Works Plan, Rutherford Road from Bathurst Street to Peter Rupert Avenue is not scheduled for any further road widening that would require Alectra Utilities to move the distribution infrastructure again.

SEC-14

Reference: Exhibit 4, Tab 1, Schedule 1, Attachment 7

In the event that the Applicant was required to keep its 2021 Powerstream RZ capital budget within the $79.3 million threshold amount, which projects would be removed from the capital projects list?

Response:

Please see Alectra Utilities’ response to 2-PWU-5.

SEC-15

Reference: Exhibit 3, Tab 1, Schedule 2, p. 6

Please explain in detail why Horizon RZ net fixed assets increased by $42 million, or 8.78%, during the calendar year 2019.

Response:

The net fixed assets in the Horizon Utilities RZ increased from $479MM to $521MM (as provided in Exhibit 3, Tab 1, Schedule 2, p. 6, Table 22) primarily as a result of an increase in 2019 investments in distribution plant assets. More particularly, the increase in distribution plant investments in 2019, as compared to 2018, is primarily due to: emerging customer work, new connections, rear lot conversions and underground asset replacement.

Emerging customer work increased significantly during 2019 as several larger projects were completed during the year. This included a waste-water treatment plant, 27kV expansion, and several other commercial and industrial customer projects.

Increased activity in 2019 in new connections was directly related to subdivisions, industrial and commercial growth in Hamilton.

Rear lot conversions increased in 2019 as a result of two large projects, Jacobson Avenue and Ridley Heights, which were completed during the year.

In addition, underground asset replacement increased in 2019 as a result of ongoing efforts in the Hamilton Mountain area.

It is important to note that the calculation of net fixed assets is relied upon solely to determine the rate base for the Horizon Utilities RZ. The distribution plant assets reflect actual capital additions from January to July and an allocation methodology to derive capital additions for the July to December 2019 period, based on the July to December 2019 capital expenditures by rate zone. Please see Alectra Utilities' response to G-Staff 6 for further details.

SEC-16

Reference: Exhibit 3, Tab 1, Schedule 2, p. 7

Please provide the detailed calculations of the allocation of General Plant as of December 31, 2019, including explanations of all assumptions used and adjustments made.

Response:

General plant is not identifiable by rate zone as these assets support the operations of Alectra Utilities as a whole. An allocation methodology was therefore developed by Alectra Utilities to determine the amount of general plant additions in the Horizon Utilities RZ as at December 31, 2019. The detailed steps and calculations used in the allocation methodology, including the relevant assumptions used, are as follows.

Alectra Utilities' fixed asset records were relied on to obtain the 2019 general plant additions. As the Guelph RZ has not migrated to Alectra Utilities' Enterprise Resource Planning ("ERP") system, fixed asset records for the Guelph RZ are maintained separately. Table 1 below summarizes the fixed asset additions as at December 31, 2019.

Table 1 - General Plant Additions as at December 31, 2019

General Plant Additions	$MM's
General plant - Alectra GL	$ 54.1
General plant - Guelph GL	$ 1.0
Total General plant new additions	$ 55.1

Adjustments were made to incorporate the impact of merger costs and savings on the 2019 general plant additions. Table 2 summarizes the resulting general plant fixed asset additions after removing merger related capital costs and including the merger related capital savings for 2019.

Table 2 – 2019 General Plant Additions Adjusted for Merger Costs/Savings

General Plant	$MM's
Alectra GP additions	$ 55.1
Less merger related capital costs energized	$ (34.5)
Add back merger related capital savings	$ 37.4
Adjusted new GP capital additions	**$ 58.0**

An allocation methodology based on each rate zone's contribution to the total pre-merger rate base was relied on to determine general plant additions for the respective rate zones. The pre-merger rate base was taken from the annual Reporting and Record keeping Requirements ("RRR") 2.1.5.6 legacy utilities' RRR filings. The 2016 pre-merger rate base was relied on for the Brampton, Enersource, Horizon Utilities and PowerStream RZs. The 2018 pre-merger rate base was relied on for the Guelph Hydro RZ as Guelph Hydro merged with Alectra Utilities in January, 2019. The allocation percentages were calculated based on each rate zone's pre-merger rate base as a proportion of the total pre-merger rate base for all rate zones. This allocation approach remains consistent with the methodology advanced in the 2020 EDR Application, and which was accepted by the OEB. Table 3 below details the calculation of the Horizon Utilities RZ allocation percentage of 17.3%.

Table 3 – General Plant Allocation Methodology

General Plant Capital Additions Allocation ($MM's)	Brampton	Enersource	Horizon	PowerStream	Guelph	Total
Rate Base from legacy ROE (2.1.5.6) filing	$ 421.7	$ 777.7	$ 506.5	$ 1,064.9	$ 154.9	$ 2,925.8
Allocation Percentage	14.41%	26.58%	17.31%	36.40%	5.30%	100.00%

The Horizon Utilities RZ allocation of general plant additions including the required merger related adjustment is shown in Table 4, below.

Table 4 – Horizon Utilities' RZ General Plant Additions

General Plant	$MM's
Alectra GP additions	$ 55.1
Less merger related capital costs energized	$ (34.5)
Add back merger related capital savings	$ 37.4
Adjusted new GP capital additions	**$ 58.0**
Allocation to Horizon Rate zone	17.31%
Horizon Rate zone capital additions	**$ 10.0**

SEC-17

Reference: Exhibit 3, Tab 1, Schedule 2, p. 9

Please provide full details of the $25.4 million of "net merger OM&A savings" added to OM&A expense for allocation purposes. Please confirm that the impact of that addition on the regulatory income before taxes of Horizon RZ was to reduce it by $5.5 million.

Response:

Please see Alectra Utilities' response to G-Staff-3 for the full details of the $25.4MM of net merger OM&A savings.

Alectra Utilities confirms that the impact of the addition of $25.4MM of net merger OM&A savings on regulatory income before taxes, was to reduce it by $5.5MM. This is consistent with the calculation of the ESM for 2017 and 2018. It is also consistent with the calculation of regulated net income and ROE per Horizon Utilities' Settlement Agreement from its 2015-2019 Custom IR Application (EB-2014-0002).

SEC-18

Reference: Exhibit 3, Tab 1, Schedule 2, Table 29

Please describe in detail the reasons for the variances between the two columns.

Response:

Alectra Utilities has reproduced Table 29 in Exhibit 3, Tab 1, Schedule 2, to provide details of the variances between the two columns in Table 29. Table 1, below provides variance explanations for related to Horizon Utilities' taxable income, and Table 2, below provides variance explanations for changes to net additions (deductions) for tax.

Table 1 – Variance of Horizon Utilities RZ Taxable Income ($000s)

Horizon Utilities Rate Zone	Actual	Annual Filing EB-2018-0016	Variance	Variance Explanation
Regulatory net income before tax	$19,119	$19,961	($841)	Lower working capital as a result of decrease in cost of power mainly attributable to the implementation of the Fair Hydro Plan.
Net additions (deductions) for tax	($17,011)	($10,360)	($6,651)	See Table 2 below for details on variance.
Taxable income	$2,108	$9,600	($7,492)	Sum of variances explained above.
Tax Rate	26.5%	26.5%	-	
Income taxes	$559	$2,544	($1,985)	Sum of variances explained above.
Tax credits	($211)	($232)	$21	
Current taxes payable	$348	$2,312	($1,964)	Sum of variances explained above.
PILs Gross-up	$ -	$834	($834)	No PILs gross-up on ESM calculation.
Income taxes	**$348**	**$3,146**	**($2,798)**	Sum of variances explained above.

Table 2 – Variance of Net additions (deductions) for tax ($000s)

Horizon Utilities Rate Zone	Actual	Annual Filing EB-2018-0016	Variance	Variance Explanation
CCA	($43,930)	($34,824)	($9,105)	CCA allocation to HUC based on depreciation allocation (17.7%). Higher CCA mainly due to high AUC actual software additions allocated to HUC at 17.7% and increase in allowed CCA on current year additions due to the Accelerated Investment Incentive.
Non-deductible reserves	$3,546	$607	$2,939	Non-deductible reserves - higher OPEB and bad debt provision balances.
Capitalized fixed asset costs, deductible for tax	($1,586)	$ -	($1,586)	Capitalized OMERS and interest costs for accounting; deducted for tax in current year.
Fixed Asset Amortization / Gains and Losses	$24,705	$23,860	$845	Actual is based on allocations per the ESM Model; equivalent to 17.7% of Alectra depreciation.
Other	$254	($3)	$257	Immaterial difference represents all other variances shown in Exhibit 3, Tab 1, Schedule 2, Attachment 13 - Table 3.
Total	**($17,011)**	**($10,360)**	**($6,651)**	

SEC-19

References: Exhibit 3, Tab 1, Schedule 3, p. 5
Exhibit 4, Tab 1, Schedule 1, Attachment 4

Please confirm that General Plant capex has declined from $58 million in 2019 to $38 million in 2021. Please explain the reasons for the high GP capex in 2019.

Response:

Alectra Utilities submits that the $58MM is in reference to general plant capital additions for 2019, and the $38MM identified in Attachment 4 of Exhibit 4, Tab 1, Schedule 1, is a forecast of 2021 general plant capital expenditures. In Exhibit 3, Tab 1, Schedule 5, general plant capital additions were reported as $58MM. These additions represent energized capital expenditures for 2019. Please see Alectra Utilities' response to SEC-16 for details on the calculation of 2019 general plant capital additions. Table 2 from SEC-16 has been reproduced below to identify that the calculation of the general plant additions of $58MM for 2019 include adjustments related to merger costs and savings.

Table 1 – Alectra Utilities' 2019 General Plant Additions

General Plant	$MM's	
Alectra GP additions	$	55.1
Less merger related capital costs energized	$	(34.5)
Add back merger related capital savings	$	37.4
Adjusted new GP capital additions	**$**	**58.0**

SEC-20

Reference: Exhibit 3, Tab 1, Schedule 8

With respect to the 2010 spreadsheet error, and the $8.1 million payment to IESO:

a. **Please provide a breakdown of the amount proposed to be borne by each rate class (broken down into fixed and variable components) to cover the cost of the error.**

b. **Please explain why customers in 2021 should bear the cost of an error by the utility that occurred in 2010. Please provide specific references to the Distribution System Code, the Board's rules, policies and guidelines, any relevant legislation or regulation, and any case precedents.**

Response:

a) Please see Alectra Utilities' response to VECC-8 c).

b) Alectra Utilities has reviewed the relevant legislation and regulations, as well as the relevant OEB codes, rules, policies and guidelines.

Based on a review of the *Ontario Energy Board Act* and its regulations, as well as the OEB's *Rules of Practice and Procedure* and the *Distribution System Code*, there is nothing that prohibits recovery by Alectra Utilities of the $8.1MM that it paid to the IESO as a result of the spreadsheet error that impacted settlements from 2011 to 2018. Under s. 78 of the OEB Act, the OEB is authorized to issue orders establishing the rates that may be charged for the distribution of electricity. The Board has broad discretion over the methodology it uses to establish just and reasonable rates.

Of particular significance is the guidance provided on p. 10 of the OEB's *Chapter 3 Filing Requirements for Incentive Rate-Setting Applications for Electricity Distributors*, dated May 14, 2020, where the OEB states:

> On October 31, 2019, the OEB issued a letter to all electricity distributors discussing its approach to address accounting or other errors, in respect of Group 1 DVA, that have previously been disposed of by the OEB on a final basis. Where an accounting or other error is discovered after the balance in one of the Group 1 accounts has been cleared by a final order of the OEB, a distributor shall refer to this letter for further guidance. The OEB expects

> electricity distributors to disclose errors that have been discovered in their accounting records as part of their rate applications and to record correcting adjustments to the affected account(s) in the year in which the error is discovered. If adjustments have taken place, a distributor must provide explanations in its application as to the nature and amounts of the adjustments and include supporting documentation under a section titled "Adjustments to Deferral and Variance Accounts".

Further, the October 31 letter explains that the OEB will, on a case-by-case basis, provide for retroactive adjustments to address accounting or other errors in respect of certain electricity distributor variance accounts for pass-through costs that have been cleared by a final order of the Board. The letter notes that, because these accounts deal with pass-through costs, they are "designed to ensure that customers ultimately pay no more and no less than what their distributor paid".

Given that Alectra Utilities has corrected the error as between it and the IESO, recovery of the relevant amount from customers as requested in this application will give effect to the purpose of the account by ensuring that customers ultimately pay no more and no less than what Alectra Utilities has paid.

While the balance of the relevant variance account has been cleared on a final basis for the years 2010 up to and including 2016, on an interim basis for 2017 and not cleared for 2018 to 2019, it is reasonable for the balances to be recovered from customers, as proposed in the Application.