TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.1

Reference**:** 2A-SEC-41, Attachment 1, Table 7, Section 5.5

Run two additional sensitivity runs that include all three of the optimistic and pessimistic sensitivities.

RESPONSE:

Table 1 provides the results of the two additional sensitivity runs for the NWS Program.

Table 1 – Sensitivity Analysis

Scenario	Parameters	Sensitivity Value	Net DST Benefits Base = $17.3M
Pessimistic Sensitivities	DER Capacity/Energy Price	20% higher	$11.6M
	Activations	7 activations / year	
	NWS OM&A Cost	20% of DER Payments	
Optimistic Sensitivities	DER Capacity/Energy Price	20% lower	$21.0M
	Activations	5 activations / year	
	NWS OM&A Cost	8% of DER Payments	

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.2

Reference: 2-Staff-52

Referring to 2-Staff-52(b), advise of why there is a difference between the agreement value of the project and the project total.

RESPONSE:

Project Centricity is intended to design and implement end-to-end capabilities for Distribution System Operations (DSO). The project will develop and implement DSO functionality that is incremental to the systems and platforms Alectra Utilities is already developing through grid modernization investments in the Integrated Network Model (INM), Planning Tools and Automation (PTA), and the DER Wholesale Market Preparedness (DWMP) platform.[1]

Alectra Utilities plans to design and implement the full incremental DSO functionality at a total cost of $10.7MM, which includes $6MM of NRCan Funding and $4.7MM in contributions from eight project partners. Alectra Utilities secured $6MM of NRCan funding in recognition of $9.9MM in foundational Grid Modernization investments in INM, PTA and DWMP, which will underpin the incremental implementation of new DSO functionality.

As such, the overall Project Centricity cost of $20.6MM comprises of $6MM of NRCan funding, $9.9MM of foundational Grid Modernization investments, and $4.7MM of project partner contributions.

[1] Exhibit 2A, Tab 1, Schedule 1, Appendix B14, Pages 614-619

Project Centricity provides value to Alectra Utilities' customers by enabling the utility to advance incremental DSO functionality through external funding sources, without requiring rate-funded capital or operating expenditure for implementation and operations during the rate period.

Upon completion of Project Centricity, Alectra Utilities' customers will benefit from a functioning DSO capability funded through grants and partner contributions. The functional benefits of the DSO capabilities include:

- planning functionality to identify where such services may be applied to address system needs;
- analytical capability to evaluate and value the distribution system services;
- development of local energy market rules, market structures, and service products; and
- market functionality to procure, evaluate, dispatch, and settle those services.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.3

Reference: 2-Staff-52

Advise what the capabilities being funded will be used for beyond 2028 and whether that has impacts on the rate base or the regulated business ratepayer, and confirm whether the systems and capabilities that will be developed under this project will be capitalized within Alectra's regulated utility business.

RESPONSE:

Project Centricity is scheduled to conclude in 2028. The project enables Alectra Utilities to develop a base level of Distribution System Operator (DSO) capability with external contributions totaling $10.7 million ($6.0 million from NRCan and $4.7 million from project partners).

As outlined in JT 2.2, the base level DSO capabilities developed through Project Centricity are incremental to the systems and platforms Alectra Utilities is already developing through grid modernization investments in the Integrated Network Model (INM), Planning Tools and Automation (PTA), and the DER Wholesale Market Preparedness (DWMP) platform. As outlined in Appendix B14 – Enabling Resiliency and Modernization, Section IV, Alectra Utilities requires the planned INM, PTA and DWMP systems to satisfy requirements for the utility's Non-Wires Solutions (NWS) alongside the various policy instruments outlined in Section 4.1 of Exhibit 2A, Tab 1, Schedule 1, Appendix B14 – Enabling Resiliency & Modernization, Section IV.

Beyond 2028, the functionality developed through Project Centricity (as outlined in JT-2.2) is expected to remain integrated within Alectra Utilities' grid modernization environment and operate on the INM, PTA, and DWMP platforms. Alectra Utilities does not expect additional capital or OM&A costs to be incurred to maintain these capabilities during the 2027-2031 rate period. To the extent any project outputs meet applicable capitalization criteria for accounting purposes, Alectra Utilities is not seeking any incremental inclusion of Project Centricity amounts in the regulated rate base or recovery through rates in this proceeding.

Project Centricity enables Alectra Utilities to develop the incremental capabilities described above without seeking incremental capital funding from the ratepayers in this application. Alectra Utilities is not proposing any incremental rate base or revenue requirement recovery associated with Project Centricity during the 2027-2031 rate period.

Alectra Utilities is actively working with the OEB (EB-2025-0060) and other stakeholders to develop a framework and expectations for electricity distributors regarding the development of DSO. As such, Alectra Utilities' DSO-related efforts include planning and collaborating with stakeholders on capabilities that serve distribution purposes in alignment with OEB expectations that DSO capabilities could capture DER benefits, enhance reliability, and optimize local distribution systems.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.4

Reference: 4-CCC-50, Part a) Table 1, Page 2 and Part g) Page 5, Table 2

Reconcile the direct labour cost between part a) and part g) of 4-CCC-50 for 2025.

RESPONSE:

The total direct labour cost between part a) and part g) of 4-CCC-50 for 2025 did not reconcile due to an error in the 2025 regular labour included in table 2 in part g).
The corrected table for 4-CCC-50 part g) is provided below. below:

Corrected 4-CCC-50 Table 2 – System Control OM&A Labour Cost

	2017	2018	2019	2020	2021	2022	2023	2024
Regular	9.32	9.64	9.80	10.41	9.88	10.62	12.34	12.30
Overtime	1.45	1.76	2.88	2.63	2.81	2.89	3.69	3.32
Total	10.77	11.39	12.68	13.04	12.69	13.51	16.03	15.62

	2025	2026	2027	2028	2029	2030	2031
Regular	9.75	12.11	13.71	14.61	15.06	15.52	16.02
Overtime	2.21	0.87	0.89	0.92	0.95	0.98	1.01
Total	11.96	12.98	14.60	15.53	16.01	16.50	17.03

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.5

Reference: 4-Staff-171, Table 1, Page 9 and 4-CCC-50, Page 5

Explain the increase in direct labour costs when no new positions are added in 2026.

RESPONSE:

The increase in System Control direct labour costs in 2026 vs 2025 is due to lower than expected actual 2025 direct labour costs resulting from vacancies. All System Control Operator apprentice positions posted in 2025 were filled, however; Alectra was not able to fill 8 vacancies for fully qualified System Control Operators in 2025. These vacancies for fully qualified System Control Operators were subsequently converted to apprentice positions which are expected to be filled by Q3 2026.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.6

Reference: 4-CCC-56, Table 1, Page 2 and Exhibit 4 Tab 2, Schedule 15, Page 6

Explain the higher segment level cost for 2025 at 6.42 million in 4-CCC-56 table forecasted in Exhibit 4 at Tab 2, Schedule 15, Page 6.

RESPONSE:

There is a $0.53M variance between planned ($5.89M per Exhibit 4, Tab 2, Schedule 15, Table 4-2-101) and actual ($6.42M per Interrogatory response 4-CCC-56 Table1) Vegetation Management Cut Cycle Segment OM&A. This variance is primarily attributable to higher than planned Direct labour, vehicle, and materials costs due to a higher proportion of reactive vegetation management calls than planned.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.7

Reference: 4-Staff-171, Table 1

Explain the increase in direct labour cost when only one new position is being added in 2026.

RESPONSE:

New positions were added to the Stations program in 2025, however; these roles were filled at various points throughout the year. As a result, 2025 labour costs reflect only partial-year costs for these positions. By contrast, 2026 represents the first year in which their full-year labour cost impact of these positions will be realized.

In addition, the Stations program experienced vacancies in 2025 due to retirements, resignations, and transfers to other Business Units. As a result, direct labour costs in 2025 were lower than budget, which also contributes to the increase in direct labour costs from 2025 to 2026. These vacancies are expected to be filled by the end of April 2026.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.8

Reference: 2-Staff-124 and Excel Attachment to the IR response for 1-SEC-24A

Reconcile the difference between the connection and cost recovery amounts shown in 2-Staff-124 and the Excel Attachment to 1-SEC-24A.

RESPONSE:

Alectra Utilities has reproduced Table 1-CCRA Payments and Credits from response to Interrogatory 2-Staff-124 and amended it to include the values from the Connection and Cost Recovery Agreements row provided in the response to Interrogatory 1-SEC-24A, together with a row showing the difference.

Table 1 – Restated Table 1–CCRA Payments and Credits from 2-Staff-124 amended to reconcile 1-SEC-24A

Project Name	Payment Date	Actual						Forecast					
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Goreway TS (Brampton) 10 Yr True-Up	12/15/2021		5.5										
Midhurst TS 15 Yr True up	12/31/2022			-0.84									
Winona TS 15 Yr True up	12/31/2022			-1									
230KV Underground Cable Supply to Heritage TS (Brampton) Construction Costs	Multi-year[(1)]											29.2	24.1
Nebo TS 27.6kV (Hamilton) 5Yr True-Up	12/31/2022			0.7									
Newton TS (Hamilton) Construction Costs	Multi-year[(1)]									8.2	8.1	9.2	
Pleasant TS - H29 H30 Reconductoring - Transmission	Multi-year[(1)]					0.3	0.8	5	5				
Kenilworth TS Power factor Correction	12/15/2026				0.2	0.6	2.1	1					
Cedar TS (Guelph) [(2)] 15 Yr True-Up	12/1/2026							0.5					
Arlen MTS (Guelph) [(2)] 10 Yr True-Up	12/1/2026							0.2					
Campbell TS Metalclad expansion (Guelph) Construction Costs	Multi-year[(1)]									8.2	8.1	9.2	
Markham TS #5 (Markham) [(2)] Construction Costs	Multi-year[(1)]							10	10				
Total (2-STAFF-124) - Ref A			**5.5**	**-1.14**	**0.2**	**0.9**	**2.9**	**16.7**	**15**	**16.3**	**16.3**	**47.5**	**24.1**
CCRA as per 1-SEC-24A - Ref B		0.0	5.5	0.7	0.0	0.0	0.0	5.0	10.0	16.3	16.3	47.5	24.1
Difference - (Ref B-Ref A)		0.0	0.0	1.8	-0.2	-0.9	-2.9	-11.7	-5.0	0.0	0.0	0.0	0.0

Alectra Utilities provides Table 2 below to reconcile the values presented in 2-Staff-124 and 1-SEC-24A

Table 2 – Reconciliation between 2-Staff-124 and 1-SEC-24A

Reconciling Differences: Items not included in CCRA under SEC-24	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CCRA Credit not included in CAPEX [2]			1.8									
Kenilworth TS Power Factor [3] *Included in Project Group - System Control and Comm Performance*				-0.2	-0.6	-2.1	-1.0					
Pleasant TS - H29 H30 Reconductoring - Transmission [4] *Included in Project Group Transmitter Related Upgrades*					-0.3	-0.8	-5.0	-5.0				
Cedar TS (Guelph)[1]							-0.5					
Arlene TS (Guelph)[1]							-0.2					
Markham TS#5[1]							-5.0					
Total	**0.0**	**0.0**	**1.8**	**-0.2**	**-0.9**	**-2.9**	**-11.7**	**-5.0**	**0.0**	**0.0**	**0.0**	**0.0**

Notes:

1. In response to 2-Staff-124, Alectra Utilities presented the expenditures for Cedar TS(Guelph), Arlene TS (Guelph) and Markham TS#5 that were carried over from 2025 into 2026. These expenditures were initially planned for 2025, however, they were deferred into 2026 to reflect delays in finalizing the payments with Hydro One. In the response to 1-SEC-24A, the 2025 actuals were provided, reflecting those delays in finalizing the payments, but the 2026 Plan was not updated to reflect the carryover into 2026.

2. In response to 2-Staff-124, Alectra Utilities included CCRA credits. Alectra Utilities recognizes credits resulting from CCRA true-ups as the derecognition of contributions paid in prior periods. These amounts are presented as disposals of fixed assets and are not included in in-service additions. Accordingly, Alectra Utilities did not include CCRA credits in response to 1-SEC-24A.

3. In response to 1-SEC-24A, the Kenilworth TS Power Factor Correction project is listed and included under the System Service category, System Control, Communications & Performance.

4. In response to 1-SEC-24A, the Pleasant TS - H29/H30 Reconductoring – Transmission project is listed and included under the System Access category, Transmitter Related Upgrades.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.9

Reference: 1-SEC-24, Attachment 2A

Consider if Alectra can provide information on the inflation impacts on Alectra's capital programs over the historic period shown in 1-SEC-24, Attachment 2AA and, if it can, to provide such information and if it cannot to advise why not.

RESPONSE:

Alectra reviewed the inflation it has experienced in contractor amounts relative to 1-SEC-24 attachment OEB Appendix 2-AA's historical period (2020-2025). In order to provide a consistent basis of comparison to evaluate the impact of inflation across a variety of projects, work types and contractor services, Alectra has considered the change in labour rates for its major High Voltage and Civil contractors over the historical period (2020-2025). From 2020-2025, Alectra experienced an annual average 2.38% inflationary increase in contractor rates. During this period, some contractor rates increased, and some decreased through competitive procurement processes.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.10

Reference: Exhibit 2A, Schedule 1, Tab 1, and Page 103, Figure 7

Explain how the risk curve is calculated pre-investment and post-investment if you don't have a failure curve for individual assets and provide an illustrative example of how risk scores are calculated in Copperleaf through the value framework.

RESPONSE:

Alectra Utilities determines the mitigated risk of a capital investment at the business case level in the Copperleaf platform.

For specific assets (poles, transformers, switchgear, and switches), the utility evaluates risks using the Copperleaf Predictive Analytics (PA) software application and applies failure rate formulas consistent with the Gompertz-Makeham Models. Please see responses to undertakings JT-2.13 and JT-2.16 for a detailed explanation of Alectra Utilities' application of the PA software platform.

There are several benefits of determining risk mitigation at the business case level. First, determining risk at the business case level enables Alectra Utilities to assess risk temporally, which is more accurate than applying a static risk value. The benefit of this approach is that when the projects undergo optimization, Copperleaf can adjust the timing of the investment while adjusting the risk mitigation assessment, thus identifying the optimal time for intervention while considering the other investment timing in the portfolio and adhering to constraints, thus maximizing the overall portfolio value. For each risk, the business case project owner specifies the consequence (i.e., risk impact) as well as the probability of the occurrence.[1]

Another benefit of determining risk mitigation at the business case level is the ability to incorporate multiple discrete risk measures into a single business case, thereby providing a more comprehensive, holistic assessment of risk mitigation. Alectra Utilities' value framework includes 23 discrete value measures, which include nine risk measures, including environmental, financial, safety and compliance risk, amongst others.

A third benefit of determining risk mitigation at the business case level is the determination of the risk based on the specific site or scope of the project. Alectra Utilities subject matter experts incorporate risks proportionate to the project site and scope that is more accurate determination of risk when compared to a generic or asset-specific risk measure.

Alectra Utilities selected the Sorbweb Oil Containment System as an illustrative example of risk mitigation assessment in the context of a risk-driven project. Alectra Utilities implements Sorbweb Oil Containment Systems as a preventative means of mitigating oil spills at municipal stations. These investments illustrate the assessment of environmental risk mitigation in a municipal station, relative to a baseline of a station without the oil containment (i.e., where a power class transformer oil leak would pose an environmental risk). The Sorbweb Oil Containment solution is further discussed Exhibit 2A, Tab 1, Schedule 1, Appendix B04 – Station Renewal, Page 163.

Step 1 – Determining the Baseline Probability

Alectra Utilities Subject Matter Experts (SME) identify the likelihood or probability of an oil leak occurring based on asset condition. In this example, based on the power transformer condition, the SME selected “Once in 10 years” likelihood, which corresponds to a 10% likelihood of an oil leak occurring during the given year or determined period.

[1] Exhibit 2A, Tab 1, Schedule 1, 5.3.1 Asset Management Framework Overview, Pages 103-104

Step 2 - Determining Baseline Consequence

For this example, the SME considers that the municipal station is located in a residential neighborhood with parks and water systems in the area, a significant clean-up would be required if the power transformer leaked. Additionally, station power transformers contain a very large amount of oil that further increases the consequences of the leak. The SME aligns the consequences of an environmental leak using the risk matrix to determine a baseline consequence value of 1,500, corresponding to an environmental spill site requiring substantial clean-up.

Step 3: Calculation of Baseline Risk

Therefore, the baseline risk from these parameters is [redacted].

Step 4: Calculation of Outcome Probability

In this case, once the Sorbweb system is installed, this significantly reduces the risk, so the likelihood is “Once in 100 years” or 1%.

Step 5: Calculation of Outcome Consequence

Since the Sorbweb system is installed, the impact to the surrounding environment would be minimal, and an impact value of 150 representing a minor oil spill is used.

Step 6: Calculation of Outcome Risk

Therefore, the outcome risk from these new parameters is [redacted].

Step 7: Calculate the Mitigated Risk

The mitigated risk then becomes the difference between baseline risk and outcome risk, or in this example, the mitigated risk is calculated as: [redacted].

This calculation is repeated for each year of the proposed solution for which risk mitigation is determined, and annual risk mitigation results are then aggregated in Copperleaf using net present value calculations.

This concept is further illustrated in Exhibit 2A - Tab 1 - Schedule 1 - Appendix C - Section 4 Figure 3.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT-2.11

Reference: 2-CCC-24 and “Economic Model”

Provide a summary of the outputs of the economic model and key assumptions.

RESPONSE:

Please refer to Table 1 below for the EEM summary showing the inputs and outputs, as requested.

Alectra Utilities acknowledges that the revenue horizon for Project 1 is 25 years, as reflected in Table 1. This was incorrectly noted as 15 years in IR Response 2-CCC-24, Table 2 – Data Centres Information for Project 1. The witness corrected this verbally on Day 2 (March 6, 2026) of the Technical Conference.

Table 1 - EEM Summary

Economic Evaluation Model (EEM) Summary	
Project Name:	Project 1
Type of Project:	Industrial/Commercial/Institutional (ICI)
Revenue Horizon:	25 Years
Connection Horizon:	15 Years
Rate Zone:	PRZ
Energization Year:	2027
Customer Connections / Load:	[redacted]

Estimated Total Project Costs:	$49.9M
Outputs:	
PV (Revenues)	[redacted]
PV (Capital and Operating Costs, inc. CCA TAX Shield)	[redacted]

The economic evaluation was conducted using the Distribution System Code Appendix B Economic Evaluation Model methodology. Assumptions include the forecasted demand, based on a staged ramp-up of customer demand over the 15-year connection horizon, the distribution rates from the approved PRZ rate schedule, a 25-year revenue horizon, an estimate of all capital and incremental OM&A costs, and a discount rate equal to the incremental after-tax cost of capital.

Consistent with the economic evaluation framework, the developer's capital contribution and associated security arrangements ensure that the costs of the connection facilities are appropriately allocated, such that other ratepayers are not exposed to the risk of under-recovery should the forecast load not materialize as expected.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.12

Reference: 2-Staff-64, Table 11 and Table 12

Provide information on the change in pole condition ratings between the 2018 and 2023 asset condition assessments including why poles rated fair or good in 2018 are shown as good and very good in 2023.

RESPONSE:

Asset condition assessment provides a snapshot of health of the asset population based on the underlying inspection and testing (wood pole only) data at a point in time. Several factors explain the observed movement of poles between health index categories between the 2018 and 2023 condition assessments, such as:

- **Harmonized Inspection and Testing Practices and Improved Data Quality:** Inspection and testing criteria and data capture practices have been standardized across Alectra Utilities in 2021 that were not available in 2018. The harmonization improved consistency and reliability of condition assessment. Assets that were previously uninspected or assessed with limited data are now being evaluated through structured inspection and testing programs.
- **Changes in Asset Population:** While marginal, new assets have been added through capital programs and system expansion between 2018 and 2023 resulting in changes to the categorized population.

As requested, Alectra Utilities has reviewed the differences for the wood pole population between 2018 and 2023, in each condition categories changed materially. Poles in the FAIR and GOOD categories declined from 57,798 in 2018 to 20,253 in 2023, while the VERY GOOD category increased from 39,224 to 75.318. However, this change in distribution does not mean that poles uniformly improved. The comparison includes 20,461 poles that are no longer present in 2023 and 20,154 new poles appearing in 2023, confirming that the two assessment years do not represent an identical asset population.

For poles appearing in both years, movement occurred in both directions. Of the common population, 36,083 remained in the same health index category, 36,006 moved to a better category, and 13,019 moved to a worse category. The majority of both upward and downward movements between health index categories are associated with new inspection and testing records obtained after 2018, indicating the observed changes are primarily driven by harmonized inspection and testing practices and improved data quality.

The same pattern is evident for poles that were rated FAIR or GOOD in 2018, as presented in Table 1 below. Of those 46,529 wood poles that appear in both years, 31,333 moved to a better category, 8,323 moved to a worse category, and 6,873 remained in the same category. Most of the upward movement is tied to new inspection and testing records after 2018, which indicates that many poles were reclassified in 2023 based on more complete and standardized condition information than was available in 2018. At the same time, some poles moved to worse categories.

Table 1 - Reconciliation of Wood Pole Condition Categories (2018 vs 2023)

Description	Number of Poles	Explanation
Poles appearing in both years (FAIR + GOOD)	**46,529**	Comparable population between assessments
Condition Improved	31,333	Reassessed to better HI category
Condition Declined	8,323	Reassessed to lower HI category
Stayed in same HI category	6,873	No condition change between assessments

Accordingly, the shift in asset condition categories between 2018 and 2023 reflects a combination of lifecycle dynamics, additional inspection and testing information obtained after 2018, and harmonized assessment practices resulting in changes to the assessed asset population. As a result, wood poles rated FAIR or GOOD in 2018 may appear in other categories in 2023 where assessment was informed by more complete and standardized inspection and testing information.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.13

Reference: 2-Staff-85

On a best-efforts basis, provide the risk and benefit inputs for one pole renewal project and one voltage conversion project from the table in IR 2-staff-85, including an explanation of why zero benefits are shown for certain projects such as pole renewal and switch removal.

RESPONSE:

Alectra Utilities provides below two illustrative examples of the risk and benefits inputs and methodology applied in scoring a voltage conversion project and a pole renewal project.

Example 1: Voltage Conversion Project 150355 Elmwood MS

This project contains six value measures. The total value has also been included in the final bullet point:

- Reliability Benefit: 63,355 value points
- Capital Financial Benefit: 10,441 value points
- OM&A Financial Benefit: 123 value points
- Environmental Risk: 1,332 value points
- Safety Risk: 1,199 value points
- Investment cost: (14,817) value points
- **Total Project Value: 61,633** value points

The investment cost is the NPV of the costs to execute the investment and is excluded from the illustration below. For the purpose of this illustrative example, Alectra Utilities has provided the derivation of the top two benefits and top two risks values, as they are the main contributors to the overall positive NPV for this investment.

Reliability Benefit Value:

For a comprehensive example demonstrating the calculation methodology of Reliability Benefit, please see undertaking response JT-1.7.

Computing the reliability benefit value for a voltage conversion project requires collecting the previous 5 years' worth of outage data impacting the station. Station specifics in terms of load and customer mix are also required. The scenario modeled is the failure of a bus/main breaker. This data is then used to populate the reliability benefit questionnaire, consisting of the following inputs:

- Failures avoided per year: 15.6 is the historical average annual number of outages on this station; no forecasting is performed. Alectra Utilities considered a conservative approach to maintain the historical average for the Reliability Benefit calculation.
- KVA affected by an outage: 5000kVA is the assumed station peak, which is 1/3 of the station's maximum capacity.

[redacted]

- Average duration of an outage: For this project from 2027-2031, 1.2hrs has been applied as the average duration based on historical reliability. From 2032 onwards, Alectra Utilities considered an average outage of 2.4hrs.
- Loss of Redundancy: 24 hours was derived by the SME to represent the time required to restore a station power transformer to service in the event of a failure.
- Customer type: Selected as mixed residential commercial, therefore Value of Lost Load for this type of load for 1 hour is [redacted] per hour.
- Worst Performing Feeder: This feeder in this project is not a worst performing feeder.

Illustrative Calculation for 2027:

[redacted]

Capital Financial Benefit Value:

This is the capital benefit of avoiding rebuilding the low voltage station and distribution assets (at 4kv instead of 13.8kV) if the voltage conversion were not to occur as planned.[1]

Step 1: Provided the estimated capital cost needed for the urgent renewals

The total estimated rebuild of the station is $4.8 MM. However, the SME applied a conservative input of $4.3 MM as required to ensure the station will operate for another 40 years.

Regarding the distribution system, if the project does not proceed, the necessary distribution assets will also need to be replaced. These costs are required either way and are estimated at $11.2 MM based on the 2023 ACA. As assets will continue to deteriorate over time, and in general these are the oldest assets in the system, the SME estimated $13.0 MM over a 6-year period.

Step 2: Provide the probability of benefit achievement that will occur

For the station assets, Alectra Utilities applied a conservative 90% achievement. For the distribution assets, Alectra Utilities applied a conservative 65% of the total capital cost avoided.

---

[1] Exhibit 2A, Tab 1, Schedule 1, Appendix B01 – Overhead Renewal, Page 45

<u>**Step 3**: Provide Labour savings</u>

Only station costs were listed as contributing to labour savings. Alectra Utilities estimated 140 hours over a 2 year period. These labour savings include design, inspection and project administration.

<u>**Step 4:** Calculate the Capital Financial Benefit Value</u>

For the station assets in 2027:

[redacted]

[redacted]

For the distribution assets in 2027:

[redacted]

[redacted]

[redacted]

[redacted]

<u>Safety Risk Value:</u>

For a comprehensive example of the methodology Alectra Utilities applies to determine risk as an input, please see the response to JT-2.10.

For this specific project, Safety Risk was evaluated as a pole failure (deteriorated distribution assets) and the serious electrical incident outcome.

<u>Step 1: Baseline Risk</u>

Baseline Probability: 1 in 10 years (10%)

Baseline Consequence: Critical Injury to member of the public (4,500)

[redacted]

<u>Step 2: Outcome Risk</u>

Outcome Probability: 1 in 1000 years (0.1%)

Outcome Consequence: Minimal damage to property (150)

[redacted]

<u>Step 3: Calculate Safety Risk Value</u>

[redacted]

<u>Environmental Risk Value:</u>

The environmental risk is based on one of the three power class transformers leaking into the surrounding neighbourhood. The inputs used are very similar to those in response provided in JT-2.10, for full details please see that response. A summary is provided below.

<u>Step 1: Baseline Risk</u>

Baseline Probability: 1 in 10 years (10%)

Baseline Consequence: Oil spill into neighbourhood backyards (1,500)

[redacted]

<u>Step 2: Outcome Risk</u>

Outcome Probability: 1 in 1000 years (0.1%)

Outcome Consequence: Minimal damage to property (150)

[redacted]

Step 3: Calculate Environmental Risk Value

[redacted]

[redacted]

For each business case in Copperleaf optimization, Alectra Utilities SME's consider the appropriate benefit or risk value questionnaires along with the investment cost, which are then applied to derive the overall project value. These individual risks and benefits questionnaires are shown in greater detail in Exhibit 2A Tab 1 Schedule 1 Appendix C Section 4 and Section 5, respectively. The aggregated value is then used to compare projects during Optimization.

Example 2: Pole Renewal

The mitigated risk value of $481.3MM for Multiple Pole Renewal projects as provided in response to interrogatory 2-Staff-85 Table 1, is the Net Present Value (NPV) of all pole investments for each Alectra Utilities' operating zone and outlined below in Table 1:

Table 1: Breakdown of Mitigated Risk for Transformer Renewal by Operating Zone

Project Code	Project Name	NPV Total Mitigated Risk ($MM)
152713	Pole Renewal - Central North (PA)	49.7
152715	Pole Renewal - Central South (PA)	112.9
152716	Pole Renewal - East (PA)	108.0
152717	Pole Renewal - Guelph (PA)	36.1
152712	Pole Renewal - West (PA)	174.6

Reliability is considered a benefit for scoring the value of projects and programs in capital investment planning optimization. However, Copperleaf's Predictive Analytics (PA) software considers all value scores as risks. For this reason, all capital investments developed using the PA software and included in response to 2-Staff-85 Table 1 indicate only risk values.

Alectra Utilities applies PA software for pole renewal, transformer renewal, switch renewal and switchgear renewal planning.

Alectra Utilities also wishes to clarify that upon exporting outputs from PA into Copperleaf for portfolio optimization, all the output values from PA are categorized under a single value, in this case, the risk value. As such, for Pole Renewal, Transformer Renewal, Switch Renewal and Switchgear Renewal investments, all value measures are represented as risk value measures.

Alectra Utilities applied Copperleaf's PA software for the development of pole renewal pacing options, discussed in detail in Exhibit 2A, Tab 1, Schedule 1, Page 320 – 324. Alectra Utilities established that the value drivers for the Pole Renewal program include: Reliability Risk, Safety Risk and Financial Risk mitigation. Details on each value driver are outlined below:

- Reliability Risk: Translation of average outage duration, customers impacted and lost load, into dollars
- Safety Risk: Exposure, severity and cost of public/employee safety event. Alectra Utilities applied a conservative assessment of low probability of occurrence with moderate impact.
- Financial Risk: Alectra Utilities assessed only the capital reactive replacement cost for the reactive replacement of the asset. Alectra Utilities applies a conservative financial risk assessment that did not include overtime or emergency premiums associated with reactive replacements.

To provide an illustrative example, Alectra Utilities provides a sample wood pole assessment which was part of Project 152716 – Pole Renewal (East).

Reliability Risk Value (Similar to Reliability Benefit outside of PA):

Since PA maps risks to time, Alectra Utilities utilized a failure rate formula for each asset class which is consistent with the Gompertz-Makeham Model used in Alectra Utilities Asset Condition Assessment (refer to *Appendix E - Asset Condition Assessment* for details). This failure rate is informed by age where an asset's age is augmented using condition factors.

For greater clarity, it is not a condition-based failure rate where condition factors directly map to probability of failure.

Step 1: Determine the probability of failure

PA utilizes augmented age to adjust the asset's age based on condition factors. For wood poles, augmented age adjustments are listed below in Table 2:

Table 2: Pole Asset Condition Parameters that impact Age

Remaining Pole Strength	<40%	<50%	<60%
Years added	30	20	10

Testing item	>2	>1
Depth surface decay [in]	30	15
Depth mechanical damage [in]	20	15

Inspection item	Major	Moderate	Minor
Pole Overall Condition	25	15	5
Pole Condition - Pole Leaning	10	5	0
Pole Condition - Top Decay	25	15	5
Pole Condition - Lightning/Fire Damage	25	15	5
Pole Condition - Insect Infestation	25	15	5
Pole Condition - Woodpecker Damage	25	15	5
Pole Condition - Cracks/Splitting	25	15	5
Pole Condition - Ground Line Rot	25	15	5
Pole Condition - Mechanical Damage	25	15	5

For the purposes of this illustration, failure is defined as the asset failure modes provided in Table 5.3.2-9.[2]

For this illustrative example, Alectra Utilities considers a 35-year-old wood pole that has remaining strength of 88% and moderate pole top decay.

[2] Exhibit 2A, Tab 1, Schedule 1, 5.3.2 Overview of Assets Managed, Page 175

Hence, the Augmented age of the pole is 35 plus 0 plus 15 for a total augmented age of 50 years. Based on the Gompertz-Makeham Model for poles with an EUL of 75 years, Alectra Utilities determined that this pole has a 75% probability of failure according to the augmented age failure curve.

<u>Step 2: Determining Load Lost per failure</u>

Alectra Utilities considered and applied that 1.6 MVA of load is lost per pole failure.

Load Lost (kW) = 1.6 MVA × [redacted]

<u>Step 3: Outage Duration</u>

Alectra Utilities considers each outage duration based on the specific asset outage statistics of the region. For this example, a wood pole outage duration of 1 hour is applied.

<u>Step 4: Value of Lost Load (VoLL)</u>

Alectra Utilities considers all poles to service mixed residential/commercial.

For this example, based on an outage duration of 1 hour and the residential/commercial customer mix a VoLL of [redacted] is applied.

<u>Step 5: Loss of Redundancy and Worst Performing Feeder</u>

For this example, Alectra Utilities applied a scenario where the feeder has no loss of redundancy and is not considered a Worst Performing Feeder.

<u>Step 6: Calculate Reliability Benefit Value</u>

Since the number of outages is based on the augmented age-based probability of failure, the benefit value per asset is only calculated if the asset has been statistically determined to reach failure within a given year. If deemed to have reached failure, the following Reliability Benefit calculation is performed as follows:

[redacted]

Where Asset Failing is the PA failure prediction binary variable, based on the probability calculation of failure based on output of Step 1. PA sets this to 1 if the asset is predicted to fail in that year or to 0 if the asset is not predicted to fail in that specific year.

If asset does not predict to fail within a specific year, its age is incremented and retested in the subsequent year in PA. This assessment continues to occur in PA until either the asset reaches failure or the projection window ends.

For this example, Alectra Utilities illustrates the scenario where the wood pole is predicted to fail, therefore:

[redacted]

Safety Risk Value:

The total safety risk value comprises the safety risk to employees or contractors and the safety risk to the public. The safety risk is evaluated using the following factors:

- the number of workers or members of the public at risk
- the likelihood factor, and
- the severity factor

To calculate the Safety Risk Value, the safety risk is multiplied by the consequence of safety event.

<u>Step 1: Baseline Risk</u>

For wood pole, the following numbers are used to calculate safety risk value:

- number of members of the public: 10
- number of workers: 1
- public safety risk likelihood factor: 1 in 10,000 years
- worker safety risk likelihood factor: 1 in 10,000 years
- public safety risk severity factor (minor injury): 0.5%
- worker safety risk severity factor (serious injury): 100%
- consequence of public safety event: $5,000,000
- consequence of employee safety event: $3,000,000

[redacted]

Step 2: Outcome Risk

The likelihood factor is reduced to zero upon pole replacement, therefore Alectra Utilities determines the [redacted]

Step 3: Calculate Safety Risk Value

[redacted]

Financial Risk Value:

This risk is based on the incurred cost to replace the pole reactively. For this example, Alectra Utilities assessed only the capital reactive replacement cost for the reactive replacement of the asset. Alectra Utilities applies a conservative financial risk assessment that did not include overtime or emergency premiums associated with reactive replacements. Pole replacement costs are provided in response to 2A-SEC-47 page 3, Table 2 – Unit-Cost.

For this example, the replacement cost for the wood pole is $34,000.

[redacted]

Aggregating the reliability risk, safety risk and financial risk of this illustrative example yields a total risk value for this asset of [redacted] value points.

The value of each pole assessed in PA is then aggregated at an operational region level. This process provides the NPV Risk Value listed in Table 1 above; the summation of each region produces the $481.3MM listed in 2-Staff-85 Table 1.

For additional details related to Alectra Utilities' application of risks and benefits utilized in Copperleaf, please see the explanation provided in Exhibit 2A Tab 1 Schedule 1 Appendix C. For a listing of individual investment value measures, please refer to SEC 2A-SEC-28, Attachment 1.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.14

Reference: 2-Staff-64, Excel Attachment for 2-Staff-64, Tables 3 and 4

On a best-efforts basis, advise why a number of transformers originally listed as fair and good moved to very good in 2023.

RESPONSE:

Asset condition assessment provides a snapshot of health of the asset population based on the underlying inspection data at a point in time. Several factors explain the observed changes between health index categories between the 2018 and 2023 condition assessments, such as:

- **Harmonized Inspection Practices and Improved Data Quality:** Inspection criteria and data capture practices have been standardized across Alectra Utilities in 2021 that were not available in 2018. The harmonization improved consistency and reliability of condition assessment. Assets that were previously uninspected or assessed with limited data are now being evaluated through structured inspection programs for transformers.
- **Changes in Asset Population:** While marginal, new assets have been added through capital programs and system expansion between 2018 and 2023 resulting in changes to the categorized population.

As requested, Alectra Utilities has reviewed the differences for the pole-mount transformer population between 2018 and 2023, in each condition category. Pole-mount transformers in the FAIR and GOOD categories declined from 13,032 in 2018 to 3,342 in 2023, while the VERY GOOD category increased from 18,076 to 27,395. However, this change in distribution does not indicate uniform improvement of transformer population. The comparison includes

7,693 pole-mount transformers that are no longer present in 2023 and 7,466 new pole-mount transformers appearing in 2023, confirming that the two assessment years do not represent an identical asset population.

For pole-mount transformers appearing in both years, movement occurred in both directions. Of the common population, 13,349 remained in the same health index category, 8,976 moved to a better category, and 2,105 moved to a worse category. The majority of both upward and downward movements between health index categories are associated with new inspection records obtained after 2018, indicating the observed changes are primarily driven by harmonized inspection practices and improved data quality.

The same pattern is evident for pole-mount transformers that were rated FAIR or GOOD in 2018, as presented in Table 1 below. Of those 10,316 pole-mount transformers that appear in both years, 8,619 moved to a better category, 747 moved to a worse category, and 950 remained in the same category. Most of the upward movement is tied to new inspection records after 2018, which indicates that many pole-mount transformers were reclassified in 2023 based on more complete and standardized condition information than was available in 2018. At the same time, some pole-mount transformers moved to worse categories, which confirms that the assessment process resulted in movement in both directions.

Table 1 - Reconciliation of Pole-mount Transformers Condition Categories (2018 vs 2023)

Description	Number of Pole-Mount Transformers	Explanation
Pole-mount Transformers appearing in both years (FAIR + GOOD)	**10,316**	Comparable population between assessments
Condition Improved	8,619	Reassessed to better HI category
Condition Declined	747	Reassessed to lower HI category
Stayed in same HI category	950	No condition change between assessments

Accordingly, the shift in asset condition categories between 2018 and 2023 reflects a combination of lifecycle dynamics, and additional inspection information obtained after 2018 through harmonized assessment practices resulting in changes to the assessed asset population. As a result, pole-mount transformers rated FAIR or GOOD in 2018 may appear in other categories in 2023 where assessment was informed by more complete and standardized inspection information.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.15

Reference: 2-Staff-97 (F)

Provide the estimated transformer renewal forecast split by transformer type including pole top, pad mount, or vault.

RESPONSE:

Alectra Utilities estimates it will replace 3,478 Padmount transformers, 331 Polemount transformers, and 962 Vault transformers during the 2027-2031 period under the Transformer Renewal investment.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.16

Reference: 2-Staff-104

On a best-efforts basis, provide the inputs used to calculate the benefit and risk values for one transformer renewal project from the first line of Table 1 on 2-Staff-104.

RESPONSE:

The mitigated risk value of $791.3MM for Multiple Transformer Renewal projects as provided in response to interrogatory 2-Staff-104 Table 1, is the Net Present Value (NPV) of all transformer investments for each Alectra Utilities operating zone and outlined below in Table 1.

Table 1 – Breakdown of Mitigated Risk for Transformer Renewal by Operating Zone

Project Code	Project Name	NPV Total Mitigated Risk ($MM)
152718	Transformer Renewal - Central North (PA)	221.0
152719	Transformer Renewal - Central South (PA)	138.5
152720	Transformer Renewal - East (PA)	332.1
152721	Transformer Renewal - Southwest (PA)	9.3
152722	Transformer Renewal - West (PA)	90.5

Alectra Utilities has already established that reliability is considered a benefit for scoring the value of projects and programs in capital investment planning optimization. However, Copperleaf's Predictive Analytics (PA) software considers all value scores outputs as risks. For this reason, all capital investments developed using the PA software and included in response to 2-Staff-104, Table 1 indicate only risk values. Alectra Utilities applies PA software for pole renewal, transformer renewal, switch renewal and switchgear renewal planning.

Alectra Utilities also wishes to clarify that upon exporting outputs from PA into Copperleaf for portfolio optimization, all the output values from PA are categorized under a single value, in this case, the risk value. Therefore, for Pole Renewal, Transformer Renewal, Switch Renewal and Switchgear Renewal investments, all value measures are represented as risk value measures.

Alectra Utilities applied Copperleaf's PA software for the development of transformer renewal pacing options, discussed in detail in Exhibit 2A, Tab 1, Schedule 1, Page 320 – 324. Alectra Utilities established that the value drivers for the Transformer Renewal program include: Reliability Risk, Safety Risk and Financial Risk mitigation. Details on each value driver are outlined below:

- <u>Reliability Risk</u>: Translation of average outage duration, customers impacted and lost load, into dollars.
- <u>Safety Risk</u>: Exposure, severity and cost of public/employee safety event. Alectra Utilities applied a conservative assessment of low probability of occurrence with moderate impact.
- <u>Financial Risk</u>: Alectra Utilities assessed only the capital reactive replacement cost for the reactive replacement of the asset. Alectra Utilities applies a conservative financial risk assessment that did not include overtime or emergency premiums associated with reactive replacements.

To provide an illustrative example of the calculations, Alectra Utilities provides a sample 3 phase padmount transformer assessment which was part of Project 152722 – Transformer Renewal (West).

Reliability Risk Value in PA (Similar to Reliability Benefit outside of PA):

Since PA maps risks to time, Alectra Utilities utilized a failure rate formula for each asset class which is consistent with the Gompertz-Makeham Model used in Alectra Utilities Asset Condition Assessment (refer to *Appendix E - Asset Condition Assessment* for details). This failure rate is informed by age where an asset's age is augmented using condition factor. For greater clarity, it is not a condition-based failure rate where condition factors directly map to probability of failure.

<u>Step 1: Determine Probability of Failure</u>

PA utilizes augmented age to adjust the asset's age based on condition factors. For transformers, augmented age adjustments are listed below in Table 2.

Table 2: Transformer Asset Condition Parameters that impact Age

Condition	Age Augmentation
Major Corrosion	set to EUL
Major Oil Leak	set to EUL
Moderate Oil Leak and PCB >2ppm	set to EUL
Delta TX	add 5 years
Live Front TX	add 10 years
Bushing Condition Damaged	add 10 years

For the purposes of this illustration, failure is defined as the asset failure modes as provided in Table 5.3.2-9.[1]

For this illustrative example, Alectra Utilities considers a three-phase 347/600V padmount transformer, supplying a commercial building, that is 33 years old and has a damaged with bushing identified.

Hence, the Augmented age of the transformer is 33 plus 10 years for a total augmented age of 43 years. Based on the Gompertz-Makeham Model for transformers with an EUL of 45 years, Alectra Utilities determined that this transformer has a 75% probability of failure according to the augmented age failure curve.

[1] Exhibit 2A, Tab 1, Schedule 1, 5.3.2 Overview of Assets Managed, Page 175

Step 2: Determining Load Lost per Failure

The lost load per transformer is based on transformer rating of the individual asset. For a 750kVA three-phase 347/600V padmount transformer:

Load Lost (kW) = 750kVA [redacted]

Step 3: Outage Duration

Alectra Utilities considers each outage duration based on the specific asset outage statistics of the region. For this example, a 3-phase transformer outage duration of 2 hours is used.

Step 4: Value of Lost Load (VoLL)

Alectra Utilities considers 120/240V single phase transformers as residential class only. 120/208V transformers are considered commercial and 347/600V transformers are considered as mixed use based on size but predominantly commercial/industrial.

For this example, the three-phase 347/600V padmount transformer supplies a commercial building. Based on an outage duration of 2 hours and the commercial customer mix, a VoLL of [redacted] is applied.

Step 5: Loss of Redundancy and Worst Performing Feeder

For this example, Alectra Utilities applied a scenario that the feeder has no loss of redundancy and is not considered a Worst Performing Feeder.

Step 6: Calculate Reliability Benefit Value

Since the number of outages is based on the augmented age-based probability of failure, the benefit value per asset is only calculated if the asset has determined statistically to reach failure within a given year. If deemed to have reached failure, the following Reliability Benefit calculation is performed as follows:

[redacted]

Where Asset Failing is the PA failure prediction binary variable, based on the probability calculation of failure based on output of Step 1. PA sets this to 1 if the asset is predicted to fail in that year or to 0 if the asset is not predicted to fail in that specific year.

If asset does not predict to fail within a specific year, its age is incremented and retested in the subsequent year in PA. This assessment continues to occur in PA until either the asset reaches failure or the projection window ends.

For this example, Alectra Utilities illustrate the scenario where the padmount transformer is predicted to fail, therefore:

[redacted]

Safety Risk Value:

The total safety risk value comprises the safety risk to employees/contractor workers and the safety risk to the public. The safety risk is evaluated using the following factors:

- the number of workers or members of the public at risk
- the likelihood factor, and
- the severity factor

To calculate the [redacted]

Step 1: Baseline Risk

For padmount transformer, Alectra Utilities illustrates the calculation with the following variables used to calculate safety risk value:

- Number of members of the public: 10
- Number of workers: 2
- Public safety risk likelihood factor: 1 in 10,000 years
- Worker safety risk likelihood factor: 1 in 1,000 years
- Public safety risk severity factor (minor injury): 0.5%
- Worker safety risk severity factor (serious injury): 100%
- Consequence of public safety event: $5,000,000
- Consequence of employee safety event: $3,000,000

[redacted]

Step 2: Outcome Risk

The likelihood factor is reduced to zero upon transformer replacement, therefore Alectra Utilities determines the [redacted]

Step 3: Calculate Safety Risk Value

[redacted]

***Financial Risk Value*:**

This risk is based on the incurred cost to replace the transformer reactively. For this example, Alectra Utilities assessed only the capital reactive replacement cost for the reactive replacement of the asset. Alectra Utilities applies a conservative financial risk assessment that did not include overtime or emergency premiums associated with reactive replacements. Transformer replacement costs are provided in response to 2A-SEC-47 page 3, Table 2 – Unit-Cost.

For this example, the replacement cost for a three-phase padmount transformer is $25,000.

[redacted]

Aggregating the reliability risk, safety risk and financial risk of this illustrative example yields a total risk value for this asset of [redacted] value points.

The value of each transformer assessed in PA is then aggregated at an operational region level. This process provides the NPV Risk Value listed in Table 1 above; the summation of each region produces the $791.3MM listed in 2-Staff-104 Table 1.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.17

Reference: JT-1.24, 2-AMPCO-21, 4-Staff-41

Reconcile the numbers used in the table in 4-Staff-41 with the information provided in undertaking JT-1.24.

RESPONSE:

Please refer to the response of JT-1.24 and Table 1 in 4-Staff-171.

As discussed in JT-1.24, Alectra Utilities applies a minimum labour hours constraint in capital portfolio optimization to ensure the optimizer balances workload across the portfolio and does not cluster labour-intensive capital work into a single year. The annual minimum labour constraint of 195,600 hours is 80% of the hours of work available for capital projects for the Lines construction crews in 2024.

Table 1 in 4-Staff-171 presents positions added over the 2025-2031.

The two data sets are not reconcilable for the following reasons:

1. The setting of the minimum hours constraint in the capital portfolio is based on information from 2024 and is kept constant across the capital optimization period to ensure a balanced workload and to prevent clustering labour-intensive capital work into a single year.
2. The minimum labour hours constraint is only related to a subset of positions within the organization, namely construction crews that work on capital projects. Whereas, Table 1 in 4-Staff-171 presents the proposed positions to be added over the 2025-2031 period for the entire organization.

The foregoing is appropriate because growing the capital labour and determining how to grow (i.e., via contractors vs internal crew) is performed after the optimization outcome is produced (i.e., in the work execution plan), rather than by forcing this as an input (constraints) to optimization. The minimum (80%) of 2024 staff ensures a minimum utilization of existing crew.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.18

Reference: 2-Staff-97 Page 3 Line 22

Provide a table summarizing the number of spills reported to the MOE per year and the equipment that failed, including oil-insulated switches.

RESPONSE:

Table 1 below summarizes the total number of spills reported to the Ministry of the Environment, Conservation and Parks (MECP) from 2020-2025, for transformers, oil-insulated switchgear and vehicles. This includes Alectra Utilities-reported spills that meet the provincial and federal reporting requirements, as well as reports made to the MECP by third-parties such as municipalities or customers notifications which did not meet the provincial and federal reporting requirements (e.g., oil volume of equal or greater than 100L).

Table 1 - Annual Report Spills to the MECP

Year	Total Reported Spills
2020	114
2021	143
2022	147
2023	48
2024	19
2025	14
Total	**485**

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.19

Reference:

Provide the amount of money spent in the historic period on spill remediation and where that is included in the OM&A budget.

RESPONSE:

Spill remediation expenditures averaged $0.93MM per year over the 2020-2025 period. These amounts are included in the maintenance budget under “Underground Inspection & Maintenance – System Reactive Repairs and Trouble Calls”.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.20

Reference:

Provide the forecast expenses for spill remediation included for the forecast period and where that is included in the Maintenance budget.

RESPONSE:

The forecast expenses for spill remediation total $1.34MM over the 2027-2031 period, as summarized in Table 1. This expense is included in the maintenance budget under “Underground Inspection & Maintenance – System Reactive Repairs and Trouble Calls”.

Table 1 - Environmental Remediation Costs 2027-2031

Expense	2027	2028	2029	2030	2031	2027-2031 Total
Environmental Remediation	$0.26M	$0.26M	$0.27M	$0.27M	$0.28M	$1.34M

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.21

Reference:

Advise whether Alectra has a strategy or plan for seeking third-party funding in relation to NWS programming as a whole, including any correspondence or plans to engage with relevant funding bodies.

RESPONSE:

Alectra Utilities does not have a standalone strategy or formal plan for seeking third-party funding in relation to NWS programming as a whole.

Alectra Utilities does not assume third-party funding as a prerequisite to establishing the viability of NWS programming. NWS programs would be evaluated based on their standalone economics and customer value.

Where third-party funding becomes available, Alectra Utilities would assess it on a case-by-case basis and, where appropriate, use it to provide incremental customer value, including by supporting additional capabilities, improving program economics, or reducing costs that might otherwise be funded through rates.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.22

Reference:

Provide a breakdown of the improvements listed from line 14 to 19 in 1-Staff-5C by forecasted spending year over year from 2027 to 2031.

RESPONSE:

Alectra Utilities prioritizes oversight of serious electrical incidents (SEI) through structured incident reporting, root-cause analysis, and asset performance monitoring processes. These processes provide Alectra Utilities with an understanding of the drivers behind electrical safety events and inform risk-based decision-making. Alectra Utilities recognizes that the top five categories impacting SEI events, which account for 88% of all SEI incidents, include:

- Failed Equipment
- Tree Contacts
- Adverse Weather
- Motor Vehicle Accidents
- Animal Contacts.

Proposed capital investments in Alectra Utilities' DSP that contribute to mitigating SEI incidents include replacement of deteriorated and undersized overhead conductors and accessories, deteriorated poles, as well as leaking or corroding transformers. Replacement programs that incorporate trends in condition and reliability, along with elements of system hardening, are designed to proactively reduce exposure to known electrical hazards. Additionally, renewing infrastructure with assets compliant with present-day standards mitigates incidents from animal and tree contacts (e.g., pole heights based on present-day standards improve clearances to the tree line and vegetation).

While these investments collectively contribute to improved safety outcomes, the relationship between individual capital programs and SEI incident reductions is not one-to-one. Many investments are designed to address multiple risk drivers simultaneously (e.g., reliability, safety, and capacity), and a single SEI outcome may be influenced by multiple asset classes and programs working in combination..

Table 1 provides a breakdown of investments pertaining to lines 14 through 19 of Interrogatory 1-Staff-5C.

Table 1 – Forecasted Annual Expenditures for the Requested Capital Investments

	Planned Expenditures ($MM)				
Project Group (System Renewal)	**2027**	**2028**	**2029**	**2030**	**2031**
Overhead Rebuilds (#6 Copper Wire Replacement and Overhead Conductor Upgrades)	6.7	6.8	11.2	16.2	20.6
Overhead (Insulator Replacement)	0.0	0.0	0.5	0.5	0.5
Pole Remediation	23.1	26.5	29.6	35.1	36.7
Voltage Conversion	12.5	8.5	25.1	18.7	24.0
Rear Lot Conversion	0.0	0.0	20.3	32.7	33.6
Transformer Renewal	16.7	20.6	22.5	29.8	30.5

Note: Immaterial variances due to rounding.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-2.23

Reference: 1-SEC-19 Table 1

Provide a version of Appendix 2K that has the GRE&T Centre direct labour costs and equivalent FTEs taken out or information that would allow it to be done in the format of Appendix 2K.

RESPONSE:

Please see the table below which provides shareholder-funded portion of the GRE&T Centre's direct labour costs and equivalent FTEs in the format of Appendix 2K.

Table 1 - Shareholder-funded Portion of the GRE&T Centre's Direct Labour Costs and Equivalent FTEs

Details of Components	2027	2028	2029	2030	2031
Number of Employees (FTEs including Part-Time)					
Management (non union including executive)	19	19.5	20	20	20
Non-Management (union)	0.00	0.00	0.00	0.00	0.00
Total	19	19.5	20	20	20
Total Salary and Wages including overtime and incentive pay ($MM)					
Management (non-union including executive)	2.09	2.04	2.20	2.31	2.41
Non-Management (union)	0.00	0.00	0.00	0.00	0.00
Total	**2.09**	**2.04**	**2.20**	**2.31**	**2.41**
Total Benefits (Current + Accrued in $MM)					
Management (non union including executive)	0.47	0.46	0.50	0.52	0.55
Non-Management (union)	0.00	0.00	0.00	0.00	0.00
Total	**0.47**	**0.46**	**0.50**	**0.52**	**0.55**
Total Compensation (Salary, Wages, & Benefits in $MM)					
Management (non union including executive)	2.56	2.50	2.70	2.83	2.96
Non-Management (union)	0.00	0.00	0.00	0.00	0.00
Total	**2.56**	**2.50**	**2.70**	**2.83**	**2.96**

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-2.24

Reference: 4-CCC-43 and Table 6

Referring to 4-CCC-43, Table 6, provide the total number of call volumes for 2025.

RESPONSE:

Table 1 provides an overview of total customer interactions by type.

Table 1 - Total Customer Interactions by Type

Inquiry Type	2025 Actuals
Customer Call Interactions	535,795
Customer E-Mail Interactions	138,530
Web Chat (introduced in 2026)	0
Chat Bot	9,247
Automated moves	15,087
Total Customer Inquiries	698,659

Total 2025 actual customer interactions were 12% lower than the 2025 forecast, due primarily to lower call volumes and automated moves, partially offset by higher email volumes. Below is an explanation of key drivers of the variance.

Call volumes were 18% lower than the 2025 forecast, primarily due to a decline in customer inquiries following the stabilization of the new MyAlectra customer portal, as well as the direct impact of the Canada Post strike. The mail disruption from September to November 2025 prevented the issuance of collection notices and led to the early suspension of residential disconnections in October 2025. This, in turn, significantly reduced collections-related calls, from customers regarding overdue balances, payment arrangements, and reconnections.

Higher collection-related call volumes are anticipated in 2026, consistent with increased customer arrears year-over-year, as customers respond to higher overdue balances and the resumption of summer disconnection activities.

Email volumes were 45% higher than the 2025 forecast, driven in part by the mail disruption and changes to the moves process, which required customers to submit account verification documents via email when not included on the automated form submission.

Automated move transactions were 63% lower than the 2025 forecast due to the delay in the applications implementation from Q1 to Q4. Chat bot functionality was introduced in Q4, resulting in 9247 customer interactions.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-2.25

Reference: 1-SEC-24, Attachment 5 Appendix 2-JC

Referring to 1-SEC-24, Attachment 2-JC, explain the variances between the actuals and the forecast for 2025 for Digital, Innovation, Operations, and Sustained.

RESPONSE:

For the Digital & Innovation program variances between 2025 actuals and 2025 forecast, please refer to undertaking JT-2.35.

In 2025, Operations program expenditures were $3MM less than what was forecast. This is primarily due to direct labour costs being lower than the Forecast Budget by $2.4MM, largely because of vacancies in Program Delivery (PDG), System Control and Stations. Vacancies in PDG are in the process of being filled. System Control and Stations vacancies are explained in undertakings JT-2.5 and JT-2.7, respectively. Additionally, outside service providers related to cable locates were lower than the forecast budget by $0.4MM.

The overall upward variance of $10.2MM in 2025 actuals compared to the 2025 forecast budget for the Sustainment program is due to the following variances within Fleet, Facilities, Overhead Inspections and Maintenance, Underground Inspections and Maintenance, and Vegetation Management:

- <u>Facilities</u>: The upward variance of $2.4MM was mainly due to the removal of fuel tanks, additional security due to unusually high copper thefts and extra offsite snow haulage costs for winter snow removal.
- <u>Fleet</u>: The upward variance of $1.6MM was incurred because of additional repairs due to aging Fleet assets as well as additional fuel costs.

- Overhead Inspections and Maintenance: The variance of $0.6MM is primarily due to additional Asset Inspection costs resulting from PCB sampling due to missing legacy utility records to confirm compliance with the Canadian Environmental Protection Act's PCB Regulations in advance of the deadline to remove units with PCB concentration over 50ppm from service. This increase was partially offset by lower direct labour costs due to vacancies.
- Underground Inspections and Maintenance: The variance of $5.1MM is due to the System Reactive Repairs and Trouble Calls segment which was $5.6MM higher than forecast primarily due to a higher incidence and cost to repair of primary and secondary cable failures. Alectra's primary and secondary cable failure repair cost was $4.7MM higher than forecast, and Alectra experienced a 17% increase in cable related outages in 2025 over 2024 levels.
- Vegetation Management: An explanation of the $0.6MM variance in Vegetation Management has been provided in Alectra's response to JT-2.6.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT-2.26

Reference: 1-SEC-12, Attachment 1

Advise whether the reference to being "incremental" refers to being incremental to the Framework Initiatives tab in 1-SEC-12 or to all of the tabs.

RESPONSE:

The word “Incremental” in the title of Table 1 of IRR 4-STAFF-177 “Table 1: Annual Incremental Productivity Savings by initiative ($MM)” is used to describe that the savings listed in the table are in addition to those savings listed in the 1-SEC-12_Attachment 1_Framework Initiatives. The savings in Table 1 are in addition to the savings in all tabs of the 1-SEC-12_Attachment 1_Framework Initiatives.

Please refer to 4-staff-177_Attach_1 Incremental Customer service initiatives Tab “i” for a reconciliation of table 1 and the 1-SEC-12_Attachment 1_Framework Initiatives.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT-2.27

Reference: 2A-SEC-53, Attachment 1, Page 3

Referring to 2A-SEC-53, provide a full calculation of the comparison of the 2027 revenue requirement of Option 3 relative to Option 2.

RESPONSE:

Please see JT-2.27 Attachment 1 (Original Calculation) and JT-2.27 Attachment 2 (Updated Calculation) where Alectra has provided an updated proforma model based on the actual cost of the Kennedy project and assuming the proceeds of sale are not returned to customers as outlined in the response to interrogatory 2A-SEC-53 (d).

Alectra would like to clarify that the original model calculation of revenue requirement underlying the 2019 options analysis presented in the response to interrogatory 2A-SEC-53, b), had the net gains on the sales of Mavis and Sandalwood modelled to be given back to customers. However, for the reasons documented in 2A-AMPCO-45, the costs and timeline associated with the Kennedy Operations Centers exceeded the initial assumptions resulting in Alectra having to self-fund approximately $14 million pre-tax between 2019-2026 to carry out this initiative. To mitigate these financial losses, Alectra relied on the net gains of Mavis and Sandalwood, which is $18.7 million pre-tax. Please note that in the response to interrogatory 2A-SEC-53 (f) the net gains on sale of Mavis and Sandalwood are shown as totalling $15.8 million on pre-tax basis which is the $18.7 million pre-tax gain less additional lease costs of $1.2 million and moving costs of $1.7 million which have been included in the $14 million of incurred costs.

In comparing the Kennedy Operations Center to the Mavis redevelopment option, it is also key to note that Kennedy provides long-term value to customers by unlocking a host operational, safety, and employee benefits, which would not have been possible to achieve at Mavis due to the limitations of the property and its less optimal location. These benefits notably include:

- efficient and effective use of space (i.e., a reduction in overall square footage – Kennedy at 215,000 square feet vs. Mavis/Sandalwood at 256,000 square feet);
- lowered operating costs of approximately $1.4 million annually as per 1-SEC-12_Attach 1_Framework Initiatives.xlsx;
- reduction of 21 fleet vehicles;
- ability to dispatch crews more efficiently when responding to emergency situations in both Brampton and Mississauga resulting in avoided outage duration benefits for customers;
- ability to cross train staff more effectively by having staff in one location;
- better flexibility to deal with priority issues in each city by coordinating larger crew assignments across the region;
- more effective prioritization of Fleet repairs by combining staff (e.g., reduced a Mechanic position within the Fleet Department);
- mitigated safety risks by having a separate Fleet repair area from the internal parking garage and warehouse; and
- secured industrial space (with outside storage) in a centralized location to efficiently service customers in a market with very limited supply.

In Attachment 2, Alectra has provided an updated proforma model which accounts for the actual costs of the Kennedy Operations Center and updated the treatment of proceeds as noted above. This evidence (summarized in Table 1 below) demonstrates that the Mavis redevelopment (Option 2) and the Kennedy project (Option 3) have a comparable revenue requirement impact for customers in 2027. However, the analysis provided in the updated financial model does not account for the productivity benefits that Alectra achieved through the Kennedy Operations Center, as outlined in Exhibit 1, Tab 6, Schedule 4 at page 14 (e.g., reduction of 21 Fleet Vehicles). Table 1 below shows that when these quantified productivity benefits are considered, the Kennedy option is clearly more favourable for customers compared to the Mavis redevelopment alternative.

1 **Table 1 – Updated Options Analysis of Kennedy Operations**

Updated Proforma Model with Kennedy Actual Costs		
$ Million	**Mavis Retrofit**	**Kennedy**
Revenue Requirement in 2027	$ 13.2	$ 13.1
Other Productivity Benefits	-	$ (0.3)
Total Projected Revenue Requirement	**$ 13.2**	**$ 12.8**

JT-2.27

Attachment 1
OP Centre Original Model

Please see live Excel

JT-2.27

Attachment 2
OP Centre Updated Model

Please see live Excel

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT-2.28

Reference: 4-CCC-43 Table 9

Provide the internal FTEs that are directly related to the call centre, including the supervisors and managers.

RESPONSE:

In 2025, there were 67 FTEs directly related to the call centre as shown in Table 1. 3 other FTE's in the segment were in roles not directly related to the contact center but are included in the Customer Care segment's total. These roles, support market research and insights, and provide support to the customer ombudsman function. The 8 positions associated with the director, manager, supervisor and specialist line items provide supervisory, work management, and data analytics support to the overall contact center, including third-party agents.

Table 1 - Contact Centre FTEs

FTE Type	2025
Customer Service Representatives	59
Call Center Director/Manager/Supervisors	6
Specialist, Customer Care Reporting & Analytics	1
Specialist, Workforce Management	1
Contact Center Internal FTE's	**67**
Customer Solutions and Market Insights FTE's	3
Customer Care Headcount	**70**

Alectra does not contemplate increasing the proportion of contact centre operations delivered by third parties, including customer service representative functions or any component of management accountabilities. The operation and oversight of the contact centre are core organizational functions and will continue to be primarily performed and maintained by internal resources.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT-2.29

Reference: 4-CCC-44

Add the number of bills by type to the table at 4-CCC-44 showing the number of E-bills and paper bills.

RESPONSE:

Please see Table 1 below for the total number and cost of e-bills and paper bills.

Table 1 - Total Paper and e-Bills and Costs

	Total Bills	Cost For e-Bill ($)	Cost for Paper Bill ($)	Total ($)	Number of Paper Bills	Number of e-Bills
2021	13,447,326	216,192	10,161,907	10,378,099	9,586,756	3,860,570
2022	13,478,174	254,863	10,003,190	10,258,053	8,927,056	4,551,118
2023	13,574,461	284,834	9,801,347	10,086,182	8,488,137	5,086,324
2024	13,783,989	317,101	9,698,969	10,016,069	8,121,479	5,662,510
2025	13,841,268	370,949	10,957,289	11,328,238	7,217,178	6,624,090
2026	13,974,273	410,103	10,477,533	10,887,636	6,651,000	7,323,274
2027	14,109,939	464,739	8,863,982	9,328,721	5,811,023	8,298,916
2028	14,392,138	494,609	8,668,160	9,162,769	5,559,834	8,832,303
2029	14,679,980	529,945	8,318,338	8,848,283	5,216,673	9,463,307
2030	14,973,580	558,510	8,154,051	8,712,562	5,000,179	9,973,401
2031	15,273,052	579,860	8,199,554	8,779,415	4,918,407	10,354,644

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

JT-2.30

Reference: 4-AMPCO-46D and Exhibit 2, Tab 1, Schedule 1 of Appendix B09 page 338

Confirm the ratio of 536 vehicle units to 534 FTEs by the end of 2031 for the lines and stations protection and control divisions.

RESPONSE:

The total Fleet units originally stated of 462 included other departments (Metering, etc.) and should have been reported as 384 for the Overhead Inspections & Maintenance and Stations programs. Thus, the ratio should have been stated as 0.9 to 1 (Fleet units to Operations, Overhead Inspections & Maintenance and Stations FTE). Operations, Overhead Inspections & Maintenance and Stations FTE are projected to grow to 534 by 2031 and the additional Fleet units required to support the growth in FTE is 74 units, thus the projected ratio of Fleet units to FTE will be slightly lower at 0.86 to 1 in 2031.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION

JT-2.31

Reference: 2A-EP-8, Page 2, Answer C and Exhibit 2A, Tab 1, Schedule 1, Exhibit 5.4.1 page 361

Advise whether customers that own an exporting distributed energy resource require a special higher cost connection.

RESPONSE:

The connection cost of a DER of a certain size is not impacted by whether the DER is exporting or not. Tables 1-3 in Interrogatory Response 8-ED-48 provide DER connection costs by size. DER connection costs are dependent upon factors such as generation size, type of metering required, and whether facilities such as a SCADA connection or Direct Transfer Trip are required. Whether a DER is exporting or not, connection costs are fully borne by the prospective DER, and not by the rest of the Alectra customer base.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION

JT-2.32

Reference: Exhibit 2A, Tab 1, Schedule 1, Exhibit 5.4.1 Page 362

Advise whether the SCADA and Automation line in Exhibit 2A, Tab 1, Schedule 1, Table 5.4.1 includes any software.

RESPONSE:

The SCADA and Automation line in Table 5.4.1 – 8 in Exhibit 2A, Tab1, Schedule 1 does not include any software. Investments in the SCADA and Automation portfolio are described in detail in Exhibit 2A, Tab 1, Schedule 1, Appendix B14 – Enabling Resiliency and Modernization. Table B14-3 in this Appendix lists these investments. These investments are for the deployment of automated devices, sensors, and fault indicators that will be monitored and controlled by the SCADA system.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION

JT-2.33

Reference: Exhibit 2A, Tab 1, Schedule 1, Exhibit 5.4.1 Page 362

Advise whether the information technology line on Exhibit 5.4.1 includes any expenditures for software for operating and dealing and collecting data from distributed energy resources.

RESPONSE:

Yes.

The information technology line on Table 5.4.1 – 8 on page 362 of Exhibit 2A, Tab 1, Schedule 1 includes one investment related to the collection of data from Distributed Energy Resources (DER)[1]: the "DER Wholesale Market Preparedness" (DWMP) project, with a budget of $2.03MM in the 2027 – 2031 period.

DWMP will not monitor, operate or control DERs. The project is intended to enable coordination and information exchange between Alectra Utilities and the IESO and to support the participation of DER in wholesale markets. The DWMP project will facilitate functions such as resource registration, qualification, data exchange, coordination of resource activity, and settlement processes associated with DER participation in Wholesale Markets.

Please refer to Exhibit 2A, Tab 1, Schedule 1, Appendix B14 – Enabling Resiliency & Modernization, Section IV for additional information about DWMP.

---

[1]As defined in the IESO Transmission-Distribution Coordination Working Group (TDWG) Glossary of Working Terms and Definitions (Revised Draft, May 2024): https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/tdwg/TDWG-20240531-B4-Working-Terms-and-Definitions.pdf

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.34

Reference: 4-Staff-178C page 3 and 4-Staff-177C; Table 6

Provide a reconciliation of the CIS Integration costs in 2025 between 4-Staff-177c and 4-Staff-178c.

RESPONSE:

The $0.37 million referenced in Table 6 of 4-STAFF-177c represents budgeted OM&A integration costs for the Guelph CIS project. This budget was developed as part of the 2020 OM&A transition budget that was carried forward for tracking of merger synergies.

In preparation of this response, it was identified that the $0.7 million referred to in 4-Staff-178, related to the Guelph CIS budget, was incorrectly classified as OM&A in the budget and should have been classified as capital. These amounts were correctly recorded as actual capital costs in 2025.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT-2.35

Reference: JT-2.25

Provide a segment-level breakdown of the $4 million variance for the digital innovation program in 2025 and provide comments on the impact of that underspending on 2026 forecast costs.

RESPONSE:

Table 1 – 2025 OM&A Variances Between Actual and Forecast by D&I Segment ($MM)

Segment	2025 Forecast	2025 Actual	Variance
Product Management	19.99	18.65	(1.34)
GRE&T Center	3.49	2.88	(0.61)
Cyber Security	3.71	3.21	(0.49)
D&I Business	6.23	6.38	0.16
IT Operations	16.27	14.56	(1.71)
Total	49.68	45.69	(3.99)

The $3.99MM variance between 2025 forecast and actual OM&A for the Digital & Innovation (D&I) program is primarily attributable to a combination of one-time cost reductions and timing-related variances across multiple D&I segments.

A key driver of the variance relates to lower-than-anticipated licensing costs. This included lower IVR licensing requirements due to reduced customer call volumes during the winter disconnection ban period; and avoided annual renewal and third-party support costs within IT Operations as Alectra transitioned away from its previous hypervisor standard.

The remaining variance is largely due to the timing of planned initiatives. Several projects experienced delays or shifts in start dates, including Alectra's Disaster Recovery Planning consulting engagement, the expansion of Alectra’s Security-as-a-Service (SECaaS) service, and certain core and operational technology initiatives. Additionally, adjustments to the Water Billing Exit project timeline contributed to lower consulting expenditures in 2025.

These timing shifts resulted in reduced reliance on external consulting, staff augmentation, and project support resources within the year. Importantly, there were no material scope reductions associated with these variances, and all planned initiatives remain in scope.

Impact on 2026 Forecast Costs:

The 2026 forecast will not experience cost pressure arising from the 2025 variance and continues to support the planned delivery of the Digital & Innovation program. The 2025 variance is largely made up of timing-related changes. Where activities were deferred, the activities and their associated costs will be incurred in 2026. Where savings have been achieved, these will be offset by the 2025 deferred cost increases and other program cost pressures (i.e.: software licensing).