

**RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO
PRE-SETTLEMENT QUESTIONS**

AMPCO-1

Reference: JT1.12

a) For each of the projects in JT1.12, please provide an explanation for the variance in the final project cost compared to the estimate.

b) For each of the projects with an SPI >90 days, please provide an explanation.

RESPONSE:

a) Table 1 below provides the variance explanation for differences between final projects costs compared to the estimated costs in JT1.12 attachment 1.

Table 1 – Explanation of variances

Project Name	Variance Explanation
Rathburn Rd W Cable Replacement	Insufficient clearance to existing utilities required excavation to be open cut (originally planned for directional drilling), resulting in more effort and restoration costs.
October Dr URD (St. Catharines)	Delayed start due to very late locates pushed work into winter conditions, which resulted in temporary restoration costs and pushed contracted work into following year's rates.
John Sub. Conv. 2019 - Ph 2, Part 1	Multiple changes on Hatt St required during construction by City of Hamilton required extra scope.
Mountain URD - Phase 2 - (North)	Extra cost due to relocations and scope changes required by municipality during construction. Higher labour due to multiple crew demobilizations to manage other reactive system repairs that occurred during the project duration.
Celtic Dr - 8 kV Conv. - Phase 2	Extra labour due to Union gas requirements to manually jackhammer sidewalks near gas lines rather than using backhoe at multiple locations.
Central Conversion - Phase 8	Additional civil and electrical contractor work required for transferring customer services and due to underground conflicts with other utilities. Restoration was

Project Name	Variance Explanation
	underestimated. Materials inflation due to duration between estimation and start date contributed to material cost overages.
331X_Part 2	Unanticipated bedrock removal required.
Baldwin Conversion - Civil Work	Conflicts with unidentified sanitary lines, realigned trenching, shoring work due to deeper excavation requirements.
Bum81 Feeder Extension Part 1 - South of Carlton (St. Cath), 3	Additional costs due to underground conflicts, Bell structure relocation and challenging stringing conditions.
452642 (WO 315651) Rutherford Road (Westburne Drive to Confederation PKWY), Vaughan	Dewatering costs and unexpected rocky ground conditions.
Ontario Street (Rr#42) - Roadway Re-Construction	Some required materials and a grade conflict at one pole location were missed on original design.
Berkley Cable Replacement 2022	Issues working around watermain, additional vacuum excavation and directional drilling work required.
636653 - 2023 Cable Injection - M25 - 14th-McCowan-Steeles-Old Kennedy	Higher contracting costs due to partial completion under new contract terms.
Central Conversion - Phase 7A	Higher than expected charges from City of Hamilton for permanent restoration work.
Stonechurch & Upper Paradise Cable Replacements (Part 1)	Scope changes due to customer location conflicts. Overtime and additional work to manage customer interruptions.
642680 - 2023 Cable Injection - M21 - Hwy 7 - Markham - 16th - McCowan	Higher contracting costs due to partial completion under new contract terms.
642682 - 2022 Cable Injection - M19	Higher contracting costs due to partial completion under new contract terms.
2024 Pole Renewal - Wilkinson Rd - Grid I5 Phase 1	Crew time and contractor support underestimated.

Project Name	Variance Explanation
2025 Pole Rebuild - Hwy 410	Working in narrow right of way caused unanticipated challenges due to vehicles needing to stage and operate in single file.
Baker St & Chapel Ln Underground Reconstruction	Redesign due to cancelled adjacent condominium project during construction. Significant increases in contractor costs due to incorrect grading provided by the City, requiring rework of structures already installed. Discovery of an abandoned underground tunnel and oil tank required significant extra cost to remediate. Location conflicts and poor locate quality required realignment of trenching. Installation of additional duct runs were required due to changes in customer requirements during construction.
Underground 27.6 kV Cable Relocation 200 Kennedy Road	Unexpected rocky ground conditions and need for generator support and accompanying overnight work.
Customer Initiated System Expansion - Bram East - Phase 4	Contracting work was higher than estimate and some services were not initially estimated for - primarily for a significant amount of tree removal/trimming and staking services. Unforeseen rocky ground conditions required extra effort for pole installations and changes to materials for anchoring. Changes to municipal permit requirements at construction start as well as unplanned road closures restricted the extended hours originally anticipated and impacted project duration.

1

2 b) Table 2 below provides explanations for the projects with an SPI >90 days.

3

4 **Table 2 – Finish Delay Explanation for Projects with SPI >90 Days**

Project Name	Finish Delay Explanation
October Dr URD (St. Catharines)	Delayed start due long delay for locates preventing excavation starting (approximately 4 months).
John Sub. Conv. 2019 - PH 2, PART 1	Delayed start due to Municipal Consent/Public Utility Coordination Committee Permit delays, temporary delay from March-May 2020 during construction due to provincial COVID-19 shutdown
Mountain URD - Phase 2 - (North)	Start delayed two months due to MC/PUCC Permit changes requested by Municipality. Short delay during project due to blocked ducts requiring additional work for which locates were delayed in completion.
Central Conversion - Phase 8	Delayed due to multiple utilities conflicts requiring redesign and requirements to complete work at night due to traffic and working around customer schedules for interruptions.
331X_Part 2	Delayed due to bedrock preventing directional drilling and conflicts with water main locations.
Baldwin Conversion - Civil Work	Delayed start due to MC/PUCC Permit delays, changes to running lines and redesign due to municipal requirements for clearance from previously unidentified storm and sanitary lines.
452642 (WO 315651) Rutherford Road (Westburne Drive to	Late start to civil work due to Municipal permit delays (approximately 5 months). Slow progress due to dewatering requirements during pipe ramming work.

Project Name	Finish Delay Explanation
Confederation PKWY), Vaughan	
Baker St & Chapel Ln Underground Reconstruction	Delays due to waiting for grading layout from Municipal surveyors, uncovering abandoned and unmarked oil tanks below grade, delays of approximately 4 months for materials due to recertifying pad switches that did not pass initial acceptance tests at manufacturer site.
Customer Initiated System Expansion - Bram East - Phase 4	Slow hydrovac excavation due to rocky ground conditions below grade. Delays due to emergency road closure occurring on approved excess load permit route. Unexpected soft ground conditions required swamp mats to be installed before crane could set up for pole installations. Minor rework due to replacing incorrect pole plates used by contractor.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

PRE-SETTLEMENT QUESTIONS

AMPCO-2

Reference: JT1.12 and JT1.21, Attachment 2

With respect to the Bunting M81 Feeder Extension project, please explain the difference between the planned and actual project costs shown in JT1.12 and in the project close out report in JT1.21, Attachment 2.

RESPONSE:

Bunting M81 Feeder Extension project consists of multiple phases of work. JT-1.21 Attachment 2 discusses the full project cost, which includes all phases of work. JT-1.12 includes only Phase 1 (South of Carlton) as other individual phases did not meet the variance requirements of the undertaking.

**RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO
PRE-SETTLEMENT QUESTIONS**

AMPCO-3

Reference: 1-AMPCO-14

- a) With respect to Capital, please show Other \$ and Contribution \$ separately. In the response provide a breakdown of Other \$.
- b) With respect to Capital, please explain the doubling of vehicle costs in 2026 compared to 2025 actuals. Please explain the increase of an additional \$13.1 million in 2027.
- c) With respect to OM&A, please provide a breakdown of Other \$ in each year.
- d) Please provide an updated excel file.

RESPONSE:

- a) Table 1 below shows 'Other \$ and Contribution \$' separately.

Table 1 – Baseline Costs

Capital (\$MM)	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual
Other \$	-	4.3	3.4	3.9	5.6	2.5	2.9
Contributions \$	(44.3)	(79.7)	(72.9)	(72.4)	(139.4)	(134.1)	(164.2)
TOTAL Other \$ / Contributions \$\$	(44.3)	(75.4)	(69.5)	(68.5)	(133.8)	(131.6)	(161.3)
Capital (\$MM)	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	
Other \$	-	-	-	-	-	-	
Contributions \$	(171.4)	(148.1)	(133.2)	(137.1)	(135.6)	(165.5)	
TOTAL Other \$ / Contributions \$\$	(171.4)	(148.1)	(133.2)	(137.1)	(135.6)	(165.5)	

Other costs represent expenditures that do not directly relate to the prescribed categories in the requested structure. These costs have been presented separately to ensure completeness and reconciliation of the total. Overall, these expenditures are primarily related to financing costs associated with capital investments and represent less than 1% of the total gross expenditures and are immaterial in nature.

b) The increase in vehicle costs in 2026 compared to 2025, and the increase in 2027 compared to 2026 is primarily due to increased planned vehicle purchases to support the accelerated capital work program. Please refer to *Appendix B08 - Fleet Renewal Exhibit 2 Tab 1 Schedule 1 Page 319 to Page 320* for vehicle expenditures and corresponding unit details.

c) The tables below show a breakdown of OM&A Other \$ in each year.

Table 2 – OM&A Other Breakdown

	2019	2020	2021	2022	2023	2024	2025
IST Licenses and Maintenance	\$ 14.7	\$ 12.8	\$ 14.9	\$ 15.8	\$ 17.5	\$ 18.3	\$ 19.9
Employee Training, Travel and Admin	\$ 12.1	\$ 11.5	\$ 10.8	\$ 11.5	\$ 13.5	\$ 12.9	\$ 13.4
Postage and Delivery	\$ 10.4	\$ 11.8	\$ 11.2	\$ 11.0	\$ 10.8	\$ 10.7	\$ 12.0
Repairs and Maintenance	\$ 9.8	\$ 12.7	\$ 14.7	\$ 14.3	\$ 14.5	\$ 15.1	\$ 15.3
Credit Losses	\$ 7.0	\$ 27.4	\$ 19.5	\$ 12.2	\$ 5.9	\$ 6.4	\$ 8.5
Property Taxes	\$ 5.0	\$ 4.9	\$ 4.2	\$ 4.2	\$ 4.6	\$ 5.1	\$ 5.3
Insurance	\$ 4.2	\$ 4.5	\$ 4.6	\$ 5.0	\$ 5.8	\$ 6.0	\$ 6.0
Management Fee Expense	\$ 3.7	\$ 5.3	\$ 5.1	\$ 8.4	\$ 7.5	\$ 8.4	\$ 6.9
Utilities	\$ 3.6	\$ 3.6	\$ 3.3	\$ 3.1	\$ 3.5	\$ 2.6	\$ 3.0
OEB costs	\$ 3.2	\$ 3.3	\$ 3.2	\$ 3.2	\$ 3.4	\$ 3.0	\$ 3.2
Printing and Office Supplies	\$ 3.0	\$ 1.0	\$ 1.3	\$ 1.4	\$ 0.8	\$ 0.7	\$ 0.7
Fuel	\$ 1.9	\$ 1.6	\$ 2.0	\$ 2.8	\$ 2.7	\$ 2.5	\$ 2.3
Bank Charges	\$ 1.9	\$ 3.6	\$ 3.3	\$ 2.9	\$ 2.3	\$ 2.5	\$ 2.5
Legal Fees	\$ 1.5	\$ 2.2	\$ 1.6	\$ 2.0	\$ 1.3	\$ 1.1	\$ 0.8
Rent Expense	\$ 1.3	\$ 1.4	\$ 1.9	\$ 1.7	\$ 1.5	\$ 1.2	\$ 1.2
Small Tools	\$ 1.0	\$ 0.9	\$ 1.1	\$ 1.3	\$ 1.1	\$ 1.2	\$ 1.2
Advertising	\$ 0.7	\$ 1.7	\$ 1.5	\$ 1.4	\$ 0.9	\$ 0.8	\$ 0.9
LEAP Program Funding	\$ 0.7	\$ 0.7	\$ 0.7	\$ 0.7	\$ 0.7	\$ 0.7	\$ 0.7
Environmental Expenses	\$ 0.5	\$ 1.0	\$ 2.2	\$ 3.3	\$ 0.9	\$ 0.9	\$ 2.7
Other	\$ 1.7	\$ (1.0)	\$ (0.6)	\$ (1.3)	\$ (0.6)	\$ (1.4)	\$ (1.3)
Inventory write-off	\$ (0.1)	\$ 0.7	\$ 0.2	\$ 0.6	\$ 0.9	\$ 1.0	\$ 1.4
Material Recoveries	\$ (7.8)	\$ (8.1)	\$ (8.5)	\$ (9.2)	\$ (9.4)	\$ (9.2)	\$ (10.1)
Fleet Recoveries	\$ (8.2)	\$ (9.7)	\$ (12.0)	\$ (12.5)	\$ (12.2)	\$ (13.5)	\$ (13.7)
Total Other \$	\$ 71.7	\$ 93.6	\$ 86.3	\$ 83.7	\$ 78.0	\$ 76.8	\$ 82.9

	2026	2027	2028	2029	2030	2031
IST Licenses and Maintenance	\$ 25.8	\$ 28.4	\$ 30.9	\$ 32.6	\$ 34.2	\$ 36.5
Employee Training, Travel and Admin	\$ 15.0	\$ 16.5	\$ 17.0	\$ 18.1	\$ 18.3	\$ 18.9
Postage and Delivery	\$ 11.4	\$ 9.8	\$ 9.6	\$ 9.3	\$ 9.2	\$ 9.3
Repairs and Maintenance	\$ 12.3	\$ 12.5	\$ 12.7	\$ 13.0	\$ 13.2	\$ 13.4
Credit Losses	\$ 6.3	\$ 7.8	\$ 8.4	\$ 8.6	\$ 8.4	\$ 8.2
Property Taxes	\$ 6.1	\$ 6.9	\$ 7.8	\$ 8.6	\$ 8.8	\$ 9.0
Insurance	\$ 6.6	\$ 7.0	\$ 7.3	\$ 7.6	\$ 8.0	\$ 8.4
Management Fee Expense	\$ 6.1	\$ 6.9	\$ 6.5	\$ 6.5	\$ 6.8	\$ 6.6
Utilities	\$ 2.8	\$ 2.9	\$ 2.9	\$ 3.0	\$ 3.0	\$ 3.1
OEB costs	\$ 3.5	\$ 7.1	\$ 7.2	\$ 7.3	\$ 7.4	\$ 7.6
Printing and Office Supplies	\$ 0.9	\$ 1.0	\$ 1.0	\$ 1.0	\$ 1.1	\$ 1.1
Fuel	\$ 2.7	\$ 2.7	\$ 2.8	\$ 2.8	\$ 2.9	\$ 3.0
Bank Charges	\$ 2.8	\$ 2.9	\$ 3.5	\$ 3.5	\$ 3.5	\$ 3.6
Legal Fees	\$ 1.4	\$ 2.3	\$ 2.1	\$ 2.1	\$ 2.2	\$ 2.2
Rent Expense	\$ 1.5	\$ 1.4	\$ 1.4	\$ 1.6	\$ 1.7	\$ 1.8
Small Tools	\$ 0.7	\$ 0.8	\$ 0.8	\$ 0.8	\$ 0.8	\$ 0.8
Advertising	\$ 1.2	\$ 1.1	\$ 1.2	\$ 1.2	\$ 1.2	\$ 1.2
LEAP Program Funding	\$ 0.7	\$ 1.8	\$ 1.9	\$ 1.9	\$ 2.0	\$ 2.0
Environmental Expenses	\$ 0.8	\$ 0.8	\$ 0.8	\$ 0.8	\$ 0.8	\$ 0.8
Other	\$ 4.4	\$ 4.4	\$ 4.5	\$ 4.7	\$ 4.8	\$ 4.8
Inventory write-off	\$ 0.5	\$ 0.5	\$ 0.5	\$ 0.5	\$ 0.5	\$ 0.6
Material Recoveries	\$ (9.0)	\$ (9.3)	\$ (10.0)	\$ (10.6)	\$ (11.0)	\$ (11.3)
Fleet Recoveries	\$ (12.8)	\$ (13.1)	\$ (13.4)	\$ (13.6)	\$ (13.9)	\$ (14.2)
Total Other \$	\$ 91.8	\$ 103.1	\$ 107.5	\$ 111.2	\$ 113.9	\$ 117.4

Note 1: The increase in Other from 2025 to 2026 is principally related to the exit of Hamilton water billing services.

d) Please see updated file AMPCO-3_Attach 1_Tables.

AMPCO-3

Attachment 1 Tables

Please see live Excel

**RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO
PRE-SETTLEMENT QUESTIONS**

AMPCO-4

Reference: 4-AMPCO-80 (b)

a) Please explain why the Regular \$ plus Overtime \$ in Table 1 Labour 2020 to 2025 do not match the compensations \$ in Appendix 2-K.

b) Please explain why the \$/hr with respect to Regular Internal Labour in 2027 (\$277.7M/3,215,939 hours = \$86.35/hr) is significantly higher than 2025 actuals (\$178.21M/2,924,909 hours= \$60.93/hr).

RESPONSE:

a) An updated table was provided in response to JT-3.1.3, and a copy is provided below for reference. The update figures for Regular and Overtime Dollars are aligned with the compensation in Appendix 2K.

Table 1 – Budget vs. Actual Labour Costs

Labour	2020	2021	2022	2023	2024	2025
Regular Hours - Budget	2,949,880	2,937,599	2,992,652	3,008,775	3,018,778	3,113,887
Regular Hours - Actual	2,436,965	2,599,837	2,804,822	2,792,622	2,790,610	2,924,909
Overtime Hours - Budget	n/a	n/a	n/a	n/a	n/a	n/a
Overtime Hours - Actual	192,464	196,369	196,896	192,324	172,261	179,827
Regular \$ - Budget	\$196.0	\$198.1	\$209.5	\$220.9	\$231.5	\$247.0
Regular \$ - Actual	\$188.2	\$196.7	\$202.3	\$209.1	\$219.0	\$233.7
Overtime \$ - Budget	\$10.0	\$10.0	\$8.9	\$10.8	\$12.3	\$16.0
Overtime \$ - Actual	\$18.1	\$17.4	\$19.0	\$20.1	\$18.6	\$20.3

- 1 Note 1: The dollar figures are provided in (\$MM).
- 2 Note 2: 2020 and 2021 'Regular Hours – Actual' and 'Overtime Hours – Actual'
- 3 exclude Guelph as the information is not available.
- 4 Note 3: The budget hours have been estimated on a best effort basis.
- 5
- 6 b) Please refer to interrogatory 4-SEC-90 h) specifically, *"With respect to 2027, the*
- 7 *incremental increase is driven by a shifting labour mix that is comprised of additional*
- 8 *technical and skilled trades positions, which are largely in support of the execution of the*
- 9 *capital investment plan."*

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO
PRE-SETTLEMENT QUESTIONS

AMPCO-5

Reference: 4-AMPCO-81

a) Please provide a breakdown of the cost driver Other \$ in each year.

b) Please provide an updated excel file.

RESPONSE:

a) Below is a breakdown of the cost driver Other \$ in each year.

1 **Table 1 – Breakdown of Cost Driver Other**

	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Actuals
LEAP Program Funding	\$ 146,064	\$ 419,226	\$ 113,596	\$ (25,415)	\$ 56,196	\$ (2,804)	\$ (19,577)	\$ 183
Bank Charges	\$ 1,262,820	\$ 434,775	\$ 168,274	\$ 1,751,611	\$ (307,006)	\$ (441,647)	\$ (567,488)	\$ 171,478
Legal Fees	\$ 1,339,528	\$ (43,106)	\$ 209,293	\$ 709,646	\$ (582,243)	\$ 376,762	\$ (674,907)	\$ (225,875)
Rent Expense	\$ 1,699,870	\$ 180,818	\$ (541,679)	\$ 72,362	\$ 458,891	\$ (196,077)	\$ (212,434)	\$ (259,838)
Utilities	\$ 3,001,803	\$ 239,363	\$ 376,078	\$ (54,959)	\$ (281,581)	\$ (171,911)	\$ 412,052	\$ (909,332)
Fuel	\$ 1,863,189	\$ 262,105	\$ (188,655)	\$ (365,587)	\$ 476,214	\$ 770,424	\$ (124,015)	\$ (209,538)
Advertising	\$ 1,026,110	\$ 22,476	\$ (357,763)	\$ 968,127	\$ (148,768)	\$ (142,049)	\$ (475,204)	\$ (103,992)
Printing and Office Supplies	\$ 2,237,274	\$ 605,916	\$ 147,648	\$ (2,013,371)	\$ 358,137	\$ 84,291	\$ (599,751)	\$ (91,098)
Direct Vehicle Costs	\$ 2,949,898	\$ 1,503,349	\$ (406,689)	\$ (653,550)	\$ 1,133,303	\$ 1,179,640	\$ (920,162)	\$ 611,814
Environmental Expenses	\$ 2,261,884	\$ (825,198)	\$ (893,875)	\$ 485,368	\$ 1,192,847	\$ 1,128,734	\$ (2,429,344)	\$ (26,086)
Inventory write-off	\$ (699,891)	\$ 774,907	\$ (212,484)	\$ 879,339	\$ (536,372)	\$ 418,378	\$ 241,742	\$ 87,835
Small Tools	\$ 694,612	\$ 3,321	\$ 267,085	\$ (112,392)	\$ 264,131	\$ 187,207	\$ (176,934)	\$ 98,917
Direct Material Costs	\$ 3,997,282	\$ 333,541	\$ 28,615	\$ (723,660)	\$ 1,127,397	\$ 82,836	\$ (302,929)	\$ 779,491
Fleet Recoveries	\$ (7,948,862)	\$ (1,023,633)	\$ 740,336	\$ (1,491,712)	\$ (2,315,141)	\$ (495,902)	\$ 375,012	\$ (1,328,168)
Postage and Delivery	\$ 7,170,359	\$ 1,708,300	\$ 1,494,540	\$ 1,403,860	\$ (608,467)	\$ (179,764)	\$ (144,111)	\$ (114,063)
Repairs and Maintenance	\$ 14,198,060	\$ (2,997,304)	\$ (1,431,893)	\$ 2,888,701	\$ 2,082,300	\$ (439,417)	\$ 188,991	\$ 575,737
Management Fee Expense	\$ (118,137)	\$ 666,937	\$ 3,164,854	\$ 1,573,074	\$ (174,589)	\$ 3,264,256	\$ (878,536)	\$ 893,088
Material Recoveries	\$ (5,798,152)	\$ (1,829,873)	\$ (177,633)	\$ (265,477)	\$ (452,282)	\$ (720,831)	\$ (185,256)	\$ 181,910
Other	\$ (431,480)	\$ 249,972	\$ 820,059	\$ (2,023,762)	\$ (48,674)	\$ 35,586	\$ (567,515)	\$ (11,063)
Total Other	\$ 28,852,230	\$ 685,893	\$ 3,319,707	\$ 3,002,204	\$ 1,694,292	\$ 4,737,711	\$ (7,060,365)	\$ 121,402

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	2025 Actuals	2026 Bridge	2027 Test Year	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast
LEAP Program Funding	\$ (1,558)	\$ (8,292)	\$ 1,144,793	\$ 45,568	\$ 46,707	\$ 47,875	\$ 49,072
Bank Charges	\$ 32,460	\$ 335,387	\$ 15,838	\$ 609,852	\$ 29,798	\$ 30,394	\$ 31,002
Legal Fees	\$ (275,898)	\$ 616,453	\$ 874,357	\$ (233,114)	\$ 29,795	\$ 30,391	\$ 30,999
Rent Expense	\$ 26,739	\$ 228,237	\$ (55,000)	\$ 31,000	\$ 180,000	\$ 96,000	\$ 126,000
Utilities	\$ 374,484	\$ (188,138)	\$ 55,957	\$ 57,076	\$ 58,218	\$ 59,382	\$ 60,570
Fuel	\$ (179,239)	\$ 376,188	\$ 53,519	\$ 54,590	\$ 55,682	\$ 56,795	\$ 57,931
Advertising	\$ 135,095	\$ 258,593	\$ (60,985)	\$ 74,008	\$ (37,517)	\$ 21,641	\$ 22,076
Printing and Office Supplies	\$ 7,765	\$ 188,623	\$ 58,199	\$ 9,967	\$ 46,339	\$ 29,647	\$ 41,109
Direct Vehicle Costs	\$ (149,308)	\$ (289,721)	\$ 99,132	\$ 101,154	\$ 103,177	\$ 105,241	\$ 107,346
Environmental Expenses	\$ 1,785,536	\$ (1,880,868)	\$ (33,979)	\$ 16,365	\$ 14,621	\$ 14,940	\$ 15,262
Inventory write-off	\$ 462,390	\$ (899,002)	\$ 5,087	\$ 5,189	\$ 10,542	\$ 10,753	\$ 10,968
Small Tools	\$ (39,164)	\$ (437,276)	\$ 14,990	\$ 15,290	\$ 15,596	\$ 15,908	\$ 16,226
Direct Material Costs	\$ 315,650	\$ (1,331,648)	\$ 86,069	\$ 87,789	\$ 89,544	\$ 92,731	\$ 94,586
Fleet Recoveries	\$ (198,832)	\$ 902,089	\$ (305,215)	\$ (299,816)	\$ (242,847)	\$ (306,210)	\$ (270,694)
Postage and Delivery	\$ 1,307,011	\$ (643,902)	\$ (1,623,692)	\$ (157,125)	\$ (305,483)	\$ (126,538)	\$ 76,220
Repairs and Maintenance	\$ 240,767	\$ (3,036,679)	\$ 234,374	\$ 236,690	\$ 237,634	\$ 247,439	\$ 199,066
Management Fee Expense	\$ (1,493,023)	\$ (822,035)	\$ 791,516	\$ (369,504)	\$ (27,384)	\$ 365,958	\$ (192,746)
Material Recoveries	\$ (893,472)	\$ 1,159,188	\$ (334,049)	\$ (707,134)	\$ (626,851)	\$ (305,013)	\$ (319,073)
Other	\$ (554,453)	\$ 6,933,300	\$ 69,682	\$ 87,735	\$ 100,148	\$ 89,503	\$ 91,294
Total Other	\$ 902,947	\$ 1,460,498	\$ 1,090,593	\$ (334,420)	\$ (222,281)	\$ 576,836	\$ 247,212

Note 1: The 2020 decrease in Other is principally related to a higher water billing contribution.

Note 2: The 2026 increase in Other is principally related to the exit of Hamilton water billing services.

b) Please see 5-AMPCO_Attach_1_App 2-JB Cost Driver Breakdown.

AMPCO-5

Attachment 1 App 2-JB Cost Driver Breakdown

Please see live Excel

**RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO
PRE-SETTLEMENT QUESTIONS**

AMPCO-6

Reference: JT3.30

Please provide an update.

RESPONSE:

The DLTDR would be 4.92% if set on April 21, 2026. See Table 1 below for the details of this calculation.

Table 1 - April 2026 DLTDR Calculation

**2026 Cost of Capital Parameter Calculations
Deemed Long-term Debt Rate
Data as at April 21, 2026**

Date of Update: 21-Apr-26

Long Canada Bond Forecast

Long Canada Bond Forecast (LCBF)	
Long Canada (30-year Government of Canada) Bond yield April 2026 (Bank of Canada)	3.910%

30-Year A-Rated Utility Corporate Bond Spread

A-Rated Utility Corporate Bond Spread September	
30-Year A-rated Utility Corporate Bond Yield BVCAUA30 BVLI Index April 2026 (Bloomberg)	4.920%
Long Canada (30-year Government of Canada) Bond yield April 2026 (Bank of Canada)	3.910%
Spread	1.010%

2026 Deemed Long-term Debt Rate (DLTDR)

Long Canada Bond Forecast April 2026	3.910%
30-Year A-rated Utility Corporate Bond Yield Spread April 2026	1.010%
Deemed Long-term Debt Rate Based on Data: April 2026	4.92%

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO
PRE-SETTLEMENT QUESTIONS

AMPCO-7

Reference: 1-SEC-24 Attach 7 App 2-K; SEC Clarification Question 8(c)

Alectra updated Appendix 2-K to reflect 2025 Actuals. The number of FTEs in 2025 is 1504 compared to 1628 (As filed 2-K); a variance of 7.6%. Please explain why the variance in 2025 compensation \$ is 3.4%.

RESPONSE:

The average budgeted FTE cost of the vacant positions was lower than the average FTE cost for all budgeted positions. A 3.4% reduction in overall compensation dollars would be achieved through a higher number of lower cost FTE vacancies vs. the number of average cost FTEs to achieve the same reduction. In addition, higher overtime costs are partially offsetting the lower compensation from vacancies, resulting in a smaller compensation variance compared to the FTE variance.

**RESPONSES TO CONSUMERS COUNCIL OF CANADA
PRE-SETTLEMENT QUESTIONS**

SC-CCC-1

Ref: JT1.17

Preamble:

Alectra provided the EEM summaries for five projects referenced in 2-CCC-17 that have no forecast capital contributions during the 2027-2031 period.

Alectra states that the “[k]ey assumptions included the forecast peak load associated with the project, a staged ramp-up of customer demand over the connection horizon, the applicable distribution rates for the rate zone, and a revenue horizon consistent with the economic evaluation framework used for the specified rate class.”

Question(s):

a) Please provide the detailed models supporting the EEM summaries for the five projects referenced in the response. The level of detail provided in the summaries does not allow for an understanding of the ramp-up of customer demand, the distribution rates applied, the capital and OM&A costs estimated, nor the discount rate used.

b) With respect to the GTAA System Expansion Project, please further explain the statement that “parts of the expansion have already been completed under an executed OTC and the associated customer contributions will be recognized prior to 2027. However, the spending associated with the remaining phases of the project scheduled for construction between 2027 and 2031 are not expected to generate additional customer contributions, as per the original mock EEM.” As part of the response, please provide the capital contribution that was already provided and explain what the “original mock EEM” is (and file it) and explain how it is different from the information provided in the summary for the project.

1 **RESPONSE:**

2
3 a) The detailed calculations supporting the EEM summaries for the five projects has been
4 filed confidentially as Attachment 1 to this response.

5
6 The attachment summarizes the economic evaluation model details for the five projects.
7 The details include the energization year, forecasted connections and demand (including
8 load ramp-up), total estimated capital and OM&A costs, and capital contribution details.

9
10 b) The original mock EEM was prepared based on the submission from the GTAA. This
11 preliminary information proposed 3 segments that comprise the entire expansion. A mock
12 EEM is used at the initial stage of the project, and the results are calculated using the
13 preliminary inputs from the customer and the preliminary high level cost estimates from
14 Alectra Utilities. The results provide estimated breakdown of the gross, net and
15 contributions for the project.

16
17 The original mock EEM calculated that there would be a contribution of \$3.1M and to be
18 collected prior to 2027. Because of this, there were no anticipated additional contributions
19 between 2027 and 2031 based on the original mock EEM.

20
21 For clarity, parts of the expansion have already been completed under an executed OTC,
22 representing the first segment, which was constructed in 2025 and early 2026. The
23 actual contributions for the first segment were \$2.2M.

24
25 The information in the summary for the project is not different from the information in the
26 original mock EEM.

SC-CCC-1

Attachment 1

Filed Confidentially

**RESPONSES TO CONSUMERS COUNCIL OF CANADA
PRE-SETTLEMENT QUESTIONS**

SC-CCC-2

Ref: JT2.11

JT1.20

2-CCC-24

Question(s):

- a) Please provide the detailed model supporting the EEM summary for the data centre project referenced in the response to JT2.11. The level of detail provided in the summary does not allow for an understanding of the ramp-up of customer demand, the distribution rates applied, the capital and OM&A costs estimated, nor the discount rate used.
- b) Please advise in which years the project costs and capital contributions (if applicable) for "Project 1" shown in JT2.11 are reflected in Table 1 of JT1.20 and 2-CCC-24.

RESPONSE:

- a) The detailed calculation supporting the EEM summary for the project has been filed confidentially as Attachment 1 to this response. The details include the energization year, forecasted connections and demand (including load ramp-up), total estimated capital and OM&A costs, and capital contribution details.
- b) Project 1 Gross and Net costs are reflected in 2025, 2026, and 2027 in Table 1 of JT1.20 and 2-CCC-24 Stations Capacity Program. Capital contributions are reflected in 2025 and 2026 in Table 1 of JT1.20 Stations Capacity Program.

SC-CCC-2

Attachment 1

Filed Confidentially

**RESPONSES TO CONSUMERS COUNCIL OF CANADA
PRE-SETTLEMENT QUESTIONS**

SC-CCC-3

Ref: JT1.18

Preamble:

Alectra notes that “[a]n example project categorized as system enhancement is Project 150716 which proposed to build a Feeder (42M69) Extension from Williams Parkway to the intersection of Heart Lake and Sandalwood to provide capacity relief to the existing feeders 136M8 and 42M45 in the area.

Alectra Utilities has not received new customer requests to connect to this new feeder (42M69) nor does the project have any Offers to Connect on the proposed feeder.”

Question(s):

Please advise whether there have been new customer requests in the Heart Lake Road and Mayfield Area in the 2024-2026 (to date) period. If so, please provide the total capacity requested in that general area in each year of that time period.

RESPONSE:

Alectra Utilities executed four Offers to Connect (OTCs) over the 2024 and 2025 period, totalling 8,570MW of committed capacity in the Heart Lake Road and Mayfield area. Alectra Utilities has not executed any OTCs in 2026 to date for this area. Furthermore, Alectra Utilities executed seven OTCs over the 2022 and 2023 period, totalling 17,560MW of committed capacity in the area. The total committed capacity under executed OTCs for the area is 26,130MW.

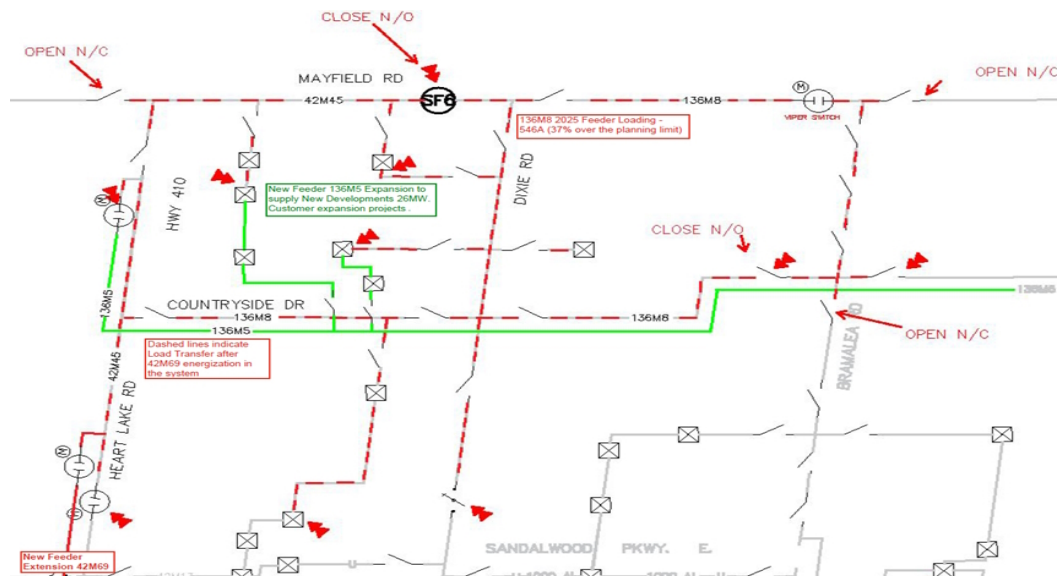
As there was no available capacity to accommodate these new specific customer connections on the existing feeders 136M8 and 42M45, Alectra Utilities implemented a system expansion project to construct a new feeder, 136M5, specifically to accommodate the new developments, as per the Distribution System Code. Accordingly, Alectra Utilities received capital contributions from the eleven developments for the construction of the new feeder 136M5.

Alectra Utilities completed the construction of the new feeder 136M5 to specifically facilitate supply to the eleven developments under contract. The entire capacity of the new feeder 136M5 has been allocated to these developments, and therefore, there is no spare capacity to provide relief to existing feeders 136M8 and 42M45.

Alectra Utilities determined that it needs to proceed with the system enhancement project 42M69 feeder extension and reconfigure the system to ensure operability and reliability, so that feeders 136M8 and 42M45 can operate within the planning limit of 400A.

For illustrative purposes, Figure 1 demonstrates the implementation of a system configuration that includes the proposed 42M69 enhancement, existing feeders 136M8 and 42M45, and completed system expansion feeder 136M5.

Figure 1 – Proposed 42M69 Enhancement, Existing Feeders 136M8 & 42M45 and Completed System Expansion Feeder 136M5



**RESPONSES TO CONSUMERS COUNCIL OF CANADA
PRE-SETTLEMENT QUESTIONS**

SC-CCC-4

Ref: JT3.13

Preamble:

Mercer states that the methodology of the study did not focus on the employee categories in the manner being requested; as such, the request to link position grades to the requested employee categories would risk misinterpretation of the study results.

Further, we specifically note the following:

- 1) As mentioned in the report, the study did not include executive jobs.
- 2) Alectra's union jobs do not have grades, and as such, a breakdown of results could not be provided on this basis.
- 3) The study's methodology does not separate the non-union and management workforce. Specifically, some grades are comprised of the two categories."

We understand Mercer's position. However, to extent that the following information is available, we ask that it be provided.

Question(s):

For each Mercer "Grade" (e.g., 11, 12, etc.), please provide the relevant job categories as set out Appendix 2-K (i.e., management, Non-Union and Union) that are reflected in the grade. In the circumstance that both management and Non-Union are in the same Mercer "Grade", please show both categories where that applies. Please confirm that the "IBEW-PWU" Grade reflects all the unionized jobs that were benchmarked.

1 **RESPONSE:**

2
3 This follow-up question to the response to JT3.13 relates to the table on page 5 of the Mercer
4 Compensation Market Review report ("Mercer Report"), setting out the findings of the
5 benchmarking study. As noted in the preamble above, in response to JT3.13 Mercer
6 indicated, among other points, that "[t]he methodology of the study did not focus on the
7 employee categories in the manner being requested; as such, the request to link position
8 grades to the requested employee categories would risk misinterpretation of the study
9 results." Alectra maintains that position. As Mercer further noted, the study's methodology
10 does not separate the "non-union" and "management" workforce.

11
12 Alectra can confirm, though, that the "IBEW & PWU" category at the bottom of table 5 reflects
13 the unionized jobs that were included in the benchmarking study (as the report shows), and
14 those jobs are listed in Appendix B of the Mercer Report. The rest of the jobs in the study
15 are non-unionized jobs. Those jobs and their titles and grades are also listed in Appendix B
16 of the Mercer Report. The study was not done to provide benchmarking findings categorized
17 by the various groups of employees requested in this question. As the Mercer Report
18 indicates, the review comprised "non-union non-executive jobs" and "union jobs" and overall
19 organization market competitiveness was assessed.

**RESPONSES TO CONSUMERS COUNCIL OF CANADA
PRE-SETTLEMENT QUESTIONS**

SC-CCC-5

Ref: 1-Staff-1, Attachment 8

Question(s):

Please advise whether the bill impacts set out in 1-Staff-1, Attachment 8 reflect all of the updates made to date over the course of the proceeding. If not, please provide an updated version of the bill impacts model.

RESPONSE:

The bill impacts set out in 1-Staff-1, Attachment 8 do not reflect updates to Group 1 and Group 2 DVA balances in response to undertaking JT 1.1.13 and interrogatory 9-Staff-288 (2nd round interrogatories).

Alectra Utilities notes that it made a correction to the Total Loss Factor - Primary Metered Customer < 5,000 kW presented in the proposed Tariff of Rates. The correction is minor in nature - from 1.0254 to 1.0253, and does not affect the bill impacts. As described in Exhibit 8, Tab 3, Schedule 3, this primary-metered loss factor is derived by dividing the Total Loss Factor of 1.0356 by the secondary-metered loss factor of 1.0100. Previously, the Total Loss Factor was left unrounded prior to the derivation of the primary-metered loss factor. The revised primary-metered loss factor was derived using the rounded Total Loss Factor.

An updated tariff schedule and bill impact model inclusive of updates to the Group 1 and Group 2 balances in response to undertaking JT 1.1.13 and interrogatory 9-Staff-288 is provided as Attachment 1. A summary of the bill impacts are presented in the tables below.

1 **Table 1 - Distribution Bill Impact, \$**

Rate Class	BRZ	ERZ	GRZ	HRZ	PRZ	Alectra					
			2027			2027	2028	2029	2030	2031	2027-2031 Average
Residential	\$13.08	\$4.56	\$0.98	(\$1.92)	\$2.85	\$3.91	\$3.69	\$1.82	\$2.39	\$2.39	\$2.84
GS<50 kW	\$24.19	(\$8.41)	\$27.99	(\$11.81)	\$2.84	\$6.96	\$9.46	\$4.24	\$5.54	\$5.55	\$6.35
GS>50 kW, Regular	\$1,176.68	(\$288.41)	\$392.72	(\$480.96)	\$137.90	\$187.59	\$158.36	\$75.98	\$99.56	\$99.83	\$124.26
GS>50 kW, Intermediate	(\$160.61)	(\$1,778.25)	(\$259.41)			(\$732.75)	(\$12.31)	\$75.98	\$99.56	\$99.83	(\$93.94)
Large Use	\$52,242.67	(\$21,087.60)	\$5,510.94	(\$31,007.96)	\$18,776.20	\$4,886.85	\$8,358.29	\$2,626.46	\$3,440.94	\$3,450.73	\$4,552.65
LUDA				(\$87,424.00)		(\$87,424.00)	\$87,994.75	\$737.77	\$966.54	\$967.80	\$648.57
Street Lighting	(\$1.50)	(\$0.23)	(\$1.92)	(\$1.49)	(\$0.26)	(\$1.08)	\$0.01	\$0.11	\$0.14	\$0.14	(\$0.14)
Sentinel Lighting			(\$0.08)	(\$2.89)	\$1.86	(\$0.37)	\$1.01	\$0.57	\$0.75	\$0.75	\$0.54
USL	\$6.93	(\$2.62)	\$2.57	(\$3.33)	(\$1.55)	\$0.40	\$1.84	\$0.87	\$1.15	\$1.15	\$1.08

2

3 **Table 2 - Distribution Bill Impact, %**

Rate Class	BRZ	ERZ	GRZ	HRZ	PRZ	Alectra					
			2027			2027	2028	2029	2030	2031	2027-2031 Average
Residential	43.1%	14.8%	2.7%	-5.8%	8.1%	12.6%	11.3%	4.5%	5.6%	5.3%	7.9%
GS<50 kW	31.4%	-9.4%	49.4%	-14.8%	3.3%	12.0%	13.0%	4.5%	5.6%	5.3%	8.1%
GS>50 kW, Regular	107.9%	-17.3%	34.8%	-37.6%	8.7%	19.3%	24.1%	4.5%	5.6%	5.3%	11.8%
GS>50 kW, Intermediate	-6.4%	-57.9%	-15.0%			-26.4%	6.0%	4.5%	5.6%	5.3%	-1.0%
Large Use	132.0%	-37.1%	12.4%	-64.5%	50.1%	18.6%	58.3%	4.5%	5.6%	5.3%	18.5%
LUDA				-551.2%		-551.2%	-123.0%	4.5%	5.6%	5.3%	-131.7%
Street Lighting	-40.1%	-9.8%	-39.4%	-45.5%	-10.7%	-29.1%	3.1%	4.7%	5.8%	5.5%	-2.0%
Sentinel Lighting			-0.6%	-21.8%	18.6%	-1.3%	9.5%	4.5%	5.7%	5.4%	4.7%
USL	51.5%	-13.3%	16.4%	-18.5%	-7.8%	5.6%	11.7%	4.4%	5.7%	5.3%	6.5%

1 **Table 3 - Total Bill Impact, \$**

Rate Class	BRZ	ERZ	GRZ	HRZ	PRZ	Alectra					
			2027			2027	2028	2029	2030	2031	2027-2031 Average
Residential	\$11.24	\$0.44	\$2.08	(\$4.16)	\$2.89	\$2.50	\$4.07	\$1.42	\$1.79	\$1.86	\$2.33
GS<50 kW	\$22.26	(\$16.64)	\$28.60	(\$15.57)	\$3.82	\$4.49	\$10.82	\$3.42	\$4.40	\$4.60	\$5.55
GS>50 kW, Regular	\$199.70	(\$2,205.27)	(\$207.81)	(\$2,134.93)	(\$1,162.49)	(\$1,102.16)	\$1,001.73	\$120.20	\$152.17	\$151.83	\$64.75
GS>50 kW, Intermediate	(\$1,538.12)	(\$3,891.32)	(\$1,058.31)			(\$2,162.58)	\$688.33	\$120.20	\$152.17	\$151.83	(\$210.01)
Large Use	\$44,680.96	(\$49,946.68)	(\$9,508.79)	(\$53,795.30)	\$19,106.27	(\$9,892.71)	\$22,008.89	\$985.88	(\$1,950.45)	\$1,228.00	\$2,475.92
LUDA				(\$107,342.09)		(\$107,342.09)	\$125,103.15	\$4,838.40	\$5,709.37	\$5,801.19	\$6,822.00
Street Lighting	(\$2.02)	(\$0.70)	(\$2.42)	(\$2.11)	(\$0.78)	(\$1.60)	\$0.25	\$0.13	\$0.17	\$0.17	(\$0.18)
Sentinel Lighting			\$0.58	(\$3.75)	\$2.26	(\$0.30)	\$1.45	\$0.67	\$0.80	\$0.78	\$0.68
USL	\$3.02	(\$3.84)	\$2.97	(\$3.81)	(\$0.98)	(\$0.53)	\$2.62	\$0.87	\$1.10	\$1.13	\$1.04

2

3 **Table 4 - Total Bill Impact, %**

Rate Class	BRZ	ERZ	GRZ	HRZ	PRZ	Alectra					
			2027			2027	2028	2029	2030	2031	2027-2031 Average
Residential	8.4%	0.3%	1.5%	-3.0%	2.1%	1.9%	3.0%	1.0%	1.2%	1.3%	1.7%
GS<50 kW	6.4%	-4.5%	8.7%	-4.4%	1.1%	1.5%	3.1%	0.9%	1.2%	1.2%	1.6%
GS>50 kW, Regular	1.1%	-11.7%	-1.2%	-11.8%	-6.4%	-6.0%	6.0%	0.7%	0.8%	0.8%	0.5%
GS>50 kW, Intermediate	-7.9%	-19.0%	-5.6%			-10.9%	4.1%	0.7%	0.8%	0.8%	-0.9%
Large Use	5.4%	-5.9%	-1.1%	-6.4%	2.4%	-1.1%	2.8%	0.1%	-0.2%	0.1%	0.3%
LUDA				-6.8%		-6.8%	8.5%	0.3%	0.4%	0.4%	0.5%
Street Lighting	-22.1%	-9.2%	-22.8%	-24.3%	-10.1%	-17.7%	4.1%	1.8%	2.2%	2.2%	-1.5%
Sentinel Lighting			2.0%	-13.4%	8.8%	-0.9%	5.8%	2.4%	2.7%	2.6%	2.5%
USL	5.3%	-5.7%	4.8%	-5.9%	-1.5%	-0.6%	4.2%	1.3%	1.7%	1.7%	1.7%

SC-CCC-5

Attachment 1
Tariff Schedule and Bill Impacts Model

Please see live Excel

**RESPONSES TO CONSUMERS COUNCIL OF CANADA
PRE-SETTLEMENT QUESTIONS**

SC-CCC-6

Ref: 4-CCC-53, Table 1

Exhibit 9, Tab 3, Schedule 14, p. 3, Table 9-3-35

Question(s):

- a) Please provide an updated version of Table 9-3-35 that shows 2025 actuals.
- b) Please advise which categories of costs in 4-CCC-53, Table 1 are reflected in Table 9-3-35 for each year during the 2023-2026 period. As part of the response, please also breakout the "Top Shelf Screening" costs in Table 1 of 4-CCC-53.

RESPONSE:

- a) Table 1 below is an updated version of Table 9-3-35 that shows 2025 actuals.

Table 1 – Updated Version of Table 9-3-35

		2023	2024	2025	2026	Total
Total Actual Cost	A	7.3	7.0	7.9	7.6	29.9
Amount in Rates	B	4.2	5.2	5.4	5.5	20.4
Difference	C=A-B	3.1	1.7	2.5	2.1	9.4

- b) Total Direct/External Contractor Locate Costs, Top Shelf Screening and Ontario One Call costs are reflected in Table 9-3-35. For 2023, Table 9-3-35 includes only costs incurred from April through December, as the GOCA variance account became effective on April 1, 2023.
- Table 2 below restates Table 1 from 4-CCC-53 with Top Shelf Screening costs broken out.

1 Table 2 - Table 1 of 4-CCC-53 restated with Top Shelf Screening Costs Breakout

[illegible]

**RESPONSES TO CONSUMERS COUNCIL OF CANADA
PRE-SETTLEMENT QUESTIONS**

SC-CCC-7

Ref: U-CCC-1

Question(s):

Please provide a revised balance for Account 1592 – PILs and Tax Variances, Sub-account CCA Changes reflecting the impact of the implementation of Bill C-15.

RESPONSE:

Please see attachment SC-CCC-7_Attach 1_1592 Bill C-15 for the impact resulting from accelerated capital cost allowance changes, including the enacted Bill C-15, based on the Approved Additions methodology.

The revised balance for Account 1592 – PILs and Tax Variances, Sub-account CCA Changes reflecting the impact of the implementation of Bill C-15 is provided below.

Table 1 – Account 1592, Sub-account CCA Changes Balance

Group 2 DVAs	Principal Balance as of December 31, 2025	Carrying Charge Balance as of December 31, 2025	Total Balance as of December 31, 2025	Principal Balance Forecast for 2026	Carrying Charge Balance Forecast for 2026	Total Balance Forecast for 2026	Principal Balance as of December 31, 2026	Carrying Charge Balance as of December 31, 2026	Total Balance as of December 31, 2026
1592 PILs and Tax Variance for 2006 and Subsequent Years, Sub-account - PILs and Tax Variances CCA Changes	(35.9)	(5.4)	(41.3)	(11.8)	(1.3)	(13.1)	(47.6)	(6.7)	(54.4)

SC-CCC-7

**Attachment 1
1592 Bill C-15**

Please see live Excel

**RESPONSES TO CONSUMERS COUNCIL OF CANADA
PRE-SETTLEMENT QUESTIONS**

SC-CCC-8

Ref: Undertaking JT3.25

Chapter 2 Appendices, 2-OA and 2-OB

Question(s):

a) Please update Undertaking JT3.25 to reflect the OEB-approved 2026 return on equity and deemed long-term debt rate.

b) Please update Chapter 2 Appendices 2-OA and 2-OB to reflect the OEB-approved 2026 return on equity and deemed long-term debt rate.

RESPONSE:

a) Table 1 below presents an updated version of Table 1-11-4.

1 **Table 1 – Updated Table 1-11-4: RGF**

Line		2027	2028	2029	2030	2031
1	Average Net Fixed Assets	4,184.5	4,441.2	4,752.1	5,123.8	5,505.1
2	Working Capital Allowance	346.1	361.4	373.8	389.7	405.2
3	Rate Base	4,530.6	4,802.6	5,125.8	5,513.4	5,910.3
4	Return on Debt	112.7	124.3	133.5	144.2	160.1
5	Return on Equity	165.1	175.0	186.8	200.9	215.4
6	Depreciation	194.4	199.9	215.6	233.6	244.6
7	PILs Taxes	23.0	38.7	30.6	34.0	39.2
8	Total Capital Related Revenue Requirement	495.2	537.9	566.5	612.7	659.2
9	Less Incremental Working Capital Related Revenue Requirement		(0.5)	(1.3)	(2.3)	(3.3)
10	Total Capital Related Revenue Requirement (including working capital adjustment)	495.2	537.4	565.2	610.4	655.9
11	OM&A	352.4	352.4	352.4	352.4	352.4
12	Add: Inflation Factor		7.0	14.4	22.0	30.0
13	Add: G Factor		6.4	13.0	19.9	27.0
14	Add: IPD Factor		1.3	2.6	4.0	5.5
15	Total OM&A	352.4	367.1	382.4	398.4	415.0
16	Revenue offset	(31.9)	(32.4)	(29.0)	(29.8)	(30.6)
17	Non-capital Related Revenue Requirement (OM&A and Revenue Offset)	320.5	334.7	353.4	368.6	384.4
18	Total Revenue Requirement	815.6	872.1	918.6	979.0	1,040.4
19	Increase in Revenue Requirement		56.4	46.5	60.4	61.4
20	Increase in Revenue Requirement as a percentage of Previous Year Revenue Requirement		6.92%	5.33%	6.58%	6.27%
21	Inflation back-off		-2.00%	-2.00%	-2.00%	-2.00%
22	Billing Determinant Growth back-off		-0.53%	-0.65%	-0.77%	-0.69%
23	Revenue Growth Factor		4.39%	2.68%	3.81%	3.58%

2

3

4 b) The updated Chapter 2 Appendices 2-OA and 2-OB are filed as SC-CCC-8_Attach 1.

SC-CCC-8

Attachment 1

Please see live Excel

RESPONSES TO ENVIRONMENTAL DEFENCE PRE-SETTLEMENT QUESTIONS

ED-1

Reference: JT-1.2.21

Further to JT-1.2.21, please provide the requested information without any customer-identifying information. If necessary, please provide the information confidentially. Alternatively, if necessary, please provide the information with aggregation by MW thresholds (e.g. 0 MW to X MW; X MW to Y MW; etc.).

RESPONSE:

Please see Table 1 below.

1 **Table 1 – Generators by Type and Capacity**

Customer	Generator Type	Generator Capacity (kW)
1	Battery Storage	990
2	Battery Storage	800
3	Battery Storage	1,400
4	Battery Storage	2,000
5	Battery Storage	500
6	Battery Storage	2,000
7	Battery Storage	490
8	Battery Storage	700
9	Battery Storage	1,000
10	Battery Storage	2,000
11	Battery Storage	2,500
12	CHP	7,000
13	CHP	3,300
14	CHP	7,904
15	CHP	10,000
16	CHP	400
17	CHP	2,000
18	CHP	6,400
19	CHP	70
20	CHP	130
21	CHP	7,000
22	CHP	400
23	Co-generation	1,250
24	Co-generation	5,200
25	Co-generation	8,000
26	Natural Gas	1,000
27	Natural Gas	3,500
28	Natural Gas	117,001
29	Natural Gas	2,000
30	Natural Gas	1,000
31	Natural Gas	1,400
32	Natural Gas	2,750
33	Natural Gas	1,400
34	Natural Gas	2,000
35	Natural Gas	1,400
36	Natural Gas	1,000
37	Natural Gas	3,000
38	Natural Gas	1,500
39	Natural Gas	1,500
40	Natural Gas	1,000
41	Natural Gas	1,000
42	Natural Gas	1,500
43	Natural Gas	1,000
44	Natural Gas	1,500
45	Natural Gas	1,000
46	Natural Gas	3,200
47	Solar	250
48	Solar	555
49	Solar	700
50	Solar	800
51	Solar	960
52	Solar	999
53	Other	200
54	Other	1,600
55	Other	1,426
56	Other	6,750
57	Other	2,240
58	Other	1,300
59	Other	13,800
60	Other	6,500
61	Other	160
62	Other	2,000
	Total	264,325

RESPONSES TO ENVIRONMENTAL DEFENCE PRE-SETTLEMENT QUESTIONS

ED-2

Reference: JT-1.2.15

Further to JT-1.2.15, please provide an estimate of the percentage of calls to the call centre in which it was possible for the request to have been addressed through online or automatic means. We are not asking Alectra to determine how many calls it is feasible to divert from the call centre to other means. We are simply trying to understand the approximate proportion of call centre requests that (i) can only be addressed by phone versus (ii) those that can be addressed online or through automatic means.

RESPONSE:

As discussed in JT-1.2.15, Alectra believes that its digital transformation forecast is reasonable, showing that chat bots and automated moves will further reduce calls by 180,965 in 2031. See Table 1 below.

Table 1 - Number of Calls Shifted to Digital Channels

	2024	2025	2026	2027	2028	2029	2030	2031
Number of Calls Before Digital Transformation	636,233	560,129	695,072	738,788	779,571	827,545	898,589	904,825
Calls Shifted to Digital Channels	0	(24,334)	(69,507)	(88,655)	(109,140)	(132,407)	(161,746)	(180,965)
Number of Calls After Digital Transformation	636,233	535,795	625,565	650,133	670,431	695,138	736,843	723,860

For context, prior to 2025, Alectra had already automated many customer service inquiry or transaction types, either through its digital on-line forms or via MyAlectra portal. The following are examples of transactions which customers can already self-serve and where processing is significantly automated: (1) rate optionality – customers elect to switch rate

1 plans; (2) enrollment in pre-authorized payment; (3) registration for an equal payment plan.
2 Eligible customers may also establish payment arrangements directly through the MyAlectra
3 portal and may also make a credit card payment online. In addition, customers can obtain
4 basic account information through the automated telephone IVR system, including account
5 balance and payment information. Collectively, these initiatives resulted in approximately
6 44% reduction in avoided calls, demonstrating strong commitment to contact center
7 efficiency through self-serve and automation, while enhancing customer service, by providing
8 customers with their channel of choice, including voice.

RESPONSES TO ENVIRONMENTAL DEFENCE PRE-SETTLEMENT QUESTIONS

ED-3

Reference: JT-1.2.13

JT-1.2.13 estimates the “all-in cost of paper billing in 2025 at \$18.99 per paper-billed customer per year.” Please provide the total number of customers with paper billing in that year and the total all-in cost for all customers with paper billing

RESPONSE:

Please see Table 1 below.

Table 1 - Postage & Printing Costs Associated With Paper Bill Customers

	2025
Total Postage & Printing Cost (\$)	11,156,945
Number of Customers Receiving a Paper Bill	587,408
Cost / Customer (\$)	18.99

RESPONSES TO ENVIRONMENTAL DEFENCE PRE-SETTLEMENT QUESTIONS

ED-4

Reference: JT-1.2.9

As discussed in JT-1.2.9, residential service upgrades are expected to cost \$113.40 million over the rate period, including \$52.90 million in costs that will be borne by ratepayers and added to rate base. However, the Alectra response suggests that these figures also include costs for new infill buildings (versus only service upgrades). Please provide the cost figures for service upgrades in existing buildings only, including a version of Table 1 applicable only to upgrades. An estimate is sufficient (i.e. if Alectra is not certain about the exact breakdown between service upgrades and new services for new building).

RESPONSE:

Alectra does not currently track costs at a level of granularity that distinguishes between residential service upgrades in existing buildings and new service connections for infill development.

However, based on historical data from the Layouts portfolio (2020–2023), approximately 76% of the total number of services are residential, and within the residential category, approximately 66% represent the number of service upgrades while 34% represent the number of new service connections.

Given the absence of discrete cost tracking between these categories, Alectra has applied the 66% proportion to the residential portion of the forecasted costs to derive an estimate of the costs attributable to residential service upgrades in existing buildings.

This approach assumes that, on average, the unit costs for residential service upgrades and new residential services are comparable. Alectra acknowledges that in practice, costs can

1 vary depending on site-specific civil and electrical requirements; however, this methodology
2 provides a reasonable estimate for the purposes of this question.

3

4 Based on this methodology, Table 1 below provides an estimated breakdown of costs
5 attributable to residential service upgrades only, consistent with the format of Table 1
6 referenced in JT-1.2.9.

7

8 **Table 1- Number of Residential Service Upgrades, Gross, Contributions and Net Costs**

Layouts - Residential Service Upgrades							
	Year	Project Count	76% Estimated Residential Services	66% Estimated Service Upgrades	Capital Costs for Residential Service Upgrades		
					Gross \$ MM	Cust Cost \$ MM	Net Cost \$ MM
Actuals	2021	2768	2104	1388	\$5.92	\$2.96	\$2.96
	2022	3321	2524	1666	\$7.82	\$3.56	\$4.26
	2023	3468	2636	1740	\$9.13	\$4.41	\$4.72
	2024	3325	2527	1668	\$10.93	\$4.61	\$6.32
	2025	2521	1916	1265	\$12.54	5.37	\$7.17
Forecast	2026	3678	2795	1845	\$7.98	\$3.86	\$4.11
	2027	4139	3146	2076	\$9.08	\$4.82	\$4.26
	2028	4613	3506	2314	\$10.23	\$5.47	\$4.77
	2029	5214	3963	2615	\$11.49	\$6.12	\$5.37
	2030	5825	4427	2922	\$12.99	\$6.92	\$6.07
	2031	5732	4356	2875	\$13.09	\$6.97	\$6.12

9

RESPONSES TO ENVIRONMENTAL DEFENCE PRE-SETTLEMENT QUESTIONS

ED-5

Reference: JT-1.2.7

Please provide a response to JT-1.2.7, which reads as follows: "Interrogatory #2-ED-17: The response to this interrogatory is unclear. Can Alectra confirm that any fossil fuel equipment that it owns that may be replaced over the rate period will be replaced with electric equipment? If not, please provide a response to parts (b) and (c) of this question." Alectra neither provided the requested confirmation nor provided a response to (b) and (c).

RESPONSE:

Alectra confirms that no fossil fuel equipment at its buildings will be replaced with Electric equipment over the DSP period.

Table 1 below shows each building owned by Alectra with 2025 annual gas consumption, the age of any fossil fuel heating equipment, the approximate life left in any fossil fuel heating equipment and the annual fossil fuel costs.

Table 1 – Fossil Fuel Equipment

Location	Equipment (NG)	Quantity	Average Age (Years)	Remaining Useful Life (Years)	2025 Overall Annual NG Consumption (m3)	2025 Overall Annual NG Consumption Cost (\$)
Derry Rd	Unit Heaters	2	11	6 to 10	53k	\$19k
	RTUs	3	12	8 to 12		
	MZ Units	4	15	8 to 10		
Kennedy Rd	IR tube heaters	12	2.5	20	81k	\$30k
	RTU	1	2.5	20		
	MUA	1	2.5	20		

Location	Equipment (NG)	Quantity	Average Age (Years)	Remaining Useful Life (Years)	2025 Overall Annual NG Consumption (m3)	2025 Overall Annual NG Consumption Cost (\$)
Cityview	RTUs	10	15	5 to 7	85k	\$29k
	MUA	2	15	5 to 7		
John St**	DHW tank	1	5	15	28k	\$11k
	IR tube heaters	4	15	10		
	RTUs	6	15	5 to 7		
Nebo	DHW tank	1	5	15	117k	\$43k
	IR tube heaters	10	15	5 to 10		
	RTUs	4	10	5 to 15		
Vansickle	RTUs	9	12	8 to 12	75k	\$27k
	DHW tank	2	3	18		
	IR tube heaters	4	15	10		
Patterson	DHW tank	1	5	15	171k	\$58k
	IR tube heaters	4	20	5		
	Boiler	1	20	5		

1

2 Alectra's John St building has a 25-year agreement (signed in 2017) with HCE Energy's
3 district energy system, providing heating and cooling water. Alectra's Addiscott facility has
4 not been listed as Alectra does not own the building. Alectra's Southgate facility is geothermal
5 and a carbon neutral building.

6

7 Alectra is not planning to replace fossil fuel equipment at its buildings during the 2027-2031
8 period. As a result, Alectra has not conducted an analysis to estimate the incremental
9 electricity costs associated with replacing fossil fuel equipment with electric equipment. To
10 conduct such an analysis, Alectra would need to create, at a minimum, preliminary plans and
11 conceptual designs for any equipment that may be replaced and would have to utilize
12 associated equipment specifications to forecast costs. That information is not currently
13 available.

RESPONSES TO ENVIRONMENTAL DEFENCE PRE-SETTLEMENT QUESTIONS

ED-6

Reference: JT-1.2.14

Alectra declined to provide a response to JT-1.2.14 on the basis that "Alectra Utilities is an urban utility" and "[d]ensity-based charges are relevant when there is a significant density differentiation between various areas." However, Alectra's service area does include rural areas with low customer density per km (see attached PDFs with three examples). Please provide a response on this basis. A high-level response is sufficient, such as an indication that the spread between urban, medium, and low density monthly service charges would be very roughly within the same order of magnitude as those in Hydro One's service territory.

RESPONSE:

Alectra Utilities is an urban utility. There is no significant customer-density differentiation across the various areas it serves. Please refer to Table 1 for customer density per circuit km (cct km) of line for each rate zone.

Table 1 – Customer Density by Rate Zone

Rate Zone	Municipality	Customers (2025)	Cct km of Line	Density (customers/cct km of line)
BRZ	Brampton	161,941	3,443	47
ERZ	Mississauga	185,331	5,209	36
GRZ	Guelph	52,683	1,187	44
HRZ	Hamilton, St. Catharines	235,779	3,849	61
PRZ	York Region, Simcoe County	354,274	8,581	41
Alectra	All Service Territory	990,008	22,269	44

Specifically, in the areas mentioned, customer density is also consistent with the Table 1 ranges: fringe areas of Hamilton have 20 customers per cct km of line, while fringe areas of St. Catharines and Vaughanⁱ have 25 and 22 customers per cct km of line, respectively.

1 Hydro One's density-based rate design responds to the significant variation in customer
2 density across its service territory, ranging from highly urbanized areas to extremely rural
3 and remote regions. Hydro One's high-density areas are defined as more than 60 customers
4 per cct km of line, medium density – more than 15 customers, and low density – less than
5 15 customers per cct km of line.

6

7 In contrast, Alectra Utilities' service territory does not exhibit comparable density differences
8 to Hydro One, as customers are generally served in similarly urbanized or suburban
9 environments with comparable system configurations and service costs. Therefore, Alectra
10 Utilities' proposed rate structure appropriately reflects its cost structure and is consistent with
11 OEB rate design principles.

ⁱ ED-6_Rural Portion of Markham.pdf file supplied refers to the Vaughan service area

RESPONSES TO SCHOOL ENERGY COALITION PRE-SETTLEMENT QUESTIONS

SEC-1

Please confirm the OEB's 2031 SAIDI and SAIFI targets for Alectra, based on the OEB's [October 5, 2025 letter](#), would be the following:

(2020-2024 SAIDI excl MED and LOS average) = 0.878 (2-AMPCO-54)

2031 OEB SAIDI Target = $0.878 * (1 - 0.01)^6$

2031 OEB SAIDI Target = 0.827

(2020-2024 SAIFI excl MED and LOS average) = 1.108 (2-AMPCO-54)

2031 OEB SAIFI Target = $1.108 * (1 - 0.0025)^6$

2031 OEB SAIFI Target = 1.0915

RESPONSE:

Not confirmed. There are two errors in the SAIDI calculation and one error in the SAIFI calculation. The correct adjustment factors for Alectra Utilities were released by the OEB on October 30, 2025 which provided a SAIDI adjustment factor of 0%. Additionally, the formula provided by the OEB is listed as:

$$\text{Target} = \text{Baseline} * (1 - \text{Adjustment Factor})^2$$

Alectra Utilities has provided the correct calculation for each value below:

(2020-2024 SAIDI excl MED and LOS average) = 0.878 (2-AMPCO-54)

2031 OEB SAIDI Target = $0.878 * (1 - 0)^2$

2031 OEB SAIDI Target = 0.878

(2020-2024 SAIFI excl MED and LOS average) = 1.108 (2-AMPCO-54)

2031 OEB SAIFI Target = $1.108 * (1 - 0.0025)^2$

2031 OEB SAIFI Target = 1.102

- 1 It should be noted that the OEB metrics exclude both Loss of Supply and MEDs. Additionally,
- 2 the OEB reliability metric does not consider specific customer level reliability i.e. problem
- 3 areas or 'hot spots', where customers could be experiencing six or more outages a year.

1 **RESPONSES TO SCHOOL ENERGY COALITION PRE-SETTLEMENT QUESTIONS**

2

3 **SEC-2**

4

5 Reference: 1-SEC-23

6

7 Please provide the full billing determinant growth calculation for each year between 2029 and
8 2031.

9

10 **RESPONSE:**

11

12 Please see tables 1 to 3 below.

1 **Table 1 - 2029 Growth From Billing Determinants Calculations**

Rate Class	MFC (2028)	Variable Rate (2028)	Customers/ Connections (2027-2028)	kWh/kW (2028)	Customers/ Connections (2028-2029)	kWh/kW (2029)	Revenue at Current Rates	Revenue at Previous Year Rates
	A1	A2	B1	B2	C1	C2	D = A1*B1*12 + A2*B2	C = A1*C1*12 + A2*C2
Res	\$40.62	\$0.0000	999,713	9,039,740,601	1,004,087	9,367,473,816	\$487,258,750	\$489,390,631
GS<50 kW	\$49.98	\$0.0220	90,740	2,959,530,314	91,444	3,048,644,735	\$119,457,621	\$121,838,138
GS>50 kW	\$313.15	\$5.5207	12,043	34,563,166	11,865	34,740,791	\$236,068,182	\$236,379,907
Large Use	\$16,702.90	\$4.1833	32	4,062,420	33	4,234,072	\$23,408,292	\$24,326,804
LUDA	\$7,527.61	\$0.4452	6	1,601,912	6	1,605,512	\$1,255,211	\$1,256,813
S/L	\$1.45	\$10.1521	274,515	264,120	275,412	265,150	\$7,472,376	\$7,498,488
Sentinel	\$6.91	\$17.4637	396	1,559	385	1,489	\$60,063	\$57,930
USL	\$10.85	\$0.0254	11,668	47,800,570	11,707	48,165,810	\$2,731,901	\$2,746,245
TOA, GS<50 kW	\$0.00	-\$0.0032	0	11,267,152	0	11,606,417	-\$36,055	-\$37,141
TOA, GS>50 kW	\$0.00	-\$0.5920	0	10,928,117	0	10,959,262	-\$6,469,136	-\$6,487,574
TOA, Large Use	\$0.00	-\$0.5920	0	3,991,734	0	4,160,400	-\$2,362,994	-\$2,462,839
							\$868,844,211	\$874,507,404
							Growth % = (C/D)-1	0.65%

3 **Table 2 - 2030 Growth From Billing Determinants Calculations**

Rate Class	MFC (2029)	Variable Rate (2029)	Customers/ Connections (2028-2029)	kWh/kW (2029)	Customers/ Connections (2029-2030)	kWh/kW (2030)	Revenue at Current Rates	Revenue at Previous Year Rates
	A1	A2	B1	B2	C1	C2	D = A1*B1*12 + A2*B2	C = A1*C1*12 + A2*C2
Res	\$42.44	\$0.0000	1,004,087	9,367,473,816	1,008,422	9,787,463,479	\$511,349,685	\$513,557,363
GS<50 kW	\$52.22	\$0.0230	91,444	3,048,644,735	92,133	3,156,460,493	\$127,305,039	\$130,212,372
GS>50 kW	\$327.20	\$5.7684	11,865	34,740,791	11,711	34,851,354	\$246,986,323	\$247,019,429
Large Use	\$17,452.37	\$4.3710	33	4,234,072	35	4,611,469	\$25,418,351	\$27,486,819
LUDA	\$7,865.37	\$0.4652	6	1,605,512	6	1,605,512	\$1,313,207	\$1,313,207
S/L	\$1.52	\$10.6076	275,412	265,150	276,311	265,240	\$7,834,947	\$7,852,295
Sentinel	\$7.22	\$18.2473	385	1,489	375	1,449	\$60,532	\$58,933
USL	\$11.34	\$0.0265	11,707	48,165,810	11,746	48,531,370	\$2,869,470	\$2,884,466
TOA, GS<50 kW	\$0.00	-\$0.0032	0	11,606,417	0	12,016,879	-\$37,141	-\$38,454
TOA, GS>50 kW	\$0.00	-\$0.5920	0	10,959,262	0	10,984,719	-\$6,487,574	-\$6,502,643
TOA, Large Use	\$0.00	-\$0.5920	0	4,160,400	0	4,531,230	-\$2,462,839	-\$2,682,360
							\$914,149,999	\$921,161,427
							Growth % = (C/D)-1	0.77%

1 **Table 3 - 2031 Growth From Billing Determinants Calculations**

Rate Class	MFC (2030)	Variable Rate (2030)	Customers/ Connections (2029-2030)	kWh/kW (2030)	Customers/ Connections (2030-2031)	kWh/kW (2031)	Revenue at Current Rates	Revenue at Previous Year Rates
	A1	A2	B1	B2	C1	C2	$D = A1*B1*12 + A2*B2$	$C = A1*C1*12 + A2*C2$
Res	\$44.83	\$0.0000	1,008,422	9,787,463,479	1,012,755	10,180,627,801	\$542,452,091	\$544,782,906
GS<50 kW	\$55.16	\$0.0243	92,133	3,156,460,493	92,806	3,259,485,792	\$137,538,624	\$140,482,761
GS>50 kW	\$345.61	\$6.0930	11,711	34,851,354	11,578	34,981,172	\$260,917,700	\$261,157,088
Large Use	\$18,434.30	\$4.6170	35	4,611,469	36	4,855,310	\$29,033,334	\$30,380,348
LUDA	\$8,307.91	\$0.4914	6	1,605,512	6	1,605,512	\$1,387,093	\$1,387,093
S/L	\$1.61	\$11.2045	276,311	265,240	277,208	265,260	\$8,294,096	\$8,311,597
Sentinel	\$7.63	\$19.2740	375	1,449	364	1,419	\$62,249	\$60,664
USL	\$11.97	\$0.0280	11,746	48,531,370	11,784	48,896,950	\$3,046,758	\$3,062,455
TOA, GS<50 kW	\$0.00	-\$0.0032	0	12,016,879	0	12,409,104	-\$38,454	-\$39,709
TOA, GS>50 kW	\$0.00	-\$0.5920	0	10,984,719	0	11,003,595	-\$6,502,643	-\$6,513,818
TOA, Large Use	\$0.00	-\$0.5920	0	4,531,230	0	4,770,828	-\$2,682,360	-\$2,824,195
							\$973,508,487	\$980,247,189
							Growth % = (C/D)-1	0.69%

2

RESPONSES TO SCHOOL ENERGY COALITION PRE-SETTLEMENT QUESTIONS

SEC-3

Reference: 2A-SEC-53

Please provide the sale proceeds on an after-tax basis.

RESPONSE:

Table 1 – Facility Sale Proceeds (after-tax basis)

Sale Proceeds	\$MM
Mavis Carrying Value	(\$11.6)
Sale Proceeds	\$25.5
Proceeds before tax	\$13.9
Tax	(\$0.9)
Proceeds after tax	\$13.0
Sandalwood Carrying Value	(\$25.5)
Sale Proceeds	\$30.3
Proceeds before tax	\$4.8
Tax	(\$0.2)
Proceeds after tax	\$4.6
Mavis/Sandalwood after tax	\$17.6

RESPONSES TO SCHOOL ENERGY COALITION PRE-SETTLEMENT QUESTIONS

SEC-4

Reference: 6-SEC-95; 6-Staff-207; JT1.1.12a

Please provide an updated PILs model that includes the impact of Bill C-15 and the updated tax credits referenced in 6-Staff-207/ JT1.1.12 (Scenario 1).

RESPONSE:

Please see Attachment SEC-4_Attach 1_PILs Model, which is based on the PILs Model provided in reference 6-SEC-95 and already incorporates the impact of Bill C-15. The following changes have been made to that version of the PILs model based on the PILs model in reference JT1.1.12a:

- i) The investment tax credit amount in Tab "T0 PILs, Tax Provision Test", row 21, has been updated from \$565,000 to \$1,000,112.
- ii) The miscellaneous tax credit amount in Tab "T0 PILs, Tax Provision Test", row 22 has been updated from \$350,000 to \$418,077.
- iii) The total investment tax credit and corresponding gross up amount in Tab "T0 PILs, Tax Provision Test", rows 31 and 32 have been deleted to remove the reclass to Other Revenue.
- iv) The adjustment to taxable income to adjust for Prior Year Investment Tax Credits Received in Tab "T1 Sch 1 Taxable Income Test", row 64, has been changed from \$915,000 to \$1,418,189.
- v) The adjustment to taxable income to adjust for Current year ITCs accrued for accounting in Tab "T1 Sch 1 Taxable Income Test" row 106 has been deleted.

SEC-4

**Attachment 1
PILs Model**

Please see live Excel

RESPONSES TO SCHOOL ENERGY COALITION PRE-SETTLEMENT QUESTIONS

SEC-5

Reference: JT1.1.12

Notwithstanding Alectra's response to part (b) and (c), has Alectra in the last 5 years included any tax credits as taxable income as part of its tax filings? If so, please provide details.

RESPONSE:

Table 1 presents the 2020 – 2024 tax credits inclusion in taxable income.

Table 1 - Tax credits included in taxable income

	Included in Taxable Income						
	2020	2021	2022	2023	2024	2025	Total
2020 Tax Credits	70,867	192,514	447,708				711,089
2021 Tax Credits		68,677	630,913				699,590
2022 Tax Credits		-	83,518	992,585	-	-	1,076,103
2023 Tax Credits		-	-	103,027	1,117,584	-	1,220,611
2024 Tax Credits		-	-	-	204,641	1,753,212	1,957,853
Total	70,867	261,191	1,162,139	1,095,612	1,322,225	1,753,212	5,665,246

Notes:

- i) The non-proxy portion of the Ontario SR&ED tax credit is included in taxable income in the year claimed.
- ii) All other tax credits are included in taxable income in the first year after the year it is utilized.
- iii) 2020 Federal SR&ED tax credit was utilized in 2021 and included in taxable income in 2022.

RESPONSES TO SCHOOL ENERGY COALITION PRE-SETTLEMENT QUESTIONS

SEC-6

Reference: JT 2.35, Table 1, Ex. 4, Table 4-1-71

- a. Please breakout the actual cost in 2025 of GRE&T shown in JT2.35 Table 1 into Revenue and Net as shown in Table 4-1-71 for the forecast.
- b. Please provide details on the source(s) of the revenue.
- c. Please confirm the actual amount funded by the shareholder for GRE&T in 2025.
- d. Please confirm that for 2027 the forecasted total cost of GRE&T is \$3.16M, external revenues (\$0.38M), net \$2.77M, of which \$2.6M will be funded by the shareholder.

RESPONSE:

- a. Please see the table below, which provides a breakdown of the Revenue and Net.

Table 1 – 2025 GRE&T Centre Costs

GRE&T Center (\$MM)	2025
Total	2.88
Revenue	(0.46)
Net	2.42

- b. The source of the revenue is primarily attributable to the Scientific Research and Experimental Development (SR&ED) tax credit (81%) from the Canadian Federal Government, with the remainder from eMobility related government funding programs through Natural Resources Canada (NRCan).
- c. The actual amount funded by the shareholder for GRE&T in 2025 was \$2.33M.
- d. Confirmed. For 2027, the forecasted total cost of GRE&T is \$3.16M, external revenues (\$0.38M), net \$2.77M, of which \$2.6M will be funded by the shareholder. Please refer to IR response 1-SEC-19 for details.

1 **RESPONSES TO SCHOOL ENERGY COALITION PRE-SETTLEMENT QUESTIONS**

2

3 **SEC-7**

4

5 Reference: JT 3.11

6

7 Please expand Table 1 to include information from 2020 to 2026.

8

9 **RESPONSE:**

10

11 The information from 2020 to 2026 is included in the table below.

12

13 **Table 1 – Net Labour-Related Shared Corporate Services**

2020	2021	2022	2023	2024	2025	2026
\$2,907,149	\$ 3,090,529	\$ 5,144,531	\$ 4,080,957	\$ 4,582,520	\$ 4,041,332	\$ 4,145,846

RESPONSES TO SCHOOL ENERGY COALITION PRE-SETTLEMENT QUESTIONS

SEC-8

Reference: JT 3.15, 1-SEC-24, Attachment 7 App 2-K

With respect to Appendix 2-K:

- a. Please update Table 1 in JT3.15 for 2025 actuals.
- b. Please explain the reasons for the variance between the total budgeted 2025 FTEs (before vacancies) of 1627.7 and the total actual 2025 FTEs (before vacancies) of 1504.
- c. Please reconcile the 123.7 fewer actual FTEs (1627.7-1504) than forecast, with only a \$0.3M (\$311.2M-\$310.9M) variance in actual compensation costs.
- d. Based on 2025 actuals, please provide for each year the number of permanent positions and how that is translated into the permanent FTEs in row 1.
- e. Based on 2025 actuals, please explain the reasons for the reduction of FTEs shown in Table 1 of JT3.15, including any eliminated positions.

RESPONSE:

- a. Table 1 below provides an update of JT3.15 with 2025 actuals.

Table 1 - FTE Updated with 2025 Actuals

FTE	Actuals				Budget			
	2025	2025	2026	2027	2028	2029	2030	2031
Permanent	1378.2	1470.8	1523.2	1535.9	1592.3	1666.5	1736.0	1759.0
Temps and Students	108.5	112.4	104.8	87.1	87.0	83.0	80.0	80.0
Total FTE Added (perm and temp)	41.4	79.0	20.9	88.5	78.3	72.0	26.0	16.0
Total FTE Removed (perm and temp)	-24.2	-34.3	-25.8	-32.3	-8.1	-5.5	-3.0	0.0

FTE	Actuals				Budget			
	2025	2025	2026	2027	2028	2029	2030	2031
Total FTE after Addition and Removal	1503.9	1627.9	1623.0	1679.2	1749.5	1816.0	1839.0	1855.0
Vacancy Assumption %	7.6%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%
Vacancy Assumption FTE	124	76.5	76.3	78.9	82.2	85.4	86.4	87.2
Total FTE (Exclude Vacancy)	1503.9	1551.4	1546.8	1600.2	1667.2	1730.6	1752.5	1767.8
Schedule 2-K FTE Total Before Vacancy		1627.9	1623.0	1679.2	1749.5	1816.0	1839.0	1855.0

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- b. The variance from total budgeted FTE in 2025 of 1628 as compared to actual 2025 FTE of 1504 is related to vacancies. The budgeted number does not include vacancies, while the actual FTE calculation is lower than budget due to vacancies.
- c. The reduction reflected in the 2025 actual labour cost is \$6.5M when compared to the budget (\$171.7M-\$165.1M). The variance of \$0.3M referenced in the question is for total OM&A. Please also see response to AMPCO-7.
- d. The table provided in JT3.15, did not include additions/removals in the permanent row. For purposes of this response, Alectra has restated the permanent FTE to include additions and removals which provides the total permanent FTE. The table below provides total permanent FTE and position by year. The variance between budgeted FTE and position is due to the recording of FTE for partial year. To clarify, an FTE may show as less than 1 if not budgeted for the full year while the position would count as 1.

1 **Table 2 – Permanent FTE and Position by Year**

	Actual				Budget			
FTE/Position	2025	2025	2026	2027	2028	2029	2030	2031
Permanent FTE	1395.3	1515.6	1518.3	1592.1	1662.5	1733.0	1759.0	1775.0
Permanent Position	1462	1523	1524	1601	1679	1733	1759	1775

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- 3 e. The reduction of FTE shown in Table 1 represents positions that have been removed due
4 to changes in operational work requirements. In some circumstances the position
5 reduction may result in a different position being added which would be included in the
6 additions line of the table.

1 **RESPONSES TO SCHOOL ENERGY COALITION PRE-SETTLEMENT QUESTIONS**

2

3 **SEC-9**

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5 Reference: JT 3.26

6

7 Please provide the underlying calculations for Table 1, Line 18.

8

9 **RESPONSE:**

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11 Please see tables 1 to 4 below for the calculation of Line 18, Revenue at Existing Rates. The
12 calculations below are based on the illustrative alternative calculation of the Revenue Growth
13 Factor provided in response to JT-3.26. As described in that response, the alternative
14 approach replaced the percentage-based inflation and billing determinant growth back-off
15 adjustments with a dollar-based approach.

1 **Table 1 - 2028 Revenue at Existing Rates Calculation**

Rate Class	MFC (2027)	Variable Rate (2027)	Customers/ Connections (2026-2027)	kWh/kW (2027)	Customers/ Connections (2027-2028)	kWh/kW (2028)	Revenue at Current Rates	Revenue at Previous Year Rates
	A1	A2	B1	B2	C1	C2	D = A1*B1*12 + A2*B2	C = A1*C1*12 + A2*C2
Res	\$38.26	\$0.0000	995,488	8,726,286,424	999,713	9,039,740,601	\$457,048,451	\$458,988,233
GS<50 kW	\$47.08	\$0.0207	90,063	2,875,761,314	90,740	2,959,530,314	\$110,410,252	\$112,526,748
GS>50 kW	\$294.98	\$5.2004	12,243	34,388,480	12,043	34,563,166	\$222,171,131	\$222,371,620
Large Use	\$15,733.81	\$3.9406	32	4,047,427	32	4,062,420	\$21,991,075	\$22,050,154
LUDA	\$7,090.86	\$0.4194	6	1,605,512	6	1,601,912	\$1,183,894	\$1,182,384
S/L	\$1.37	\$9.5631	273,617	264,100	274,515	264,120	\$7,023,878	\$7,038,833
Sentinel	\$6.51	\$16.4505	406	1,609	396	1,559	\$58,184	\$56,579
USL	\$10.22	\$0.0239	11,624	47,436,520	11,668	47,800,570	\$2,559,300	\$2,573,397
TOA, GS<50 kW	\$0.00	-\$0.0032	0	10,948,237	0	11,267,152	-\$35,034	-\$36,055
TOA, GS>50 kW	\$0.00	-\$0.5920	0	10,895,945	0	10,928,117	-\$6,450,092	-\$6,469,136
TOA, Large Use	\$0.00	-\$0.5920	0	3,977,002	0	3,991,734	-\$2,354,273	-\$2,362,994
							\$813,606,766	\$817,919,762

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4 **Table 2 - 2029 Revenue at Existing Rates Calculation**

Rate Class	MFC (2028)	Variable Rate (2028)	Customers/ Connections (2027-2028)	kWh/kW (2028)	Customers/ Connections (2028-2029)	kWh/kW (2029)	Revenue at Current Rates	Revenue at Previous Year Rates
	A1	A2	B1	B2	C1	C2	D = A1*B1*12 + A2*B2	C = A1*C1*12 + A2*C2
Res	\$40.61	\$0.0000	999,713	9,039,740,601	1,004,087	9,367,473,816	\$487,124,444	\$489,255,738
GS<50 kW	\$49.97	\$0.0220	90,740	2,959,530,314	91,444	3,048,644,735	\$119,424,695	\$121,804,555
GS>50 kW	\$313.06	\$5.5192	12,043	34,563,166	11,865	34,740,791	\$236,003,113	\$236,314,753
Large Use	\$16,698.30	\$4.1822	32	4,062,420	33	4,234,072	\$23,401,840	\$24,320,098
LUDA	\$7,525.53	\$0.4451	6	1,601,912	6	1,605,512	\$1,254,865	\$1,256,467
S/L	\$1.45	\$10.1493	274,515	264,120	275,412	265,150	\$7,470,317	\$7,496,421
Sentinel	\$6.91	\$17.4589	396	1,559	385	1,489	\$60,047	\$57,914
USL	\$10.85	\$0.0254	11,668	47,800,570	11,707	48,165,810	\$2,731,148	\$2,745,488
TOA, GS<50 kW	\$0.00	-\$0.0032	0	11,267,152	0	11,606,417	-\$36,055	-\$37,141
TOA, GS>50 kW	\$0.00	-\$0.5920	0	10,928,117	0	10,959,262	-\$6,469,136	-\$6,487,574
TOA, Large Use	\$0.00	-\$0.5920	0	3,991,734	0	4,160,400	-\$2,362,994	-\$2,462,839
							\$868,602,282	\$874,263,881

1 **Table 3 - 2030 Revenue at Existing Rates Calculation**

Rate Class	MFC (2029)	Variable Rate (2029)	Customers/ Connections (2028-2029)	kWh/kW (2029)	Customers/ Connections (2029-2030)	kWh/kW (2030)	Revenue at Current Rates	Revenue at Previous Year Rates
	A1	A2	B1	B2	C1	C2	D = A1*B1*12 + A2*B2	C = A1*C1*12 + A2*C2
Res	\$42.45	\$0.0000	1,004,087	9,367,473,816	1,008,422	9,787,463,479	\$511,464,417	\$513,672,591
GS<50 kW	\$52.23	\$0.0230	91,444	3,048,644,735	92,133	3,156,460,493	\$127,333,603	\$130,241,588
GS>50 kW	\$327.27	\$5.7697	11,865	34,740,791	11,711	34,851,354	\$247,041,737	\$247,074,853
Large Use	\$17,456.28	\$4.3720	33	4,234,072	35	4,611,469	\$25,424,055	\$27,492,986
LUDA	\$7,867.14	\$0.4653	6	1,605,512	6	1,605,512	\$1,313,501	\$1,313,501
S/L	\$1.52	\$10.6100	275,412	265,150	276,311	265,240	\$7,836,704	\$7,854,057
Sentinel	\$7.22	\$18.2514	385	1,489	375	1,449	\$60,543	\$58,947
USL	\$11.34	\$0.0265	11,707	48,165,810	11,746	48,531,370	\$2,870,114	\$2,885,113
TOA, GS<50 kW	\$0.00	-\$0.0032	0	11,606,417	0	12,016,879	-\$37,141	-\$38,454
TOA, GS>50 kW	\$0.00	-\$0.5920	0	10,959,262	0	10,984,719	-\$6,487,574	-\$6,502,643
TOA, Large Use	\$0.00	-\$0.5920	0	4,160,400	0	4,531,230	-\$2,462,839	-\$2,682,360
							\$914,357,122	\$921,370,179

3 **Table 4 - 2031 Revenue at Existing Rates Calculation**

Rate Class	MFC (2030)	Variable Rate (2030)	Customers/ Connections (2029-2030)	kWh/kW (2030)	Customers/ Connections (2030-2031)	kWh/kW (2031)	Revenue at Current Rates	Revenue at Previous Year Rates
	A1	A2	B1	B2	C1	C2	D = A1*B1*12 + A2*B2	C = A1*C1*12 + A2*C2
Res	\$44.86	\$0.0000	1,008,422	9,787,463,479	1,012,755	10,180,627,801	\$542,884,558	\$545,217,231
GS<50 kW	\$55.20	\$0.0243	92,133	3,156,460,493	92,806	3,259,485,792	\$137,648,276	\$140,594,761
GS>50 kW	\$345.88	\$6.0978	11,711	34,851,354	11,578	34,981,172	\$261,125,715	\$261,365,294
Large Use	\$18,449.00	\$4.6206	35	4,611,469	36	4,855,310	\$29,056,481	\$30,404,568
LUDA	\$8,314.53	\$0.4918	6	1,605,512	6	1,605,512	\$1,388,199	\$1,388,199
S/L	\$1.61	\$11.2134	276,311	265,240	277,208	265,260	\$8,300,708	\$8,318,224
Sentinel	\$7.63	\$19.2894	375	1,449	364	1,419	\$62,299	\$60,713
USL	\$11.98	\$0.0280	11,746	48,531,370	11,784	48,896,950	\$3,049,187	\$3,064,896
TOA, GS<50 kW	\$0.00	-\$0.0032	0	12,016,879	0	12,409,104	-\$38,454	-\$39,709
TOA, GS>50 kW	\$0.00	-\$0.5920	0	10,984,719	0	11,003,595	-\$6,502,643	-\$6,513,818
TOA, Large Use	\$0.00	-\$0.5920	0	4,531,230	0	4,770,828	-\$2,682,360	-\$2,824,195
							\$974,291,966	\$981,036,163

RESPONSES TO SCHOOL ENERGY COALITION PRE-SETTLEMENT QUESTIONS

SEC-10

Reference: JT 3.33

The undertaking provides the impact for a hypothetical customer in three different scenarios under Alectra's proposal. However, the undertaking sought a comparison between that and what the status quo would be for that same customer in each existing rate zone based on the current approved standby rate and/or gross load billing methodologies (as applicable), using common rates to better understand the impact of the proposal. Please provide an updated response.

RESPONSE:

Alectra Utilities expands its response to JT-3.33 to demonstrate the impact of the standby proposal in comparison to the current OEB-approved standby and/or gross load billing (GLB) methodologies in each rate zone.

Tables 1 and 2 provide the assumptions used to illustrate the impacts. Only volumetric demand charges were considered, as only those are affected by the standby proposal. Table 1 lists the 2027 transmission and delivery rates¹. A hypothetical rate rider of \$1.00/kW is assumed for the purpose of illustrating the impact. Table 2 provides assumptions for kW volumes.

¹ Last updated through the interrogatory responses submitted on February 20, 2026

1 **Table 1 – Assumptions: Common Set of Rates for GS>50 kW Example**

	Rate (\$/kW)
2027 Proposed Distribution Volumetric Rate	5.2004
2027 Proposed Standby Power Rate	5.2004
Hypothetical Volumetric Rate Riders (to illustrate the impact)	1.0000
2027 Proposed Low Voltage	0.1706
2027 Proposed RTSR - Network	4.8104
2027 Proposed RTSR - Line and Transformation Connection	2.8600

4 **Table 2 - Assumptions: Volumes (kW) for GS>50 kW Example**

	Volume (kW)
Average Billed Demand	300
Generator Capacity	100
Contract Demand	400

7 Table 3 summarizes current methodologies for billing standby in each rate zone.

9 **Table 3 – Current Approved Standby and GLB Methodologies**

Rate Zone	Standby Methodology
BRZ	Gross Demand less Metered Demand
ERZ	Gross Demand (GLB)
GRZ	Gross Demand less Metered Demand
HRZ	Contracted Reserve Capacity; or Gross Demand less Metered Demand
PRZ	Contracted Reserve Capacity

11 Table 4 illustrates the resulting gross demand and standby volumes under the current and
12 proposed methodologies.

1 **Table 4 – Customer Volumes (kW) for GLB and Standby**

	Current	Proposed
Metered Demand	300	300
Generation Capacity	100	100
Gross Demand (Metered + Generation)	$300 + 100 = 400$	$300 + 100 = 400$
Contracted Reserve Capacity	100	$300 + 100 = 400$
Standby Demand	Contracted Reserve Capacity <u>or</u> Gross Demand /less Metered Demand 100	Contracted Reserve Capacity /less Metered Demand, where min=0, max=Generation Capacity 100

2

1 Table 5 illustrates the calculation of the applicable bill components under the current vs. proposed method by rate zone and the resulting differences for customers who are billed
2 standby charges².

3
4 **Table 5 – Impact under the Standby Power Method**

	2027 Proposed Rates (\$/kW)	BRZ					ERZ					GRZ					HRZ					PRZ				
		Current		Proposed Contract		Impact	Current		Proposed Contract		Impact	Current		Proposed Contract		Impact	Current		Proposed Contract		Impact	Current		Proposed Contract		Impact
		kW	\$	kW	\$		kW	\$	kW	\$		kW	\$	kW	\$		kW	\$	kW	\$		kW	\$	kW	\$	
Dx Volumetric Rate	5.2004	300	1,560	300	1,560	\$ -	400	2,080	300	1,560	\$ (520)	300	1,560	300	1,560	\$ -	300	1,560	300	1,560	\$ -	300	1,560	300	1,560	\$ -
Standby Charge	5.2004	100	520	100	520	\$ -	0	-	100	520	\$ 520	100	520	100	520	\$ -	100	520	100	520	\$ -	100	520	100	520	\$ -
Volumetric Rate Riders	1.0000	300	300	300	300	\$ -	400	400	300	300	\$ (100)	300	300	300	300	\$ -	300	300	300	300	\$ -	300	300	300	300	\$ -
Low Voltage	0.1706	300	51	300	51	\$ -	400	68	300	51	\$ (17)	300	51	300	51	\$ -	300	51	300	51	\$ -	300	51	300	51	\$ -
RTSR Network	4.8104	300	1,443	300	1,443	\$ -	300	1,443	300	1,443	\$ -	300	1,443	300	1,443	\$ -	300	1,443	300	1,443	\$ -	300	1,443	300	1,443	\$ -
RTSR Connection	2.8600	300	858	300	858	\$ -	300	858	300	858	\$ -	300	858	300	858	\$ -	300	858	300	858	\$ -	300	858	300	858	\$ -
Total Impact						\$ -					\$ (117)					\$ -					\$ -					\$ -

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6
7 Table 6 illustrates the calculation of the applicable bill components under the current vs. proposed method by rate zone and the resulting differences for GLB customers.

8
9 **Table 6 – Impact under the GLB Method**

	2027 Proposed Rates (\$/kW)	BRZ					ERZ					GRZ					HRZ					PRZ				
		Current		Proposed GLB		Impact	Current		Proposed GLB		Impact	Current		Proposed GLB		Impact	Current		Proposed GLB		Impact	Current		Proposed GLB		Impact
		kW	\$	kW	\$		kW	\$	kW	\$		kW	\$	kW	\$		kW	\$	kW	\$		kW	\$	kW	\$	
Dx Volumetric Rate	5.2004	400	2,080	400	2,080	\$ -	400	2,080	400	2,080	\$ -	400	2,080	400	2,080	\$ -	400	2,080	400	2,080	\$ -	400	2,080	400	2,080	\$ -
Standby Charge	5.2004	0	-	0	-	\$ -	0	-	0	-	\$ -	0	-	0	-	\$ -	0	-	0	-	\$ -	0	-	0	-	\$ -
Volumetric Rate Riders	1.0000	400	400	300	300	\$ (100)	400	400	300	300	\$ (100)	400	400	300	300	\$ (100)	400	400	300	300	\$ (100)	400	400	300	300	\$ (100)
Low Voltage	0.1706	400	68	300	51	\$ (17)	400	68	300	51	\$ (17)	400	68	300	51	\$ (17)	400	68	300	51	\$ (17)	400	68	300	51	\$ (17)
RTSR Network	4.8104	300	1,443	300	1,443	\$ -	300	1,443	300	1,443	\$ -	300	1,443	300	1,443	\$ -	300	1,443	300	1,443	\$ -	300	1,443	300	1,443	\$ -
RTSR Connection	2.8600	300	858	300	858	\$ -	300	858	300	858	\$ -	300	858	300	858	\$ -	300	858	300	858	\$ -	300	858	300	858	\$ -
Total Impact						\$ (117)					\$ (117)					\$ (117)					\$ (117)					\$ (117)

² The impacts for customers in ERZ is comparison of current GLB method vs. proposed Contract demand method.

RESPONSES TO SCHOOL ENERGY COALITION PRE-SETTLEMENT QUESTIONS

SEC-11

Reference: JT 3.35, Attach 1, Tab Data Centre Adjustment; 2A-SEC-38, Table 1

With respect to data centres:

- a. Please reconcile the number of data centres shown in Table 1 with the added customers in Attachment 1.
- b. Please show how the MWs included in Attachment 1 for data centres were derived from the MWs shown in Table 1.

RESPONSE:

- a. 2A-SEC-38, Table 1 provides the projected monthly load capacity from 11 data centre applications, broken down by application and year, and JT-3.35, Attachment 1, "Data Centre Adjustment" tab illustrates actual adjustments that are made to the baseline customer and load forecast as a result of the "observed events to-date" approach as described in 3-SEC-75.

Specifically, Alectra Utilities reviewed the events observed to date for each of the 11 data centres included in 2A-SEC-38, Table 1, and updated its customer forecast with information on five (5) of the data centres, of which two (2) are current GS>50 kW customers. Therefore, three (3) new customers were added to the customer forecast, while two (2) existing customers were reclassified from GS>50 kW to Large Use, as illustrated in JT-3.35, Attachment 1.

1 b. The projected peak load in 2A-SEC-38, Table 1, was converted to annual billed demand
2 for inclusion in the load forecast adjustments in JT-3.35, per the methodology described
3 in 3-SEC-75 (b). Alectra Utilities applied the derived phased load growth percentages to
4 the projected peak load of the five (5) projects described in part a above. The resulting
5 load was then multiplied by 12 months to derive the annual billed demand adjustments
6 included in the JT-3.35, Attachment 1, "Data Centre Adjustment" tab.

7

8 Table 1 below demonstrates how the annual billed demand included in JT-3.35,
9 Attachment 1 were derived from 2A-SEC-38, Table 1.

1 **Table 1 – Data Centre Annual Billed Demand Derivation**

Application #	i) 2A-SEC-38, Table 1 (MW)						ii) 3-SEC-75, Table 1 x 3-SEC-75, Table 2 (MW)						iii) ii x 12, JT 3.35, Attachment 1 (MW)					
	'26	'27	'28	'29	'30	'31	'26	'27	'28	'29	'30	'31	'26	'27	'28	'29	'30	'31
1	40	49	75	81	89	100	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	0	4	12	48	-	-	-	-	-	-	-	-	-	-	-	-
3	-	17	22	16	30	40	-	5	7	5	13	19	-	61	79	60	159	225
4	-	-	10	17	10	40	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	10	17	40	-	-	-	-	-	-	-	-	-	-	-	-
6	-	2	10	12	12	24	-	1	3	4	5	11	-	7	36	43	64	135
7	3	4	6	7	8	8	1	1	2	3	4	4	11	14	21	37	45	48
8	5	8	13	18	22	22	1	2	4	8	10	11	18	29	46	96	124	132
9	4	1	4	6	8	15	1	0	1	3	4	8	14	4	14	32	45	90
10	-	-	-	40	40	40	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	5	8	20	48	-	-	-	-	-	-	-	-	-	-	-	-
Total	51	82	144	219	268	425	4	10	16	22	36	52	43	114	196	268	437	630

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1 **RESPONSES TO SCHOOL ENERGY COALITION PRE-SETTLEMENT QUESTIONS**

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3 **SEC-12**

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5 Reference: SC-SEC-8

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7 a) Please confirm that in Table 1 for line 'Total FTE (Exclude Vacancy)' 2025 actual 1503.9
8 is comparable to 2025 budget 1551.4.

9 b) Please expand Tables 1 and 2 to include actuals for 2020-2024.

10 c) Please explain the relationship between the numbers shown in Table 2 for line
11 'Permanent FTE' and the numbers shown in Table 1.

12

13 **RESPONSE:**

14

15 a) The line 'Total FTE (Exclude Vacancy)' 2025 actual 1503.9 is comparable to 2025 budget
16 1551.4. The 2025 budget figure does not include vacancies.

17

18 b) The tables below have been updated to provide the actuals for 2020 to 2024. Please
19 note that the vacancy rate is calculated based on the budgeted total FTE compared to
20 actual vacant FTE. For example, for 2025, the actual vacancy rate (%) is calculated as
21 follows: 124 vacant FTE divided by 1627.9 budgeted FTE (per table 1 in SEC-8), results
22 in a vacancy % of 7.6%.

1 **Table 1- FTE Actuals 2020-2025**

FTE	Actuals					
	2020	2021	2022	2023	2024	2025
Permanent	1356.52	1374.31	1365.51	1344.39	1361.60	1378.20
Temps and Students	65.5	90.4	80.2	94.4	101.3	108.5
Total FTE Added						41.4
Total FTE Removed						(24.2)
Total FTE after Addition and Removal	1422.0	1464.7	1445.7	1438.7	1462.9	1503.9
Vacancy Rate %	6.5%	3.4%	6.8%	8.6%	7.6%	7.6%
Vacancy FTE	99.4	51.9	105.2	136.0	120.3	124
Total FTE (Exclude Vacancy)	1422.0	1464.7	1445.7	1438.7	1462.9	1503.9

Schedule 2-K FTE Total	1422.0	1464.7	1445.7	1438.7	1462.9	1503.9
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Note: In order to provide the actual Total FTE Added and Total FTE removed for 2025, Alectra Utilities undertook a manual exercise and is unable to complete the exercise for 2020-2024 within the expected timeframe. The FTE figures provided are net of any additions or removals.

Table 2 – Actual Permanent FTE/Position 2020-2025

FTE/Position	Actual					
	2020	2021	2022	2023	2024	2025
Permanent FTE	1356.5	1374.3	1365.5	1344.4	1361.6	1395.3
Permanent Position	1414	1474	1476	1413	1438	1462

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- c) The difference between the numbers shown in SEC-8 Table 2 for line 'Permanent FTE' and the numbers shown in Table 1 is related to the treatment of added and removed positions. In Table 1 the permanent figure excludes the addition and removals while they are included in Table 2. For example, Table 1 states 1378.2 for 2025, and when the permanent additions and removals are accounted for (i.e., net FTE added/removed of 17.1 FTE) the total is 1395.3 as stated in Table 2. Note: for Table 1 and 2 updated with 2020-2024 actuals the permanent FTE are the same as additions and removals are not show in the table per the note in b).

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

PRE-SETTLEMENT QUESTIONS

VECC-CQ#1

Reference: JT-3.21.5

a) The undertaking asked: "Please explain how the LoadLoss-type variables used in Itron's models were constructed". The response does not specifically do so. Please provide an explanation as to the historic/forecast values for this variable were established

RESPONSE:

a) Loss-load variable accounts for the COVID-related change in electricity usage that is not captured by other variables, such as GMR or economic variables. The time-series index variable is used in three models: ERZ Residential Average Use, BRZ GS 50-699 kW, and BRZ GS 700-4,999 kW. The impact of the variable is small but helps explain some of the variance during the COVID period (April 2020 – March 2022) and, as a result, improves the model fit as measured by the Adjusted R^2 and other model statistics. Loss-load variables are used in models where the GMR variable or embedded model economic variables did not adequately account for the impact of COVID and measure the weather-normal (WN) variance relative to the 2019 (pre-COVID) reference point.

The calculations are as follows:

1) For each month of 2019 (base period), derive the WN monthly sales:

WN kWh Sales = Actual kWh Sales – Weather Impact, *where*

Weather impact = (Actual HDD – Normal HDD) x HDD Model Coefficient
+ (Actual CDD – Normal CDD) x CDD Model Coefficient

2) Weather-normalize the monthly sales from April 2020 through March 2022 as described in Step 1.

- 1 3) For each month from April 2020 through March 2022, calculate the change in
- 2 electricity usage (LossLoad) as the difference between WN monthly sales and
- 3 2019 WN sales.
- 4
- 5 4) Index the resulting time-series to April 2020 (with a value of 1.0) – the first month
- 6 of the “work at home” mandate.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

PRE-SETTLEMENT QUESTIONS

VECC-CQ#2

Reference: JT-3.21.7.1.1

a) The response states:

“COVID-19-related variables (incl. GMR variable) were not explicitly tested for inclusion in the updated (per SEC 69 (b)) GS<50 kW sales models. COVID variables that were in the original models were left in the updated models. There was no need to further test for COVID impact, as the updated models only incorporated new and customer data starting May 2025. The COVID variables do not impact the forecast.”

Were COVID-19 related variables (e.g. GMR variables) explicitly tested for inclusion in the initial Application’s GS<50 sales models for all five rate zones?

i. If not, why not?

ii. If yes, on what basis were they excluded from some models?

RESPONSE:

Response provided by Itron

Yes. COVID-19 GMR variables were explicitly tested in all the initial GS<50 kW sales models. The COVID variable was statistically significant in the BRZ, HRZ, and PRZ models, and statistically insignificant in the ERZ and GRZ models. Because the variable was not statistically significant, it was excluded from the ERZ and GRZ models. Its inclusion did not materially improve the model’s explanatory power (F-test, Adjusted R^2) and, as such, the variable was not retained in the final model specifications.

**RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION
PRE-SETTLEMENT QUESTIONS**

VECC-CQ#3

Reference: Exhibit 3, Tab 1, Schedule 4, Table 3-1-10

2-DRC-9

3-DRC-15

2-VECC-13, Table 2

a) Please reconcile the EV population forecast provided in DRC-9 and DRC-15 with that provided in Exhibit 3, Table 3-1-10.

b) Please reconcile the EV population forecast for 2030 provided in VECC-13, Table 2 with that provided in Exhibit 3, Table 3-1-10.

RESPONSE:

a) The EV population forecast figures presented in Exhibit 3, Table 3-1-10 are derived using the actual number of electric vehicles (EVs) in 2024 as the base year, with incremental forecast EV unit additions applied in the subsequent years. The incremental EV units are based on System Planning's EV projections, as documented in 2-DRC-9, 3-DRC-15, and 2-VECC-13, Table 2.

As the 2024 base-year EV adoption levels are already reflected in both the actual sales data and the baseline load forecast, only the incremental EV units beyond the 2024 actual count should be applied as an EV adjustment layer to the baseline load forecast. Please refer to Table 1 for EV Unit reconciliation.

1 **Table 1 - EV Unit Reconciliation**

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
2024 Base Year Actuals		59,308										
2-DRC-9, 3-DRC-15, 2-VECC-13	A	51,663	70,908	105,527	157,200	226,969	318,869	433,511	534,349	648,937	775,842	914,639
Incremental Additions (100%)	B		11,600	34,619	51,673	69,769	91,900	114,642	100,838	114,588	126,905	138,797
Incremental Additions (50%)	B/2		5,800	17,310								
Ex 3, Table 3-1-10			65,108	82,418	134,091	203,860	295,760	410,402	511,240			

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4 The 2025 incremental additions (100%) are derived based on 2024 actuals. The same
5 applies for 2025 EV population in Exhibit 3, Table 3-1-10 – it is derived by adding
6 incremental additions (50%) to 2024 actuals. Total EV population for 2025 is the sum of
7 2024 base year actuals of 59,308 and incremental additions (50%) for 2025 of 5,800.
8 Total EV population for 2026 is the sum of 2025 total population of 65,108 and
9 incremental additions (50%) of 17,310. As identified in Exhibit 3, Tab 1, Schedule 4, p.5,
10 Alectra reduced the incremental EV population growth for 2025-2026 by 50% due to
11 macroeconomic uncertainty and trade-related impacts. For 2027 to 2031, the EV
12 population is calculated as the sum of the prior year total and incremental additions
13 (100%).

14

15 b) Please see part a).

**RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION
PRE-SETTLEMENT QUESTIONS**

VECC-CQ#4

Reference: JT-3.21.9.2

a) What would be the impact on the 2026-2031 EV MWh/MW forecast if the EV sales target for 2035 was changed to 75%? Please provide supporting calculations in excel format.

RESPONSE:

a) Please refer to Table 1 below that show the impact on the 2026-2031 EV MWh forecast if the EV sales target for 2035 was changed to 75%. To illustrate the impact, Alectra Utilities adjusted the base EV adoption trajectory for Ontario's light-duty vehicle (LDV) ¹ segment derived from the Guidehouse Insights provincial forecast to 75% by 2035. The supporting calculations are supplied in VECC-CQ#4_Attach 1.

Please note that these calculations do not consider any additional impacts to EV projections as identified in response to JT-3.21.9. In that response, Alectra Utilities noted that as the government's announcements identify the policy objectives to accelerate EV uptake by increasing customer options for lower-priced EVs, providing incentives and improving charging infrastructure to reduce customer concerns of range anxiety, the announcements demonstrate a commitment to EV uptake. Alectra Utilities does not expect material changes to its EV projections over the 2027-2031 planning period.

¹ LDV charging loads are allocated for Residential and GS<50 kW rate classes (80% and 20%, respectively)

1 **Table 1 – 2026-2031 EV MWh Impact**

Year	100% Target (JT3.35)	75% Target	Impact on EV Sales Forecast (MWh)	Total Alectra Sales Forecast (MWh)	Impact as % of Total Sales
2026	69,979	56,374	(13,604)	27,592,239	-0.05%
2027	272,376	216,619	(55,757)	27,922,546	-0.20%
2028	541,505	428,241	(113,263)	28,437,676	-0.40%
2029	892,293	702,342	(189,951)	28,950,515	-0.66%
2030	1,325,720	1,039,917	(285,803)	29,622,532	-0.96%
2031	1,724,180	1,346,593	(377,587)	30,218,171	-1.25%

VECC-CQ#4

Attachment 1

Please see live Excel

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

PRE-SETTLEMENT QUESTIONS

VECC-CQ#5

Reference: Exhibit 3, Attachment 3-2, pages 32-36

Exhibit 2, Appendix J, page 42

a) Are the assumptions used in Ex 3, Attachment 2, pages 32-36 regarding building electrification for existing and new residential and ICI stock consistent with the Medium scenario in App. J?

b) If not, how do they differ?

RESPONSE:

a) Alectra Utilities confirms that all building electrification assumptions used in Exhibit 3, Attachment 2, pages 32-36, are consistent with the Medium scenario in Appendix J.

b) Please see part a).

**RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION
PRE-SETTLEMENT QUESTIONS**

VECC-CQ#6

Reference: 2.0-VECC-13 e)
3.0-VECC-39

- a) With respect to VECC 13 e) - Table 5, please breakout the residential and commercial contributions to decarbonization.
- b) Please reconcile the commercial values from part (a) with the commercial values in VECC 39, Table 1.

RESPONSE:

- a) Please see Table 1 below.

Table 1 – Decarbonization MW (Residential and Commercial)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	5.3	11.0	26.8	48.4	80.9	119.2	168.5	220.8	283.7	351.9	441.5
ICI	1.9	3.8	11.4	22.0	37.8	56.8	80.5	106.6	137.8	171.5	213.5
Total	7.0	15.0	38.0	70.0	119.0	176.0	249.0	327.0	421.0	523.0	655.0

- b) Please see Table 2 below.

Table 2 – VECC-39 and VECC-CQ6, Table 1 Reconciliation

Year	3-VECC-39 Chart 1 (MW)	VECC-CQ6 Table 1 (ICI MW)	Difference
2026	11.4	11.4	0
2027	21.98	21.98	0
2028	37.8	37.8	0
2029	56.78	56.78	0
2030	80.48	80.48	0
2031	106.56	106.56	0

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

PRE-SETTLEMENT QUESTIONS

VECC-CQ#7

Reference: 2A-SEC-38
3-SEC-75 b)

a) With respect to SEC 38-Table 1, for those projects where the OTC is denoted as imminent, please identify those where the OTC is now completed.

b) With respect to SEC 38-Table 1, for those projects that are noted as energized, what year were they first energized?

c) With respect to SEC 75 b), based on the same 5 years of history, what percentage of Data Centres that had an imminent OTC actually proceeded to be energized?

RESPONSE:

a) With respect to SEC 38-Table 1 as of May 5, 2026, the Offer to Connect for Application 1 has been finalized.

b) Table 2 below reflects an update on projects noted as 'energized', to include what year were they first energized.

1 **Table 2 - Data Centre Load and Energization Year for Applications Previously**
2 **Noted as Energized**

Application #	Data Centre Load (MW)						Status	Update on Projects Identified as Energized (Including Year of Energization)
	2026	2027	2028	2029	2030	2031		
7	3	4	6	7	8	8	Energized, OTC Completed	Energized in 2024
8	5	8	13	18	22	22	Energized, OTC Completed	Energized in 2025
9	4	1	4	6	8	15	Partially Energized	Phase 1 was energized in 2023, Phase 2 was energized in 2024

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4

5 c) The Data Centre projects included are those with a confirmed customer commitment.
6 Based on the past five years of history, all Data Centre projects that had an OTC
7 Imminent status have proceeded to be energized. Alectra Utilities has observed that
8 actual Data Centre load growth trajectories were lower and took longer to reach after
9 energization than the customer-provided load ramp-up schedule indicated. Data Centre
10 demand load is informed by the customer. The actual demand and timing of the load are
11 customer-dependent.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

PRE-SETTLEMENT QUESTIONS

VECC-CQ#8

Reference: Technical Conference, Day 4, pages 22-23
JT-4.3

a) In JT4.3-Table 2, if Adjustment #2 is for customer reclassification, as indicated during the Technical Conference, why doesn't the decrease in GS>50 MWh equal the increase in GS<50 MWh??

RESPONSE:

a) The 77 MWh variance between the GS<50 kW rate class and the GS>50 kW rate classes shown in JT4.3-Table 2, Adjustment #2, is attributable to GRZ FIT customers. As stated in response to JT-4.3, Adjustment #2 includes ERZ FIT MWh and MW reclassified from GS>50 to GS<50 and estimated GRZ FIT MWhs added to the forecast.

1 **Table 1 - Breakdown of Table 3-1-24: 2025-2031 General Service Consumption**
2 **Forecast Adjustment (MWh)**

Adjustment Type	Rate Class	2025	2026	2027	2028	2029	2030	2031
Adjustment #1: BRZ DGEN Customer Count/MWh	GS<50 kW	-	-	294	294	294	294	294
	GS>50 kW, Regular	-	-	-	-	-	-	-
Adjustment #2: ERZ MWh/MW	GS<50 kW	145	217	217	217	217	217	217
	GS>50 kW, Regular	(145)	(217)	(217)	(217)	(217)	(217)	(217)
Adjustment #2: GRZ MWh/MW	GS<50 kW	51	77	77	77	77	77	77
	GS>50 kW, Regular	-	-	-	-	-	-	-
Adjustment #3: ERZ, GRZ, HRZ, PRZ Customer Count	GS<50 kW	-	-	-	-	-	-	-
	GS>50 kW, Regular	-	-	-	-	-	-	-
Total Adjustments	GS<50 kW	196	294	588	588	588	588	588
	GS>50 kW, Regular	(145)	(217)	(217)	(217)	(217)	(217)	(217)
	Total	51	77	371	371	371	371	371

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

PRE-SETTLEMENT QUESTIONS

VECC-CQ#9

Reference: 1-SEC-24, Attachment 6 (updated Appendix 2H)
6-CCC-46 b)
JT-3.21.22

a) In JT 3.21.22 are the values for 2024 and 2025 set out in Table 1 determined on the same basis as those for 2026-2031 in Table 2 (i.e., only 50% of the forecasted arrears in the 1–30-day category are included)? If not, please re-do Table 1 so as to be consistent with Table 2.

b) Please provide a schedule that for each of the years 2024 to 2031 sets out: i) the total actual/forecast distribution revenue plus cost of power revenues, ii) total actual/forecast arrears based on methodology used for Table 2 and iii) actual/forecast Late Payment revenues.

RESPONSE:

a) Table 1 in JT 3.21.22 includes 2024 and 2025 actual billed arrears greater than 1 day old. For further clarification, Table 2 contains forecast billed arrears from 2026-2031 and is presented on a consistent basis as Table 1. For the purposes of the Late Payment Charge (LPC) forecast, the monthly arrears in Table 2 are further broken down into their respective aging categories: arrears in the 31-60-day, 61-90-day and greater than 90-day categories forecast arrears are added to 50% of arrears in the 1–30-day category. The combined arrears are then multiplied by 1.5%.

b) A schedule of the 2024 to 2031 revenues and arrears is presented in Table 1 below.

1 **Table 1 – Schedule of Revenues, Arrears and Late Payment Revenues**

		Actual		Forecast					
\$MM		2024	2025	2026	2027	2028	2029	2030	2031
Distribution Revenue (excluding rate riders)		651.0	679.0	702.6	813.6	868.9	914.3	973.7	1,033.3
Cost of Power Revenue (excluding OER)		3,199.6	3,274.4	3,364.3	4,011.9	4,159.5	4,309.0	4,482.1	4,653.3
Total Revenues	(i)	3,850.6	3,953.4	4,066.9	4,825.5	5,028.5	5,223.3	5,455.8	5,686.6
Arrears	(ii)	761.9	728.6	634.1	731.3	760.0	794.3	835.6	875.3
Late Payment Revenues	(iii)	9.4	10.0	7.5	8.7	9.1	9.5	10.0	10.5

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

PRE-SETTLEMENT QUESTIONS

VECC-CQ#10

Reference: 7-Staff-232

a) What year's data was used for determining the number of accounts by class and the Biller FTE Allocation by Rate Class in Staff 232 – Table 1?

RESPONSE:

a) The number of accounts by class and the biller FTE information was based on data from Alectra's Customer Information System ("CIS") as of May 2024.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

PRE-SETTLEMENT QUESTIONS

VECC-CQ#11

Reference: 2.0-VECC-13 c)

1.0-Staff-1, Attachment 6 (Cost Allocation Model)

a) Please provide the EV charging load profiles used per VECC 13.

b) Please recalculate 4NCP allocator for each class: i) excluding MWh associated with building electrification and ii) using the EV charging profiles to determine impact of EV load on 4NCP values.

c) Please provide a revised version of Staff-1, Attachment 6, using the 4NCP values from part (b).

RESPONSE:

a) Please see Table 1 below.

Table 1 – EV Charging Load Profiles

Vehicle Type	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
LDV (MW)	186	140	106	80	61	59	78	121	156	158	142	144	155	166	189	251	312	417	480	490	450	374	317	253
MDV (MW)	0	0	0	0	25	50	75	70	64	49	30	8	0	0	0	6	31	57	74	60	51	42	24	6
HDV (MW)	0	0	0	0	0	0	0	0	6	6	6	0	0	0	0	0	13	24	32	23	16	9	0	0
Total	186	140	106	80	86	110	154	191	227	213	179	152	155	166	189	257	356	498	586	573	517	426	341	258

b) Please see Table 2, which presents the recalculated 4NCP values for each rate class in comparison to 4NCP values used in Staff-1, Attachment 6.

Table 2 – 4NCP Allocators (DNCP4)

Rate Class	1-STAFF-1	Updated
Residential	9,652,074	9,565,501
GS<50	2,573,342	2,537,513
GS>50	8,876,480	8,850,224
Large User	1,191,143	1,191,365
Large User Dedicated Asset	496,284	496,284
Street Lighting	91,377	91,377
Sentinel Lighting	589	589
Embedded Distributor	-	-
USL	21,498	21,498

c) Please see VECC-CQ#11_Attach 1.

VECC-CQ#11

Attachment 1

Please see live Excel

**RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION
PRE-SETTLEMENT QUESTIONS**

VECC-CQ#12

Reference: 8-SEC-105 a)
8-ED-39 c)
JT-4.12

a) SEC 105 shows 66 Standby customers in total but ED 39 & JT4.12 only show 62.
Please reconcile.

RESPONSE:

a) Alectra Utilities clarifies that Table 1 in 8-SEC-105 identifies 66 current Standby customers. In comparison, Table 2 in 8-ED-39 lists the Standby customers that would be subject to the proposed 2027 Standby rates, totaling 62 customers. As described in Exhibit 8, Tab 2, Schedule 2, page 18, Alectra Utilities proposes to exempt customers with generation capacity below 50 kW and customers with emergency backup generators from Standby charges. Four (4) of the 66 current Standby customers meet the proposed exemption criteria. Table 1 below reconciles the customer counts between the tables in responses to 8-SEC-105 and 8-ED-39.

Table 1 – Standby Customer Reconciliation

Reconciliation	Standby Customer Count
Existing Standby customers (8-SEC-105, Table 1)	66
Less: Existing Standby customers with generator capacity below 50 kW	(2)
Less: Emergency Backup Generator customers	(2)
Standby customers subject to proposed 2027 Standby rates (8-ED-39, Table 2)	62

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

PRE-SETTLEMENT QUESTIONS

VECC-CQ#13

Reference: Technical Conference, Day 3, pages 147-148

Preamble: The transcript reads:

“A. FRANK: Oh, I see. So just so I understand, it is the customers over a --
over the threshold would then be on gross load billing for both RTSRs and for
standby, and those under the threshold have the choice but only if they are
willing to have the metering arrangement installed; is that correct?

V. QUENVILLE: Below the threshold, they will have the choice if they have,
yes, metering infrastructure in place to measure gross load output.”

a) Will customers over the RTSR gross load billing threshold have a choice of being on
contract demand if they want to?

b) Could there be situations where a LDG customer is over the RTSR gross load billing
threshold but it is not technically possible to install a meter on the generation? If so, how
would GLB for the Connection RTSR be implemented?

RESPONSE:

a) Alectra Utilities proposes offering a choice between two billing methods - gross load
billing (GLB) or contract demand - to customers exceeding the RTSR gross load billing
threshold.

b) Alectra Utilities acknowledges there could be a situation where it is not technically
feasible to install a meter on the generation for an LDG customer exceeding the RTSR
gross load billing threshold. Alectra Utilities will assess the use of deductive metering or
the contract demand method to implement gross load billing of RTSR Connection
charges.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

PRE-SETTLEMENT QUESTIONS

VECC-CQ#14

Reference: JT-4.8

a) Does Alectra currently bill its LV charges on a gross load basis and, if not, does it propose to do so for 2027?

b) If the answer is no to both parts, please explain why.

RESPONSE:

a) Alectra Utilities currently bills LV charges on a gross load basis to the customers summarized in Table 3 of 8-SEC-105. Alectra Utilities is required to pay gross load billing to Hydro One for the ST volumetric charges with respect to customers with load displacement generation at 1MW or above, or 2MW or above for renewable generation, installed after October 1998.

Alectra Utilities expects to continue billing LV charges to those customers in a similar manner for 2027 and beyond.

b) Please see response to a).

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

PRE-SETTLEMENT QUESTIONS

VECC-CQ#15

Reference: VECC-CQ#14

In VECC's CQ#14 Alectra was asked: "Does Alectra currently bill its LV charges on a gross load basis and, if not, does it propose to do so for 2027?". In its response, Alectra states:

"Alectra Utilities currently bills LV charges on a gross load basis to the customers summarized in Table 3 of 8-SEC-105. Alectra Utilities is required to pay gross load billing to Hydro One for the ST volumetric charges with respect to customers with load displacement generation at 1MW or above, or 2MW or above for renewable generation, installed after October 1998."

It is noted that Table 3 only includes those customers that are subject to and billed for Standby using the Gross Load Billing approach. For those load displacement customers that are subject to and billed for Standby using the Contract Demand approach and the generation capacity is over the stated thresholds:

- a) How are they currently billed for LV charges and how does Alectra propose to bill them in 2027 and after?
- b) More specifically, how is the monthly kW billing determinant established?

RESPONSE:

- a) Load displacement customers that are subject to and billed for Standby using the Contract Demand approach and whose generation capacity exceeds the stated thresholds (refer to: 8-SEC-105, Table 2) are currently billed for LV charges on net (metered) kW demand. Those exceeding the threshold are currently billed on gross kW demand for Transmission Connection only.

Alectra Utilities proposes that effective January 1, 2027, all customers - regardless of the selected Standby Power option (GLB or Contract Demand) – be billed LV and Transmission Network/Transmission Connection on a net (metered) kW demand. However, if they exceed the applicable threshold and are on a true-up list by Hydro One, they will instead be billed on a gross kW demand for Transmission Connection and LV.

- b) Table 1 summarizes Alectra Utilities' current and proposed scenarios to establish the LV monthly kW billing determinant.

Table 1 – Current and Proposed Standby Power Options

	Standby Power Options	Below Threshold ¹	Above Threshold
Current	Gross Load Billing (GLB)	Gross kW	Gross kW
	Standby Charges	Net (Metered) kW	Net (Metered) kW
Proposed	Gross Load Billing (GLB)	Net (Metered) kW	Gross kW
	Contract Demand	Net (Metered) kW	Gross kW or Contract kW if not feasible to install meter on generator

1. Threshold: load displacement generation at 1MW or above, or 2MW or above for renewable generation