Responses to Interrogatories

Algoma Power Inc.
EB-2024-0007

Contents

Preamble

API wishes to inform the OEB and Intervenors of the potential of a future development affecting the #4 Circuit project outlined in Exhibit 2 of the Application and Interrogatories 2-Staff-8 and 1-VECC-1, and others.

API has been approached by an industrial customer regarding the potential sale to the customer of the distribution lines connecting the customer to the #4 circuit, which were constructed as part of the #4 circuit project. The purchase/sale of the assets is currently being considered by API and by the customer and there is no confirmation that such a transaction would occur. API and the customer are aware that OEB approval would be required prior to completing such a transaction if both parties were to agree to move forward.

Exhibit 1 – Administration

1-Staff-1

Updated Revenue Requirement Work Form (RRWF) and Models

Upon completing all interrogatories from Ontario Energy Board (OEB) staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), 12 and 13 (Rate Design) as well as the RRRP tab should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet and may also be included on other sheets in the RRWF to assist understanding of changes.

In addition, please file an updated set of models that reflects the interrogatory responses. Please ensure the models used are the latest available models on the OEB's 2024 Electricity Distributor Rate Applications webpage.

API Response:

Please see the attached set of models. The table below outlines the changes made:

Interrogatory Reference	Explanation	Line on RRWF Tracking Sheet
8-Staff-64	Update RTSR for UTRs	1
8-VECC-43	Update RTSR for 2023 RRR	1
8-Staff-61/8-VECC-45	Updated Misc. Charges for Pole Attachment	2
5-Staff-52	Update Cost of Capital -LTD	3
7-VECC-38	Update Cost Allocation- USL Meters	N/A- Later Tabs Affected
7-Staff-59	Update Cost Allocation Street Light Bills	N/A- Later Tabs Affected
8-VECC-40	Update DRP	N/A - Bill Impact Only
6-Staff-57	Update 1592 Balance (2023 Pr. Adj).	N/A-Bill Impact Only

In addition to the changes made above to the RRWF, API has also updated the following models:

Model	Reason For Updates
PILS	Updated Rate Base
RTSR Model	Updated UTRs, Use of 2023 RRR Data & Loss Factor
Cost Allocation	Update Revenue Requirement per changes above; update Street Lights number of bills and USL meter capital/meter reads
Chapter 2 Appendix	Updated Debt Instruments Schedule (2OB); And Capital Structure (2OA); Updated COP Calculation 2ZB for RTSR; Updated 2H for Pole Att.
DVA Model	Updated 1592 Balance per 6-Staff-57; Updated Revenue Requirement Allocator
Tariff and Bill Impact	Changes from Above; Updated Inflation Factor and DRP; Draft RRRP Adjustment per 8-Staff-62; Updated Rate Riders from DVA Model

API notes that as a result of the changes to the cost allocation model, the original rate mitigation measures proposed for the street lighting class are no longer required. API continues to propose mitigation measures for the Seasonal Class, namely a 2-step phase in of the revenue-to-cost ratio to be completed in 2026, as well as deferring the 2025 increase in fixed-variable split. These measures are reflected in tabs “11. Cost Allocation” and “12.Res_Rate_Design” of the attached RRWF model.

The bill impacts from this approach are reflected in the tables below:

	Distribution				Total Bill			
Classification	Current Bill	2025 Propose	Change ($)	Change (%)	Current Bill	2025 Propose	Change ($)	Change (%)
Residential R1(i)	$ 41.39	$ 35.36	$ (6.03)	-14.6%	$ 145.34	$ 138.78	$ (6.56)	-4.51%
Residential R1(ii)	$ 110.04	$ 109.18	$ (0.86)	-0.8%	$ 386.22	$ 382.98	$ (3.23)	-0.84%
Residential R2	$ 2,644.81	$ 1,247.54	$ (1,397.27)	-52.8%	$ 34,173.69	$ 26,659.43	$ (7,514.26)	-21.99%
Seasonal	$ 95.75	$ 104.82	$ 9.07	9.5%	$ 118.42	$ 126.79	$ 8.36	7.06%
Seasonal-10th percentile	$ 88.65	$ 96.58	$ 7.93	9.0%	$ 85.80	$ 93.22	$ 7.42	8.65%
Street Lighting	$ 1,275.00	$ 1,253.48	$ (21.52)	-1.7%	$ 1,549.84	$ 1,473.60	$ (76.25)	-4.92%

Additionally, the proposed RRRP funding has been updated to $ 20,690,577, based on the updated revenue requirement and allocations, as well as the draft RRRP factor mentioned in 8-Staff-62

1-Staff-2

Activity and Program Benchmarking
Ref 1: 2022 Unit Cost Calculations - October 11, 2023
Ref 2: Exhibit 1, Table 22, p. 72
Ref 3: Exhibit 1, p. 77

Preamble:
References 2 provides a summary of the Activity and Program Benchmarking unit cost results for Metering OM&A from reference 1.

In reference 2, Algoma Power states that:

> The higher-than-average Metering OM&A are in part due to the ongoing presence of hard-to-reach remote manually read meters. Algoma Power noted that its ability to limit manual meter reads is limited due to communication challenges with meters located in remote areas that make automated meter reading very difficult.
>
> Algoma Power further noted that cost increases are forecasted over the next few years due to inflationary impact. However, Algoma Power noted that the allocation of metering department time to the Smart Metering capital program beginning in 2025 will result in a reduction over 2023/2024.
>
> Reference 1 shows the following Unit costs ($/Customers) Metering OM&A for the historic period 2018-2022.

Unit Costs ($/Customers)

2018	2019	2020	2021	2022	Avg.
74.85	70.72	75.25	70.64	73.56	73.00

Question(s):

a) Reference 2 (Exh. 1, Table 22, p. 72) shows a constant cost of $74.85 per customer for Metering OM&A, while Reference 1 provides costs shown in the table above. Please explain the difference.

b) Please provide the allocation of the metering department's time for the Smart Metering capital program to Algoma Power.

c) Please provide a breakdown of smart meters to manually read meters in the Algoma Power service area.

d) In reference 3, Algoma Power notes that it has commissioned a study to evaluate the feasibility and performance of the cellular communication network throughout its service territory. Please explain the impact of the growth and evolution of the cellular network in recent years on the expansion of smart meters and the forecasted impact on Metering OM&A going forward.

API Response:

a) The contents of Table 22 contained a transposition error for the Metering O&M metric which incorrectly carried over the 2018 cost across all years.

b) The planned test year labour allocation to the Smart Meter Renewal project is $88,817; $39,336 is allocated from the Metering department, with the remaining labour cost coming from the technical services team.

c) API notes that some customers have smart meters which are manually read. The table below indicates the number of *communicating* smart meters versus the number of manually read meters. API further notes the table below does not include interval meters or unmetered connections. This data is accurate as of 2023. The data represents estimated values based on some meters being in fringe communication areas (ie: inconsistently communicate, low-read interval success).

Number of Communicating Smart Meters	12,257
Number of Manual Read Meters	128

d) The cellular network in API's territory has expanded over the years, but many locations still do not have proper cellular service. API has commissioned a comprehensive study to evaluate all communication needs, including proper backhaul for the smart meter system, including alternate communication means in those areas without adequate cell service.

Furthermore, API is working with our smart meter vendor on a propagation study to target those meters that are not communicating, looking at relocating tower sites to resolve communication issues and ensure towers have proper backhaul. Nonetheless, for some very remote customers, there are some locations where proper meter communications may not be feasible based on low customer density and geographic meter location. This would include the economic considerations, where for some customers, it may cost as much as $20,000 up front to meter the customer, plus an estimated $700 monthly.

1-Staff-3

Activity and Program Benchmarking
Ref 1: Exhibit 1, Table 22, p. 72

Preamble:
References 1 provides a summary of the Activity and Program Benchmarking unit cost results for Lines O&M OM&A from reference 1.

Question(s):

a) Please confirm the unit cost values from 2018 to 2023 Lines O&M. Through RRR OEB staff has unit values which appear to be offset by +1 year as seen provided below.

Distributor	Unit Cost ($/Circuit km of Primary Line)					
	2019	2020	2021	2022	2023	Average
Algoma Power Inc.	529.73	773.46	649.35	791.34	668.59	682.49

API Response:

The values for the unit cost per Primary line have been revised to reflect the correct period in the column, in line with the 2018- 2022 values of the cost calculation reports issued by the OEB. The value provided for 2023 was a forecasted value and not based on actuals. A revised chart is featured below:

Activity/Program	Most Recent APB Report							Forecast		
	2018	2019	2020	2021	2022	2018-2022 Avg	Industry Avg 2018-2022	2023	2024	2025
Billing ($/customer)	$ 13.62	$ 16.21	$ 18.78	$ 16.65	$ 15.41	**$ 16.14**	**$ 26.43**	$ 16.48	$ 20.19	$ 20.49
Metering O&M ($/customer)	$ 74.85	$ 70.72	$ 75.25	$ 70.64	$ 73.56	**$ 73.00**	**$ 13.96**	$ 79.28	$ 79.12	$ 75.83
Vegetation Management O&M ($/pole)	$ 119.15	$ 118.80	$ 124.03	$ 133.71	$ 132.10	**$ 125.56**	**$ 67.76**	$ 139.10	$ 138.29	$ 166.48
Lines O&M ($/circ. km Prim. Line)	$ 567.11	$ 529.73	$ 773.46	$ 649.35	$ 791.34	**$ 662.20**	**$ 1,042.09**	$ 672.33	$ 837.10	$1,093.89
Stations O&M ($/MVA)**	$ 718.11	$ 524.59	$ 281.52	$ 696.90	$ 589.27	**$ 562.08**	**$ 1,399.12**	$ 520.28	$ 823.81	$1,072.16
Poles, Towers and Fixtures O&M ($/Pole)	$ 3.35	$ 4.67	$ 3.92	$ 4.26	$ 3.09	**$ 3.86**	**$ 11.65**	$ 2.14	$ 5.33	$ 5.09
Stations CAPEX ($/MVA)**	$ 2.82	$ 1,330.11	$ 409.99	$5,636.21	$16,215.09	**$4,718.84**	**$ 3,234.89**	$ 234.41	$30,439.20	$ 189.30
Poles, Towers and Fixtures CAPEX ($/Pole Addition)	$ 6,153.97	$ 9,301.20	$ 6,828.43	$6,982.19	$ 5,263.19	**$6,905.80**	**$24,157.88**	$23,246.73	$13,134.50	$7,084.91
Line Transformers CAPEX ($/Tranformer Addition)	$ 5,748.59	$ 4,350.29	$ 8,813.56	$6,277.61	$ 9,103.96	**$6,858.80**	**$16,976.24**	$11,192.05	$ 8,205.68	$9,304.32
Meter CAPEX ($/customer)	$ 3.64	$ 4.02	$ 24.92	$ 7.35	$ 2.35	**$ 8.46**	**$ 136.36**	$ 17.55	$ 10.72	$ 43.08

1-Staff-4

Revenue Requirement Variance
Ref 1: Exhibit 1, pp. 31-32 and Table 2

Preamble:
On p. 31 of Exhibit 1, Algoma Power noted that proposed Service Revenue Requirement for the 2025 test year of $35,768,551 reflects an increase of $2,654,124 or 36.1% relative to 2020 Board approved.

In table 2, the evidence shows a service revenue requirement of $26,284,138 for 2020 Board approved.

Question(s):

a) Please confirm that the $ amount increase is $9,484,413, which represents a 36.1% increase.

API Response:

API confirms that the amount of the service revenue requirement increased by $9,484,413 which represents a 36.1% increase.

2-Staff-5

2024 Bridge Year Actuals
Ref 1: Chapter 2 Appendix 2-AA
Ref 2: Distribution System Plan Part 1, Table 4.26, p.155

Preamble:
Algoma Power has provided its forecasted capital plan for 2024 but has not specified how many months of data are included in the forecast as actual spending.

Question(s):

a) Please update Chapter 2 Appendices 2-AA, 2-AB, 2-BA, and other affected models to reflect updates to 2024 estimates, if any.
b) Please provide the actual spending to date for each project or program in 2024. Please clarify for how many months of actuals are included in the 2024 budget.
c) Please correct the models for 2022, given that 2-AA has a capital expenditure of $11k for the Subtransmission Line Rebuilds. In reference 2, the capital expenditure is listed at $11k.

API Response:

a) API confirms there are no material updates to the capital expenditures slated for 2024. API therefore has not made any updates to Chapter 2 Appendix 2-AA, 2-AC, 2-BA.

b) Please see attachment 2-Staff-5, which is a version of Appendix 2-AA which contains a column for 2024 June YTD actuals. The update reflects capital spending up to the end of June 2024 (ie: 6 months are included). The figures provided represent Capital Expenditures rather than in-service additions, however API confirms material prior WIP balances have been capitalized in 2024. API estimates a total of $10.96M has been put into service so far in 2024 (CAPEX+ in service CWIP from years prior to 2024).
There were no months of actuals included in the 2024 budget, as it was developed in 2023.

Projects	2020	2021	2022	2023	2024 Bridge Year	2024 Bridge Year YTD Jun
Reporting Basis	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE, CAPEX not In Service
System Access						
Meters	$ 302,112	$ 83,982	$ 137,956	$ 110,307	$ 132,952	$ 9,399
Service Connections	$ 981,859	$1,506,238	$ 1,284,929	$ 12,463,740	$ 2,998,014	$ 314,770
Transformers - SA	$ 51,982	$ 248,886	$ 278,992	$ 317,632	$ 154,000	$ 145,082
Relocation/Joint-Use	$ 182,808	$ 648,395	$ 380,336	$ 97,786	$ 10,000	$ 114,530
$ -	$ -	$ -	$ -	$ -	$ -	$ -
System Access Gross Expenditure	1,518,760	2,487,501	2,082,212	12,989,466	3,294,967	583,781
System Access Capital Contributic	144,984	472,311	33,820	141,704	5,252,085	-$ 1,685,801
Sub-Total	1,373,776	2,015,190	2,048,392	12,847,762	-1,957,118	-1,102,020
System Renewal						
Storm Capital	$ 78,102	$ 100,323	$ 37,690	$ 16,323	$ -	$ 14,791
Small Lines/Station Capital	$ 484,152	$ 317,612	$ 381,283	$ 385,481	$ 423,625	$ 237,554
Replacements	$ 65,673	$ -	$ 16,219	$ 48,785	$ 62,100	$ 38,336
Distribution Line Rebuilds	$ 3,198,061	$4,364,427	$ 4,234,143	$ 3,153,365	$ 5,454,691	$ 2,092,512
Subtransmission Line Rebuilds	$ 57,830	$ 206,603	$ 11	$ 249,775	$ 1,994,380	$ 49,058
Transformers - SR	$ 157,891	$ 150,133	$ 74,390	$ 225,373	$ 116,800	$ 134,545
Dubreuilville DS Rebuild	$ 10,088	$ -	$ 2,823,393	$ 22,757	$ -	$ -
Smart Meter Replacements	$ -	$ -	$ -	$ -	$ -	$ -
Bruce Mines DS Rebuild	$ -	$ -	$ -	-$ 0	$ 4,345,863	$ 804,236
Wawa #2 DS Rebuild	$ -	$ -	$ -	$ -	$ -	$ -
System Renewal Gross Expenditure	4,051,798	5,139,098	7,567,129	4,101,859	12,397,459	3,371,032
System Renewal Capital Contributi	$ 23,480	$ -	$ 2,024	$ 31,153	$ -	
Sub-Total	4,028,318	5,139,098	7,565,105	4,070,705	12,397,459	3,371,032
System Service						
Transformers - SS	$ -	$ 115,963	$ 30,979	$ 179,697	$ 55,000	$ -
Hawk Junction DS	$ -	$ 856,045	$ 699	$ -	$ -	$ -
Goulais Voltage Conversion	$ -	$ -	$ -	$ -	$ -	$ 36,810
Protection, Automation, Reliabilit	$ 255,092	$ 8,118	$ -	$ 11,213,244	$ 1,484,971	$ 606,725
Desbarats DS Upgrades	$ 3,487	$ -	$ -	-$ 0	$ 143,911	$ 1,975
Goulais TS Refurbishment	$ -	$ -	$ -	-$ 0	$ 0	$ -
System Service Gross Expenditure	258,579	980,125	31,678	11,392,940	1,683,882	645,510
System Service Capital Contributic	0	0	227,852	98,993	0	
Sub-Total	258,579	980,125	-196,174	11,293,947	1,683,882	645,510
General Plant						
ROW Expansion	$ 105,630	$ -	$ -	$ -	$ -	$ -
Tools & Equipment	$ 29,186	$ 83,318	$ 59,546	$ 164,421	$ 90,000	$ 36,135
Business Systems	$ -	$ 15,575	$ 9,179	$ 66,409	$ 485,448	-$ 568
Land Rights	$ 29,425	$ 62,085	$ 63,601	$ 76,710	$ 39,336	$ 45,215
Communication & SCADA	$ -	$ -	$ -	$ -	$ -	$ 35,954
Equipment	$ 784,824	$ 499,513	$ 138,882	$ 1,145,318	$ 584,674	$ 6,578
IT Hardware/Software	$ 61,070	$ 124,961	$ 240,475	$ 106,934	$ 58,933	$ 36,657
Buildings, Facilities & Yards	$ 135,485	$ 53,185	$ 165,728	$ 25,498	$ 154,147	$ 35,337
Sault Facility	$ -	$ -	$ 15,708,824	$ 640,323	$ 200,622	$ -
ROW Access Program	$ 279,359	-$ 19,969	$ -	$ 15,000	$ 288,217	$ 4,184
General Plant Gross Expenditures	1,424,978	818,668	16,386,235	2,240,612	1,901,377	199,492
General Plant Capital Contribution	0	0	0	0	0	
Sub-Total	1,424,978	818,668	16,386,235	2,240,612	1,901,377	199,492
Miscellaneous						
Total	**7,085,650**	**8,953,081**	**25,803,557**	**30,453,026**	**14,025,600**	**3,114,014**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets						
Total	**7,085,650**	**8,953,081**	**25,803,557**	**30,453,026**	**14,025,600**	**3,114,014**

c)API confirms the correct total in-service additions is $11, rather than $11,000. No update is required to Appendix 2-AA.

2-Staff-6

Planned versus Actual Historical Spending
Ref 1: Chapter 2 Appendix 2-AB

Preamble:
OEB staff has created the following table outlining the planned and actual cumulative gross and net spending for 2020-2024.

Table 1: Planned vs. Net Spending (2020-2024) ($ millions)

	Planned	2020-2023 Actual + 2024 Forecast	Variance (%)
Gross Capital Expenditures	60.0	92.7	54%
Net Capital Expenditures	59.5	86.3	45%

Question(s):

a) Given that Algoma Power plans to spend 45% more over 2020-2024 than it had forecasted in its 2020 Distribution System Plan, please explain what specific measures were taken to reprioritize or defer projects to ensure prudent spending.

API Response:

a) As described in Section 5.4.1. of the DSP, API has had numerous capital projects and programs that had expenditure cost increases since 2020. API has described the cost drivers for these cost increases in response to 1-VECC-1 (#4 Circuit project), 2-VECC-7 (Line Rebuilds and Station Projects) and 2-SEC-10 (SSM Facility Project). Cost increase drivers for the Echo River TS project are described in Section 5.4.1.1.3 of the DSP. As a result of these increases, API sought opportunities to reprioritize and/or defer projects where it was feasible and prudent to do so. The surge in non-discretionary requests (customer demand and third-party requests) coupled with the material and cost increases that were experienced and following the COVID-19 pandemic reduced the opportunities to do so without a material increased risk to service outcomes.

   In particular, API scaled back its total targeted pole replaced under its Line Rebuild programs as a result of pole upgrade/replacement that were required under other programs or projects. The total poles replaced under API's Line Rebuild program is 2,197 and 376 under other programs.

   As part of API's larger projects over the historical period (Station Rebuilds, SSM facility projects, etc.), API sought competitive pricing through tender processes to ensure costs were prudent and justifiable while also ensuring project requirements were still being met.

2-Staff-7

METSCO Asset Condition Assessment
Ref 1: API Asset Condition Assessment, pp. 65-66
Ref 2: API Asset Condition Assessment, Table 4-1, p. 26
Ref 3: Distribution System Plan part 1, Table 3.6, p.85

Preamble:
METSCO conducted an Asset Condition Assessment for Algoma Power. In reference 1, METSCO noted that Algoma Power's quality and availability of data was generally low. METSCO made several recommendations to improve the quality and availability of data for different asset types.

In reference 2, METSCO could not calculate a valid health index for overhead conductors, underground cables, distribution transformers, or reclosers.

In Table 3.6 of reference 3, Algoma Power provided a breakdown of assets by health index distribution from very good to very poor.

Question(s):

a) Please explain if and/or how Algoma Power has addressed or plans to address the recommendations made by METSCO when it comes to improving data availability and data quality.
b) Did METSCO provide a flag-for-action plan or a recommendation of how many assets of each type to address per year?
c) Is Algoma Power improving its testing methods going forward so that a valid health index can be calculated for overhead conductors, underground cables, distribution transformers, and reclosers?
d) The Health Index Distribution shown in Table 3.6 indicates that Algoma Power has very few assets in Poor or Very Poor condition. Please quantify how many assets in Fair or better condition Algoma Power plans to replace during the rate period based on the proposed capital investment levels.

API Response:

a) Algoma Power's focus for improving its data availability will be through enhancements to its data entry, capture and validation processes. These process improvements will focus on ensuring that asset condition data that is captured is more seamlessly bound to the asset's record and that the information collected is reviewed and validated against defined asset data criteria.
b) No, METSCO did not provide this type of recommendation.
c) As it relates to the assets for which a valid health index was unable to be formulated, Algoma Power intends to make the following improvements to its asset and condition data:
    1) Overhead Conductors – Review service age information based on conductor records and assign this information to the asset records in the asset database.

2) Underground Conductors - Review service age information based on conductor records and assign this information to the asset records in the asset database.
3) Distribution Transformers – enhance Algoma Power’s annual line inspection program to include a detailed visual inspection of pole-mount and pad-mount transformers.
4) Reclosers – enhance Algoma Power’s annual line inspection program to include a detailed visual inspection of reclosers. Review service age information based on recloser records and assign this information to the asset records in the asset database.

The above improvements are in-line with the recommendation in the Asset Condition Assessment for improving asset health index formulations and as such, with the implementation of the above improvements, Algoma Power will be able to form a valid health index for these assets.

d) See table below:

Asset Class	Total Assets in FAIR or better condition	Total Assets Replaced in FAIR or better condition
Station Power Transformers & Voltage Regulators	15	1
Station Reclosers	8	0
Station Switches	10	0
Station Yards	9	0
Wood Poles	22,224	See note below
Ratio-Bank Transformers	22	0
Capacitor Banks	4	0
Voltage Regulators	6	0

Note: Algoma Power’s Distribution and Subtransmission line rebuild programs have a combined target of 2500 poles that would be replaced within the rate period. Algoma Power has not yet defined specifically all the poles that would be replaced in the rate period and as such could not specify how many poles that are in Fair or better condition would be replaced.

While pole asset condition is an important factor in determining whether it should be replaced, other factors, such as pole height, working clearances, mechanical loading and customer or third-party requirements, etc. may necessitate the need for replacement.

Algoma Power has planned for the replacement of the power transformer at the Wawa #2 distribution station, which was deemed in Fair condition in the Asset Condition Assessment. The rationale behind replacing this transformer is that the health index, which had score of 56% is expected to be at the mid-point by 2027 and has signs of physical deficiencies, degradation of the conservator tank, corrosion of its control wiring, etc. Furthermore, the condition of the yard of the Wawa #2 DS as well as the operational restrictions associated the inside the station. As such, Algoma Power has planned to rebuild the Wawa #2 distribution station in-situ, which is further described in Section 5.4.2.4.2.5 of the DSP. As this station would be rebuilt at its current location, the station yard will essentially be refurbished and will address the noted yard deficiencies that were noted in Section 5.3.2.3 of the DSP.

2-Staff-8

Customer-Hours Interrupted
Ref 1: Distribution System Plan part 1, Table 2.15, p.58

Preamble:
In Table 2.15 of reference 1, Algoma Power provided a breakdown of customer-hours interrupted by cause code.

Question(s):

a) What happened in 2023 to drive the outlier customer hours interrupted due to defective equipment?
b) Please provide a breakdown of defective equipment customer interruptions and customer hours of interruption by asset type each year.
c) Please identify the capital investments targeted in the test year at reducing outages caused by, 3 – Tree Contacts and 5 – Defective Equipment?

API Response:

a) In 2023, Algoma Power had a significant outage event that was the result of an older oil-insulated vacuum interrupter recloser failing. This recloser is located on Algoma Power's 34.5kV Subtransmission system East of Sault Ste Marie and consequently the failure resulted in an outage on Algoma Power's ER1 34.5kv feeder.

   At the time and date of this outage, Algoma Power's ER2 feeder was isolated at the Echo River TS (which had been previously requested by Hydro One), which meant that this outage impacted significantly more customer than it would otherwise have had the ER2 feeder not been isolated.

   The outage itself impacted a total of 5,617 customers and the restoration took approximately 3.25 hours. On the day following this outage, Algoma Power replaced the failed device, which required another outage in order to establish a sufficient work zone and working clearances. Algoma Power was able to limit this subsequent outage to 2,307 customers and only lasted 1.43 hours.

b)

	Total Outages				
Asset Type	2019	2020	2021	2022	2023
Wood Poles	4	0	0	1	2
Transformers	16	17	19	22	15
Switches	83	71	59	80	51
OH Conductors	8	7	15	5	11
UG Cabes	0	0	0	0	0
Connecting Device	14	6	6	14	6
Line Hardware	6	7	2	4	2
Protection Equipment	5	8	5	4	0
Substations	0	0	0	0	0

Total Customers Interrupted					
Asset Type	2019	2020	2021	2022	2023
Wood Poles	1,222	0	0	534	636
Transformers	47	153	1,285	98	63
Switches	942	2,390	2,152	1,808	10,893
OH Conductors	526	60	772	44	145
UG Cabes	0	0	0	0	0
Connecting Device	192	132	208	810	50
Line Hardware	2,141	3,438	15	2,889	101
Protection Equipment	4,210	2,442	31	12	0
Substations	0	0	0	0	0

Total Customer-Hours of Interruptions					
Asset Type	2019	2020	2021	2022	2023
Wood Poles	4,500	0	0	401	1,313
Transformers	157	516	2,911	241	164
Switches	2,801	2,280	2,596	2,464	25,293
OH Conductors	1,075	73	652	103	151
UG Cabes	0	0	0	0	0
Connecting Device	361	146	229	2,236	81
Line Hardware	3,008	4,543	5	4,125	116
Protection Equipment	2,923	4,733	44	25	0
Substations	0	0	0	0	0

c) Algoma Power's Distribution and Subtransmission Line Rebuild programs will indirectly support the reduction of tree-related (3 – Tree Contacts) outages and directly support the reduction of defective-equipment (5 – Defective Equipment) outages. Algoma Power's Switching Automation project under its Protection, Automation and Reliability program will directly support the reduction of defective-equipment (5 – Defective Equipment) outages.

As is described in 2-Staff-10, Algoma Power's line rebuild programs generally includes the installation of a taller pole. With the installation of a taller pole, there is a reduced arc of exposure for backline trees. If a backline tree breaks and falls towards the powerline, it is less likely to now hit the powerline. As such this program supports the reduction of tree-related outages.

While Algoma Power does not see many instances of pole failure, the continued investment towards its targeted pole replacement in the Line Rebuild programs will ensure that were minimizing the occurrences of pole failures. The Line Rebuild programs also includes the replacement of other at end-of-life equipment on the pole, such as all the framing hardware, switches, transformer fuse cutouts, and in some cases the transformer itself. While there aren't a lot of this type of equipment on a per project basis, continued replacement on these assets would in the long-term result in minimizing outages because of equipment failure.

Algoma Power's switching automation project will target the installation of new and replacement of existing older reclosers and switches. Older assets, such as these can fail and result in outages. While the main driver for this project investment is not renewal-based, the replacement of older assets will support the reduction of defective-equipment outages.

2-Staff-9

Reliability Targets
Ref 1: Distribution System Plan part 1, p.42
Ref 2: Distribution System Plan part 1, p.61

Preamble:
In reference 2, Algoma Power states:

"API sets targets annually for its reliability performance, which normally involve a set percentage improvement over a multi-year rolling average performance. This target therefore incentivizes continuous improvement in reliability performance."

Question(s):

a) What has changed materially in customer preference that API is targeting an improvement in SAIDI from 7.36 to 5.42?
b) What has changed materially in customer preference that API is targeting an improvement in SAIFI from 3.16 to 2.47?

Have customers stated they want continuously improving reliability, rather than maintaining reliability and controlling costs?

API Response:

a) Algoma Power's targeted improvement in SAIDI is based on a continuous improvement strategy. API notes the SAIDI target referred to is consistent with the previous 5-year rolling average; absent the availability of final 2024 SAIDI data, this approach is consistent with the OEB's standard approach for setting distributors' SAIDI and SAIFI targets on the distributor scorecard.
b) The same explanation provided above re: SAIDI also applies to SAIFI.

Customers have indicated that delivering electricity at reasonable distribution rates remains the most important priority, whereas ensuring reliable electrical service is the second most important (please refer to Exhibit 1, page 211). As it relates to Algoma Power providing reliable electrical service and reliability priority, Customers have indicated that reducing the length and frequency of outages are priority (see Exhibit 1, page 217)

2-Staff-10

Tree Contacts and Major Event Days
Ref 1: Distribution System Plan part 1, p.141
Ref 2: Distribution System Plan part 1, Table 2.12, p.48

Preamble:
In reference 1, Algoma Power states:

“Under API’s line rebuild program, API is generally installing taller, stronger poles which will inherently result in better reliability and resilience.”

As per reference 2, tree contacts represent the preponderance of number of outages, number of customers interrupted, and number of customers hours interrupted pertaining to Major Event Days.

Question(s):

a) Considering that the most significant proportion of Algoma Power outages (including major event days but excluding Loss of Supply) are driven by Tree Contacts (reference 2), please explain and quantify how increased investment in taller, stronger poles will mitigate outages caused by such events.
b) Please provide the Benefit-Cost Analysis used to justify the installation of “*taller, stronger poles which will inherently result in better reliability and resilience.”*
c) What would be the cost difference to the line rebuild programs in each year of the forecast period if like-for-like poles are used instead of taller, stronger poles?
d) Please confirm that capital expenditures do not typically mitigate Major Event Day (MED) outages caused by 3 - Tree Contacts.
    a. If not confirmed, please explain which capital investments improve MED results, and quantify the correlation between increased spending and improved results.

API Response:

a) Poles that are typically replaced under Algoma Power’s Line Rebuild programs are shorter than what is required by overhead design standards, such as CSA. It is not uncommon for older poles to be 30’ to 35’ in length, whereas new poles are 40’ in length at a minimum. With a taller pole being installed, the conductor that is supported by the pole is raised higher above ground. This will result in a reduced arc of exposure to trees that fall towards the powerline. Shorter trees and lower branches are also less likely to fall on conductors supporting by taller poles.

   Installing a stronger is generally required compared to an older pole as a results of current overhead design standards. As a result, if a tree does fall and contact the powerline, it would be less likely that the pole itself will be damaged or fail catastrophically. The response that is then required does not necessitate a pole to be replaced, and as such would result in a quicker restoration.

b) Algoma Power is not proposing to install taller, stronger poles on the sole basis of improving reliability and resilience, and as such does not have a BCA to support this. Rather, long standing overhead design standards, that were developed in response to the implementation of Ontario Regulation 22/04 requires that taller, stronger poles be installed compared to the pole being replaced. Furthermore, not all poles that would be replaced would require a taller pole. In locations where the height of the existing pole is sufficient to meet the design standards, then a pole of similar height would be installed. That said, the general anticipated incremental cost of a taller, stronger pole is the incremental material cost and is minimal compared to the overall cost of replacement. On average, the incremental cost of increasing the height of pole by 5' is $360. The relatively small increase associated with this incremental cost provide benefits for improving system reliability in addition to meeting design standards.

c) Generally speaking, if Algoma Power where to replace its poles like-for-like, the differential cost would be based on the material cost difference of the pole itself. This approach however is not one in which Algoma Power would be able to follow. The poles that are replaced are typically shorter and smaller in class and would not meet the minimum overhead design standards.

d) Algoma Power has included in its Capital Expenditure plan projects that specifically target improving reliability, which as a result would support the reduction of Major Event Days.

Under Algoma Power's 34.5kV Switching Automation project, described in Section 5.4.2.4.3.2 of the DSP, Algoma Power has proposed to install intelligent automated switches along the major subtransmission system East of Sault Ste. Marie. Given the larger customer base supplied from this system, and the anticipated reduction in restoration times, Algoma Power would likely see reduced overall outage impacts even during a Major Event.

2-Staff-11

Outage Trends
Ref 1: Distribution System Plan part 1, Table 2.13, p.55
Ref 2: Distribution System Plan part 1, Figure 2.12, p.55

Preamble:
Table 2.13 in reference 1 shows an increasing trend in the number of outages for several cause codes.

Figure 2.12 in reference 1 shows an increasing trend in number of outages per year excluding MEDs but including 1-Scheduled Outage, 2-Loss of Supply, and 9-Foreign Interference.

Question(s):

a) What is causing the increasing frequency of outages caused by 0 - Unknown/Other, 1 - Scheduled Outage and 9 - Foreign Interference?
b) What is causing the decreasing frequency of outages caused by 3 – Tree Contacts?
c) Please restate Figure 2.12 in reference 2 after removing 1-Scheduled Outage, 2-Loss of Supply, and 9-Foreign Interference.

API Response:

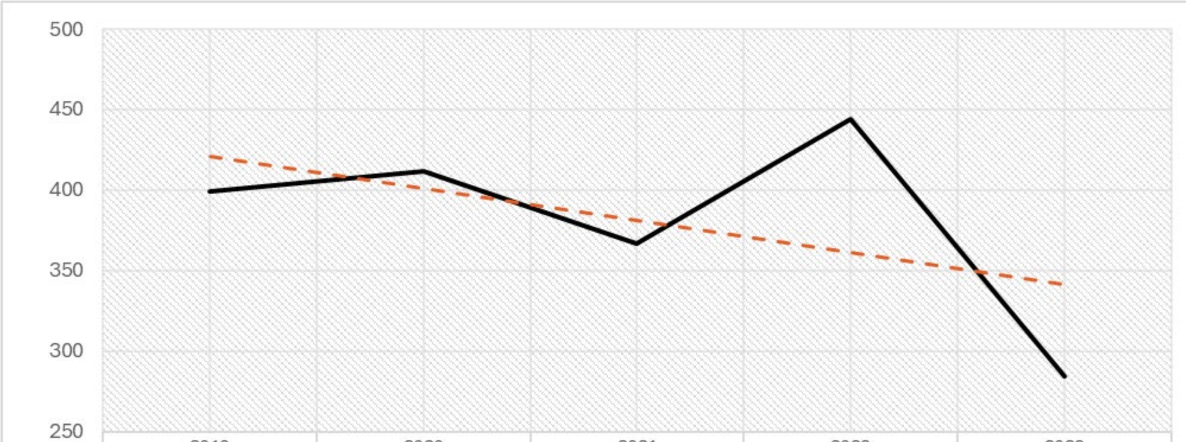
a) Algoma Power has not completed a detailed outage cause investigation to determine likely cause of the outages that are assigned unknown/other cause code. API will monitor this trend going forward and will investigate further if warranted. Generally, this cause code is used when there was no evidence of what may have caused an outage. After the responding crew arrives on site, they perform a patrol in an attempt to find the fault cause. In some instances, however, a patrol is completed, and no clear evidence of the cause is found.

   The increasing frequency associated with scheduled outages is the result of an increase of work activity that required an outage in order to safely perform the work. While the quantity of outage has had an increasing trend, the trend in customers interrupted and customer-hours of interruption has had a decreasing trend.

   The increasing frequency of outages associated with foreign interference has the result of increasing wildlife contact.

b) The decreasing frequency of tree-contact related outage can be attributed to the efforts under Algoma Power Vegetation Management program over the last 15-20 years and to a smaller extent Algoma Power's line rebuild program as is explained in 2-Staff-10.

c) The reinstated Figure 2.12 after removing 1-Scheduled Outage, 2-Loss of Supply, and 9-Foreign Interference is included below:



	2019	2020	2021	2022	2023
Totals	399	412	367	444	284

2-Staff-12

Wildfires
Ref 1: Distribution System Plan part 1, p.73

Preamble:
In reference 1, Algoma Power states:

"Given the nature of API's service territory, API is very aware of potential risks associated with wildfires. As a result, API is in the process of developing a wildfire mitigation plan and strategy, that will outline the protocols that would be followed to further mitigate the wildfire risks."

Question(s):
a) When will the wildfire mitigation plan and strategy be completed?
b) Please quantify any planned rate period expenditures that may need to be modified after the wildfire mitigation plan and strategy are available.

API Response:

a) API anticipates the wildfire mitigation plan and strategy to be completed before the end of 2024. Reviews of outcomes, recommendation and any subsequent project planning will commence 2025, with work implementation starting in 2026 and beyond.
b) Pending the outcomes of the mitigation plan and strategy API would expect to implement any recommendations on a multi-year program basis. The sequencing will take into consideration budgeting, resources, available technology and risk levels.

   At this time, API has not planned for any modifications to its planned rate period expenditures as a result of the development of this plan and strategy. This will cause upwards pressure on costs, however API plans on managing within its OM&A budget.

2-Staff-13

Vulnerability of Assets
Ref 1: Distribution System Plan part 1, p.73

Preamble:
In reference 1, Algoma Power states:

"API's line rebuilds programs (distribution and subtransmission), target in general the most vulnerable poles in API's service territory. These rebuild will result in a stronger distribution network."

Question(s):

a) Please describe how "most vulnerable" is determined.
b) How does Algoma Power take into account the 'risk' when determining which poles to replace? Specifically, how are the probability and consequence of failure taken into account.

API Response:

a) Most vulnerable poles in the context of API's Line Rebuild program means those that are most susceptible to failure. API determines the most vulnerable poles based on in-service age, overall condition, result from pole testing and annual line inspections, the supported assets and the location.

b) The rationale and strategy behind API's Line Rebuild programs are described in response to 2-Staff-16(b). In terms of assessing risk, API places focus on the consequences of failure as opposed to probability of failure, with the main consequences being downed powerlines and system outages. These investment drivers are further described in Sections 5.4.2.4.2.2 and 5.4.2.4.2.3 of the DSP.

2-Staff-14

Accessibility
Ref 1: Distribution System Plan part 1, p.82

Preamble:
In reference 1, Algoma Power states:

"Prior to 2009, many of these sections were accessible via rail through informal agreements between API (or its predecessor companies) and Algoma Central Railway ("ACR"). Rail cars would generally be provided on a cost basis for both forced outage situations and for planned work. Following the acquisition of ACR by Canadian National ("CN") Rail, API has been unable to obtain reliable rail access to these sections. In 2021, Watco purchased this rail line from CN, and since then API has had discussion with Watco regarding establishing agreements to use the rail but has not yet been able to obtain formal rail access to these sections."

Question(s):

a) Please describe how Algoma Power adapted its asset management strategy to address restricted access to sections that were previously accessible by rail.
b) What are the incremental rate period costs (by year) resulting from the restricted access?

API Response:

a) In locations that had been previously accessible by rail, Algoma Power had has sought alternative means of access such as establishing and/or enhancement of trails to and on the Right-of-Way. This has generally entailed landowner engagement in order to review and ultimately establish any required land tenure rights. In locations where establishing and/or enhancing a trail is not a feasible option, due to terrain constraints Algoma Power has planned for the installation of helipads that would allow for helicopter access.

b) Due to the declining rail access over a long-term period (ie: as mentioned above, since 2009), API no longer has relevant "baseline" records to estimate the incremental costs associated with the loss of access, and is not able to provide a meaningful quantification.

2-Staff-15

Distribution Line Rebuilds & Subtransmission Line Rebuilds
Ref 1: Chapter 2 Appendix 2-AA

Preamble:
Algoma Power spent on average $3.7 million from 2020-2023 in its Distribution Line Rebuilds program. In 2024, the program cost increased to $5.5 million.
Algoma Power spent on average $131k on the Subtransmission Line Rebuilds program from 2020-2023 (assuming $11k was spent on the program in 2022). In 2024, the program cost increased to $2.0 million and $1 million each year of the forecast period.

Question(s):

a) Please provide a table outlining how many poles were replaced each year from 2020 to 2023 and how many are estimated to be replaced in 2024-2029 separated by the Distribution Line Rebuilds program and the Subtransmission Line Rebuilds program.
b) Please provide another table similar to the last question but for all poles replaced in all of Algoma Power's programs.
c) How many poles have been replaced to date in 2024 in each program?
d) Please explain the need for increased spending in the bridge year for each program and the increased budget for the Subtransmission Line Rebuilds program over the forecast period given the downward trend in SAIDI and SAIFI.
e) What is the estimated count of poles in each health index class by the end of the rate period if program spending is reduced by 10% for each of the two programs separately?

API Response:

a) Please see the table below:

Line Rebuilds	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Distribution	250	483	422	360	481	400	400	400	400	400
Subtransmission	2	17	0	17	165	100	100	100	100	100

b) Please see the table below:

Other Programs	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Customer Connections	22	52	29	181[1]	8	30	30	30	30	30
Third-Party Requests	27	57	44	6	See Note 2		5	5	5	5
Small Lines Capital	29	12	15	22	22	12	12	12	12	12
Storm Capital	8	12	2	0	0	0	0	0	0	0
Reliability/Station Projects	0	1	6	1	1	0	0	2	0	0

Note 1 – Algoma Power has included in this total the poles that were required to be replaced under the Goudreau 44kV Expansion project

Note 2 – Algoma Power is currently receiving permit requests under the Broadband program and is currently anticipating anywhere between 400 and 600 poles that will require replacement

c) Please see the table below:

Programs	2024 to Date
Distribution Line Rebuilds	230
Subtransmission Line Rebuilds	48
Customer Connections	8
Third-Party Requests	0
Small Lines Capital	22
Storm Capital	0
Reliability	1

d) Algoma Power has anticipated a larger quantity of poles through its Line Rebuild program coming into service in 2024.

The main driver and objective for Algoma Power's Subtransmission rebuild program is sustainability through effective and prudent asset management that maximizes safety and customer reliability whilst minimizing short and long terms costs. Algoma Power believes that the increased budget associated with the program as well as the continued replacement rate will allow the objective and driver of this program to be met.

e) Given the factors that into determining the health index of a pole, Algoma Power is not able to predict or estimate with any level of accuracy the pole count in the different health index classes. However, if Algoma Power were to reduce its target replacement rate by 10% or 50 poles, this would mean that 50 poles current aged 50 years or older would unreplaced and likely be at the poor to very condition at the end of the forecast period.

2-Staff-16

Line Rebuild Program Replacement Rationale
Ref 1: Distribution System Plan part 1, p.32
Ref 2: Appendix 2-H

Preamble:
In reference 1, Algoma Power states:

"API's Line Rebuild program is the core of API's sustaining asset replacement strategy and is predicated on the proactive approach to asset replacement. Proactive asset replacement allows for the replacement of older, at end-of-life assets, prior to failure. The result is a balance between the cost of the asset replacement and relatively larger costs, reliability impacts, and safety concerns associated with reactive replacement of these assets. The proactive approach also affords more efficient mobilization of material, equipment, and crews as well as provides the least impact on reliability and improves infrastructure resiliency."

In Reference 2, Algoma Power forecasted a loss of $25,000 in USoA 4360 loss on disposition of utility and other property for bridge year and test year.

Question(s):

a) What is the annual probability of failure of poles due largely to asset condition? Please provide the probability of failure organized by Health index category.
b) Please explain how Algoma Power avoids prematurely replacing its assets, especially for those asset types without a calculated health index and for poles, where a health index has not been calculated for 20% of the population.
c) What is the annual probability of failure of pole top transformers in each Health index category?
d) How many poles are being replaced in totality by assessed condition category for each of the planning period years?
e) Please provide the business case to justify premature retirement to the anticipated reliability benefits to customers.
f) Please provide the journal entry for the proactive asset replacement.
g) Please confirm if the forecasted loss in other revenues is related to the proactive asset replacement. If not, please explain.
h) Please explain how Algoma Power derives its forecast of the loss of $25,000 on the disposition of the utility assets.
i) Please confirm that the forecasted loss of $25,000 is to increase the revenue requirement rather than decrease the revenue requirement.

API Response:

a) API has not performed any type of statistical analysis for which it could derive a failure probability rate for its pole assets.
b) API's pole replacement strategy under its Line Rebuild program is centered around long-term sustainability as opposed to strict adherence to calculated health indices. API

considers several factors in determining what sections of line should be rebuilt (such as age, location, 3rd party report, internal condition assessments, etc.) and once determined, API evaluates each pole to confirm which warrant replacement and for those that do, the scope of replacement. The Line Rebuild programs generally don't include sporadic pole replacement due to the expansive nature of API's service territory and the incremental mobilization and associated cost that would be incurred.

c) API has not performed any type of statistical analysis for which it could derive a failure probability rate for its pole top transformer assets.

d) API has not yet correlated the planned Line Rebuilds to the assessed condition category. API can say however with certainty that sections of line that were assessed as having an overall lower health index would have higher priority over a similar vintage of line with a higher health index.

e) API does not replace poles prematurely under this program from an asset lifecycle perspective. API's asset lifecycle approach proactively replaces poles prior to failure in a cost-effective manner, consistent with the answer provided in b) above.

f) API uses a consistent approach when retiring its assets from its accounting records, which includes assets that may be getting proactively replaced. The dollars for both the capitalized cost and associated depreciation are removed from the appropriate asset and accumulated amortization/depreciation OEB accounts. If there is any remaining net book value in API's accounting records, that value is then recorded in OEB 4360, with any proceeds (if received from the disposition of that asset) also being recorded in that account.

g) The proactive replacement of assets noted above generally occurs when the asset has a negligible remaining net book value for accounting purposes, so the impact on the losses recorded in other revenues OEB 4360 is not material.

h) Given the variability of this account year-over-year, API considered historical averaging in deriving its $25,000 loss estimate for both 2024 and 2025. API notes that for the year-to-date June 2024, a loss of $23,715 has been recorded.

i) Confirmed.

2-Staff-17

Pole Expected Life and Health Index Distribution
Ref 1: Distribution System Plan part 1, Figure 3.13 & Figure 3.14, pp. 92-93

Preamble:
In reference 1, Algoma Power provided a separate count of wood poles by age and by health index.

Question(s):

a) Please provide a table for the data in Figure 3.13 of reference 1 that shows the Health Index by age category.
b) Based on available data what is the expected service life (not depreciation life) of wood poles used for asset planning purposes?

API Response:

a) Please see the table below:

	Age						
Condition	0-10	11-20	21-30	31-40	41-50	50+	Total
Very Good	1,382	4,218	1,369	318	225	0	7,512
Good	241	1,602	1,158	3,416	3,219	636	10,272
Fair	3	60	113	1,205	1,804	1,255	4,440
Poor	0	24	26	91	245	332	718
Very Poor	0	0	2	26	57	72	157
Total	1,626	5,904	2,668	5,056	5,550	2,295	23,099

b) In estimating the expected service life of a wood pole, Algoma Power would consider the CSA overhead standard design requirement of 60% initially. Once a pole has deteriorated to 60% of its rated strength, then per the standard, it needs to be replaced. As the table outlines, an increasing proportion of poles are in poor condition after 40 years and is a consideration as well as the degraded strength.

2-Staff-18

Transformer Service Life
Ref 1: Distribution System Plan Part 1, pp. 86-87

Preamble:
In reference 1, Algoma Power states:
“API currently has 14 power transformers and 2 voltage regulating transformers in-service, located within API’s distribution stations. Of API’s sixteen total assets, fifteen had sufficient data to form a health index, two of which were in Fair or worse condition. The breakdown of station transformer and voltage regulator assets, their data availability index (“DAI”), and their calculated Health Index(“HI”) is presented in Table 3.7
…
The transformer in Fair condition, at Garden River DS, has reached a more advanced age (31 years in service) and scored poorly on the dissolved gas analysis and very poorly on the oil quality analysis. The transformer in Fair condition, at Wawa #2, is of a significantly advanced age (44 years in service) and has serious deficiencies in its physical condition. There is evidence of an oil leak on the conservator tank, damage to relays and paint, and significant corrosion of its control wiring.”

Question(s):

a) Please explain why Algoma Power considers 31 years to be an “advanced age” for a winter peaking transformer and why Algoma Power believes the Garden River DS scored poorly on the gas and oil quality analysis at this age.
   i. Has this transformer been replaced or are there plans to replace it? If so, in which capital program, what year, and at what cost?
b) What are Algoma Power's expected service lives (not depreciation lives), respectively, for power transformers, regulating transformers and pole top transformers?
   i. Are the expected service lives of each of these transformer classes greater than, less than or equal to their depreciation life? Please explain for each class.
c) Does Algoma Power plan to retire any classes of assets at the end of their depreciation lives?
   i. If yes, please identify those asset classes and explain why they are retired at the end of their depreciation lives.

API Response:

a) The “advanced age” qualification of the power transformer at the Garden River DS was based on comparing it to the other in-service power transformers. It was not intended to be an indicator for replacement. Currently, Algoma Power does not have any plans to replace this transformer.

b) The expected service life of transformers (power, regulating and pole top) is 50 years. This matches the deprecation life cycle of transformers.

c) Algoma Power takes into consideration several different factors when deciding to replace and retire an asset, such as the number, type, condition and criticality of the assets that are in service. Algoma Power also considers several risks associated with the existing asset, such as failure, security, health, safety and environmental, etc. Algoma Power's asset lifecycle optimization policies and practices are further described in Section 5.3.3 of the DSP.

2-Staff-19

Ratio Bank Transformers
Ref 1: Distribution System Plan Part 1, pp.95-96

Preamble:
In reference 1, Algoma Power states:

"22 of API's ratio-bank transformers have enough data to construct a valid health index, 20 of which of which are currently installed. The average health index of installed units is 95%. Figure 3.16 shows the HI results for this asset class…No recommendations to improve the health index formulation of the ratio bank transformers."

Question(s):

a) Please provide the failure rates of Ratio Bank Transformers for each of the past 5 years.
b) Please provide the planned replacement rates of these assets for each year of the forecasted period.

API Response:

a) The failure rate for the ratio bank transformers in the last 5 years is 6%. API experienced a failure of two (2) ratio transformers in this period.
b) There is no planned replacement for ratio transformers during the next forecasted period. API has available spares that will be installed in place in the event of a transformer failure. API will execute a replacement of a ratio transformer if annual inspections of the transformers warrant a replacement.

2-Staff-20

Electrification
Ref 1: Distribution System Plan part 1, p.115
Ref 2: Distribution System Plan part 1, p.75

Preamble:
In reference 2, Algoma Power developed a load forecast with and without consideration of electric vehicle and electrification adoption growth. Algoma Power used a 1.7% annual growth to forecast the load growth due to these technologies.

In reference 1, Algoma Power noted that it changed its distribution transformer standard size from 15kV to 25kV and 37kVA due to the onset of electrification and electric vehicle charging requirements.

Also in reference 2, Algoma Power stated that it will consider opportunities to install larger capacity transformers when installing new or needing to replace an existing transformer (e.g. end-of-life replacement). Algoma Power also noted that there was still uncertainty around the timing of when these load increases would be realized.
Question(s):

a) Given that Algoma Power has changed its distribution transformer size standard due to electrification, please confirm if Algoma Power up-sizes all new and replacement transformers, or if it "consider[s] opportunities to install larger capacity transformer[s]" as per reference 2?
b) Given that Algoma Power is uncertain about the timing of when these load increases would be realized (as per reference 2), what was the rationale behind changing Algoma Power's standard transformer size?

API Response:

a) When replacing an existing transformer, Algoma Power may install a larger capacity transformer based on its distribution transformer size standard. Smaller capacity transformers, such as a 15kVA capacity transformer would be replaced by a 25kVA capacity transformer at a minimum based on the new sizing standard. Where larger capacity transformers exist and are being replaced, the same capacity transformer are initially planned for the replacement.

   Algoma Power considers opportunities to install larger capacity transformers based on customer feedback during the customer connection process.

b) The decision to change the transformer sizing standard was based ensuring that Algoma Power can provide new and upgrading customers the necessary transformation capacity for a 200A service as part of the basic connection allowance.

2-Staff-21

Right of Way Access Program
Ref 1: Chapter 2 Appendix 2-AA
Ref 2: Distribution System Plan Part 1, p.183

Preamble:
Algoma Power spent on average $69k from 2020-2023 in its ROW Access Program. From 2024-2029, the average spend in this program is forecasted to be $172k.

In reference 2, Algoma Power states that “the quality of the access can further affect the costs of on-going maintenance activities. Poor access will cause O&M costs to be higher than sections with better access.”

Question(s):

a) Please explain the increased spending in this program in 2024 and 2025 ($288k and $226k respectively).
b) Has Algoma Power quantified the 2025 O&M savings due to the increased capital spending from the ROW Access program? If not, please quantify the expected savings and explain how this savings has been applied to the OM&A budget.

API Response:

a) In 2024 and 2025, API has planned for the establishment and installation of helipads along with No.4 Circuit. The investment is in response to re-establishing access that had been previously available via rail as is described in 2-Staff-14. API’s No.4 Circuit currently supplies several remote communities in Northern Ontario (Dubreuilville, Missanabie, etc.), and the planned investment will support API’s ability to respond to outages in a reasonable timeframe.

b) API has not quantified the anticipated 2025 O&M savings due to this investment. Where API is required to perform ongoing maintenance on its No.4 Circuit, poor access will result in having to navigate the ROW using specialized equipment and require much longer travel times, resulting in increased mobilization and demobilization costs. Through the use of the helipads, API expects a decrease in mobilization time of about 3-6 hours, depending on location of work.

2-Staff-22

Vehicles
Ref 1: Chapter 2 Appendix 2-AA
Ref 2: Distribution System Plan Part 1, p.108

Preamble:
Algoma Power plans to spend $0.6 million in 2024 and 1.2 million in 2025 on transportation and work equipment according to reference 1. In reference 2, Algoma Power notes that "annual allowance is made for replacement of one aerial device, as well as about three pickup trucks and a variety of other items as required."

Question(s):

a) Please explain the basis for the proposed significant increase in annual spending on transportation and work equipment above historical average spending.
b) Please explain what fleet vehicles are being replaced in 2024 and 2025. What are the conditions of the vehicles, including age, mileage, etc.
c) What is the cost of each vehicle being replaced in 2024 and 2025? Have vehicles already been ordered for these two years? Are costs for vehicles that have not yet been ordered based on inflationary estimates or quotes?
d) What is the status of the vehicle acquisitions for 2024?
e) Has Algoma Power considered the electrification of its fleet? If so, why is it choosing not to electrify its fleet. If not, why not?

API Response:

a) Algoma Power has seen significant annual fleet replacement costs over the historical period. For example, ½ ton and ¾ ton have increased in cost by 30-40% since 2017.
b) Please see the details in the tables below:

2024 Replacement plan						
Truck No	Year	Mileage	Condition	Make	Model	Description
13.37	2013	303000	Poor	Ford	F150	4 x 4 Supercab
14.42	2014	192000	Poor	Ford	F150	4 x 4 Supercab
14.43	2014	193000	Poor	Ford	F150	4x4 Crew Cab
15.48	2015	243000	Poor	Ford	F250	4x4 Crew Cab
16.53	2017	316000	Poor	Ford	F150	1/2 ton 4 x 4
16.54	2017	235000	Poor	Ford	F250	4x4 Crew Cab

2025 Replacement plan						
Truck No	Year	Mileage	Condition	Make	Model	Description
11.30	2011	214000	Poor	Freight	Posi 400-46	MHD
13.40	2013	243000	Poor	Freight	Posi 400-46	MHD

c) Vehicles that are planned for replacement in 2024 and 2025 have been ordered. The breakdown of these purchases are as follows:

Year	Vehicle Description	Total Cost	Status
2024	½ Ton 1500 Ram	$ 62,953.00	Delivered
2024	½ Ton Ford F150	$ 80,077.00	September Delivery
2024	½ Ton Chevrolet 1500	$ 63,593.00	Delivered
2024	½ Ton Ford F150	$ 74,599.00	September Delivery
2024	¾ Ton Ford F250	$ 81,066.00	September Delivery
2024	¾ Ton 2500 RAM	$ 80,792.00	Delivered
2024	¾ Ton Ford F250	$ 81,599.00	September Delivery
2024	16ft Landscape Trailer	$ 9,475.00	Delivered
2025	Freightliner Posi 400-46 Material Handler	$ 550,730.05	To be delivered in 2025
2025	Freightliner Posi 400-46 Material Handler	$ 549,560.05	To be delivered in 2025

d) Status of vehicle acquisitions is included in the response to 2-Staff-22 (c)

e) As mentioned in Exhibit 1 page 78 of the Application, Algoma Power is considering the electrification of its fleet. In 2023 as part of the pilot project investigation, one of the pick-up truck replacements was an electric truck (E-truck). Algoma Power is currently evaluating range capacity of the E-truck in our service territory under various driving conditions including climate, driving distance, type of work activities and available charging options. Algoma's Sault Ste Marie facility is currently equipped with two (dual) level 2 charging stations. Charging infrastructure continues to grow in the area. Future light vehicle and heavy fleet specifications will include options for hybrid and other electrification of work equipment options such as electric Power take-off units (ePTOs). As technologies continue to improve, Algoma Power will continue to pursue electrification and other green fleet options.

2-Staff-23

Business Systems
Ref 1: Chapter 2 Appendix 2-AA
Ref 2: Exhibit 2, p.50

Preamble:
Algoma Power increased spending in its Business Systems program in 2024 to $485k. Algoma Power notes in reference 2 that the capital expenditure is an investment in SCADA, including 20 relay intelligent electronic devices which are planned to come online and connect to the SCADA system in 2024. The functionality of these devices initially includes remote supervision, real-time system monitoring and fault indication during outages.

Question(s):

a) Please provide the cost-benefit rationale for proceeding with this project versus the alternative of doing nothing.
b) What is the status of this project?

a) **API Response:**
b) As part of Algoma Power's 2020 Cost of Service, investment in SCADA was a key component of this Business System investment program. Prior to this submission, Algoma Power had retained a third-party to develop a SCADA System Business Case for Algoma Power, which weighed the implementation and operating cost of a SCADA system versus the reliability and avoided operating expenses.

   In essence, the long-term cost-benefits were reductions in operating expenses associated with switching operations (establishing work protection, applying hold-offs, etc.), reduction in after-hours call centre costs, and reduction in field-related operating expenses in performing fault investigations and analysis.

   Other tangible benefits included improved visibility of distribution system conditions, allowing Algoma Power to not only better respond to system issues, but be able to proactively respond resulting in a quicker response. This program will also better position Algoma Power to be able to support and supply the integration of Distributed-Energy Resources within its service territory.

c) At the end of 2024, Algoma Power will have installed and connected 20 intelligent electronic devices. As of August 2024, Algoma Power has installed and connected 15 of these devices.

d) 2-Staff-24

Buildings, Facilities & Yards
Ref 1: Chapter 2 Appendix 2-AA
Ref 2: Distribution System Plan Part 1, pp.187-188

Preamble:
Algoma Power plans to increase spending in the Buildings, Facilities & Yards program in the 2025 Test Year to $214k.

Question(s):

a) Please list the capital expenditures that form the 2025 budget for the buildings, facilities & yard program. Are these costs related to the new Sault St. Marie Facility?
b) Please provide the need and priority level for the individual projects that make up the 2025 budget for this program, including why spending has increased in 2025 for this program.

API Response:

a) Included in the Buildings, Facilities & Yards program are investments tied to Each API building facility, the property or yards at each facility and the office furniture and equipment within each facility.

The capital expenditures for this program can be broken down into the following key areas:

Area of Investment	2025 Investment Plan	
Desbarats Facility	$	51,683
Wawa Facility	$	51,683
SSM Facility	$	19,288
Office Furniture & Equipment	$	69,128
Buildings & Yards Improvement	$	22,084
Total	$	213,866

API has included a small budget amount for the Sault Ste Marie Facility that will support smaller investment needs identified through regular inspections and ongoing maintenance.

b) Please see the table below:

Area of Investment	Individual Identified Projects	Budget	Priority Level
Desbarats Facility	Compound Lightning	$ 22,371	High
Desbarats Facility	Automated Gate	$ 24,312	Medium
Desbarats Facility	Miscellaneous Expenditures	$ 5,000	Low/As-needed
Wawa Facility	Net-Zero Initiative/DER	$ 35,000	Medium
Wawa Facility	Cantilever Rack (for Wire Reels)	$ 11,683	Medium
Wawa Facility	Miscellaneous Expenditures	$ 5,000	Low/As-needed
SSM Facility	Awning over West Entrance	$ 2,605	High
SSM Facility	Cantilever Rack (for Wire Reels)	$ 11,683	Medium
SSM Facility	Miscellaneous Expenditures	$ 5,000	Low/As-needed
Office Furniture & Equipment	Floor Sweeper	$ 30,000	High
Office Furniture & Equipment	Desk Replacement (Ergonomic Driver)	$ 24,480	High
Office Furniture & Equipment	Table and Chair Replacement - Sault Operations	$ 7,148	Medium
Office Furniture & Equipment	Miscellaneous Expenditures	$ 7,500	Low/As-needed
Buildings & Yards Improvement	Parking lots bollards	$ 17,084	Medium
Buildings & Yards Improvement	Miscellaneous Expenditures	$ 5,000	Low/As-needed

2-Staff-25

Communication & SCADA
Ref 1: Chapter 2 Appendix 2-AA

Preamble:
Algoma Power plans to spend $480k in its Communication & SCADA program from 2025 through 2028.

Question(s):

a) Please explain what the capital expenditures are for in this program from 2025 through 2028.

API Response:

a) The capital expenditures include the following. This expenditure covers purchasing and programming of 10 devices per year (roughly $12,000 per device)
   - Purchase of communication modem and hardware.
   - Labour for programming of the automation controller (Telemetry data from field devices via DNP are accumulated in the automation controller).
   - Labour for programming SCADA database and HMI.
   - Labour for programming and field injection commissioning of the devices in the field (point by point verification)

2-Staff-26

Goulais Area Voltage Conversion
Ref 1: Chapter 2 Appendix 2-AA
Ref 2: Distribution System Plan Part 1, pp.171
Ref 3: Distribution System Plan part 1, p.125

Preamble:
Algoma Power plans to spend $297k on the Goulais Area Voltage Conversion project in 2025.

According to reference 2, the entire project would consist of converting 202km of overhead primary distribution, upgrading 891 transformers, and reinsulating 1,948 distribution poles.

In reference 3, Algoma Power states:
"HOSSM had identified a need to refurbish their Batchawana TS. At the time of submitting its previous DSP, API was just beginning to discuss alternatives for refurbishment work at this station. In July 2019, API commissioned a Greenfield TS study, which considered the alternatives presented by HOSSM in the supply configuration in the Batchawana and Goulais region. The recommendation of this report was to pursue refurbishing both stations and indicated that there would be significant challenges in operating at the existing supply over the next 15 years."

Question(s):

a) Please explain how much of this work in reference 2 is being completed in the 2025 test year.
b) Please confirm that there is no overlap in work to be completed between the voltage conversion project and the distribution lines or subtransmission lines rebuild programs.
c) Based on reference 3, What proportion of the ultimate Batchawana and Goulais region 25 kV conversion costs does this early investment in the Batchawana TS refurbishment represent?
d) Based on reference 3, what is the estimated NPV cost saving attributable to undertaking this early investment now versus deferring the investment until the 25 kV upgrade is needed in the next 10 to 15 years?

API Response:

a) Algoma Power has proposed a partial conversion based on Alternative B as described in Section 5.4.2.4.3.1 of the DSP, which consist of converting 76 km of primary distribution, upgrading 205 distribution transformers and reinsulating 532 primary distribution poles.

   In the 2025 test year, Algoma Power has planned to complete the following:
   a. Upgrade 65 distribution transformers
   b. Reinsulate 157 primary distribution poles
   c. Make-ready for conversion approximately 18km of primary distribution

b) Algoma Power confirms that there is no overlap between the work to be completed as part of the voltage conversion project and the work under the Line Rebuild programs.

c) Algoma Power's total estimate for the full voltage conversion of the Goulais and Batchawana regions is approximately $10M. This effort would include upgrading a total of approximately 1,400 distribution transformers, reinsulating approximately 4,000 primary distribution poles and converting about 415 km of primary distribution. The investment in the Batchawana TS refurbishment today represents about 4% of the overall voltage conversion cost. Moreover, Algoma Power felt the investment was prudent given the overall refurbishment upgrade that was being undertaken by Hydro One. Had Algoma Power not invested in this future consideration, then the cost of upgrading the supply would have been significant and required the Supply transformer to be changed.

d) Algoma Power has planned for a voltage conversion in the Goulais region due to the recommendation in the Greenfield TS Study report and Area Planning Study. Algoma Power has chosen to advance this investment for two key reasons:

i. To ensure that in the near term, the distribution supply voltage remains within acceptable range based on the studied load projections; and
ii. To minimize the investment required as part of the Goulais TS Refurbishment.

In deferring the investment to a later date, Algoma Power would require a significant increase in its investment plan as part of the Goulais TS Refurbishment project. As part of the Refurbishment project, Algoma would need to construct a substation for its Autotransformer that supplies the existing 25kV distribution in the Goulais region. In addition, to support a future voltage conversion, Algoma Power would invest in ensuring that the Goulais TS 115kV transformer could support 25kV. This would require Algoma Power providing Hydro One a contribution towards the 115kV transformer that would be required.
Algoma Power has estimated that there will not be any NPV savings in deferring the voltage conversion work as a result of the additional investment requirements highlighted above. The estimated cost avoidance in following its proposed investment plan is $1.4M over the next 15 years. Algoma Power has included a copy of the NPV analysis for both options under consideration.

Time Frame of Analysis (Years) :	15
Inflation Rate (Escalation -%) :	2.0%
Discount Rate (Interest Rate - %) :	7.06%

Alt. #	Alternative Description
1	Performed Voltage Conversion Make-Ready work 2025-2029 with Conversion to 25kV once Goulais TS Refurbishment is complete.
2	Defer Voltage Conversion Work. API will need to construct a substation for its AutoTransformer as well as pay HOSSM for incremental TX cost

API will see the annual savings associated with required station maintenance associated with the AutoTransformer

Status quo until the voltage conversion work occurs. No savings expected.

	Alternative #1	Alternative #2
	Performed Voltage Conversion Make-Ready work 2025-2029 with Conversion to 25kV once Goulais TS Refurbishment is complete.	Defer Voltage Conversion Work. API will need to construct a substation for its AutoTransformer as well as pay HOSSM for incremental TX cost
NPV:	-$1,874,063	-$3,253,798

	Alternative #1				Alternative #2			
Year	Voltage Conversion (-$k)	Goulais TS Refurb. (-$k)	Annual Savings ($k)	PV C&S	Voltage Conversion (-$k)	Goulais TS Refurb. (-$k)	Annual Savings ($k)	PV C&S
1	$ (297)	$ -	$ -	$ (297)	$ -	$ -	$ -	$ -
2	$ (297)	$ -	$ -	$ (283)	$ -	$ -	$ -	$ -
3	$ (297)	$ -	$ -	$ (269)	$ -	$ -	$ -	$ -
4	$ (297)	$ -	$ -	$ (256)	$ -	$ -	$ -	$ -
5	$ (297)	$ (680)	$ -	$ (805)	$ -	$ (3,080)	$ -	$ (2,538)
6	$ (3)	$ -	$ 5	$ 2	$ -	$ (5)	$ 3	$ (2)
7	$ (3)	$ -	$ 5	$ 2	$ -	$ (5)	$ 3	$ (2)
8	$ (3)	$ -	$ 5	$ 2	$ -	$ (5)	$ 3	$ (2)
9	$ (3)	$ -	$ 5	$ 2	$ -	$ (5)	$ 3	$ (2)
10	$ (3)	$ -	$ 5	$ 2	$ -	$ (5)	$ 3	$ (2)
11	$ (3)	$ -	$ 40	$ 23	$ (297)	$ (40)	$ 3	$ (206)
12	$ (3)	$ -	$ 5	$ 1	$ (297)	$ (5)	$ 3	$ (175)
13	$ (3)	$ -	$ 5	$ 1	$ (297)	$ (5)	$ 3	$ (167)
14	$ (3)	$ -	$ 5	$ 1	$ (297)	$ (5)	$ 3	$ (159)
15	$ (3)	$ -	$ 5	$ 1	$ (297)	$ (5)	$ 3	$ (152)

2-Staff-27

Protection, Automation, Reliability
Ref 1: Chapter 2 Appendix 2-AA
Ref 2: Exhibit 2, p.46
Ref 3: Distribution System Plan Part 1, pp.173-175

Preamble:
Algoma Power plans to spend $1.5M in the Protection, Automation, Reliability program in 2024, and $758k in 2025.

As per reference 2, in 2024, Algoma Power will complete additional subtransmission reliability project work, specifically the Desbarats Distribution Station refurbishment and Batchawana Transmission Station Supply Reconfiguration.

As per reference 3, in 2025, Algoma Power will complete two projects: upgrading the primary transformer protections at the Bar River DS (Project D) and procuring suitable contingency replacement for the power transformer at the Dubreuilville Sub 87 (Project E).

Question(s):

a) Please break down the need and cost of the two reliability projects in 2024 as described in reference 2.
b) Please provide the status of the two projects described in reference 2 for 2024.
c) Please break down the cost of the five reliability projects (Project A-E) in the forecast period as described in reference 3 by year. Why are costs so much greater in 2025 and 2026?
d) It appears the alternatives considered and the cost-benefit analysis provided in reference 3 is for Project A (with an in-service date of 2027). Please provide the alternatives considered and cost-benefit analysis for Project D and E (with an in-service date of 2025).

API Response:

a) The Desbarats Distribution Station refurbishment project is a contingency and reliability enhancement project that was previously in API’s 2020 Cost of Service. The scope of this project includes the installation of a 3MVA platform bank that will provide transformer contingency for T1 and T2 at the Desbarats DS.

   The total cost of this project is $463,494

   The Batchawana Transmission Station Supply Reconfiguration is an Algoma Power project that was initiated as a result of Hydro One’s larger Batchawana Transmission Station Refurbishment project. As described in the DSP section 5.4.1.1.3, Algoma Power’s scope of work included its feeder point of connection and wholesale revenue meter and equipment. Feeder protection upgrades were also required to ensure proper operation with Hydro One.

The total cost of this project is $724,669

b) The Desbarats DS Refurbishment project is ongoing and expected to be placed into service by the end of October 2024. The Batchawana Transmission Station Supply Reconfiguration is nearly complete and is expected to be placed into service by mid-September 2024.

c) The following is the cost breakdown of the five Reliability projects under Algoma Power's Protection, Automation and Reliability program:

	2025	2026	2027	2028	2029
Project A (34.5kV Switching Automation)	319	189	344	0	0
Project B (12.5kV Voltage Reinforcement)	155	259	0	438	309
Project C (Construct 2nd 3-Phase circuit along Feeder 5120)	0	360	0	0	0
Project D (Upgrading Primary Protections at Bar River DS)	196	0	0	0	0
Project E (Dubreuilville Sub 87 Contingency Transformer)	87	0	0	0	0

d) The only alternative that API considered for Projects D and E was a do-nothing alternative.

For Project E, this wasn't considered a viable alternative as would result in Algoma Power not having a suitable contingency spare, and in the event that the T1 transformer at the Dubreuilville Sub 87 DS were to fail, then the restoration timeline would far exceed reasonable and acceptable timelines.

For Project D, the do-nothing alternative would be the least cost option, however would lessen the operational flexibility and benefits in the long-term. With improved modern transformer protections, API would gain improved visibility of transformer loading and be able to implement more specialized protections. The current primary protections are power fuses, which are limited in their operation.

2-Staff-28

#4 Circuit 10MW Capacity Increase Project
Ref 1: Exhibit 2, pp.6-8
Ref 2: Chapter 2 Appendix 2-AA/AB
Ref 3: Exhibit 2, p.40

Preamble:
Algoma Power stated that "in early 2022, API entered into an agreement for the "Goudreau East 44kV Expansion Project" to construct 11.2km of new and replacement 44kV lines and remove 9.2km of existing line along the #4 Circuit." The project facilitates the request to provide 8MW in total incremental General Service >50kW load.

The gross cost of the project was $11.2M according to Algoma Power. Algoma Power added a replacement credit or capital contribution of $3.5M in the 2024 in-service additions representing the discounted value of work which Algoma Power would have completed in the future if the assets were not replaced early due to the customer-driven need.

In reference 3, Algoma Power noted that there were additional related project costs of $1.7M with an offsetting capital contribution of $1.7M (with a net nil impact).

Question(s):

a) Please confirm if the 8MW incremental load forecast was determined by the industrial customer(s) or by Algoma Power.
b) Please clarify what the additional related project costs of $1.7M pertain to.
c) Please clarify based on the quote in reference 1, whether any of the 11.2km of line is being replaced. If so, why wasn't a credit determined for this portion of the line?
d) Please provide an Excel workbook with the calculations in Table 2 of reference 1. In the Excel workbook, please show a breakdown of the discount factor.
    a. In the same Excel workbook, please provide a comparative calculation of the contribution amount using the OEB-approved inflation factors for 2023, 2024, and 2025 of 3.7%, 4.8%, and 3.6% respectively instead of 2%.

API Response:

a) As discussed in 3-VECC-23, the original customer requests were for greater levels of capacity, for which API developed proposed solutions, which involved costlier and longer duration projects. The 8 MW of incremental load available to the customers was the solution representing the maximum available capacity in the short-to-medium term, at a lower magnitude of cost than the prior solutions. The 8 MW represents the incremental capacity available on the #4 Circuit after replacing and upgrading the conductor assets (incremental capacity : 10 MW), less the 2 MW API reserved for natural system growth, which would have materialized in 2033 when API had planned to replace these sections of line due to age and condition.
b) The additional project costs of $1.7M are related to work undertaken related to preliminary work requested by the customers to explore other project options under consideration prior to entering into the Offer to Connect.
c) The 11.2km of line consists of:

- 6km of line being replaced following the existing Right of Way
- 3.2km of line being constructed following a new Right of Way in order to replace an existing line section (with a similar length) that the customer requested Algoma Power to relocate.
- 2km of line being constructed following a new Right of Way to serve the new Customer

As a result, the "replacement credit" represents the discounted value of work which Algoma Power would have completed in the future, assuming only 9.2km (i.e., 6km +3.2km above) would need to be replaced following the existing Right of Way, i.e., there was no credit considered for 2 km portion of line that is newly built and did not replace existing lines.

d)Please see Attachment 2-Staff-28 d. API notes the assumptions for the discount rate are consistent with the 2020 COS Application outcomes.

The updated Table, using OEB inflation rates for 2023-2025 is included in the same workbook and results in the calculation below:

	Proportion of Line to be Rebuilt in Lieu of Project	Km of Line Replaced per Year in Lieu of Project	Rebuild Cost per km of Line (adj. 2% annually)	Estimated Rebuild Cost Per Year	Mid Year Discount Factor (5.454% after tax)	Discounted Replacement Cost per Year
2022	1.84%	0.2	$527,226	$ 89,249	97%	$ 86,910
2023	1.84%	0.2	$546,733	$ 92,551	92%	$ 85,464
2024	1.84%	0.2	$572,976	$ 96,993	88%	$ 84,934
2025	1.84%	0.2	$593,603	$ 100,485	83%	$ 83,441
2026	1.84%	0.2	$605,476	$ 102,495	79%	$ 80,708
2027	1.84%	0.2	$617,585	$ 104,545	75%	$ 78,064
2028	1.84%	0.2	$629,937	$ 106,636	71%	$ 75,507
2029	1.84%	0.2	$642,535	$ 108,768	67%	$ 73,034
2030	1.84%	0.2	$655,386	$ 110,944	64%	$ 70,641
2031	1.84%	0.2	$668,494	$ 113,163	60%	$ 68,328
2032	41%	3.8	$681,864	$2,559,444	57%	$1,465,461
2033	41%	3.8	$695,501	$2,610,633	54%	$1,417,443
	100.00%	**9.2**				**$3,669,934**

2-Staff-29

Echo River TS ACM Project
Ref 1: Distribution System Plan part 1, Table 4.7, p.124

Preamble:
In Table 4.7 of reference 1, Algoma Power provided a breakdown of the Echo River TS ACM Project budget and the total actual cost variance.

Question(s):

a) Please explain why Algoma Power did not budget for any of its own activities i.e., Algoma Power Internal Cost, Study Cost (for Alternative & Business Case), Modification required to Algoma Power Wholesale Meter as part of its ACM request.
b) Please explain the recourse available to Algoma Power when HOSSM notifies it of material cost increases above the CCRA estimate amount.
    i. Please describe the actions taken (beyond those described in reference 1 and Exhibit 2) by Algoma Power to validate each of the proposed HOSSM cost increases and to mitigate the impact of those cost increases on the total project cost.

API Response:

a) Algoma Power did not budget for its own activities as it had not known and anticipated that these activities at the time of submitting its previous DSP.

b) Included in the CCRA are clauses pertaining to final true-up cost as well as dispute clauses. Under Part B of the CCRA, a final true-up of actual cost would occur within 180 days after the ready-for-service date is met. Under Part D, Algoma Power had dispute capabilities pertaining to cost and the allocation of costs.

    The notices of cost increases that were provided by Hydro One were not specifically spelled out in the CCRA. When these notices were received, Algoma Power proceeded to challenge Hydro One on the prudency of the cost and appropriateness of the cost allocation. As part of the initial response to the cost increase notices, Algoma Power requested an explanation of cost increases, why they had or were to occur and why the cost would be allocated to Algoma Power. In several instances API sought clarification to the response provided by HOSSM.

    Once the final cost increase notice was received, Algoma Power proceeded to draft and issue a formal letter to HOSSM to substantiate the full incremental costs compared to the initial estimate that was included in the CCRA. This letter and the response provided by HOSSM has been included as Attachment 2-Staff-29.

2-Staff-30

Sault Ste. Marie Facility ACM
Ref 1: Exhibit 2, pp.80-84
Ref 2: Exhibit 2, p.72
Ref 3: Exhibit 2, p.76
Ref 4: Exhibit 2, Table 41, p.79
Ref 5: Exhibit 2, p.75

Preamble:
In reference 1, Algoma Power conducted a benchmarking study comparing various OEB-approved building costs. As part of the benchmarking study, Algoma Power removed the geotechnical issues ($417k) from its actual cost for comparison with the other buildings, noting that these geotechnical issues were outside of Algoma Power's control and are unlikely to have occurred at the other comparators.

In reference 2, Algoma Power notes that following a competitive bidding process, the contract for the project was awarded to S&T Group at a value of $14.7M.

In reference 3, Algoma Power notes that it installed overhead doors, a motorized shop door, and motorized gates to the new facility costs.

Question(s):

a) Please provide the Excel sheet showing all calculations in producing Table 43 in reference 1.
b) Can Algoma Power confirm that the other comparators in the benchmarking study did not have other complications outside of their control (not strictly geotechnical related)? If not, please provide the benchmarking analysis with the geotechnical issues included.
c) Please provide the value of the other bids received for the project.
d) Reference 4 indicates that it was unclear what proportion of the cost overrun was attributable to Covid-19. Please make best efforts to estimate the proportion of the project cost overrun attributable to Covid-19.
e) Please confirm whether the old facility had motorized shop doors/gates. If so, why weren't these additions included in the initial ACM budget? If not, what is the new need for these additions?
f) Please explain why the parking and driveway modifications as detailed in reference 5 were not considered at the time of the initial ACM filing.

API Response:

a) Please see attachment 2-Staff-30 for the calculations supporting the building benchmarking comparisons in Exhibit 2 of the Application.

b) API cannot confirm that the other comparators faced unforeseen circumstances, as many construction projects do. Nonetheless, API considers that the congruence of multiple high-cost issues, namely the impact of COVID-19 and the unforeseen Geotechnical work, are unlikely to have occurred at the other comparators.

API has provided the benchmarking analysis with the Geotechnical costs added back in the table below.

Taking into consideration the two comparable identified buildings, Innisfil Hydro ($372.38/sqft) and Waterloo North Hydro ($319.36/sqft), API's adjusted cost per square foot including the geotechnical costs is $346.87, which is within the previously approved range, and very closely in line with the average of these two comparators (which is $345.87/square foot.

LDC	Milton Hydro	Waterloo North	Innisfil Hydro	PUC Hydro	Energy+	Enersource	PowerStream	Brantford Power	Algoma Power Inc.
Function	Admin & Operatic	Admin & Operatic	Admin & Operatic	Admin & Operatic	Admin	Admin	Admin	Admin & Operatic	Admin & Operatio
Custom Build vs. Purchase and Refurbish	Purchase and Refu	Custom Build	Custom Build	Custom Build	Purchase and Refurb	Purchase and Refu	Custom Build	Purchase and Refu	Custom Build
Application No.	EB-2015-0089	EB-2010-0144 EB-2015-0108	EB-2014-0086	EB- 2012-0162	EB-2018-0028 EB-2021-0018	EB-2012-0033	EB-2008-0244	EB-2021-0009	EB-2024-0007
Building In-Service Year	2015	2011	2015	2012	2022	2012	2008	2020	2022
Northern Ontario?	No	No	No	Yes	No	No	No	No	Yes
OEB Approved Capital	$ 13,030,798.00	$ 26,476,961.00	$ 11,141,210.00	$ 23,000,000.00	$ 7,800,000.00	$ 18,000,000.00	$ 27,700,000.00	$ 14,829,117.00	$ 13,545,538.52
Customers (2021*)	42,082	58,746	19,703	33,865	68,193	201,359	353,284	41,065	12,227
Square Footage	91,828	105,000	36,172	110,382	21,892	79,000	92,000	72,668	39,051
FTEs (2021)	59	120	55	78	124	150	250	63	50
cost/sqft	$ 141.90	$ 252.16	$ 308.01	$ 208.37	$ 356.29	$ 227.85	$ 301.09	$ 204.07	$ 346.87
Construction Price Index between estimated construction year and 2022	120.90%	126.65%	120.90%	126.68%	100%	126.68%	137.60%	107.48%	1.00
Inflation Adjusted Approved	**$ 171.56**	**$ 319.36**	**$ 372.38**	$ 267.33	**$ 356.29**	**$ 288.63**	**$ 414.30**	**$ 219.32**	$ 346.87
Cost per FTE	$ 269,303.16	$ 279,442.26	$ 243,840.02	$ 374,392.83	$ 62,700.96	$ 152,010.00	$ 152,460.80	$ 251,619.73	$ 270,910.77

c) In order to maintain the integrity of the RFP process, API has provided summary information as to the nature of the bids received. API confirms it accepted the lowest bid. API received more than three bids, and the average price was $17.1M.

d) API estimates approximately $980k in COVID impacts based on the calculations in the following table.

Labour and Consulting Estimate - Impact of COVID				
Labour and OE in 2020-2022			$	626,736
Project delay due to COVID	original schedule		18 months	
	final duration		24 months	
% Increase Project Length				33%
Estimated Cost without delays			$	470,052
Potential Impact due to project Delays			$	156,684
Construction Portion				
Total Construction Budget			$	13,891,064
S&T Cost Estimate Impact at start of contract				6.30%
Estimated reduced budget without COVID			$	13,067,793
Estimated impact of COVID on budget			$	823,271
Estimated Potential Impact of COVID			**$**	**979,955**

e) Yes the previous facility did have a motorized gate and shop doors.

The budgets presented in the 2020 ACM application were not at a sufficiently detailed level to account for the number of motorized doors. Through the design process the need for the quantity of overhead doors and gates were defined, which was after the ACM submission. Through the design process, the reduction in square footage which brought about the majority of the savings in Change Order #1 resulted in a greater number of motorized doors required.

f) Similar to the answer above, at the time of developing the budgets used in the ACM, API had not yet proceeded sufficiently to budget on the basis of the final location. As discussed in the Application, following the in-service of the facility, API became aware of functional inefficiencies and other concerns once the facility was occupied and circulation of vehicles and employees began.

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Sault Ste. Marie Facility ACM - Operational Efficiencies
Ref 1: Exhibit 2, pp.86-87

Preamble:
In reference 1, Algoma Power provided a list of efficiency improvements as a result of the new facility. Algoma Power notes that for the most part, it cannot quantify these efficiency improvements.

Question(s):

a) Please confirm whether Algoma Power has accounted for any efficiencies from the Sault Ste. Marie Facility in its 2024 and 2025 OM&A budgets.

API Response:

One of the mentioned efficiency gains relates to the energy efficiency of the facility. API's operating budget for utilities reflects the forecasted efficient heating, cooling and lighting parameters incorporated into the building design.

2-Staff-32

NWS/CDM in Distribution System Planning
Ref 1: EB-2024-0118, Non-Wires Solutions Guidelines for Electricity Distributors, March 28, 2024
Ref 2: EB-2024-0007, Exhibit 2 – Rate Base & Distribution System Plan, Distribution System Plan, Part 1, Attachment 2A, Section 5.3.5

Preamble:
Per the OEB's Non-Wires Solutions Guidelines for Electricity Distributors (NWS Guidelines), electricity distributors are required to incorporate consideration of non-wires solutions (NWSs) into their distribution system planning process by considering whether a distribution rate-funded NWS may be a preferred approach to meeting a system need, thus avoiding or deferring spending on traditional infrastructure. Per the NWS Guidelines, traditional conservation and demand management (CDM) is a potential NWS that electricity distributors may consider. Furthermore, electricity distributors are required to document their consideration of NWSs when making investment decisions on electricity system needs with an expected capital cost of $2 million or more as part of distribution system planning, excluding general plant investments.

Algoma Power has indicated that it is not aware of any planned CDM programs within its service territory which would need consideration in its system planning. Further, Algoma Power noted that it will continue to consider CDM opportunities to address system needs and will consider the relative costs and benefits associated with a CDM option.

Question(s):

a) Please describe how Algoma Power has addressed or plans to address the requirement in the OEB's NWS Guidelines for distributors to incorporate consideration of NWSs into their distribution system planning process.

API Response:
API has taken NWS into consideration for some time, including as a consideration in the early development of the #4 Circuit project (or its predecessors).

API is in the process of implementing the OEB's NWS Guidelines including the recently introduced Benefit Cost Analysis, however the BCA framework was not released in time for API to incorporate the BCA framework into its budgets, DSP and Application. The BCA framework indicates that distributors filing rate applications in 2026 and beyond need to apply the guidelines, and therefore API was not required to implement the guidelines into this Application, nor would it have been possible to do so within the application filing timelines. The OEB's framework encourages LDCs to use the BCA particularly for applications seeking funding for NWS, however API is not seeking such funding at this time.

Exhibit 3 – Customer and Load Forecast

3-Staff-33

Customer Forecast
Ref 1: Exhibit 3, page 20

Preamble:
Algoma Power states,
"*During the COVID-19 pandemic, API observed above-average customer growth due to individuals relocating from other areas of the province. API believes this trend was limited to the COVID-19 pandemic, and is unlikely to continue. API considers that the geomean excluding 2020, 2021 and 2022 presents a more accurate viewpoint of the typical customer growth expected in future years, now that COVID impacts are slowing.*
Additionally, 2020 had an
'above normal increase due to the acquisition of a new service area, ie: the customers of the former Dubreuil Lumber Inc. (DLI)"

Algoma Power has used historical customer/connection usage from 2014 to 2023 to forecast future usage.

Question(s):
a) Please provide customer numbers for all rate classes for the most recent historical months available for 2024.
b) Please provide a customer forecast based on the geomean from 2014-2023.

API Response:

a) Please see the table below which includes the customer numbers by class at June 30, 2024.

Customer Class	Number of Customers/Connections 30-Jun-24
R1(i)	8,564
R1(ii)	1,071
R2	47
Seasonal	2,759
Street Lighting (Connections)	1,117
Total	**13,558**
R1 Subtotal	*9,635*

b) Please see below the geomean values per class using 2014-2023 data.

Year	R1(i) Residential	R1(ii) GS < 50 kW	R2 GS>50 kW	Seasonal	Street Lights	Total
2024	8,613	1,066	47	2,744	1,144	13,614
2025	8,744	1,078	46	2,696	1,156	13,720

The figures above are based on the following geomean customer growth forecast assumptions.

	R1(i) Residential	R1(ii) GS < 50 kW	R2 GS>50 kW	Seasonal	Street Lights
Geomean 2014 to 2023	1.0151	1.0108	0.9940	0.9825	1.0106

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Energy Forecast
Ref 1: Exhibit 3, page 24

Preamble:
Algoma Power states,

> *"API believes that 2023 represents an appropriate assumption for post pandemic usage per customer, reflecting new trends such as a long-term increase in working from home, but not the impacts of stay-home or other emergency public health requirements."*

Question(s):

a) Please provide a rate class consumption model based on average annual kwh usage per customer from 2014-2023 applied to the forecasted customer counts for the bridge and test years.
b) Did Algoma Power undertake any analysis to test the impact of COVID-19 on the load forecast (e.g., including a Covid variable in the regression model)? If so, please provide the results. If not, please explain why not.

API Response:

a) Please see the updated kWh per rate class based on average usage per customer 2014-2023.

The forecasts below include the manual adjustments of 51,899,642 kwh and 86,880 kW in the R2 class.

Th average consumption per customer using 2014-2023 average is outlined in the table below:

Year	R1(i) Residential	R1(ii) GS < 50 kW	R2 GS>50 kW	Seasonal	Street Lights
Avg 2014-2023	11,065	27,575	2,493,045	2,141	567

Using the consumption per customer it the table above, the following tables outline the forecasted consumption per class. Please see Attachment 3-Staff-34 for the corresponding forecast model.

Weather Corrected Forecast kWh					
Year	R1(i) Residential	R1(ii) GS < 50 kW	R2 GS>50 kW	Seasonal	Street Lights
2024	103,299,259	31,723,252	123,270,818	5,898,189	648,411
2025	105,196,041	32,018,918	173,861,743	5,817,732	655,379

b) Algoma Power did not test the impact of COVID-19 on the load forecast since the variables chosen provided very good statistical results on their own and produced a reasonable power purchased forecast for 2024 and 2025. It did not appear worthwhile to pursue including any additional variables.

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Load Forecast
Ref 1: Exhibit 3, page 5
Ref 2: DSP, page 75

Preamble:
Algoma Power provided a load forecast in Exhibit 3. In reference 2, Algoma Power provides a load projection based on an annual increase of 1.7% associated with EV charging and electrification.

Question(s):

a) Has Algoma Power considered the impact of Distributed Energy Resources or other emerging technologies such as electric vehicles on its load forecast provided in Exhibit 3? Please explain your response.

API Response:

a) API has not made any specific adjustments for DERs or electrification in its load forecast provided in Exhibit 3.

   API does not anticipate that growth levels associated with electrification will necessarily materialize via steady year over year growth of 1.7%, which is the factor used for the purpose of distribution system planning forecasts. Rather, growth rates will likely vary year-over-year, likely with slower growth rates in earlier years.

   API anticipates technological uptake may be slower in Algoma for Electric Vehicles due to longer typical driving distances, lower availability of charging infrastructure (at least in the near term), and the realities or customer perceptions regarding worse battery performance in low temperatures.

   For these reasons, API did not believe it is appropriate to make an adjustment for electrification in the 2025 test year.

   Furthermore, API has included the forecasted 1.7% as a conservative measure of reasonable load growth, erring on the side of a high but realistic estimate. This approach is reasonable for the purposes of distribution planning, where an understated growth forecast may lead to inadequate capacity to meet customer needs, reduced reliability, or early asset replacements which increase cost.

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Load Forecast
Ref 1: Exhibit 3, page 25
Ref 2: Distribution System Plan part 1, Figure 3.3, p.75

Preamble:
In reference 1, Algoma Power states,
"For the R2 commercial class, API has made a manual adjustment to increase the forecast for the anticipated load associated with increased customer usage from the #4 Circuit project which is detailed in Exhibit 2. The project will bring 8MW in increased maximum customer load."

OEB staff notes that the load forecast for R2 rate class includes a manual adjustment of 86,880 kW and 51,899,642kWh.

Question(s):

a) Please explain the derivation and provide the full calculation of the 86,880 kW and 51,899,642kWh manual adjustments included in the load forecast.
   a. Does the 0.905 multiplier in the calculations represent a 91% power factor?
   b. Does the calculation account for the actual peak load of the industrial customers? If not, why not?

b) Please explain why Algoma Power has accounted for the increased load due to the new industrial customer in 2023 in Figure 3.3 of reference 2 but has made a manual adjustment for the 8MW increase in the 2025 load forecast as per reference 1.

c) Does the load forecast in reference 1 account for the 0.92% annual growth increase included in Figure 3.3 of reference 2? If not, why not?

API Response:

a) i. No, the .905 multiplier represents an estimated relationship between the annual non-coincident peak MW and monthly average non-coincident peak MW.

ii. Yes the multiplier accounts for the forecasted annual peak load of the customer, but takes into consideration that the average monthly peak load applicable for billing purposes will be lower than the annual peak load.

b) The timing of the new load was uncertain at the time of developing the forecasts. For the billing forecast API has reflected the forecasted impact of the additional kW load and kWh consumption in the Test Year, to ensure the rate-setting calculations reflect the expectation that 2025 will have the new incremental capacity in place throughout the test year.

c) No, the load forecast in reference 1 does not directly account for the same annual growth as reference 2. Directionally, however, both forecasts account for historic changes in usage due to customer growth and other usage trends.

There are many differences between the methodology and purpose of the load forecast in reference 1 and reference 2, as outlined in the table below:

	APS/DSP Load Forecast	**Billing Load Forecast**
Weather Normalized?	No	Yes
Peak Values	Annual Coincident	Monthly Non-Coincident
Consumption?	No	Yes
Timing focus	Long Term	Short Term- 2025 Test Year
Last Actuals	2022	2023

Nonetheless, API notes that compared to 2022, which is the consistent year of historical actuals between the two, the load forecast in reference 2 (Exhibit 3), shows the following geomean growth levels:

	Billing kWh	Billing KW		
	Before Ind. Customer	Before Ind. Customer	YOY % Change kWh	YOY% Change kW
2022	256,287,580	262,532		
2023	259,742,424	279,560	101.3%	106.5%
2024	264,839,930	290,034	102.0%	103.7%
2025	265,650,171	287,110	100.3%	99.0%
Geomean Growth			**101.2%**	**103.0%**

Based on the table above, average growth between 2022 and 2025 for the kWh consumption exceeds the 0.92% p.a. level assumed in Reference 1 (APS/DSP), as does Non-Coincident monthly peak consumption.

Exhibit 4 – Operations, Maintenance & Administration

4-Staff- 37

OM&A Summary
Ref 1: Exhibit 4, p. 5
Ref 2: Appendix 2-Jc

Question:

a) Please provide a revised version of Appendix 2-JC with an additional column showing year-to-date actuals.

API Response:

a) Please see response provided in 4-SEC-22.

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Use of Non-Wires Solutions to Meet Identified Customer Needs
Ref 1: EB-2024-0007, Exhibit 4 – Operating Expenses, Section 4.8.1
Ref 2: EB-2023-0125, Benefit-Cost Analysis Framework for Addressing Electricity System Needs, May 16, 2024

Preamble:
Algoma Power indicated that it has received a request for a connection for which a non-wires solution (NWS) may be a viable option to meet a customer's need. Further, Algoma noted that it is examining the wires and NWSs options available to meet this specific customer's need, while considering the OEB's Benefit-Cost Analysis (BCA) Framework and the customer's needs and preferences.

The OEB's BCA Framework consists of a pre-assessment, distribution service test, and optional energy system test that electricity distributors are to use when evaluating the viability of NWSs to meet a given electricity system need.

Question(s):

a) Please provide further details as to the specific need for which an NWS may be a viable option. In the response, please identify the specific wires and NWS options under consideration for evaluation.
b) Please confirm whether Algoma Power is seeking ratepayer funding as part of the current application to address the identified customer need. If so, please provide the total estimated costs of the wires and NWSs under consideration.
c) If ratepayer funding is being sought, please confirm whether the pre-assessment stage of the BCA Framework has been applied for this system need. If so, please provide the rationale and outcome of the pre-assessment.
d) If ratepayer funding is being sought, please confirm whether the distribution service test or energy system test were employed for this system need. If so, please provide the outcomes of the tests employed using the OEB approved templates required by the BCA Framework.

API Response:

a) API has received a customer request for a 2.5MW maximum demand. The customer is located in an area that currently has less than 2.5MW in available capacity. Accordingly, API is comparing the business case for expanding distribution and potentially transmission assets versus addressing a portion of the customer's new capacity requirement through the use of a battery storage solution. At this time, API is also consulting with the connecting customer on its preferences to determine whether an NWS would be an acceptable solution from this perspective. Furthermore, API is consulting as to whether the customer has preferences as to the ownership of the potential BESS.

API has previously discussed with the customer whether demand response or load shedding would be available for the customer, however the customer advised this was not a viable option due to the nature of the customer's load and operating patterns/requirements.

API is currently exploring the technical and cost requirements of a BESS solution with technical consultants.

API notes its current understanding that BESS solution implementation in Northern Ontario may differ from Southern Ontario implementations, due to the prevalence of lower winter temperatures potentially affecting the operating efficiency of batteries.

b) Currently, API is consulting as to the preference of the customer regarding the potential BESS. Depending on the outcome of these discussions, and if the project moves forward, API will consider the available funding options under the OEB's framework for NWS.

c) and d) At this time, API does not have sufficient certainty with respect to this project to undertake the associated assessments. API is in the process of developing its pre-screening. Should the project reach a greater certainty, API will conduct the applicable steps at that time.

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Corporate Cost Allocation
Ref 1: Exhibit 4, pp. 70-71
Ref 2: Ch. 2 Appendices, Tab 2-N Corp_Cost_Allocation
Ref 3: EB-2021-0011 CNPI 2022 CoS_Ch. 2 Appendices, Tab 2-N Corp_Cost_Allocation
Ref 4: Exhibit 1, p. 25

Preamble:
On p. 70 of Ref. 1, the shared services include: executive; finance; information technology; human resources; health, safety and environmental; regulatory; and procurement and contract management. In Ref. 4, Algoma also listed legal and engineering as a shared service.

Algoma Power noted that the corporate cost allocation methodology, which includes the relative percentage allocation to the Fortis Ontario business units, are updated when Canadian Niagara Power Inc. (CNPI) rebases.

In Ref. 2, CNPI allocated 24% or $1,690,874 for administrative services to Algoma in its 2022 CoS application.

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
FortisOntario	CNPI-Distribution	corporate services	cost based	$554,988	$554,988	21%
FortisOntario	CNPI-Distribution	building rent	market based	$410,315	$410,315	65%
CNPI-Distribution	Cornwall Electric	administrative services	cost based	$1,285,749	$1,285,749	19%
CNPI-Distribution	FortisOntario	administrative services	cost based	$148,284	$148,284	2%
CNPI-Distribution	CNPI-Transmission	administrative services	cost based	$343,874	$343,874	5%
CNPI-Distribution	Algoma Power	administrative services	cost based	$1,690,874	$1,690,874	24%
Cornwall Electric	CNPI-Distribution	administrative services	cost based	$20,189	$20,189	13%
Fortis Inc.	CNPI-Distribution	administrative services	cost based	$259,044	$259,044	0%
CNPI-Distribution	Cornwall Electric	shared IT & equipment	cost based (Note 1)	$382,675	$382,675	21%
CNPI-Distribution	FortisOntario	shared IT	cost based (Note 1)	$38,070	$38,070	3%
CNPI-Distribution	CNPI-Transmission	shared IT & equipment	cost based (Note 1)	$125,576	$125,576	7%
CNPI-Distribution	Algoma Power	shared IT	cost based (Note 1)	$478,299	$478,299	31%

In its 2025 CoS application, Algoma Power showed the following corporate cost allocation from CNPI totalling $2,092,148, which is a 24% increase over the cost CNPI allocated in 2022:

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
FortisOntario	API	corporate services	cost based	22%	$639,570
FortisOntario	API	building rent	market based	13%	$88,223
CNPI-Distribution	API	Finance & Purchas	cost based	32%	$718,385
CNPI-Distribution	API	IT	cost based	31%	$726,351
CNPI-Distribution	API	HR	cost based	34%	$180,588
CNPI-Distribution	API	Health, Safety, Env	cost based	34%	$321,528
CNPI-Distribution	API	Regulatory	cost based	40%	$145,296
Fortis Inc.	API	administrative servi	cost based	0%	$183,747
CNPI-Distribution	API	shared IT	cost based (Note 1	31%	$431,621

Question(s):

a) Please confirm that administrative services of $1,690,874 approved as part of CNPI's cost of service application includes the same services in the amount of $2,092,148 highlighted in the table above.
b) Please explain the cost increases for each service provided by CNPI from 2022 onwards by departments in more detail.
c) Please confirm that the 'building rent' charged by Fortis Ontario to Algoma Power is not included in the fully allocated costs for services charged by CNPI. Please provide a more detailed explanation for this cost allocation.

API Response:

a) Confirmed. API notes that the 24% percentage value provided in CNPI's 2022 application is a lower value than each of the individual function values allocated to API in 2022 per Reference 2 above because the property maintenance shared service function for the Niagara area facilities is not allocated to API. See table below for an updated breakdown, similar to as presented in this Application, of the 2-N as provided in the CNPI application for 2022 totaling $1,690,874. API notes the % allocators are consistent between the CNPI 2022 and API 2025 applications, when taking into account the allocators below.

Year: **2022 CNPI COS BREAKDOWN**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
CNPI-Distribution	API	Finance & Purchasing	cost based	$657,900	$657,900
CNPI-Distribution	API	IT (OM&A component)	cost based	$542,003	$542,003
CNPI-Distribution	API	HR	cost based	$147,922	$147,922
CNPI-Distribution	API	Health, Safety, Environment	cost based	$230,295	$230,295
CNPI-Distribution	API	Regulatory	cost based	$112,754	$112,754

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
CNPI-Distribution	API	Finance & Purchasing	cost based	32%	$657,900
CNPI-Distribution	API	IT (OM&A component)	cost based	31%	$542,003
CNPI-Distribution	API	HR	cost based	34%	$147,922
CNPI-Distribution	API	Health, Safety, Environment	cost based	34%	$230,295
CNPI-Distribution	API	Regulatory	cost based	40%	$112,754

b) The cumulative increase from 2022 to 2025 for the Finance & Purchasing and HR functions have remained in-line with general inflationary factors. Aside from general inflationary factors, the IT allocation has increased due to a combination of a shift from cloud based solutions previously capitalized to on-going annual subscriptions totaling approximately an $85,000 increase in allocations to API, and also API's portion of the IT Security Analyst to be hired in 2025 as noted in 4-Staff-46. The IT Security Analyst will focus on Information and Operational Technology Security across all FortisOntario companies. In addition to general inflationary factors, with the continued ease of the Covid restrictions beyond 2022, the Health, Safety, Environment has worked towards a return to the full execution of their program as some components of the program had been put on pause during Covid. This return included the completion of corporate training sessions and corporate safety recognition days, which in turn drove up associated related costs such training fees and travel related costs (these have contributed an increase in allocation to API of approximately $35,000 in 2025 as compared to 2022). The Regulatory function in 2022 had a one-time credit expense financially posted, which in turn resulted in a $14,000 credit applied through the shared service allocation to API. Outside of this one-time credit value from 2022, the Regulatory increase over 2022 has been due to general inflationary factors.

c) Confirmed. The allocation of rent is based on relative FTE allocation and to the extent that there are shared administration and corporate services physically located in Fort Erie, that rent cost is then allocated to FortisOntario subsidiaries. The allocation methodology including the overall allocation percentages are reviewed every 5 years when Canadian Niagara Power distribution rebases (last reviewed and updated in 2022). The allocation of rent for shared admin and corporate services is consistent with the requirements in the Affiliate Relationship Code for fully allocated costing.

4-Staff-40

Corporate Cost Allocation – Administrative Service
Ref 1: Ch. 2 Appendices, 2-N, 2025 Corporate Cost Allocation

Preamble:
In Ref 1, Algoma Power shows a corporate cost allocation of 0% from Fortis Inc. to Algoma Power for administrative service but applies a cost of $183,474.

Question(s):

a) Please explain why Fortis Inc. charges Algoma $183,747 for administrative service given the allocated cost is 0%.
b) If costs are allocated to Algoma Power, please provide the percentage over the last five years and a detailed description of the service(s).
c) Please update Appendix 2-N if necessary.

API Response:

a) The percentages in Appendix 2-N presented in the application are rounded to nearest whole percentage values. See table below for the additional decimal place shown for the Fortis Inc. allocations year-over-year. FortisOntario (including its subsidiaries) is allocated, ~1.1% to ~1.2% of total Fortis Inc. shared costs, which in turn is then allocated to FortisOntario's subsidiaries. The allocation percentage split within FortisOntario is a combination of the relative revenue and also rate base. The percentages reflected in the table below (taken to an extra decimal place) are the percentages allocated to API relative to Fortis Inc. total shared costs.

	Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
Year	From	To			%	$
2020	Fortis Inc.	API	administrative services	cost based	0.4%	$197,277
2021	Fortis Inc.	API	administrative services	cost based	0.4%	$201,502
2022	Fortis Inc.	API	administrative services	cost based	0.4%	$200,962
2023	Fortis Inc.	API	administrative services	cost based	0.4%	$165,877
2024	Fortis Inc.	API	administrative services	cost based	0.4%	$179,830
2025	Fortis Inc.	API	administrative services	cost based	0.4%	$183,747

b) Confirmed that dollars are allocated to API. See a) above. Fortis provides a key strategic oversight role over the business and strategic planning and corporate governance of the subsidiaries and facilitates and coordinates the cross-functional sharing of best practices across the group. Fortis holding company operating costs, which are incurred in support of the above-noted activities are allocated and recovered from the subsidiaries. Examples of such operating costs include, but are not limited to, salaries and benefits, and fees and expenses related to public equity capital market-related governance, compliance, listing, filing, trustee, common share purchase plan and reporting requirements.
c) No further updates required to 2-N.

4-Staff-41

Cloud Computing
Ref 1: Exhibit 1, p. 74

Preamble:
On p. 74, Algoma Power noted that the increase for administrative services from CNPI to Algoma Power in the amount of $426,815 from 2020 Board Approved to 2025 Test is due to general increases in labour, material and contracted service costs.

Algoma Power stated that cybersecurity related costs continue to increase, and the implementation of the cloud computing standard gives rise to additional third party maintenance agreement costs that were previously capitalized.

Question(s):

a) Please confirm that third party maintenance agreement cost are based on subscription-based model/cloud-based solution. If not, please explain what is included in this cost.
b) Please complete the following tables on capital and OM&A spending between on-premise solutions and subscription-based model/cloud-based solutions.

Costs for On-premise Solutions from 2020-2029

	2020	2021	2022	2023	2024
Capex	$	$	$	$	$
OM&A	$	$	$	$	$

	2025	2026	2027	2028	2029
Capex	$	$	$	$	$
OM&A	$	$	$	$	$

Costs for Subscription-based/Cloud-based Solutions from 2020-2029

	2020	2021	2022	2023	2024
Capex	$	$	$	$	$
OM&A	$	$	$	$	$

	2025	2026	2027	2028	2029
Capex	$	$	$	$	$
OM&A	$	$	$	$	$

c) Please explain any cost savings as a result of moving to a subscription-based model or cloud-based solutions which Algoma Power would otherwise incur with on-premise solutions.

API Response:

a) Confirmed. Third-party maintenance agreement costs pertain directly to the hosting, disaster recovery/high availability, and backup of Algoma Power's mission critical Customer Information System and Enterprise Resource Planning system on the Amazon Web Services cloud infrastructure platform.

b) API pays, through the shared service and corporate allocation from CNPI distribution, in its operating budget for the use of FortisOntario on-premise and cloud based software. While the costs incurred in some years represent capital investments for CNPI, they are recorded as OM&A for API.
API-specific capital expenditures for on-premise software solutions is not significant, and is limited to the implementation of Outage Management Software in 2022 as presented in the tables below. The corresponding annual fees are also reflected as OM&A in the table below. Capital expenditures for API specific subscription-based/Cloud-based solutions has been limited to the roll-out of a new website in 2021 and a planned new vegetation management program rollout in 2024.
On-going annual OM&A fees are reflected in the table below.
API has not prepared detailed OM&A budgets for the years beyond 2025 at this time and so is not able to provide a meaningful forecast. API is aware that during the upcoming rebase period, CNPI will review a potential need for an SAP upgrade.

Costs for On-premise Solutions from 2020-2029

	2020	**2021**	**2022**	**2023**	**2024**
Capex	$0	$0	$6,254	$0	$0
OM&A	$0	$0	$16,338	$19,345	$20,000

	2025	**2026**	**2027**	**2028**	**2029**
Capex	$0	$0	$0	$0	$0
OM&A	$21,000	N/A	N/A	N/A	N/A

Costs for Subscription-based/Cloud-based Solutions from 2020-2029

	2020	**2021**	**2022**	**2023**	**2024**
Capex	$0	$12,353	$0	$0	$30,000
OM&A	$	$600	$2,160	$2,600	$22,000

	2025	**2026**	**2027**	**2028**	**2029**
Capex	$0	$ -	$ -	$ -	$ -
OM&A	$19,000	N/A	N/A	N/A	N/A

c) Although API was unable to provide readily available quantifications, some potential cost savings regarding cloud-based systems:

- Various cybersecurity controls are inherited from the cloud hosting environment, which would otherwise be expensive and resource-intensive to implement and sustain on-premise (i.e. data encryption in transit and at rest).
- High availability and disaster recovery objectives are more economical on cloud platforms, as they do not require additional hardware, data centre facilities, etc. and do not result in depreciation of infrequently used hardware and software assets.
- Cloud infrastructure can be sized up or down to meet changing system performance demands, whereas on-premise solutions need to be sized with maximum desired performance considerations.
- Operational costs associated with maintaining on-premise infrastructure (system patching, hardware maintenance, etc.) are reduced by moving to cloud-based systems and/or infrastructure, resulting in overall reductions in labour spent to maintain environments.
- Development and test systems can be powered off when not required, reducing or eliminating costs when not in use, whereas on-premise environments incur initial capital costs regardless of their usage requirements.

4-Staff-42

Vegetation Management
Ref 1: Exhibit 4, pp. 28-37 and Table 7
Ref 2: Ch. 2 Appendices, Tab 2-JB_OM&A Cost Drivers

Preamble:
On p. 28 of Ref 1, Algoma Power noted that the increase in vegetation management is due to the volume of work, as well as variations in the cost per unit to complete the work.

On p. 35, Algoma Power noted that the $1.24M increase compared to 2020 Board-approved is due to the following factors:

- An increase in the level and cost of work required for brush control, as a result of lower ability to complete brush control though herbicide application during this cycle
- An additional increase in the cost of work required for brush control, as a result of brush growth volume caused by inability to apply herbicide in past years/cycles
- An estimated $745k increase or 21% in costs associated with general inflation since 2020
- Above-inflationary levels of increases in contractor cost per km pricing (estimated at 26%)

Question(s):

a) Please provide Algoma Power's current vegetation management plan for the last five years as well as its five-year plan going forward.

    i. Please discuss Algoma Power's vegetation management plan with respect to the clearing of hazard trees in addition to brush management.

b) Please provide the customer interruptions as well as customer hours of interruption due to tree contacts to date. Please explain the decreases in 2021 and 2023.
c) Please explain what is special about the test year with respect to cost trends and vegetation management program unit costs that causes the single year step increase in spending.
d) OEB staff notes that in 2020, Algoma Power was able to maintain 280km of medium to heavy density brush. Please explain why Algoma Power feels that vegetation management for a forecast length of 355 km of line with medium density/complexity is achievable in the 2025 test year.
e) Please provide a table showing the break-down of in-house labour vs. third-party contractors' costs for vegetation management.
    i. Please provide a variance analysis from year to year for each category.
    ii. Provide an explanation how Algoma Power determines whether to use contractors vs. internal labour.
f) Has Algoma Power considered a shorter vegetation management cycle?
g) OEB staff noted that the per km cost of $13,567.42 for the test year represents an increase of 5.67% over 2020. Please explain the above noted inflationary increase of 21% compared to this increase.

API Response:

a) Please see the table below:

5 Year Plan 2020-2025					
Year	**Forestry Part**	**Kms**	**Work Type**	**Unit Cost/Km**	**Density**
2020	No. 4 Circuit	49.60	BC	6,907.10	heavy
2020	Bruce Mines Part 1	48.00	LC,BC	14,789.21	medium
2020	Bruce Mines Part 4	35.00	LC,BC	8,573.26	medium
2020	Garden River First Nation	13.40	BC	3,358.20	medium
2020	Garden River First Nation	6.00	LC	API	
2020	Goulais Part 4	32.00	LCBC	15,751.65	medium
2020	Bar River Part 1	22.00	LCBC	13,336.18	medium
2020	St Joe Part 4	74.00	BC	3,348.32	light
	Total Kms	**280**			
2021	Bar River Part 1	37.37	LC,BC	14,225.07	medium
2021	Bruce Mines Part 1	48.40	LCBC	14,789.21	medium
2021	Bruce Mines Part 2	72.00	BC	1,551.09	medium
2021	Bruce Mines Part 4	44.00	LCBC	9,772.52	medium
2021	Garden River Part 3	4.70	BC	9,468.09	medium
2021	Garden River Part 3	4.70	LC	API	
2021	Goulais Part 2	63.30	BC	2,534.36	light
2021	Goulais Part 3	32.80	BC	6,199.00	medium
2021	HWY 101 Part 1	49.90	BC	2,802.88	light
2021	St. Joe Part 4	50.00	LC	API	
	Total Kms	**407.17**			
2022	Bar River Part 3	58.80	LC	1,276.89	medium
2022	Bar River Part 3	58.80	BC	1,787.87	light
2022	Batchawana Part 2	21.80	LC,BC	20,949.90	heavy
2022	Bruce Mines Part 2	72.00	LC	1,770.00	light
2022	HWY 101 Part 1	36.60	LC	3,441.87	light
2022	Garden River Cycle 3&4	17.00	BC	7,142.65	heavy
2022	Garden River Cycle 3&4	17.00	LC	API	
2022	No. 4 Circuit	43.12	BC	7,265.00	heavy
2022	Wawa Part 3	46.00	BC	4,949.31	medium
2022	Wawa 1&2	15.00	BC	4,205.14	light
2022	St. Joe Island Part 1	73.60	LC,BC	6,285.71	medium
2022	Goulais Part 3	20.00	LC	API	
	Total Kms	**479.72**			
2023	Batchawana Part 1	31.80	LC,BC	21,819.84	heavy
2023	34.5kv Off Road	45.00	BC	6,375.18	very heavy

2023	Wawa Part 3	20.00	BC	4,949.31	medium
2023	Bruce Mines Part 3	55.00	LC	API	
2023	Bar River Part 2	40.00	LC,BC	13,151.90	medium
2023	Batchawana Part 2	34.40	LC	12,104.09	med-heavy
2023	Batchawana Part 1	7.00	LC	API	heavy
2023	Goulais Part 3	10.00	BC	API	medium
2023	No. 4 Circuit	0.00	LC	API	light
	Total Kms	**243.20**			
2024	Dubreuilville	13	BC	5,028.85	light
2024	Missanabie	6.4	BC	11,110.16	medium
2024	Hawk Part 1	13	BC	2,900.38	medium
2024	Lochalsh	4.3	BC	7,500.00	medium
2024	Goudreau	16	BC	945.94	medium
2024	Goulais Part 1	54.7	LC,BC	18,137.89	heavy
2024	Desbarats Part 1	41.55	LC,BC	23,072.38	medium
2024	Bruce Mines Part 3	20	LC	API	heavy
2024	Goulais Part 3	9	LC	API	heavy
2024	Goulais Reserve	20	BC	API	heavy
2024	Batchawana Reserve	15	Herb	API	heavy
	Total Kms	**212.95**			

5 Year Forecasted Plan 2025-2029			
Year	**Forestry Part**	**Kms**	**Work Type**
2025	Wawa Part 2	35	BC
	Andrews Part 1	10	LCBC
	Goulais Part 5	35	BC
	Goulais Part 6	55	BC
	Desbarats Part 2	84	LC,BC
	Bruce Mines Part 3	45	LC
	St Joe Part 2	26.8	LC,BC
	Garden River Cycle 5	10	LC,BC
	No. 4 Circuit	30	BC
	Searchmont Line	25	BC
	Total Km	**355.80**	
2026	Wawa Part 2	35	LC
	Michipicoten Part 1	15	BC
	Goulais Part 5	35	LC

	Goulais Part 6	55	LC
	St Joe Part 2	30	LC,BC
	St. Joe Part 3	48	LC,BC
	Bruce Mines Part 1	50	BC
	Bar River Part 1	38.2	LC,BC
	Garden River Cycle 1	15	LC,BC
	Harbour Circuit	30	BC
	Total Km	**351.20**	
2027	LSPP	77	BC
	Goulais Part 2	59	BC
	Goulais Part 3	24	BC
	Bruce Mines Part 1	50	LC
	Bruce Mines Part 2	78	LC,BC
	Bruce Mines Part 3	48	BC
	Garden River Cycle 2	10	LC,BC
	Batchewana Reserve	10	LC,BC
	Goulais Reserve	10	LC,BC
	34.5kv Rd Side	40	BC,LC
	Total Km	**406.20**	
2028	HWY 101 Part 1	13	BC
	Missanabie	6	BC
	Goulais Part 4	49	LC,BC
	Goulais Part 1	55	
	Bar River Part 2	39	LC,BC
	St. Joe Part 4	66	LC,BC
	Garden River Cycle 3	10	LC,BC
	Wawa 1&2	20	BC
	Searchmont	20	BC
	LSPP	77	BC
	Total Km	**354.20**	
2029	Wawa Part 3	60	LC,BC
	Batchawana Part 1	28	BC
	Batchawana Part 2	56	BC
	Bar River Part 3	66	LC,BC
	Bruce Mines Part 2	78	BC
	Bruce Mines Part 4	80	LC,BC
	Garden River Cycle 4	10	LC,BC
	34.5 Off Rd	20	
	Total Km	**397.00**	

i) API's line clearing program manages tree growth and hazard trees to control vegetation encroaching and/or falling into the lines. The establishment of ROW clearance standards and specifications has been a major contributor in reducing the risk of exposure to tree caused outages (hazard trees) with a decline in outage frequency and duration. Although API reliability stats are on an improving trend, trees are still a primary cause of outages for API and should continue to be managed as priority through the line clearing program. In addition to prioritizing hazard rating based on tree health, API stays abreast of environmental factors that may contribute to a change in forest health such as pest infestations (spruce budworm) and seasonal weather patterns.

b) The following table shows tree contact outages during the historic period, as well as YTD 2024

	Customer Hours of Interruption				
	2020	**2021**	**2022**	**2023**	**2024 YTD**
Tree Contact	24,419	95,321	23,296	11,741	36,936
Major Event- Tree Contact	5	83,677	-	-	17,306
ME Adjusted	24,413	11,645	23,296	11,741	19,631
	Customer Interruptions				
	2020	**2021**	**2022**	**2023**	**2024 YTD**
Tree Contact	11,820	17,695	10,436	6,200	16,022
Major Event- Tree Contact	1	10,819	-	-	5,927
ME Adjusted	11,819	6,876	10,436	6,200	10,095

API notes that consistent with OEB guidance, its approach to the outages considered Tree Contact and Adverse Weather have been updated as of June 2023, however API does not believe any significant impacts from these changes are reflected in the figures above.
API notes that before adjusting for Major Events, the customer interruptions and customer hours of interruption *increased* from 2020 to 2021.
With respect to the decreases in 2021 and 2023, API notes that these years represented relatively better weather years (aside from the 2021 ME), which may explain the lower instances of tree contacts which typically occur when there is wind or precipitation.

c) The VM cycle parts identified to be required to be completed in 2025, through cycle frequencies as well as condition assessments, involve a total 355km, made up of:
   a. 45 km of Line Clearing, which API plans to complete using internal crews;
   b. 190 km of Brush Control, which API plans to complete primarily using contract services; and
   c. 120 km of both Line Clearing and Brush Control, which API also plans to complete primarily through contract services.

Based on the unit cost data provided in the response to 4.0 VECC-29, API has summarized the following table that shows contractor costs per km for line clearing (LC), brush control (BC), and both line clearing and brush control (LC/BC). In this table, API has also provided a km-weighted-average density & complexity for the areas covered in each historical year and planned to be covered in 2024 and 2025. API has assessed each area's density & complexity on a scale from 1 (light) to 6 (very heavy/difficult).

As shown below, the average density & complexity for the brush control planned for 2025 is 4.4, and the average cost per km planned is $6,900. The last time API completed a similar level of density & complexity was in 2023. API is forecasting a similar cost to the inflation-adjusted cost per km for brush control in 2023 of $6,433/km.

For those spans where both line clearing and brush control is planned, API has assessed an average density & complexity of 3.0. API last completed similar complexity of LC,BC work in 2020 and 2021. The forecasted costs per km of work in 2025 are in line with (and lower than) the actual costs per km of similar density & complexity work, as adjusted by inflation.

Contractor Costs/Contractor Km						
	2020	2021	2022	2023	2024	2025
LC	N/A	N/A	$ 1,962.33	$ 12,104.09	N/A	N/A
BC	$ 4,633.03	$ 2,962.70	$ 4,616.30	$ 5,936.45	$ 3,990.50	$ 6,901.40
LC,BC	$ 13,197.82	$ 12,925.79	$ 9,636.65	$ 16,990.90	$ 19,237.09	$ 13,099.16
2020LC BC Adj by Inflaiton		$ 13,488.17	$ 13,933.28	$ 14,448.81	$ 15,113.45	$ 15,657.54
2021LC BC Adj by inflation			$ 13,352.34	$ 13,846.38	$ 14,483.31	$ 15,004.71
2023 BC Adj by Inflation					$ 6,209.53	$ 6,433.07
Average Density/Complexity						
	2020	2021	2022	2023	2024	2025
LC	N/A	N/A	1.7	3.0	N/A	N/A
BC	2.6	2.0	2.8	4.4	2.5	4.4
LC,BC	3.0	3.0	3.5	3.9	4.1	3.0

The combination of the km required to be completed, and the relative density & complexity of the areas to be covered by the BC and LC/BC programs are what drive the level of cost required for 2025.

d) For the 2025 work program of 355km, most of the work program will be completed by contracted services and API has already initiated the Request for Proposals (RFP) process. Multiple RFPs are underway for the 2025 work program and bid prices have been received and are being reviewed in order to select and award work to contractors. API will have secured approximately 65% of the 2025 Contracted Services work program through this RFP process.
Additionally, with the recent patrol data to confirm workload requirements, an RFP will be released in September 2024 for the remainder of the 2025 contracted services work program. Also, as shown in the table above historical cost per km with similar density & complexity have been compared to the 2025 work program.

e) Please see the table below for the breakout of Internal vs. External costs per year.

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Budget	2025 Budget
Internal	$1,465,247	$1,522,306	$1,563,355	$1,709,704	$1,939,013	$1,922,789
External	$2,129,914	$2,316,750	$2,258,456	$2,314,476	$2,061,869	$2,893,644
Total	$3,595,161	$3,839,056	$3,821,811	$4,024,180	$4,000,882	$4,816,433
YOY Internal		$57,059	$41,049	$146,349	$229,309	-$16,224
YOY External		$186,836	-$58,294	$56,020	-$252,607	$831,775
YOY Total		$243,895	-$17,245	$202,369	-$23,298	$815,551

i.) In the section below, API has explained the material variances in each category.

Internal:

2023: API hired 2 additional seasonal labourers compared to prior years (2020-2022).Hiring of these positions was suspended during COVID.

2024: API hired 4 seasonal labourers similar to pre-COVID operations resourcing

Contract Service:

2021: API completed significantly more km of line in 2021 through contract services (352 km) as compared to 2020 (275 km). Relatively lower complexity and lower cost brush clearing offset some of the decrease.

2024: Due to changes in market conditions with respect to vendor rates in 2023, API incurred higher costs than expected in 2023, however these trends were not known to API in time to reflect them in the 2024 budget.

2025: Please see response in 4-SEC-24 comparing 2024 and 2025 budgets.

ii) API generally uses internal staff and contract services for different aspects of the vegetation management program, as outlined in the descriptions below:

Internal Staff

Internal staff are solely responsible for the administration of the program, as well as “demand” work. Demand work is day-to-day ad hoc work required due to customer requests or other drivers. This work is most efficiently completed using internal resources, as API has greater flexibility, and the completion of “unplanned” work through internal staff is much more cost-effective. Similarly, API internal staff are exclusively used to address off-cycle work, ie: those VM activities identified through patrols, condition assessment, line inspection and other sources, which are critical enough to require immediate attention, ahead of the regularly scheduled cycle.

Internal staff also support many of the “cycle parts” assigned for a given year. For example, API will assign internal Utility Arborists to complete the work required near powerlines, ahead of contractor crews that are only qualified to complete work outside of the safe limits of approach to power lines. Through this approach, API minimizes the cost to complete these VM cycle parts.

It is also planned that Internal staff also complete the brush control and line clearing for some cycle parts each year, however API relies on external contractors to complete the majority of this work. API chooses cycle parts to be completed by internal staff which allow internal staff to remain relatively flexible and mobile to enable prompt response to demand work. This aspect of the planned work is at times re-allocated to contract services, for example if internal staff allocate higher than expected levels of capital projects.

External Contractors
API primarily (but not exclusively) relies on contract service to complete most or all of the brush control and/or line clearing for the planned cycle parts each year.

f) API has both considered and attempted different cycle frequencies to gain cost efficiencies to try and find a more effective level of control to reduce annual workload volume (AWV). While a 6-year cycle is ideal for API service territory based on tree growth and mortality rates, it has also been recommended that a 3-year herbicide application (midcycle) is required to reduce densities overtime. API will continue to utilize midcycle applications related to brush control where possible to achieve efficiency gain targets.

g) The cost per km included in Table 7 of the Application included the km of line clearing and brush control for each year, while the costs included in the table for each year are the costs for the total VM Program. As outlined above, many of the functions API completes through internal resources are unrelated to the line clearing and brush control cyclical work. These types of functions include the administration of the VM program, as well as demand and off-cycle work.

The estimated 21% inflation increase corresponds with the estimated annual inflation since 2020 as presented in Table 4 of Exhibit 4, rather than an estimate specific to the VM program. API also confirms that actual contractor hourly labour and equipment rates have increased on average by 20% or more between 2020 and 2024.

API does not believe the 5.67% change in cost/km since 2020 is a fair comparison for the following reasons:

1) A more appropriate measure would be change in contractor cost per contractor km (ie: excluding those km which API has completed internally); which is an increase of 4.4%.
2) Additionally, the work-hours required to complete brush control alone versus brush control and line clearing and other factors such as density may lead to a naturally higher cost/km from one year to another, that is not due to an inflationary type change (increase in $ per units) but rather due to the level of work required. Please see the table in response to subsection c above for the factors affecting the relative cost of work for some cycle parts versus others.

   Generally, cost/km of work is highest to complete both line clearing and brush control, followed by line clearing alone, with brush control the lowest cost/km. Additionally, API has labeled each of the cycle parts completed each year on the basis of high/medium/low density and complexity, which can also affect the cost per km.

4-Staff-43

Land Use Fees
Ref 1: Exhibit 4, pp. 37
Ref 2: Ch. 2 Appendices, Tab 2-JB_OM&A Cost Drivers
Preamble:
Algoma Power stated the following:

> *ROW Land Fees have fluctuated during the historical (2020 to 2023) period primarily as a result of one-time payments such as legal fees in relation to the negotiation of agreements. API incurred significant such costs in 2022, with non-material costs also impacting the costs in 2021 and 2023. The first annual payment under an ongoing annual agreement was introduced in 2021, which will be relatively stable in future years (and increases with inflation). Additionally, in 2023, API recorded "catch up" payments related to 2019-2023.*

In Ref 1, Algoma Power noted that rights payments for the 2025 test year are budgeted to be $767,909 per year.

On page 37, Algoma Power noted that it capitalizes easements and/or other permanent agreements, as well as the costs required to facilitate these costs.

Question(s):

a) Please provide a detailed breakdown, including one-time payments such as legal fees, from 2020 to 2025.
b) Please provide the year to date expense for the 2024 bridge year and explain the increase in RoW Land Fees of $386k in the test year over the bridge year.
c) Please provide the breakdown between capitalized and expensed ROW Land Fees from 2020 to 2023 and forecasted cost for the bridge and test year.

	2020	2021	2022	2023	2024	2025
Capex	$	$	$	$	$	$
OM&A	$	$	$	$	$	$

API Response:

a) Please see the table below. For 2025, API has considered the portion of the budget amount related to each item, however as discussed in 4-SEC-25, many of the costs included in the account are forecasted to be capitalized. The amounts presented are the revenue requirement related to the forecasted capital and OM&A amounts. The 2025 amounts also include the revenue requirement impacts of amounts forecasted to be capitalized in 2024.

	2020	2021	2022	2023	2024	2025*
Legal/Consulting Fees	$ 2,850.00	$ 34,959.88	$173,827.00	$ 37,902.12	$ -	$ 30,605.61
Rental/Easement Expense/I	$ 14,871.50	$114,893.55	$110,796.77	$226,116.24	$376,832.23	$566,942.48
Labour	$ 2,596.69	$ 3,221.03	$ 3,729.95	$ 4,728.12	$ 5,043.84	$ 4,108.08
Surveying/Field Assessments						$166,253.24
Total	**$ 20,318.19**	**$153,074.46**	**$288,353.72**	**$268,746.48**	**$381,876.07**	**$767,909.41**

b) As of June 30 YTD the ROW Land fees expense costs are $238,862; however API notes that roughly $90k of this value will be reversed with an accrual reversal prior to year end. The change in 2025 Test Year is a result of additional land use fees anticipated to be incurred in the bridge and test years. API is currently actively negotiating with the interest holders representing the majority of the expected new budget.

c) Please see the table below:

	2020	2021	2022	2023	2024	2025
CAPEX *	126,444	121,867	354,675	348,394	$ 3,960,000	$ 1,585,969
OM&A	$ 20,318	$ 153,074	$ 288,354	$ 268,746	$ 381,876	$ 124,122
*Note in service additions						

4-Staff-44

Engineering Cost
Ref 1: Exhibit 4, p. 41
Ref 2: Exhibit 4, pp. 62-65
Ref 3: Ch. 2 Appendices, 2-JC

Preamble:
Algoma Power noted that some of the increase in direct time allocated to Algoma Power if due to general operating engineering support for area planning studies provided to Algoma Power.

As per the data provided in Appendix 2-JC, OEB staff calculated that the average cost for the supervision and engineering program from 2020 actual to the 2024 test year is $226,755. Algoma Power's requests for this program in the 2025 test year is $258,583, which represents a 14% increase over the average.

Question(s):

a) Please provide a further justification for the increase to this line item and note how much of the increase is due to the direct time allocation for engineering support.
b) Compared to the historical years, Algoma Power forecasts a 36% decrease in capital spending for the next five years. Please explain why it is appropriate to allocate more time and costs for engineering support to Algoma Power given this decrease.

API Response:

a) To clarify, the increase in direct time allocation to API OM&A for engineering support per 2-JC is approximately $32,000 and is reported in the Other Operating and Maintenance program expenses. The supervision and engineering program per 2-JC was lower than planned because of temporary vacancies in Supervision in two API operational departments and variances in labour. As a result, the 2020 to 2024 average is underrepresented. 2025 Test is reflective of expected expenditures going forward now that positions have been filled.
b) Additional engineering support is expected in support of the evolving industry trends towards electrification, grid modernization, DER, and etc. API is also expected to continue to be supported in the areas of SCADA and distribution automation (which requires specialties in Protection & Control), engineering analysis to support short-term and long-term system planning, engineering studies to facilitate the connection of DERs, and solution exploration on better demand management. API is also looking for support on climate change vulnerability assessment and relevant mitigation plans along with non-wire solution analysis from an engineering perspective.

   The forecast spending decrease in API's capital program is mainly due to the 3 major projects completed from 2020 to 2024. There remains capital projects in API's plan that still require engineering support around design, specification, field commissioning, etc., especially when API plans to incorporate the operational technology into the projects.

4-Staff-45

Overhead lines and feeders
Ref 1: Exhibit 4, p. 53
Ref 2: Appendix 2-JC

Preamble:

In Ref 2, Algoma Power shows an increase of $800k in overhead lines and feeders expenses in the test year over 2020 OEB-approved. On p. 53 of Exhibit 4, Algoma Power indicates that the increase for this line item over this time period is $441k.

In Ref 1, Algoma Power stated that the increase is primarily the result of a combination of increased right of way land fees, outage costs and general maintenance of overheads services as follows: Right of Way land fees of $299,000, maintenance of overhead services of $57,000 and outage increase of $90,000.

Questions:

a) Please confirm that the increase over 2020 OEB-approved cost for this line item is $806,174.
b) If so, please explain what causes the remainder of the increase and provide detailed explanation for each driver.

API Response:

a) Confirmed.
b) Please see below for corrected Right of Maintenance program variance explanation for 4.3.2 of the application. The cumulative updated increase in Right of Way land fees of $664,000 from 2020 to 2025 Board Approved is due to the cumulative impact of multiple land use agreements. In 4.2.2, API noted that it expects further fluctuations in the Bridge and Test Years, and has proposed a Deferral and Variance Account (DVA) in Exhibit 9 to address a high likelihood of forecasting differences between the proposed Test Year and actual costs - due to accounting treatment, forms of payments, and payment amounts.

<u>Overhead Lines and Feeders</u>

<u>2023 Actuals vs 2025 Test, 2020 Board Approved vs 2025 Test</u>

Increase of $832,987, Increase of $806,174

The increase in overhead lines and feeders expenses from 2023 Actuals to 2025 Test is primarily the result of a combination of increased right of way land fees, outage costs and general maintenance of overheads services. Each of these costs are explicitly outlined in the cost driver table and the cost driver analysis completed in Section 4.2 of this Exhibit; right of way land fees shows a cumulative increase of $499,000, maintenance of overhead services an increase of $54,000 and outages an increase of $202,000.

The increase in overhead lines and feeders expenses from 2020 Board Approved to 2025 Test is also primarily the result of a combination of increased right of way land fees, outage costs and general maintenance of overheads services. Each of these costs are explicitly outlined in the cost driver table and the cost driver analysis completed in Section 4.2 of this Exhibit; right of way land fees shows a cumulative increase of $664,000, maintenance of overhead services an increase of $57,000 and outages an increase of $90,000.

The increases noted above related to increased right of way lands fees and outage costs are driven by factors primarily outside of API's control.

4-Staff-46

Compensation
Ref 1: Exhibit 4, p. 41
Ref 2: Exhibit 4, pp. 62-65
Ref 3: Ch. 2 Appendices, 2-N, 2025 Corporate Cost Allocation

Preamble:
On p. 41 of Exhibit 4, Algoma Power stated that the 2025 Test year total FTE of 74 is an addition of four FTE as compared to 2020 Board Approved and this 6% increase is a combination of an additional new hire for operations administrative support, and more operational (i.e. customer service and engineering) direct time allocation to Algoma Power from the operations group of another FortisOntario group of companies.

The increase in direct time allocation is a result of enhanced billing and customer engagement, general operating engineering support for area planning studies and GIS system operations, and internal legal support provided to Algoma Power.

In addition, on p. 64, Algoma Power noted that increased affiliated allocation includes allocated time from a new GIS position at FortisOntario.

Question(s):

a) Algoma noted that the 4 new FTEs are due to a combination of an additional hire and more operational direct time allocated to Algoma Power. Please provide a breakdown of the four FTEs.
b) Please show the time allocated to the various affiliates for each direct time allocation as shown in the table below. Please add rows if necessary.

Position	% allocated API	% allocated to CNPI	% allocated to Fortis Inc.	% allocated to Fortis Ontario

c) Please provide the quantum associated with each allocation.
d) Please confirm that these FTEs are not included in shared corporate costs allocated to Algoma from its affiliates.
e) For new hires 100% allocated to Algoma Power, please provide the business case for the creation of the new position(s).

API Response:

a) See table below.

Position	Cost Category	FTE Increase Value
Customer Service	API Employee	- 1.0
Co-op Student, Engineering	API Employee	0.3
Operations Assistant	API Employee	1.0
Senior Legal Counsel & Assistance Corporate Secretary	Direct Time from Affiliates	0.2
Articling Student	Direct Time from Affiliates	0.1
Customer Service Employee - API Billing and Support	Direct Time from Affiliates	0.6
Manager Customer Engagegement, Corporate	Direct Time from Affiliates	0.2
GIS Analyst	Direct Time from Affiliates	0.2
Distribution Engineer	Direct Time from Affiliates	0.7
Director Engineering, Innovation & Climate Change, Corporate	Direct Time from Affiliates	0.5
Contract Advisor/Business Analyst	Shared Services/Corporate Allocation	0.3
Manager Regulatory Affairs - Corporate	Shared Services/Corporate Allocation	0.3
Regulatory Analyst	Shared Services/Corporate Allocation	0.3
Net Other Changes Individually Insignificant		0.6
		4.2

b) Allocations below provided based on 2025 Test Year.

Position	% allocated API	% allocated to CNPI	% allocated to Fortis Inc.	% allocated to Fortis Ontario (or Cornwall Electric)
Senior Legal Counsel & Assistance Corporate Secretary	25%	27%	0%	48%
Articling Student	28%	28%	0%	44%
Customer Service Employee - API Billing and Support (Note 1)	100%	0%	0%	0%
Manager Customer Engagegement, Corporate	21%	58%	0%	21%
GIS Analyst	22%	17%	0%	61%
Distribution Engineer	66%	26%	0%	8%
Director Engineering, Innovation & Climate Change, Corporate	49%	36%	0%	15%

c) Providing quantum for individual positions identified in b) above would mean providing a quantum for three or fewer employees. Therefore, in accordance with Chapter 2 filing requirements Section 2.4.3.1, API has noted that the combined total compensation value of the 2.5 FTE increase of direct time allocated from affiliates to API is approximately $380,000.

d) There is a total of a 0.9 FTE increase noted in a) above related to shared corporate costs allocated to Algoma from its affiliates.

e) The new position of Operations Administrative Assistant is required to provide administrative support for various department at API due to ever increasing workloads associated data collection, processing, reporting and filing. This position helps to ensure filing deadlines and action items are achieved. Additionally, they are responsible for appropriate document management, retention and ensuring confidentiality and adherence to retention record processes.

4-Staff-47

Internal Legal Support
Ref 1: Exhibit 4, p. 41

Preamble:
Algoma Power noted that some of the increase in direct time allocated to Algoma Power is due to internal legal support provided to Algoma Power.

Question(s):

a) Please provide a more detailed explanations for this increase and confirm that this expense is not covered under the corporate costs allocated to Algoma Power by its affiliate. If it is, please provide the affiliate and the quantum that provides legal services to Algoma Power.
b) Please discuss Algoma Power's expectations to continue increased legal support in relation to the Right of Way Land Fee cost driver.

API Response:

a) A dedicated legal counsel resource was hired at Canadian Niagara Power Inc. with an objective to provide internal legal resource support to all of FortisOntario's affiliated subsidiaries, including Algoma Power Inc. An additional articling student is planned to be hired in 2025. These legal resources directly charge their time to the affiliates for which they have provided legal support. Given time is directly charged based on support provided, the legal resources are not included in Appendix 2-N but are included in the direct time charged values provided in 4-SEC-27. The following is a table of the direct time dollar charges allocated to Algoma Power from 2020 to 2025. June 2024 year-to-date time charged to API was $27,000.

	2020 Last Rebasing Year OEB Approved	2020 Last Rebasing Year Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Affiliate Legal Support Provided to API	11,300	3,700	6,400	35,200	46,800	47,600	76,500

b) Algoma Power expects to use external legal counsel for real estate matters, including the related work to negotiate and register agreements in support of the Right of Way Land Fee cost driver.

4-Staff-48

Pension and OPEB
Ref 1: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, December 15, 2022, page 31
Ref 2: Exhibit 4, Section 4.4.3, Pension Expense and Post Retirement Benefits Expense

Preamble:
Chapter 2 Filing Requirements states that:

> *The distributor must provide details of employee benefit programs, including pensions, other post-employment retirement benefits (OPEBs), and other costs charged to OM&A. A breakdown of the pension and OPEBs amounts included in OM&A and capital must be provided for in the last OEB-approved rebasing application, and for historical, bridge and test years. The most recent actuarial report(s) must be included in the pre-filed evidence and be reconciled with the pension and OPEBs amounts (as applicable). The basis on which pension and OPEBs amounts are forecast for the bridge and test years must also be explained. What is documented in the tax section of the evidence must agree with this analysis."*

In Reference 2, Algoma Power states that:

> *The actuarial reports will not be directly reconcilable to pension and OPEB expense amounts reported in bridge and test years given the differing accounting standards and the multiple DVA accounts relating to pension and OPEB.*

Table 19 of reference 2 outlines Defined Benefit Pension Plan expenses from 2020 Board Approved to Test Year 2025.

Table 19 - Defined Benefit Pension Plan Expenses and Assumptions

Defined Benefit Pension Plan	2020 Board Approved	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Year	2025 Test Year
Pension Expense	$284,218	$418,656	$625,390	$399,693	$93,410	$44,415	$42,998
Pension Expense Allocated to Capital	$102,533	$151,849	$260,996	$154,089	$37,262	$17,254	$17,419
Pension Expense Allocated to OM&A	$181,685	$266,807	$364,394	$245,604	$56,148	$27,161	$25,579
Significant assumptions used:							
Discount rate	3.70%	3.20%	2.70%	3.30%	5.30%	4.60%	4.90%
Expected long-term rate of return on plan assets	5.25%	4.85%	4.35%	4.70%	5.75%	5.75%	5.75%
Rate of compensation increase	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%

Table 21 of Reference 2 outlines Post Retirement Benefits expenses and assumptions used for the 2020 Board Approved to 2025 Test.

Table 21 - Post Retirement Benefits Expenses and Assumptions

Post-Retirement Benefits Expense	2020 Board Approved	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Year	2025 Test Year
Post-retirement benefit costs	$540,111	$601,600	$672,600	$619,200	$472,960	$565,600	$547,500
Post-retirement benefit costs Allocated to Capital	$194,847	$218,205	$280,698	$238,713	$188,669	$219,724	$221,800
Significant assumptions used:							
Discount rate	3.90%	2.80%	3.30%	5.30%	4.60%	4.60%	5.20%

OEB staff outlines the capital and OM&A allocation percentages for the defined benefit pension expenses and the post retirement benefits (OPEBs) expenses in the table below.

Table 1: Capital and OM&A Allocation

	2020 Board Approved	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Birdge Year	2025 Test Year
Defined Benefit (DB) Pension Expense	284,218	418,656	625,390	399,693	93,410	44,415	42,998
Allocation to Capital	102,533	151,849	260,996	154,089	37,262	17,254	17,419
DB Pension: Capital Allocation	**36.08%**	**36.27%**	**41.73%**	**38.55%**	**39.89%**	**38.85%**	**40.51%**
Allocation to OM&A	181,685	266,807	364,394	245,604	56,148	27,161	25,579
DB Pension: OM&A Allocation	**63.92%**	**63.73%**	**58.27%**	**61.45%**	**60.11%**	**61.15%**	**59.49%**
OPEBs Costs	540,111	601,600	672,600	619,200	472,960	565,600	547,500
Allocation to Capital	194,847	218,205	280,698	238,713	188,669	219,724	221,800
OPEBs: Capital Allocation %	**36.08%**	**36.27%**	**41.73%**	**38.55%**	**39.89%**	**38.85%**	**40.51%**

Question(s):

a) OEB staff notes from Table 19 that the defined benefit pension expense has decreased significantly from $399,693 in 2022 to $99,410 in 2023 and the expense is forecasted to further decrease to $44,415 in 2024 and $42,998 in 2025 while the corresponding discount rates have increased from 3.30% in 2022 to 5.3% in 2023, 4.6% in 2024 and 4.9% in 2025. Given the inverse relationship between the discount rate and pension liability and pension expense, please explain why the defined benefit pension expense has decreased significantly from 2022 despite the discount rate having increased since 2022.

b) Please explain the changes in the allocation between the capital expenditures and OM&A expenses compared to the 2020 allocation percentages in the 2020 rebasing application.

c) Algoma Power stated that "the actuarial reports will not be directly reconcilable to pension and OPEB expense amounts reported in bridge and test years given the differing accounting standards and the multiple DVA accounts relating to pension and OPEB".

   i. Please explain whether the actuarial reports support the pension and OPEB expenses recorded on Algoma Power's audited financial statements. If so, please provide the reconciliation between the actuarial reports and the pension and OPEB expenses on the audited financial statements. If not, please explain why not.

ii. Please elaborate further on what are the differing accounting standards and how the different accounting standards impact the pension and OPEB expenses in bridge and test years.

iii. Please elaborate further on what are the multiple DVAs and how these DVAs impact the pension and OPEB expenses in the bridge and test years.

API Response:

a) The decline in the projected pension expense is mostly due to the increase in discount rates. The discount rate for the 2022 pension expense was 3.30% vs the discount rate used in the 2025 projection of 4.90%, an almost 2% higher discount rate. The greatest impact of this increase in the discount rate is in the current service cost component, which will continue to decrease with the increase in discount rates.

b) The relative hours spent on capital and OM&A work fluctuate year over year. Therefore, attributable costs included in the labour rates calculated by department, such as pension expense, contribute to the labor costs that are charged to respective capital and OM&A.

c)

i. There are two types of reports that API receives from the actuary (Mercer):

- Report on the Actuarial Valuation for Funding Purposes (included in Application Attachment 4A)
- Section 3461 pension and OPEB expense

The report on the Actuarial Valuation is completed every three years and for funding purposes only. The purpose of the report is to determine the funding status and minimum contribution requirement for the pension plan. It does not reconcile to the pension and OPEB expenses.

The section 3461 pension and OPEB expense reports, provided by the actuary, are completed for accounting purposes. They are reconcilable to the actual and projected pension and OPEB expenses as submitted in Exhibit 4. The corresponding reports for pension and OPEB for both bridge and test years have been attached for reference.

Please see below table for the reconciliation of pension and OPEB expenses to the actuarial accounting reports in 2023 (also attached as Attachment 4-Staff-48 for reference):

2023
(000's)

	Pension Expense	OPEB Expense
Note 4 in Audited FS (page 15)	**104**	**473**
3461 Actuarial Pension and OPEB Report:		
Current service cost	445	184
Interest cost	1,364	311
Expected return on plan assets	(1,706)	- 22
	104	**473**

In preparing the above table, API noticed a typo in the 2023 pension expense included in Exhibit 4. There revised table has been included as follows (the updated values are highlighted in red):

DB Pension Expense

Defined Benefit Pension Plan	2020 Board Approved	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Year	2025 Test Year
Pension Expense	$284,218	$418,656	$625,390	$399,693	$103,672	$44,415	$42,998
Pension Expense Allocated to Capital	$102,533	$151,849	$260,996	$154,089	$37,262	$17,254	$17,419
Pension Expense Allocated to OM&A	$181,685	$266,807	$364,394	$245,604	$66,410	$27,161	$25,579

ii. ASPE Section 3462 disallows amortization to income of actuarial gains and losses which means that all of actuarial gains and losses are recognized on the income statement at year end. Effective January 1st, 2013, API was approved to continue to record pension and OPEB expense under section 3461 to its Income Statement which mitigates against the possible material fluctuations resulting from the adoption of section 3462. Therefore, only the pension and OPEB expense under 3461 are recognized on the API's income statement.

As previously approved by the OEB, the difference between the pension and OPEB expenses under 3461 and 3462 are recorded in 1508 – Other Regulatory Assets – Pension Expense Variance Sub-Account and 1508 – Other Regulatory Assets – OPEB Expense Variance Sub-Account, respectively.

iii. The following DVA accounts are currently used related to pension and OPEB accounting:

- 1508 – Other Regulatory Assets – Pension Deferral Sub-Account
  - record the initial recognition of "Unrecognized losses," "unrecognized past service cost," and "unrecognized transition obligations" for API's transition to Section 3462
- 1508 – Other Regulatory Assets – Pension Expense Variance Sub-Account
  - record the difference between pension expense under Section 3461 and Section 3462
- 1508 – Other Regulatory Assets –OPEB Deferral Sub-Account
  - record the initial recognition of "Unrecognized losses," "unrecognized past service cost," and "unrecognized transition obligations" for API's transition to Section 3462
- 1508 – Other Regulatory Assets – OPEB Expense Variance Sub-Account
  - record the difference between OPEB expense under Section 3461 and Section 3462
- 1522 – Pension and Other Post-Employment Benefits (OPEBs) Costs
  - track the differences between the forecast accrual amounts recovered in rates under Section 3461 and the actual cash payments made for both pension and OPEBs, effective January 1st, 2018.
- 1508 – Other Regulatory Assets – Amortized Pension Actuarial Gains/Losses
  - record the amortized pension actuarial gains/losses under S3461
- 1508 – Other Regulatory Assets – Amortized OPEB Actuarial Gains/Losses
  - record the amortized OPEB actuarial gains/losses under S3461

These DVA accounts have an impact on the pension and OPEB expense recorded in API's bridge and test years only on the basis that the cumulative difference between Section 3461 as used in calculating pension and OPEB expense in bridge and test years, and Section 3462 will be captured in the accounts noted above. Additionally, any amortized gains/losses will be captured in the accounts above (rather than recorded as a pension and OPEB expense), along with tracking of the difference between cash payments made to the funds as compared to what is being collected in rates (and interest will be calculated to be paid back to rate payers in a future proceeding).

4-Staff-49

Pension and OPEB
Ref 1: Algoma Power's 2020 Cost of service application EB-2019-0019, settlement proposal, pages 47 and 48
Ref 2: Exhibit 9, DVA continuity schedule
Ref 3: Exhibit 4, Section 4.4.3, Pension Expense and Post Retirement Benefits Expense

In Reference 1, The Parties agreed to remove the amortization of net actuarial gains in 2020 which resulted in increased capital expenditures of $8,038 and increased OM&A expenses of $14,244.

OEB staff summarizes the removal of the amortized actuarial gains and losses outlined in Table 21 of Reference 1 in the table below:

Table 2: Amortized Actuarial Gains and Losses in Pension and OPEB Expense in Last Rebasing Application

	Defined Benefit Pension Plan	Post Retirement Benefit	Total
Amortized Gain/(loss) (from Table 21 of 2020 Settlement Proposal)	54,418	(76,700)	(22,282)
Amortized Gain/(loss) allocated to capital (from Table 21 of 2020 Settlement Proposal)	19,631	(27,670)	(8,039)
Amortized Gain/(loss) allocated to OM&A (calculated by OEB staff)	34,787	(49,030)	(14,243)

In Reference 3, OEB staff notes that the 2020 Board approved Pension and OPEB expenses align with the Pension and OPEB expenses, excluding amortized actuarial gains and losses, as outlined in Reference 1.

Additionally, in Reference 1, the Parties agreed to accumulate all actual amortized actuarial gains and losses in the following accounts starting from the effective date of the 2020 cost of service proceeding: Account 1508, Subaccount – Amortized Pension Actuarial Gains/Losses and Account 1508, Subaccount – Amortized OPEB Actuarial Gains/Losses.

In this rate application, according to Reference 2, Algoma Power requests the continuance of these two DVAs.

Question(s):

a) Please clarify the treatment of the actuarial gains/loss of pension and OPEB in this application.
   i. Please confirm If the amortization of the actuarial gains/losses is included in the revenue requirement.
   ii. If confirmed, please explain why Algoma changed its proposal of the treatment for actuarial gains/losses in this application and not request for discontinuance of the two DVAs mentioned above.
   iii. If not, please confirm that Algoma is proposing to continue the regulatory treatment of the pension and OPEB as approved in its last rebasing application (i.e. use the two DVAs to continue tracking the actuarial gains/losses)

b) Please provide the actuarial gains/losses of pension and OPEB respectively since 2020.

API Response:

a) Confirmed that the same approach as applied in the 2020 Settlement Agreement was adopted in this application. Amortization of actuarial gains and losses for both pension and OPEB were removed in calculating revenue requirement.
   i. Not confirmed; the amortization of the actuarial gains/losses is not included in the revenue requirement.
   ii. N/A per i. above.
   iii. Confirmed, API is proposing to continue the regulatory treatment of the pension and OPEB as approved in its last rebasing application.

b) Please see the table below:

Amortization of Actuarial Gains or (Losses)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Year	2025 Test Year
Pension	(103,017)	(102,920)	6,049	-	-	-
OPEB	12,500	-	28,000	197,400	130,200	166,400

Exhibit 5 – Cost of Capital

5-Staff-50

Ref 1: EB-2024-0063, Notice, March 6, 2024
Ref 2: EB-2024-0063, OEB Letter, April 22, 2024

Preamble:
On March 6, 2024, the OEB commenced a hearing (EB-2024-0063) on its own motion to consider the methodology for determining the values of the cost of capital parameters and deemed capital structure to be used to set rates for electricity transmitters, electricity distributors, natural gas utilities, and Ontario Power Generation Inc. The methodology for determining the OEB's prescribed interest rates and matters related to the OEB's Cloud Computing Deferral Account will also be considered, including what type of interest rate, if any, should apply to this deferral account.

On April 22, 2024, the OEB approved the final Issues List for this proceeding, including the following two issues, amongst other issues:

18. How should any changes in the cost of capital parameters and/or capital structure of a utility be implemented (e.g., on a one-time basis upon rebasing or gradually over a rate term)?

19. Should changes in the cost of capital parameters and/or capital structure arising out of this proceeding (if any) be implemented for utilities that are in the middle of an approved rate term, and if so, how?

Question:
a) Please confirm that the applicant proposes to implement the outcomes from the OEB's generic cost of capital proceeding, including what the OEB decides with respect to implementation. If this is not the case, please explain.

API Response:

API expects to implement the outcomes from the OEB's generic cost of capital proceeding (EB-2024-0063), including what the OEB decides with respect to implementation, insofar as those outcomes are applicable to API.

5-Staff-51

Ref 1: EB-2024-0063, OEB Letter, July 26, 2024

Preamble:
On July 26, 2024, the OEB issued a Letter and Accounting Order regarding prescribed interest rates and the deemed short-term debt rate (DSTDR).

Question(s):

a) Please confirm that the applicant will use the 2025 DSTDR to be set in October 2024 on an interim basis.
b) Please confirm that the applicant will follow all other direction included in the OEB's Letter and Accounting Order issued on July 26, 2024, including the establishment of a new variance account for the DSTDR.

API Response:

(a and b) API confirms it will comply with the OEB's Letter.

5-Staff-52

Long Term Debt
Ref 1: Exhibit 5, Page 12-13, 16
Ref 2: Ch. 2 Appendices, Tab 2-OB_Debt Instruments
Ref 3: Exhibit 5, Attachment 5B

Preamble:
In 2024 Algoma Power is planning to secure an additional $55M in third party debt, to bring its actual capital structure to more closely match the OEB deemed structure. In doing this, API plans to also retire all its existing affiliated debt of $12.75M.

Algoma Power has assumed debt issuance of $55M at a 6% interest rate based on recent research, issued on July 1, 2024.

The rate on the promissory note is 3.21%

Questions:
a) Please provide the updated information about the new loan expected to be funded on July 1, 2024.
b) What due diligence has Algoma Power undertaken to ensure its preferred lender is offering a competitive rate and product?
c) Please explain why Algoma Power decided to finance during a high rate environment, given that Algoma Power has been drawing from Short Term Debt since 2021.
d) Please explain why Algoma Power plans to use new loan with forecasted rate of 6% to repay existing affiliated debt with a rate of 3.21%.

API Response:

a) The new loan was funded on August 22, 2024, the term of the loan is 30 years, interest only with a balloon payment at the end of the maturity period. The stated interest rate is 5.054% with an effective interest rate of 5.09% with interest payable semi-annually. API has reflected the updated impacts to the proposed revenue requirement as part of its response to 1-Staff-1.

b) API engaged Scotia to act as agent for the loan to ensure the preferred lender is offering a competitive rate and product. Scotia marketed the debt facility to approximately 20 potential lenders to achieve the best available pricing and terms for the credit facility. API and Scotia selected 2 lenders to fund the credit facility ensuring there is market pressure to achieve the best possible outcome. Prior to closing Scotia provided market analysis to indicative pricing, the achieved stated rate for the credit facility was 10bps better than indicative pricing.

c) As noted in response to (a) above, the stated and effective interest rate on the new credit facility is 5.054% and 5.09%, respectively. The stated interest rate on the existing short-term is 5.63690% and is variable. API was able to achieve a better fixed interest rate than the existing variable short-term driving value to API's ratepayers.

d) The existing affiliate debt was used to fund historical capital expenditures and the rate of 3.21% was the deemed long-term debt applicable for 2020 rate-setting, API's last rebasing year, as published by the OEB. If the $55M debt issuance had not occurred, API would have first updated the $12.75M debt rate to reflect the OEB's deemed long-term debt rate for rates effective January 1, 2025 (which would be worked into the overall revenue requirement at a later stage in the proceeding once that information is published). This approach is consistent with API's understanding of the OEB's policy with respect to affiliate debt.
The OEB's most recent deemed long term debt rate for January 1, 2024 rates was 4.58% and so it can be reasonably assumed that the rate that will be posted for use in 2025 rate-setting will be a rate higher than the 3.21% rate noted above.

The need to refinance with the goal of better aligning with the OEB's deemed, short term debt, long term debt, and equity capital structure, arising from recent capital expenditures, including two large Advanced Capital Module programs. The proceeds from the long term debt issuance was used primarily used to paydown short term debt including $25 million for the revolving credit facility, $12.75 million for FortisOntario payable on demand promissory note, approximately $8.8 million (as of December 31st, 2023) in intercorporate borrowings.

Exhibit 6 – Revenue Requirement

6-Staff-53

Other Revenue – Other Electric Revenues
Ref 1: Chapter 2 Appendix 2-H
Ref 2: Exhibit 6, pp. 26-27
Ref 3: Accounting Procedures Handbook (APH) Guidance_March 2015, section 13

Preamble:
Appendix 2-H in reference 1 shows a breakdown of Account 4220 – Other Electric Revenues which includes returns on rate base and PILS accruals for the ACM projects.

In reference 2, Algoma Power states that:

> *OEB 4220 has a balance in 2023 of $1,009,072 (2022 $64,796) related to a combination of the return on rate base and grossed-up PILS for the two ACM projects, based on the number of months the assets were in service in 2023 (12 months for the Sault building, 5 months for the Echo River substation project). OEB 4305 increased primarily related to $188,688 (2022 $Nil as the catch-up for 2022 was recorded in 2023) in PILS amount recorded with offset to OEB 1592 for the two ACM projects. The offset amount has been recorded under OEB 1110.*
>
> *OEB 4220 has a balance in 2024 of $1,234,000 (2023 $1,009,792) related to a combination of the return on rate base and grossed-up PILS for the two ACM projects, based on months in service in 2023 (12 months for both the Sault building and the Echo River substation project). OEB 4305 includes a credit balance in 2024 of $44,000 (2023 debit balance of $188,688) related to PILS amount recorded with offset to OEB 1592 for the two ACM projects.*

In reference 3, the APH Guidance from March 2015, section 13 provides guidance on how to record ACM projects.

Question(s):

a) Please provide the accounting entries for the two ACM projects including the rate riders/ RRRP funding recovery.
   i. Please describe the accounting treatment for revenues collected for Algoma Power's R1 and R2 rate classes vs. Seasonal and Streetlighting customers.
b) Please explain why Algoma Power has included ACM revenue requirement amounts in other revenues Account 4220 - Other Electric Revenues when the assets were in service, rather than transferring the in-service assets from construction work in progress to the 1508 Subaccount and recording the ACM depreciation expenses in the 1508 Subaccount, as required by the OEB accounting guidance provided in Reference 3.

API Response:

a) To date, API has followed the guidance, including the journal entries, as laid out in Reference 3 above. There is one additional set of accrual based accounting entries that have been recorded by API for purposes of its audited ASPE financial statements so as to show (in its earnings) an estimated return on rate base along with grossed-up PILS earned, for the two ACM projects for each of the years. These entries will be reversed upon API's effective date of its 2025 rates. Here are the additional entries booked (outside of those noted in Reference 3 above):

Dr. OEB 1110 Other Accounts Receivable	$64,796	
Cr. OEB 4220 Other Electric Revenue		$64,796

To record 2022 return on rate base and grossed-up PILS for the Sault building facility (1 month in service)

Dr. OEB 1110 Other Accounts Receivable	$1,009,072	
Cr. OEB 4220 Other Electric Revenue		$1,009,072

To record 2023 return on rate base and grossed-up PILS for both the Sault building facility (12 months in service) and the Echo River substation (5 months in service) projects

Dr. OEB 1110 Other Accounts Receivable	$1,234,000	
Cr. OEB 4220 Other Electric Revenue		$1,234,000

To record 2024 return on rate base and grossed-up PILS for both the Sault building facility (12 months in service) and the Echo River substation (12 months in service) projects

Note: For purposes of calculating its ROE in 2023 in its annual RRR filing, the 2023 accrual based entries for 2023 were removed from API's earnings.

i. Rate rider revenues collected to date have been recorded in the appropriate OEB 1508 Sub-Account as per guidance in Reference 3 above.

b) See a) above. API has done this for accrual based purposes of its audited ASPE financial statements.

6-Staff-54

Other Revenue – Pole Rental Revenue
Ref 1: Chapter 2 Appendix 2-H

Preamble:
Algoma Power evidence in Ref 1 shows and average revenue offset of $498,515 from 2020 actual to 2024.

Question(s):

a) Please explain why Algoma Power is estimating an income of $444,000 from pole rentals, which is approx. 11% below the average.

API Response:

a) Please see response provided in 6-SEC-33.

6-Staff-55

PILs
Ref 1: 2025 PILs Workform
Ref 2: Appendix 2-BA

Preamble:
In Reference 2, Algoma Power reports a total depreciation of $6,320,421 for the Test Year, based on a total PP&E of $276,304,269, which includes the addition of the ACM assets.

According to Tab T1 in Reference 1, Algoma Power adjusts regulatory taxable income by adding back the total depreciation before deducting the CCA amounts calculated in Tab T8 Sch 8 CCA Test. The total depreciation of $6,320,421 reported as an addition to the regulatory taxable income matches the total depreciation reported in Appendix 2-BA. However, OEB staff notes the CCA amounts calculated in Tab T8 Sch 8 CCA Test are based on the UCC without the addition of the ACM assets.

Question(s):

a) Please confirm the OEB staff's observation and explain why the ACM assets are not included in the Tab 8 CCA Test in the Test Year.
b) Please update the 2025 PILs Workform to reflect the inclusion of the ACM assets in the Test Year.

API Response:

a) The ACM projects were added to Schedule 8 CCA in API's actual corporate tax returns each of the years in which the assets came into service. Therefore, Schedule 8 CCA for 2025 as presented in the PILs model already reflects CCA for both of the ACM projects.
b) No update required.

6-Staff-56

PILs
Ref 1: Exhibit 6, S.6.4.2, page 18
Ref 2: Exhibit 6, Attachment 6C, 2023 API Corporate Tax Return
Ref 3: EB-2019-0019 Decision and Order, Nov 07, 2019, 2020 RRWF
Ref 4: 2025 PILs Workform
Ref 5: 2006 Electricity Distribution Rate Handbook, May 11, 2005

Preamble:
In Reference 1, Algoma Power notes "a taxable loss was triggered primarily as a result of enhanced CCA in 2023 as shown in the PILS model; however, that loss is being carried back and will be applied to 2022 taxable income. 2024 Bridge and 2025 Test Years both show positive taxable income." As per Tab H1 of Reference 4, Algoma Power has reported a taxable loss of $1,465,677 in 2023.

In its 2023 corporate income tax return as filed in Reference 2, Algoma Power has elected to carry back the current year loss of $1,728,346 to the previous tax year, with a remaining balance of $31,012 available for future tax years.

According to Reference 3, OEB staff notes that Algoma Power's approved PILs in its 2020 cost of service application is a debit amount of $333,974.

Section 7.2.3 of the 2006 Electricity Distribution Rate Handbook (2006 EDR Report) states that,

> *A distributor expecting to have any loss carry-forwards still available on December 31, 2005 must disclose the amount of those loss carry-forwards in the 2006 application, and apply them in full to reduce the taxable income calculated in the 2006 regulatory tax calculation. These amounts are to be entered in the 2006 OEB Tax Model.*

Question(s):

a) Please reconcile the tax loss of $1,728,346 filed in the 2023 corporate income tax with the loss of 1,465,677 reported in the 2025 PILs Workform.
b) Please explain why Algoma Power believes it is reasonable to carry back the 2023 tax loss to the 2022 taxable income instead of carrying it forward, as stated in the 2006 EDR Report.
c) Please provide the 2025 PILs Workform based on the scenario where the tax loss is carried forward to the bridge and test years.

API Response:

a) The PILs model has been updated in Attachment 6-Staff-56, specifically tab 'H1 Sch 1 Taxable Income Hist.' The difference relates to the Schedule 8 CCA Class 14.1 deduction for the year, which has then also been removed as a non-distribution elimination. Class 14.1 being excluded from PILs model is consistent with the historical approach as this value relates to a historical amount previously disallowed by the OEB.

b) API is unaware of any requirement, in the 2006 EDR Report or otherwise, that tax losses must be brought forward to test year as opposed to carried back when feasible. It is API's understanding that the requirement on the distributor is to exercise sounds tax planning and to maximize tax credits and take the maximum deductions allowed. In the present case, it is API's view that sound planning means carrying back tax losses when feasible given that there is a limitation period on the number of years tax losses can be carried back.
Furthermore, the taxable losses generated in 2023 are **primarily due to the difference between amortization/depreciation and Capital Cost Allowance deduction** of which significant contributors to this variance are the two Advanced Capital Module projects. A separate true-up of these two projects, including consideration around their respective impact on PILs has already been proposed within this proceeding. Therefore, carrying forward these taxable losses to 2025 Test year would effectively be **double counting the tax impact** of the two ACM projects.
c) Model has been provided as Attachment 6-Staff-56.

6-Staff-57

Accelerated CCA
Ref 1: Exhibit 6, section 6.4.2, pages 18 – 19
Ref 2: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, December 15, 2022, pages 63-64
Ref 3: OEB Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance, July 25, 2019

Preamble:
In Table 12 of Reference 1, Algoma Power outlined the CCA variance of $269,942 accumulated in Account 1592, Sub-Account CCA changes for 2018 and 2019.

Additionally, Algoma Power has proposed to smooth the phase-out of the accelerated CCA by adjusting "the 2025 Test Year PILS amount equal to 1/5 of the grossed up PILs impact of the calculated CCA differences for the years 2028 to 2029 under the current enhanced CCA rates in effect for 2025, and the elimination of enhanced CCA rates that will be in effect for those same years."

According to Reference 3, the OEB issued a letter in 2019 while establishing the sub-account CCA changes under Account 1592. The letter states that:

> *Under the Accounting Procedures Handbook, electricity distributors and transmitters are to record the impact of any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the OEB Tax Model that is used to determine the tax amount that underpins rates.*

The letter also states that:

> *The OEB expects Utilities, including those whose applications are currently before the OEB, to reflect any impacts arising from CCA rule changes in their cost-based applications for 2020 rates and beyond. The OEB recognizes that there may be timing differences that could lead to volatility in tax deductions over the rate-setting term. The OEB may consider a smoothing mechanism to address this.*

Section 2.9.1.5 of the Filing Requirements states that distributors are to provide calculations for accelerated CCA differences per year, based on actual capital additions. These calculations should include:

- The undepreciated capital cost (UCC) continuity schedules for each year, itemized by CCA class.
- The calculated PILs/tax differences.
- The grossed-up PILs/tax differences.
- Any other applicable information.
- Confirmation that Account 1592 amounts related to ICM/ACM have been included in the account, if applicable.

- A reconciliation of these amounts to the amounts presented in the Account 1592 sub-account for CCA changes in the DVA continuity schedule.

Question(s):

a) Please provide the following information as noted in Section 2.9.1.5 of the Filing Requirement to support Account 1592 – PILS and Tax Variances requested in this application for disposition:
   i. The undepreciated capital cost (UCC) continuity schedules for each year, itemized by CCA class.
   ii. A reconciliation of these amounts to the amounts presented in the Account 1592 sub-account for CCA changes in the DVA continuity schedule, if necessary.

API Response:

a) API has accumulated variances in the 1592 Sub-Account PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes, per Exhibit 9 DVA continuity schedule, for 2018 and 2019 activity. For ease of reconciliation, API reported 1592 balances related to the two ACM projects in the 1592 'PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)' row in Exhibit 9 DVA continuity schedule. See Exhibit 9 for further information around the detailed 1592 CCA calculations for the two ACM projects as well as response provided in 9-Staff-69. Answers to i. and ii. below focus on the 2018 and 2019 differences recorded in the 1592 Sub-Account PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes.
   i. See table below which shows the calculated differences for 2018 and 2019 which has been accumulated in 1592. An $8,200 additional adjustment was noted and has been added as an adjustment to Principal Adjustments during 2023 in updated DVA continuity schedule provided as Attachment 6-Staff-57.

1592 PILs DVA Calculation		2018A					2019A				
		UCC - Opening	Total Additions Less Proceeds on Dispositions	Additions Subject to Enhanced CCA	Less: CCA Deduction	UCC - Closing	UCC - Opening	Total Additions Less Proceeds on Dispositions	Additions Subject to Enhanced CCA	Less: CCA Deduction	UCC - Closing
Enhanced Year 1 CCA Calculation (Note 1)											
Per Schedule 8											
Class	CCA Rate										
1.3	4.0%	23,336,799	-	-	(933,472)	22,403,327	22,403,327	-	-	(896,133)	21,507,194
8	20.0%	474,912	77,941	-	(102,776)	450,077	450,077	101,864	95,344	(119,271)	432,670
10	30.0%	1,596,729	476,308	288,273	(636,947)	1,436,090	1,436,090	93,425	85,978	(470,634)	1,058,881
12	100.0%	-	240,876	-	(120,438)	120,438	120,438	65,123	65,123	(185,561)	-
45	45.0%	916	-	-	(412)	504	504	-	-	(227)	277
46	30.0%	16,290	-	-	(4,887)	11,403	11,403	-	-	(3,421)	7,982
47	8.0%	59,784,052	6,334,426	-	(5,036,101)	61,082,377	61,082,377	7,568,430	6,440,007	(5,704,528)	62,946,279
50	55.0%	89,525	103,552	-	(77,716)	115,361	115,361	132,672	132,366	(172,735)	75,298
	Total	85,299,223	7,233,103	288,273	(6,912,749)	85,619,577	85,619,577	7,961,514	6,818,818	(7,552,510)	86,028,581
14.1 (Non-Dist)	7.0%	6,030,671	-	-	(422,147)	5,608,524	5,608,524	-	-	(392,596)	5,215,928
Total Schedule 8		91,329,894	7,233,103	288,273	(7,334,896)	91,228,101	91,228,101	7,961,514	6,818,818	(7,945,106)	91,244,509
Non-Enhanced 1/2 Year 1 CCA Calculation (Note 2)											
Per Schedule 8 (Hypothetical)											
Class	CCA Rate										
1.3	4.0%	23,336,799	-		(933,472)	22,403,327	22,403,327	-		(896,133)	21,507,194
8	20.0%	474,912	77,941		(102,776)	450,077	450,077	101,864		(100,201)	451,740
10	30.0%	1,596,729	476,308		(550,465)	1,522,572	1,522,572	93,425		(470,785)	1,145,212
12	100.0%	-	240,876	N/A	(120,438)	120,438	120,438	65,123	N/A	(153,000)	32,561
45	45.0%	916	-		(412)	504	504	-		(227)	277
46	30.0%	16,290	-		(4,887)	11,403	11,403	-		(3,421)	7,982
47	8.0%	59,784,052	6,334,426		(5,036,101)	61,082,377	61,082,377	7,568,430		(5,189,327)	63,461,480
50	55.0%	89,525	103,552		(77,716)	115,361	115,361	132,672		(99,933)	148,100
	Total	85,299,223	7,233,103	-	(6,826,267)	85,706,059	85,706,059	7,961,514	-	(6,913,027)	86,754,546
14.1 (Non-Dist)	7.0%	6,030,671	-	N/A	(422,147)	5,608,524	5,608,524	-	N/A	(392,597)	5,215,927
Total Schedule 8		91,329,894	7,233,103	-	(7,248,414)	91,314,583	91,314,583	7,961,514	-	(7,305,624)	91,970,473
1592 PILs DVA Differential											
Enhanced Year 1 CCA (excludes Non-Dist 14.1)					(6,912,749)					(7,552,510)	
Non-Enhanced 1/2 Year 1 CCA (excludes Non-Dist 14.1)					(6,826,267)					(6,913,027)	
CCA Difference					(86,482)					(639,483)	
	Rate										
Taxes/PILs Before Gross Up	26.50%				(22,918)					(169,463)	
Grossed-Up Taxes/PILs Principal to 1592					(31,180)					(230,562)	
Cumulative 1592 Principal Per Above					(31,180)					(261,742)	
Cumulative 1592 Principal Per Exhibit 9 DVA as of December 31, 2023										(269,942)	
Difference										8,200	added to prin adj during 2023 in DVA continuity

ii. A reconciliation was provided in Table 12 of Reference 1 above.

6-Staff-58

Other Taxes
Ref 1: Exhibit 6, page 20
Ref 2: Exhibit 2, pages 70-71

Preamble:
In Reference 1, Algoma Power has proposed property tax expenses of $260K for the 2025 Test Year compared to the $119K approved in its 2020 cost of service application. Algoma Power states that the increases in property taxes started in 2023 due to property taxes being paid on the new facility in Sault Ste. Marie.

According to Reference 2, Algoma Power completed its land purchase agreement on the 12.08-acre parcel of land located at 251 Industrial Park Crescent in Sault Ste. Marie. The purchase agreement included the purchase of 7.94 acres of land for the new work centre with severance and reconveyance of 4.14 acres of the property back to its original owner.

Question(s):

a) Please provide a breakdown of the $260k property tax expense by the facilities.
b) Please confirm the budgeted property taxes for the new facility in Sault Ste. Marie, included in the total proposed 2025 property tax expenses of $260K, is for the 7.94 acres of land for the new work centre.

API Response:

a) The property tax of $260k includes the following:
   - Sault Ste. Marie work center: $202k
   - Wawa work center: $24k
   - Desbarats work center: $21k
   - Stations: $13k

b) The budgeted property tax for the Sault Ste. Marie work center of $202,000 includes the property tax for the 12.08 acres of land including the new facility. No adjustment was made for the potential reconveyance on the 4.14 acres as the reconveyance is not approved at this point. If the reconveyance is approved and the land is split, the estimated property tax on the 4.14 acres of land would be approximately $4,700 per year based on the 2023 tax bill received from the city of Sault Ste. Marie.

Exhibit 7 – Cost Allocation

7-Staff-59

Cost Allocation
Ref 1: Exhibit 7, page 19
Ref 2: EB-2019-0019, Cost Allocation Model DRO, Tab I6.2

Preamble:
The status quo revenue to cost ratio for the Street Lighting rate class is 44% and seasonal rate class is 74.63%. Algoma Power has proposed to gradually increase the revenue to cost ratio for Street Lighting to the lower limit of OEB's policy range over 5 years and for the seasonal rate class over 3 years. In order to maintain revenue neutrality Algoma Power proposes to reduce the revenue to cost ratio of the Residential R2 rate class.

Question(s):

a) Can Algoma Power identify the reasons for the marked difference in the status quo revenue to cost ratio between 2020 cost of service in reference 2 and 2025 for the street lighting rate class?
b) Please explain how the number of bills issued to streetlighting rate class have changed significantly between 2020 in reference 2 and 2025? The number of bills in 2020 was 15 vs in 2025 it's 13,871.
c) Please describe any other rate mitigation proposals considered by Algoma Power for the Street Lighting and seasonal rate class and why they were not proposed in the current application.

API Response:

a) API attributes the difference primarily to the issue identified in subsection b) below.
b) API confirms the 2025 value of 13 871 was is incorrect. The number of bills per month is 15 (180 per year), as API issues one bill per account rather than per device. API will reflect this correction with the models provided in response to 1-Staff-1. API notes that once corrected, the revenue- to cost ratio for the street lighting class is 94% and this is within the Board's target range, and therefore the rate mitigation proposal for the street lighting class in the Application is no longer required.
c) API is not aware of other mechanisms which would have been applicable other than a phasing-in of the revenue to cost ratio.

7-Staff-60

Weighting Factors
Ref: Exhibit 7, p. 12 and Cost Allocation Model, Tab I5.2

Preamble:
OEB staff notes that weighting factors for some of the rate classes have changed compared to the last OEB approved weighing factors used in 2020 for Billing and Collecting.

Question(s):

a) Please provide the derivation of the proposed weighting factors.
b) Please explain why the weighting factors have changed from the 2020 OEB approved.

API Response:

a) API estimated allocations per class for six major cost drivers in OEB accounts 5315, 5320, and 5340 to derive an estimated cost per customer for each classification. The 2022 expenses for billing labour, postage, collections, customer service labour, and after hours outage calls were allocated to each rate class based on different percentage allocators.

   For postage and print, costs were allocated based on the number of paper bills printed monthly. Customer service labour was allocated based on the FTE billing activities (ie: smart meter vs. Interval meter billing) and number of customers in each meter type per class. The outage call centre costs were allocated based on the number of accounts. The other expense accounts were distributed based on allocations determined by API and corporate billing subject matter experts. The allocated costs for each function were divided by the number of customers per class, and added together to determine a billing and collecting allocated cost per customer per class.

   The relative cost was then established using Residential R1 as the base of 1, with the cost per customer of the other rate classes divided by the cost of Residential R1 to establish the weight factors.

   Please also refer to 7-Sec-34b for a sample of these calculations.

b) For the 2020 cost of service application, the weigh factors the values remained unchanged from the 2015 cost of service application's weight factors. For the 2025 weight factors, API updated its weighting factors, using more recent cost data (2022).

   API employed an updated methodology in completing its 2025 assessment of the Billing and Collecting weight factor, which takes into account the recent cost drivers in the Billing and Collecting accounts, and estimation/quantification of the relative costs per customer. API notes that since its last Application, certain cost elements and allocators have changed, for example increased customer uptake of e-billing has increased.

Exhibit 8 – Rate Design

8-Staff-61

Ref 1: Tariff Schedule and Bill Impact Model
Ref 2: OEB Letter - 2025 Inflation Parameters

Preamble:
The Tariff Schedule and Bill Impact Model in reference 1, Tab 3 contains Miscellaneous Service Charges which are calculated based on an inflation factor of 4.8% for 2023.

In reference 2, the OEB has recently issued a letter on June 20, 2024 with updated 2025 Inflation Parameters. In the letter, the OEB states that it has calculated the 2025 inflation factor for electricity distributors to be 3.6%.

Question(s):

a) Please update the Miscellaneous Service Charges in Tab 3 (reference 1) to reflect the 2025 inflation factor of 3.6%.
b) Please revise other tabs in reference 1 to reflect the update in (a).

API Response:

a) The Miscellaneous Service Charges in Tab 3 were updated to reflect the 2025 inflation factor of 3.6%, please see the updates with the Tariff and Bill Impact model provided in the response to 1-Staff-1.
b) The proposed tariff provided in 1-Staff-1 reflects this requested update.

8-Staff-62

RRRP Adjustment Factor
Ref 1: RRWF
Ref 2: Appendix A

Preamble:
In Appendix A, OEB staff has provided an updated RRRP adjustment factor of 4.75% and the associated analysis.

Question:

a) Please review and confirm that Algoma Power agrees with the calculated RRRP adjustment factor of 4.75%.
b) If not, please revise the analysis and explain what has been revised as applicable.

API Response:

a) API has reviewed and agrees with the calculated adjustment factor of 4.75%
b) N/A.

8-Staff-63

Fully Fixed Rate Design
Ref 1: Exhibit 8, p. 16
Ref 2: RRWF

Preamble:
Algoma Power stated that it has used the RRWF, with adjustments, to calculate the adjustment for the Seasonal rate class. In the scenario where Algoma Power applied the $4 incremental amount to the fixed rate for the Seasonal Class, the Seasonal bill impact at the 10th percentile of usage (ie: a small Seasonal customer using only 15kWh per month), the total bill impact exceeded the 10% threshold.

For the Seasonal rate class, Algoma Power is proposing to maintain the current fixed-variable split of 8%/92%.

Question(s):

a) Please provide a schedule showing the fixed variable/split for each remaining transition year.
b) Please state how many seasonal customers are at the 10th percentile.
c) Please provide a scenario showing the continued transition towards a fully fixed rate design for seasonal customers, including the associated bill impacts.

API Response:

a) The following table shows the transition to the fixed variable split for the remaining transition years. The table accounts for the proposed phase-in by 2026 of the revenue-to-cost ratio, but not the annual IRM adjustment.

	2025	2026	2027	2028	2029
R-C Ratio	80%	85%	85%	85%	85%
allocated revenue requirement	$3,419,639.24	$3,617,878.79	$3,617,878.79	$3,617,878.79	$3,617,878.79
number of customers	2,717	2,717	2,717	2,717	2,717
kWh	5,958,052	5,958,052	5,958,052	5,958,052	5,958,052
target monthly fixed charge (100% fixed)	$104.88	$110.96	$110.96	$110.96	$110.96
Proposed Fixed	$96.68	$100.68	$104.68	$108.68	$110.96
Proposed Variable (per kWh)	$0.0448	$0.0563	$0.0344	$0.0125	0
Fixed RR	$3,152,526.96	$3,282,570.72	$3,412,986.72	$3,543,402.72	$3,617,878.79
Variable RR	$267,112.28	$335,308.07	$204,892.07	$74,476.07	$0.00
Fixed %	92.19%	91%	94%	98%	100%
Variable %	7.81%	9%	6%	2%	0%

b) 47 customers are at or around 15kWh(ie: within +/-2.5kWh).

c) API has modeled a scenario where the fixed charge is increased by the maximum $4. This scenario maintains the phased increase to the target revenue to cost ratio. The resultant bill impact for the Seasonal class at 200 kWh is $7.69 or 6.49%. At the 10th percentile, it is $11.18 or $13.03 %.

The same scenario with no phase- in of the R-C ratio results in a bill impact for the seasonal class at 200 kWh of $13.42 or 11.33%, and at the 10th percentile it is $16.47 or 19.19%.

8-Staff-64

Retail Service Transmission Rates
Ref 1: RTSR Workform
Ref 2: EB-2024-0183_2024 Uniform Transmission Rates_Update, June 27, 2024

Preamble:
On June 27, 2024 the OEB issued its decision and order on updated Uniform Transmission Rates, which are as follows:

- $6.12/kW/Month Network Service Rate (a $0.34/kW increase)
- $0.95/kW/Month Line Connection Service Rate (no change)
- $3.21/kW/Month Transformation Connection Service Rate (no change)

Question(s):

a) Please update the RTSR work form to reflect the updated UTRs.
b) Please update the tariff and bill impact model accordingly.

API Response:

Both the RTSR work form and Tariff & Bill Impact Model have been updated accordingly in the models provided in 1-Staff-1.

8-Staff-65

Regulatory charges
Ref 1: Tariff and Bill Impact Model_API Version
Ref 2: OEB Letter: 2025 Inflation Parameters, June 20, 2024

Preamble:
On June 20, 2024 the OEB issued the 2025 inflation factor of 3.6% for electricity distributors.

Question(s):

a) Please update the regulatory charges in tariff and bill impact model to reflect the inflations factor of 3.6%.

API Response:

API has made the inflation factor update in Tab 3 of the Tariff and Bill Impact model provided with 1-Staff-1.

8-Staff-66

Loss Factor
Ref 1: Chapter 2 Appendix 2-R
Ref 2: Exhibit 8, Table 17, p. 30

Preamble:
OEB staff notes distribution line losses have remained above 5% in the 5 historical years in reference 1.

Question(s):

a) Please explain why the actual purchased power in the load forecast model or that reported in RRR do not match either the higher or lower wholesale kWh Delivered to the Distributor values in reference 1.
b) Please explain why the distribution losses are higher than average in 2020.
c) Is Algoma Power considering a line loss study?

API Response:

a) Consistent with the instructions in Appendix 2-R, API obtained the annual data via a request to the IESO for power purchases with and without upstream losses (as adjusted to include embedded generation). API is not able to provide a full reconciliation to the RRR and load forecast amounts. The source of the amounts used in the load forecast and RRR reporting for wholesale purchases are reconciled to the monthly AQEW from the IESO invoice (as adjusted for the variances identified by MEGS). API notes that the average variance between the "higher value" and the RRR power purchases is 0.3%.

b) API cannot confirm the reason for the higher than average losses in 2020. API notes that at various factors can impact line losses, such as changes in usage patterns of larger customers, changes in system supply configurations (where looped configurations exist), as well as non-technical losses, such as unmetered losses, theft of power, etc.

c) At this time, Algoma Power is not considering a line loss study.

Exhibit 9 – Deferral & Variance Accounts

9-Staff-67

Echo River TS ACM
Ref 1: Exhibit 9, Table 9-11, page 31
Ref 2: Exhibit 2, Table 46, page 93
Ref 3: Exhibit 2, Table 45, page 91
Ref 4: Report of the Board, New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (OEB ACM Report), September 18, 2014

Preamble:
In Reference 1, Algoma Power provides the incremental revenue requirement calculation for the Echo River TS ACM project based on the actual costs as well as a forecast for 2024.

Table 9-11 - IRR Calculation Echo River TS ACM Project

Incremental Revenue Requirement Based on Actual Costs Advanced Capital Module Echo River TS Project			2023A	2024F
ACM Fixed Assets				
Gross Fixed Assets - Opening			-	10,851,932
Additions			10,851,932	154,279
Gross Fixed Assets - Closing			10,851,932	11,006,211
Accumulated Depreciation/Amortization - Opening			-	(100,481)
Depreciation/Amortization Expense (Note 1)			(100,481)	(244,582)
Accumulated Depreciation/Amortization - Closing			(100,481)	(345,063)
Net Book Value - Opening			-	10,751,451
Net Book Value - Closing			10,751,451	10,661,148
Net Book Value - Average			5,375,726	10,706,300
Return on Rate Base				
	Deemed %	Rate		
Short Term Debt	4.00%	2.75%	5,913	11,777
Long Term Debt	56.00%	4.77%	143,596	285,987
			149,509	297,764
Return on Equity (ROE)	40.00%	8.52%	183,205	364,871
Return on Rate Base	100.00%	6.19%	332,714	662,635
Grossed-up Taxes/PILS				
Regulatory Taxable Income (ROE)			183,205	364,871
Add: Depreciation/Amortization Expense			100,481	244,582
Less: CCA (Note 3)			(868,155)	(811,044)
Incremental Taxable Income			(584,469)	(201,591)
		Rate		
Taxes/PILs Before Gross-Up		26.50%	(154,884)	(53,422)
Grossed-Up Taxes/PILs			(210,727)	(72,683)
Incremental Revenue Requirement (IRR)				
Return on Rate Base			332,714	662,635
Amortization Expense			100,481	244,582
Grossed-Up Taxes/PILs			(210,727)	(72,683)
IRR Total			222,468	834,534
Cumulative IRR			**222,468**	**1,057,002**

Note 1 Depreciation/Amortization based on in service month.

Note 2 Original ACM modeling submitted assumed Year 1 CCA effective rate = 1x CCA rate and so that approach was taken in the calculation of IRR above. Remaining difference has been calculated for OEB 1592 DVA allocation purposes. Cumulatively, API will have passed the benefit of the enhanced CCA deductions through between a combination of the recalculated IRR and the OEB 1592 DVA forecasted amounts.

Reference 2 outlines the in-service actual spending associated with each project in each year.

Table 46- ACM Project Spending – In-Service Timing

	SSM Facility	Notes	ERTS	Notes
Approved ACM Amounts	$ 12,690,000	2022 in-service	$ 7,500,000	2021 In-Service
Actual In-Service Additions	**SSM Facility**	**Notes**	**ERTS**	**Notes**
2022	$ 15,708,824	Building in-service, occupancy	$ -	
2023	$ 640,323	Close-out improvements, parking and driveway adjustments.	$ 10,906,211	Spare Transformer
2024	$ 200,622	Additional costs for severance and other items.	$ 100,000	Station Transformer Work
Actual In-Service Additions	**$ 16,549,769**		**$ 11,006,211**	
Adjust for IT Assets - see note	**$ 104,894**		**N/A**	
Total With Adjustment	**$ 16,654,663**			

Algoma Power provides a breakdown of the Echo River TS project budget and actual costs in Reference 3.

Table 45- ERTS Cost Breakdown

Cost Item	Budget	Total Actual Cost	Variance ($)
Cost payable to HOSSM/IESO	$7,500,000	$10,754,279	$3,254,279
API Internal Cost		$63,207	$63,207
Study Cost (for Alternative & Business Case		$181,111	$181,111
Modification required to API Wholesale Meter		$7,614	$7,614
Total	$7,500,000	$11,006,211	$3,506,211

Section 7.1.1 of the OEB ACM report states that,

> *The Board's general guidance on the application of the half-year rule is provided in the Supplemental Report. In that report the Board determined that the half-year rule should not apply so as not to build a deficiency for the subsequent years of the IR plan term. In a subsequent decision with respect to the application of the half-year rule in the context of an ICM, the Board decided that the half-year rule would apply in the final year of the Price Cap IR plan term. The Board adopted this as a clarification to the policy on ICM in the Filing Requirements. This approach is unchanged for the new ACM/ICM policy.*

Question(s):

a) Please explain why the fixed assets additions for 2023 and 2024 reported in Reference 1 differ from the in-service additions for those years as reported in Reference 2. Please update the evidence as needed.
b) Please confirm in which year the Echo River TS was considered to be in service according to the Accounting Standards for Private Enterprises (ASPE).
    i. Did Algoma Power's external auditors of its financial statements agree on the capitalization of this asset in the year?
    ii. If not, why not?

c) Please explain in detail what Algoma Power internal cost and Study Cost outlined in Reference 3 entail.
   i. Please clarify which section of the ASPE allows for the inclusion of these types of costs as part of the capital asset cost.
d) Please confirm the total cost for the Echo River TS ACM project is to be included in the rate base based on the ASPE capitalization policy.
e) Please provide a fixed asset continuity schedule using the same format as Appendix 2-BA for the Echo River project by year, itemized by asset class.

API Response:

a) API confirms the figures reflected in reference 1 reflect the correct in-service additions per year. API notes that the total cumulative in-service additions for the project up to 2024 year-end are consistent with both references, however there roughly $50k in higher 2023 additions in Reference 2, followed by an equal and offsetting variance in the 2024 additions. API confirms that the ACM true up calculations are correct as presented.
b) The ERTS was considered to be in service in 2023.
   i. API received an unqualified audit opinion for its financial statements for year ending December 31, 2023.
c)

As part of API's 2020 Cost of Service settlement agreement, API committed to provide information and business case analysis that incorporates the updated forecast and cost responsibility for this project. A Business Case report was drafted with a recommended to pursue the Transmission alternative.

The internal cost identified in Table 45 refers to the direct time allocation of API Engineering in managing the Study efforts as well as ongoing project management and coordination with the Hydro One team.

   i. Section 3064 (related to intangible assets).

I)

d) Confirmed.
e) See below.

Year 2023 MIFRS

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
47	1609A	Capital Contributions Paid	$ -	$ 10,851,932	$ -	10,851,932	$ -	-$ 100,481	$ -	-100,481	10,751,451
		Sub-Total	0	10,851,932	0	10,851,932	0	-100,481	0	-100,481	10,751,451

Year 2024 MIFRS

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
47	1609A	Capital Contributions Paid	$ 10,851,932	$ 154,279	$ -	11,006,211	-$ 100,481	-$ 242,868	$ -	-343,349	10,662,862
		Sub-Total	10,851,932	154,279	0	11,006,211	-100,481	-242,868	0	-343,349	10,662,862

9-Staff-68

SSM Facility ACM
Ref 1: Exhibit 9, Section 9.3.12, Pg. 26 - 32
Ref 2: Exhibit 2, Table 46, page 93
Ref 3: Appendix 2-BA

Preamble:
In Table 9-9 of Reference 1, Algoma Power provides the incremental revenue requirement calculation for the SSM facility ACM project. Additionally, Algoma Power states a pro-rata approach is used to allocate the capped amount of $12.69M by asset class based on the actual cost of $15.71M (used and useful in 2022) for depreciation expense and associated CCA deduction calculations.

Table 9-9 - IRR Calculation Sault Facility ACM Project

Incremental Revenue Requirement Based on Actual Costs Advanced Capital Module Sault Facility Project - Capped at $12,690,000			2022A	2023A	2024F
ACM Fixed Assets					
Gross Fixed Assets - Opening			-	12,690,000	12,690,000
Additions (Note 1)			12,690,000	-	-
Gross Fixed Assets - Closing			12,690,000	12,690,000	12,690,000
Accumulated Depreciation/Amortization - Opening			-	(21,550)	(280,151)
Depreciation/Amortization Expense (Note 2)			(21,550)	(258,601)	(258,601)
Accumulated Depreciation/Amortization - Closing			(21,550)	(280,151)	(538,752)
Net Book Value - Opening			-	12,668,450	12,409,849
Net Book Value - Closing			12,668,450	12,409,849	12,151,248
Net Book Value - Average			6,334,225	12,539,150	12,280,549
Return on Rate Base					
	Deemed %	Rate			
Short Term Debt	4.00%	2.75%	6,968	13,793	13,509
Long Term Debt	56.00%	4.77%	169,200	334,946	328,038
			176,168	348,739	341,547
Return on Equity (ROE)	40.00%	8.52%	215,870	427,334	418,521
Return on Rate Base	100.00%	6.19%	392,038	776,073	760,068
Grossed-up Taxes/PILS					
Regulatory Taxable Income (ROE)			215,870	427,334	418,521
Add: Depreciation/Amortization Expense			21,550	258,601	258,601
Less: CCA (Note 3)			(768,685)	(696,694)	(643,009)
Incremental Taxable Income			(531,265)	(10,759)	34,113
		Rate			
Taxes/PILs Before Gross-Up		26.50%	(140,785)	(2,851)	9,040
Grossed-Up Taxes/PILs			(191,544)	(3,879)	12,299
Incremental Revenue Requirement (IRR)					
Return on Rate Base			392,038	776,073	760,068
Amortization Expense			21,550	258,601	258,601
Grossed-Up Taxes/PILs			(191,544)	(3,879)	12,299
IRR Total			222,044	1,030,795	1,030,968
Cumulative IRR			**222,044**	**1,252,839**	**2,283,807**

Note 1 With $15,708,824 in costs used and useful in 2022, API used a pro-rata approach to allocate the capped amount of $12,690,000 by asset class for depreciation expense and associated CCA deduction calculations.
Note 2 Depreciation/Amortization based on in service month.
Note 3 Original ACM modeling submitted assumed Year 1 CCA effective rate = 1x CCA rate and so that approach was taken in the calculation of IRR above. Remaining difference has been calculated for OEB 1592 DVA allocation purposes. Cumulatively, API will have passed the benefit of the enhanced CCA deductions through between a combination of the recalculated IRR and the OEB 1592 DVA forecasted amounts.

Reference 2 outlines the in-service actual spending associated with each project in each year.

Table 46- ACM Project Spending – In-Service Timing

	SSM Facility	Notes	ERTS	Notes
Approved ACM Amounts	$ 12,690,000	2022 in-service	$ 7,500,000	2021 In-Service
Actual In-Service Additions	**SSM Facility**	**Notes**	**ERTS**	**Notes**
2022	$ 15,708,824	Building in-service, occupancy	$ -	
2023	$ 640,323	Close-out improvements, parking and driveway adjustments.	$ 10,906,211	Spare Transformer
2024	$ 200,622	Additional costs for severance and other items.	$ 100,000	Station Transformer Work
Actual In-Service Additions	$ 16,549,769		$ 11,006,211	
Adjust for IT Assets - see note	$ 104,894		N/A	
Total With Adjustment	$ 16,654,663			

Section 7.1.1 of the OEB ACM report states that,

> The Board's general guidance on the application of the half-year rule is provided in the Supplemental Report. In that report the Board determined that the half-year rule should not apply so as not to build a deficiency for the subsequent years of the IR plan term. In a subsequent decision with respect to the application of the half-year rule in the context of an ICM, the Board decided that the half-year rule would apply in the final year of the Price Cap IR plan term.13 The Board adopted this as a clarification to the policy on ICM in the Filing Requirements. This approach is unchanged for the new ACM/ICM policy.

Question(s):

a) Please confirm in which year the SSM facility was considered to be in service according to the ASPE.
   i. Did Algoma Power's external auditors of its financial statements agree on the capitalization of this asset in the year?
   ii. If not, why not?
b) Please clarify why the land severance cost is considered as part of the total asset cost and provide the reference to the relevant section of ASPE.
c) Please confirm the total cost for the SSM Facility ACM project is to be included in the rate base based on the ASPE capitalization accounting policy.
d) Please provide a fixed asset continuity schedule using the same format as Appendix 2-BA for the SSM Facility ACM project by year, itemized by asset class, based on the actual project spending and capped amount.

API Response:

a) The SSM Facility was considered to be in service in 2022.
   i. API received an unqualified audit opinion for its financial statements for year ending December 31, 2022.
b) A large part of the bridge year budget related to the SSM Facility was related to additional site preparation costs on the existing land which would otherwise be

necessary with or without the severance and reconveyance. Additionally slated for inclusion in this budget was a lower level of expected costs related to the severance and reconveyance (ex: legal fees). API's rationale for proposing these (severance and reconveyance) fees into rate base is that the costs are necessary to enable a reduced land cost.

API's most up to date forecasted costs for the SSM Facility indicate the entire 2024 budget of $200,662 will be used towards the additional site preparation of the current site, which is clearly attributable directly to the existing 7.9 Acres. Section 3061 is the relevant section of ASPE.

c) Confirmed.
d) Please see below.

<u>Actual Project Spending</u>

Year 2022 MIFRS

			Cost				Accumulated Depreciation				
Class	**OEB**	**Description**	**Balance**	**Additions**	**Disposals**	**Balance**	**Balance**	**Additions**	**Disposals**	**Balance**	**Net Book Value**
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -	$ 713	$ -	713	$ -	-$ 2	$ -	-2	711
N/A	1805	Land	$ -	$ 865,341	$ -	865,341	$ -	$ -	$ -	0	865,341
47	1808	Buildings - Fixtures	$ -	$ 14,696,796	$ -	14,696,796	$ -	-$ 24,154	$ -	-24,154	14,672,642
47	1808A	Buildings - Components	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1915	Office Furniture & Equipment (10 years)	$ -	$ 8,991	$ -	8,991	$ -	-$ 75	$ -	-75	8,916
50	1920	Computer Equipment - Hardware	$ -	$ 220,574	$ -	220,574	$ -	-$ 3,676	$ -	-3,676	216,898
10	1935	Stores Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1960	Miscellaneous Equipment - 10 yr	$ -	$ 21,304	$ -	21,304	$ -	-$ 179	$ -	-179	21,125
		Sub-Total	**0**	**15,813,719**	**0**	**15,813,719**	**0**	**-28,086**	**0**	**-28,086**	**15,785,633**

Year 2023 MIFRS

			Cost				Accumulated Depreciation				
Class	**OEB**	**Description**	**Balance**	**Additions**	**Disposals**	**Balance**	**Balance**	**Additions**	**Disposals**	**Balance**	**Net Book Value**
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 713	$ -	$ -	713	-$ 2	-$ 18	$ -	-20	693
N/A	1805	Land	$ 865,341	$ -	$ -	865,341	$ -	$ -	$ -	0	865,341
47	1808	Buildings - Fixtures	$ 14,696,796	$ 540,226	$ -	15,237,022	-$ 24,154	-$ 294,173	$ -	-318,327	14,918,695
47	1808A	Buildings - Components	$ -	$ 10,745	$ -	10,745	$ -	$ -	$ -	0	10,745
8	1915	Office Furniture & Equipment (10 years)	$ 8,991	$ -	$ -	8,991	-$ 75	-$ 899	$ -	-974	8,017
50	1920	Computer Equipment - Hardware	$ 220,574	$ -	$ -	220,574	-$ 3,676	-$ 44,114	$ -	-47,790	172,784
10	1935	Stores Equipment	$ -	$ 55,244	$ -	55,244	$ -	-$ 4,604	$ -	-4,604	50,640
8	1960	Miscellaneous Equipment - 10 yr	$ 21,304	$ 34,107	$ -	55,411	-$ 179	-$ 2,131	$ -	-2,310	53,101
		Sub-Total	**15,813,719**	**640,322**	**0**	**16,454,041**	**-28,086**	**-345,939**	**0**	**-374,025**	**16,080,016**

Year 2024 MIFRS

			Cost				Accumulated Depreciation				
Class	**OEB**	**Description**	**Balance**	**Additions**	**Disposals**	**Balance**	**Balance**	**Additions**	**Disposals**	**Balance**	**Net Book Value**
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 713	$ -	$ -	713	-$ 20	-$ 18	$ -	-38	675
N/A	1805	Land	$ 865,341	$ 200,622	$ -	1,065,963	$ -	$ -	$ -	0	1,065,963
47	1808	Buildings - Fixtures	$ 15,237,022	$ -	$ -	15,237,022	-$ 318,327	-$ 304,748	$ -	-623,075	14,613,947
47	1808A	Buildings - Components	$ 10,745	$ -	$ -	10,745	$ -	-$ 430	$ -	-430	10,315
8	1915	Office Furniture & Equipment (10 years)	$ 8,991	$ -	$ -	8,991	-$ 974	-$ 899	$ -	-1,873	7,118
50	1920	Computer Equipment - Hardware	$ 220,574	$ -	$ -	220,574	-$ 47,790	-$ 44,115	$ -	-91,905	128,669
10	1935	Stores Equipment	$ 55,244	$ -	$ -	55,244	-$ 4,604	-$ 5,525	$ -	-10,129	45,115
8	1960	Miscellaneous Equipment - 10 yr	$ 55,411	$ -	$ -	55,411	-$ 2,310	-$ 5,542	$ -	-7,852	47,559
		Sub-Total	**16,454,041**	**200,622**	**0**	**16,654,663**	**-374,025**	**-361,277**	**0**	**-735,302**	**15,919,361**

<u>Capped Project Spending</u>

Year 2022 MIFRS

			Cost				Accumulated Depreciation				
Class	OEB	Description	Balance	Additions	Disposals	Balance	Balance	Additions	Disposals	Balance	Net Book Value
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -	$ 576	$ -	576	$ -	-$ 1	$ -	-1	574
N/A	1805	Land	$ -	$ 699,045	$ -	699,045	$ -	$ -	$ -	0	699,045
47	1808	Buildings - Fixtures	$ -	$ 11,872,458	$ -	11,872,458	$ -	-$ 19,787	$ -	-19,787	11,852,670
47	1808A	Buildings - Components	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1915	Office Furniture & Equipment (10 years)	$ -	$ 7,263	$ -	7,263	$ -	-$ 61	$ -	-61	7,203
50	1920	Computer Equipment - Hardware	$ -	$ 93,449	$ -	93,449	$ -	-$ 1,557	$ -	-1,557	91,891
10	1935	Stores Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1960	Miscellaneous Equipment - 10 yr	$ -	$ 17,210	$ -	17,210	$ -	-$ 143	$ -	-143	17,066
		Sub-Total	**0**	**12,690,000**	**0**	**12,690,000**	**0**	**-21,550**	**0**	**-21,550**	**12,668,450**

Year 2023 MIFRS

			Cost				Accumulated Depreciation				
Class	OEB	Description	Balance	Additions	Disposals	Balance	Balance	Additions	Disposals	Balance	Net Book Value
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 576	$ -	$ -	576	-$ 1	-$ 14	$ -	-16	560
N/A	1805	Land	$ 699,045	$ -	$ -	699,045	$ -	$ -	$ -	0	699,045
47	1808	Buildings - Fixtures	$ 11,872,458	$ -	$ -	11,872,458	-$ 19,787	-$ 237,449	$ -	-257,237	11,615,221
47	1808A	Buildings - Components	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1915	Office Furniture & Equipment (10 years)	$ 7,263	$ -	$ -	7,263	-$ 61	-$ 726	$ -	-787	6,476
50	1920	Computer Equipment - Hardware	$ 93,449	$ -	$ -	93,449	-$ 1,557	-$ 18,690	$ -	-20,247	73,202
10	1935	Stores Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1960	Miscellaneous Equipment - 10 yr	$ 17,210	$ -	$ -	17,210	-$ 143	-$ 1,721	$ -	-1,864	15,345
		Sub-Total	**12,690,000**	**0**	**0**	**12,690,000**	**-21,550**	**-258,601**	**0**	**-280,151**	**12,409,849**

Year 2024 MIFRS

			Cost				Accumulated Depreciation				
Class	OEB	Description	Balance	Additions	Disposals	Balance	Balance	Additions	Disposals	Balance	Net Book Value
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 576	$ -	$ -	576	-$ 16	-$ 14	$ -	-30	546
N/A	1805	Land	$ 699,045	$ -	$ -	699,045	$ -	$ -	$ -	0	699,045
47	1808	Buildings - Fixtures	$ 11,872,458	$ -	$ -	11,872,458	-$ 257,237	-$ 237,449	$ -	-494,686	11,377,772
47	1808A	Buildings - Components	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1915	Office Furniture & Equipment (10 years)	$ 7,263	$ -	$ -	7,263	-$ 787	-$ 726	$ -	-1,513	5,750
50	1920	Computer Equipment - Hardware	$ 93,449	$ -	$ -	93,449	-$ 20,247	-$ 18,690	$ -	-38,937	54,512
10	1935	Stores Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1960	Miscellaneous Equipment - 10 yr	$ 17,210	$ -	$ -	17,210	-$ 1,864	-$ 1,721	$ -	-3,585	13,624
		Sub-Total	**12,690,000**	**0**	**0**	**12,690,000**	**-280,151**	**-258,601**	**0**	**-538,751**	**12,151,249**

c) Please see above.

d) Please see above.

9-Staff-69

ACM True-up CCA
Ref 1: Exhibit 9, Section 9.3.12, pages 26 - 32
Ref 2: 2025 Continuity Schedule
Ref 3: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, December 15, 2022, Section 2.2.8, pages 22-23

Preamble:
According to the 1592 PILs calculations outlined in Table 9-12 and Table 9-10 of Reference 1, OEB staff summarizes the CCA differences for both projects in the table below.

CCA Difference	2022	2023	2024
Echo River TS		(156,503)	12,520
SSM	(138,573)	12,978	9,678
Total	**(138,573)**	**(143,525)**	**22,198**
Accumulated Total	**(138,573.00)**	**(282,098.00)**	**(259,900.00)**

In Reference 3, the OEB provides guidance on the impacts of the accelerated capital cost allowance (CCA) related to the ACM/ICM true-up.

> The impacts of accelerated capital cost allowance (CCA)17 should not be reflected in an ACM revenue requirement proposal associated with these projects. The OEB will assess the impact of the accelerated CCA on all capital investments at the time of rebasing to minimize the complexity of the review. Distributors should include the impact of the CCA rule change associated with any ACM projects that are approved for ACM treatment in Account 1592 - PILs and Tax Variances – CCA Changes. Disposition of amounts tracked in the applicable Account 1592 CCA sub-account should be brought forward at the time of a distributor’s next rebasing.

Question(s):

a) Please reconcile the CCA differences outlined in Reference 1 with the amounts reported in Reference 2 in Account 1592, Sub-Account PILs and Tax variance for 2006 and Subsequent Years, by year.
b) Please provide the CCA calculation for amounts recorded in Sub-Account PILs and Tax variance for 2006 and Subsequent Years, based on the actual cost for both ACM projects. These calculations should include:
    a) The undepreciated capital cost (UCC) continuity schedules for each year, itemized by CCA class.
    b) The calculated PILs/tax differences.
    c) The grossed-up PILs/tax differences.
    d) Any other applicable information.
    e) Confirmation that Account 1592 amounts related to ICM/ACM have been included in the account, if applicable.
    f) A reconciliation of these amounts to the amounts presented in the Account 1592 sub-account for CCA changes in the DVA continuity schedule.

c) Please provide a revised 2025 Continuity Schedule, if necessary.

API Response:

a) The ($259,900) can be agreed to cell BG82 of tab 2b. Continuity Schedule of the DVA model. The associated accumulated calculated interest of ($26,816) can also be found in cell BL82 of the same tab. Although there were some timing differences (API's final PILS calculations associated with these projects including a forecast for 2024 was completed in 2024 in advance of the application submission), API has used the principal and interest adjustments during 2023 columns to ensure that closing balances are reflective of the appropriate amounts including a forecast to end of 2024.
b) API has previously provided the requested values and they can be found in Reference 1 above. Table 9-10 and 9-12 of Exhibit 9 provide a CCA calculation for each of the projects, separated by CCA class. UCC values at the end of each of 2022, 2023 and 2024 forecast are also provided. API has completed this calculation for the full costing of the Echo River project. API notes that given that the Sault facility building spend was capped at $12,690,000, it has calculated balances to be reported in 1592 based on the capped spending. Given that during API's last rebasing in 2020, the calculated PILs for that test year considered enhanced CCA deductions, any incremental spend on the building beyond the capped amount above should not be subjected to 1592, which is a consistent approach with all other capital expenditures during API's rebasing period. The only exception is that enhanced CCA is being phased out starting in 2024 and API expects to quantify the difference in CCA under fully enhanced CCA rates and the partially phased out CCA rates for 2024 only, and this will be requested for disposition in a future proceeding.
c) Revised continuity not required to be provided.

9-Staff-70

DLI Rate Rider Recoveries
Ref 1: Exhibit 9, section 9.3.11, pages 24-25
Ref 2: 2025 Continuity Schedule

Preamble:
Table 9-5 in Reference 1 summarizes the differences in the DLI incremental revenue requirement calculations.

Table 9-5 - DLI Revenue Requirement

	2020 COS Submitted	Actual	Difference
Deferred and forecasted Incremental Revenue Requirement	273,697	209,779	(63,918)
Net Interest	10,265	8,993	(1,272)
Net Deferred Revenue Requirement	283,962	218,772	(65,190)

Table 9-6 in Reference 1 outlines the DLI rate rider recoveries compared to the actual revenue requirement.

Table 9-6 - DLI Rate Rider Recoveries

	2019	2020	2021	2022	2023	2024 Estimated	Cumulative Total	Actual Revenue Requirement	Difference (Over Collected)	# of Customers	Refund Rate Rider
DLI Rate Rider Recoveries	15,163	50,378	44,974	44,634	45,467	45,467	246,083	218,772	27,311	340	6.70

In Reference 1, Algoma Power proposes that “this remaining forecasted residual balance be disposed of on a final basis and that a one-year refund rate rider be provided to former DLI customers to return the excess rate riders collected to date.”

OEB staff notes the total claim amount for Account 1508, Sub-Account Dubreuilville Costs & Revenues is a credit balance of $65,190 according to Reference 2.

Question(s):

a) Please confirm whether the requested disposition amount related to the DLI revenue requirement is a credit amount of $27,311, resulting from the overcollection as calculated in Table 9-6.
   i. If so, please explain why the ending balance of the Sub-Account Dubreuilville in the 2025 Continuity Schedule does not match the over-collected amount of $27,211 and revise Reference 2 accordingly.

ii. If not, please explain why.

API Response:

a) API confirms that the requested disposition should have been a credit of $27,311 and not $65,190. The DVA model has been updated accordingly by changing the Principal Adjustments during 2023 column amount from a credit of $138,295 to a credit amount of $100,416. The model is included as Attachment 9-Staff-70. The corresponding calculation of the DLI specific rate rider as noted in the Table 9-6 referenced above remains unchanged.

9-Staff-71

Accounts 1588 and 1589
Ref 1: Exhibit 9, section 9.3.4, pages 20 -21
Ref 2: Electricity Act, section 36.1.1
Ref 3: 2025 GA Analysis Workform

Preamble:
In Reference 1, Algoma Power states:

> It appears the adjustments and payments it requires from the IESO in order to facilitate the disposition of accounts 1588 and 1589 for the years 2021 and 2022 fall outside the two-year limitation period imposed on the IESO under O. Reg. 153/23, which came into effect on July 1, 2023. Accordingly, API respectfully requests that, further to Sub-Section (7)(b), of Section 36.1.1 of the Electricity Act, the OEB issue an order requiring the IESO to:
>
> A) accept the proposed adjustments to API's Class A values for both May 2021 and January 2022 as set out in this application in furtherance of the final disposition of API's 1588 and 1589 variance accounts, and
> B) make payments to API in accordance with those adjustments so that API may dispose of those variance accounts on a final basis.
>
> API requests that this Order be contemplated in conjunction with API's request for approval of disposition of its Group 1 and 2 balances.

Sub-Section (7)(b) of Section 36.1.1 of the Electricity Act states that,

> (7) Despite subsection (1), the IESO shall not be restricted from making or receiving any payment or adjustment of any amount to or from a market participant, a consumer, an entity or a person in respect of an entitlement or a specified charge to which that subsection applies where such payment or adjustment results from,
>
> …
>
> (b) a decision, an order or a direction of the Board in respect of a variance account.

In Table 3 below, OEB staff summarizes the principal adjustments recorded in Accounts 1588 and 1589 related to the settlement true-up as reported in reference 3.

Table 3: Summary of Principal Adjustments Pertaining to the Order to the IESO

Principal Adjustments Reported in GA Analysis Workform	**1588**	**1589**	**Settlement True-ups Subject to the Two-year Limitation**
CT 148 Recalculated Settlement True-up for **2021**	(400,222)	61,135	**(339,087)**
CT 148 Recalculated Settlement True-up for **2022**	2,540	(21,657)	**(19,117)**
Total	**(397,682)**	**39,478**	**(358,204)**

OEB staff notes from the GA Analysis Workform that the above 2021 and 2022 adjustments for Accounts 1588 and 1589 have been reflected in the principal adjustments of the respective years on the DVA continuity schedule.

In Reference 1, Algoma Power further states that:

> *Given that API continues to review its 2023 1588/1589 activity and balances, it is not requesting disposition of 2023 activity for these accounts as part of the initial Application submission. If API is able to complete a timely internal review of the 2023 1588/1589 balances and is also able show that variances are within the +/-1% as required, it will consider bringing forward an updated disposition request within this proceeding for 2023 (in addition to 2021 and 2022 already requested). Alternatively, if the reconciliation work is not fully completed early on enough in the proceeding, API respectfully requests a deferral of the request of 2023 1588/1589 balances until an application is submitted for 2026 rates.*

Question(s):

a) Please clarify whether Algoma Power requested a resubmission to the IESO.
   i. If so, please provide details on when Algoma Power communicated with the IESO and IESO's response to Algoma Power's request.
   ii. If not, please explain why.
b) In Algoma Power's view, in order to get around the two year limitation period, must the order under section 36.1.1(7)(b) of the Electricity Act be directed to the IESO, or would a decision and rate order directed to Algoma Power be sufficient.
   i. Please provide a draft order in respect of the resettlement issue.
c) Please confirm the table compiled by OEB staff as above and revise the table as applicable.
d) Please explain why Algoma Power has considered the 2022 adjustment for a total of ($19,117) material.
e) Please confirm that the principal adjustments recorded in Accounts 1588 and 1589 are based on the assumption that the IESO resettles the adjustments for CT148 and refunds these adjustments to Algoma Power. If not, please clarify.
f) Please explain what Algoma Power intends to do with the principal adjustments if the OEB does not issue the requested order requiring the IESO to resettle. Under this scenario, please clarify if Algoma Power needs to write off the overcharged amount in its financial statements. If so, please provide the journal entries for the write off and please also quantify any impact on Algoma's return on equity.
g) Please fill out the impacts on Algoma Power and its customers in the table below.

	Scenario #1 – OEB makes the order as requested by Algoma Power	Scenario #2 – OEB does not make the order as requested by Algoma Power

	Impact on Algoma Power	Impact on customers	Impact on Algoma Power	Impact on customers
Account 1588 (all customers)				
Account 1589 (Non-RPP customers)				

h) Please provide an update on the review of the 2023 activities.

API Response:

a) API began the process of coordinating a resubmission with the IESO on March 7, 2024 by sending an email request to the IESO.
  - This initial request informed the IESO that Class A load information needed to be corrected on the Embedded Generation, Energy Storage and Class A Load Information submission for the months of May 2021 and January 2022, with changes of approximately 3,445,000 kWhs and 437,000 kWhs, respectively.
    - IESO responded on March 15, 2024 with a reference to limitation periods per link below that may be relevant and are to be considered in this scenario https://www.ieso.ca/en/Sector-Participants/IESO-News/2023/07/Regulation-Changes-to-Impact-Online-Settlement-Forms
    - API responded back via email on March 18, 2024 requesting that further consideration be given to opening up the periods for resubmission on the basis that:
      1. There was a significant time delay of around 15 months before the error was identified based on following the OEB reporting requirements as a possible error was revealed while preparing the GA Workform for IRM submission
      2. A third party with expertise to assist with the 1588/1589 review did not appear to exist in the industry until API was able to engage a newly formed third party consulting company (MEGS) in October 2024
      3. Based on regulation changes, the IESO had changed the settlement rules recently, and that there should be allowance for settlement corrections on a transitional basis for those distributors who have made serious attempts to take appropriate actions to address issues with their commodity pass through accounts
      4. API had proactively reached out to the IESO in a timely manner once the corrections were known per the final Stage Two Report that was issued by MEGS (report dated March 2024).
  - API requested a Microsoft Teams call with IESO representatives to discuss the topic further on April 4, 2024, and a follow up call was also had on April 15, 2024.

  - The IESO pointed API back to the regulation changes that came into effect July 1, 2023 (O. Reg. 153/23: LIMITATION PERIODS (ontario.ca)) and it was of the IESO's view that it would not accept a re-submission of Class A consumption for May 2021 and January 2022 and therefore did not open those periods back up for re-submission to API.
  - The IESO acknowledged that there is currently not a timing limitation on the RPP settlements process
- It is of API's view that Class A values should be able to re-submitted as the kWhs submitted for Class A for a particular period have a direct impact on basis of the kWhs for the Class B dollars that are to be billed for that same period, and the Class B dollars billed are used directly in the RPP settlements calculation process

b) In API's view, it would be the most beneficial to have a draft order directed to the IESO to ensure API has the ability to proceed with the resubmission.

Draft Order: Resubmission of Class A Global Adjustment

Background

Regulation changes came into effect July 1, 2023 -> O. Reg. 153/23: LIMITATION PERIODS, a time during which time API was actively working to resolve differences with its GA Workform for 2021 and 2022 differences as variances exceeded the 1% allowable threshold. The regulation changes were introduced in with minimal lead time provided to distributors. At the time of implementation, API was unaware that this limitation period may come in to play with respect to resolving it's 2021 and 2022 1588/1589 balances which had not yet been disposed of on a final basis.

Investigative work for API's accounts was completed in March 2024 by a combination of internal resources and a recently formed consulting firm with expertise in this area. It was discovered that corrections needed to be made to Class A load information on the Embedded Generation, Energy Storage and Class A Load Information submission for the months of May 2021 and January 2022, with changes of approximately 3,445,000 kWhs and 437,000 kWhs, respectively.

Throughout both correspondence and conversations with the IESO that started in March 2024, the IESO remained of the opinion that it would not accept a re-submission of Class A consumption for May 2021 and Jan 2022 given the limitation periods identified in the regulation changes noted above.

Order

This order establishes the ability for API to submit corrected Class information for May 2021 and January 2022 to facilitate the disposition of accounts 1588 and 1589 for the years 2021 and 2022. This is further to Sub-Section (7)(b), of Section 36.1.1 of the Electricity Act, the OEB requires the IESO to:

i. accept the proposed adjustments to API's Class A values for both May 2021 and January 2022 as set out in this application in furtherance of the final disposition of API's 1588 and 1589 variance accounts, and

ii. make payments to API in accordance with those adjustments so that API may dispose of those variance accounts on a final basis.

c) API agrees with the total Settlement True-Ups subject to the two-year limitation amounts of (339,087) for 2021 and (19,117) for 2022. The principal adjustments being reported on the GA Workform are further broken down in Table 18 (2021), and Table 19 (2022) in Exhibit 9 of the Cost of Service Application. These tables show that the 4705 and 4707 debits/credits reflect the allocation between RPP and non-RPP customers due to the recalculation of the RPP settlement true ups, of which only May 2021, and January 2022 had a material impact. See below for slightly updated table.

Adjusted Table:

Principal Adjustments Reported in GA Analysis Workform	1588	1589	Settlement True-Ups Subject to the Two-year Limitation
CT 148 Recalculated Settlement True-up for 2021 (May 2021)	(251,633)	(87,454)	**(339,087)**
CT 148 Recalculated Settlement True-up for 2022 (January 2022)	271	(19,388)	**(19,117)**
Total	**(251,362)**	**(106,842)**	**(358,204)**

d) The 2022 adjustment for a total of ($19,117), while not material from a dollar perspective was proposed to ensure that the same methodology was used in the both calculations of 2021 and 2022 calculations as proposed by MEGS. This allows for consistency amongst the two years that the 1588 and 1589 recalculations are being prepared for, as well as to ensure that we meet the 1% threshold on the GA workform. Given materiality, API is open to not resubmitting the January 2022 Class A value and instead completing a further RPP settlements recalculation on the basis that Class B calculated rate for settlements calculation purposes will be slightly higher.

e) Confirmed. For May 2021 and January 2022, the RPP settlement calculations and associated adjustments are reflective of the assumption that the IESO accepts the re-submission of Class A information for those periods.

f) If the OEB does not issue the requested order requiring the IESO to resettle, API will look to be held whole by the customers in this situation. Based on the reasons outlined in response b) above, API is of the opinion that it should not be made to write off these amounts from their financial statements. Please refer to comments under g) for further details regarding quantification of impact on customers.

g) Under scenario #1, where API can re-submit the proposed resubmission with the IESO (through the order to the IESO from the OEB), there would be no further impact on API or its customers, as we would be getting held whole for the correction.
Under scenario #2, where API is unable to re-submit the proposed resubmission with the IESO, API is of the opinion that we should not have to write off the amounts in the financial statements, and that the customers should be ensuring that API is held whole.

If API is unable to resubmit Class A values, we propose adjusting our settlements to be based on the GA actual values of 0.12724/kWh that we were billed by the IESO rather than the posted GA rate for May 2021 of 0.10054/kWh as allowed under the guidance. This in turn will result in an adjustment to settlement for 1588 of $265,568 (due to calculated RPP settlement amount being increased because of this increase to the GA rate being utilized to the actual GA rate IESO billed), and an amount receivable from the customers of $73,518 relating to 1589 (please see table below for the details of the breakdown). For January 2022 we will adjust our settlements to be based on the GA actual values of 0.4430/kWh that we were billed by the IESO rather than the posted GA rate for January 2022 of 0.04353/kWh. This in turn will result in an adjustment to settlement for 1588 of $16,510, and an amount receivable from the customers of $2,608 relating to 1589.

After adjusting the recalculated settlement amounts to remove the total resubmission amount of $358,204 as calculated originally and was included as an adjustment in the Glass B – GA amount, leaving a total receivable increase in 1589 from the customers of $76,126 ($73,518 from May 2021 and $2,607.90 from January 2022).

May 2021 Table

Account	Original Proposed	New GA Rate Proposed for Settlement	Difference	
1588	-251,632.60	13,938.50	265,571.10	Settlement
1589	-87,454.24	-13,938.50	73,515.74	DVA

January 2022 Table

Account	Original Proposed	New GA Rate Proposed for Settlement	Difference	
1588	270.75	16,780.15	16,509.40	Settlement
1589	-19,388.05	-16,780.15	2,607.90	DVA

Total of May 2021 and January 2022

Account	Original Proposed	New GA Rate Proposed for Settlement	Difference	
1588	-251,903.35	30,718.65	282,080.50	Settlement
1589	-106,842.29	-30,718.65	76,126.64	DVA
Total	-358,745.64	-	358,207.14	

Table As Requested:

	Scenario #1 – OEB makes the order as requested by Algoma Power		Scenario #2 – OEB does not make the order as requested by Algoma Power	
	Impact on Algoma Power	Impact on Customers	Impact on Algoma Power	Impact on Customers
Account 1588 (all Customers	-	-	-	-
Account 1589 (Non-RPP Customers)	-	-	-	76,126

h) API is continuing to work on the full review of the 2023 activities using the approach outlined by MEGS. As of interrogatory submission date, the work had not yet been fully completed and reviewed and so API respectfully requests a possible deferral of 2023 until its 2026 IRM proceeding.

9-Staff-72

Pole Attachment Variance
Ref 1: Exhibit 9, section 9.3.10, page 24
Ref 2: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, December 15, 2022, page 65
Ref 3: Accounting Guidance on Wireline Pole Attachment Charges, July 20, 2018, page 3

Preamble:
Algoma Power is requesting the disposition of Account 1508 – Pole Attachment Revenue Variance (debit balance of $296,246).

Section 2.9.1.7 of the Filing Requirements states that distributors are to provide a table showing the calculation of the account balance, showing at a minimum, the annual balance broken down by customer type, if applicable, and:

- the number of poles used in the calculation.
- the pole attachment charge incorporated in rates.
- the updated charge.

Question(s):

a) Please provide the information as noted in Section 2.9.1.7 of the Filing Requirement to support the Account 1508 – Pole Attachment Revenue variance balances requested in this application for disposition.

API Response:

a) See table below.

Year	$ of Poles	Rate Incorporated in Rates Charged ($/pole attacher/year)	Rate Charged to Customer ($/pole attacher/year)	Principal Amount Recorded in 1508 Account
2022	11,120	$44.50	$34.76	$106,072
2023	11,120	$44.50	$36.05	$93,980
2024F	11,120	$44.50	$37.78	$74,748

9-Staff-73

Generic Cloud DVA
Ref 1: EB-003-2023, Accounting Order, November 2, 2023
Ref 2: Cloud Computing Implementation Q&A Document, PDF, February 2024
Ref 3: EB-2024-0063, Notice, March 6, 2024

Preamble:
On November 2, 2023, the OEB issued the Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs (Cloud Computing Implementation Report). The Cloud Computing Implementation Report noted that the Cloud Computing Implementation Account is generally intended to record cloud computing implementation costs when utilities first transition from on-premise solutions to cloud computing. In February 2024, the OEB hosted a webinar and Q&A session related to the Accounting Order for the establishment of a deferral account to record cloud computing arrangement implementation costs and issued a Q&A document.

On March 6, 2024, the OEB commenced a generic hearing (EB-2024-0063) on its own motion to consider the cost of capital and other matters, including those related to the OEB's Cloud Computing Deferral Account (e.g., what type of interest rate, if any, should apply to this deferral account).

Question(s):

a) Please confirm whether Algoma Power has considered cloud computing solutions in its rebasing term and whether any amounts have been included in its forecast.
b) If not confirmed, please explain why and Algoma Power's proposal to address its cloud solution implementation needs during its rebasing term.

API Response:

a) Algoma Power considered future adoption and expansion of cloud computing solutions in its Test Year forecast for technology costs, including consideration of the forecasted allocations from shared services (CNPI). For the years beyond the test year, API has not made specific OM&A adjustments in the current test year, and therefore will consider the applicability of the Cloud Computing DVA if any related costs materialize.
b) N/A

9-Staff-74

GOCA Variance Account
Ref 1: The OEB's Decision and Order for Getting Ontario Connected Act Variance Account, October 31, 2023

Preamble:
On October 31, 2023, the OEB issued a decision and order EB-2023-0143 for the Getting Ontario Connected Act Variance Account (GOCA variance account). The decision states that:

The OEB notes that the GOCA variance account will only be available to a utility until the end of its current IRM period. The account is not available for utilities that have reflected Bill 93 in their most recent rebasing applications.

OEB staff notes from the DVA continuity schedule that the GOCA sub-account under Account 1508 does not have any amount claimed in this application.

Question(s):

a) Please confirm that the OM&A cost in the test year reflects the Bill 93 impact for the utility's locate cost.
b) If so, please confirm that the Account 1508 sub-account GOCA variance account is to be discontinued after this rebasing application and update the evidence accordingly.
c) If not, please provide the rationale why the Bill 93 impact is not reflected in the test year's OM&A cost.

API Response:

a) API has not been able to quantify the impacts of Bill 93 in its Test Year budget. API does not have accurate forecasts for how many locates will be required for to facilitate the GOCA (and when these are expected to materialize). Furthermore, to the extent that most locates are expected to be covered by the dedicated locator model, API would not incur additional costs where this is the case. For these reasons, API requests that the OEB approve its continued use of the GOCA variance account.
b) See a) above. API requests continued used of the GOCA variance account.
c) See a) and b) above.

9-Staff-75

Land Use Revenue Requirement Variance Account
Ref 1: Exhibit 9, section 9.4.1, pages 33-35
Ref 2: Exhibit 4, pages 37 – 40

Preamble:
In Reference 1, Algoma Power states that the forecasted $767,909 in the test year OM&A “will be the proposed ‘baseline’ against which any entries into the DVA will be assessed, ensuring that the net entries into the proposed account are clearly outside the base upon which rates were set. Algoma Power further states that “At this time API has limited certainty with respect to the land use payments to be incurred, therefore API expects the account balances will be material.”

Additionally, Algoma Power states in Reference 2 that,

> *API cannot predict with accuracy the aggregate amount that it may have to pay to maintain these land rights. For planning purposes, however, the rights payments for the 2025 test year are budgeted to be $767,909 per year. This amount is based on continuing payments and the OM&A equivalent of the current revenue requirement estimate (subject to all of the uncertainty factors below) for negotiations with various entities.*

Algoma Power states that the 767,909 is based on continuing payments and the OM&A equivalent of the current revenue requirement estimate (subject to all of the uncertainty factors below) for negotiations with various entities. These factors are:

1. *Negotiated form of agreement will impact the accounting treatment for the agreement. API capitalizes easements and/or other permanent agreements, as well as the costs required to facilitate these costs. In the case of an easement form of agreement, API also typically incurs survey costs associated with the easement, which can be material in nature. Survey costs are part of the capitalized amount. API’s preference is to arrange for permanent easements in order to have long-term price stability, as well as certainty regarding its ability to maintain its use of the lands in question, however some land owners/interest holders may not be willing or able to agree to a permanent arrangement with a one-time payment.*
2. *At this time, API is not able to accurately predict the cost levels associated with the negotiation outcomes.*
3. *API is unable to predict and control the timing and phasing of these payments over the test year and subsequent COS term. Different forms of agreement may also require a combination of ongoing and one-time costs, with the one-time implementation costs being related to such items as legal fees, up-front payments, and/or other expenses incurred during negotiations or included as requirements in the final agreements.”*

Algoma Power notes that some of the test year OM&A payments “may ultimately take the form of capitalized one-time payments, which has the potential of reducing the annual revenue requirement associated with those agreements.”

Question(s):

a) Please explain in detail why Algoma Power believes the materiality eligibility criterion is met, given the limited certainty regarding the land use payments to be incurred and the challenges in accurately predicting the baselined land cost embedded in the 2025 rates.
b) Given the level of uncertainty that is demonstrated by the factors listed by Algoma, please provide Algoma’s thoughts on removing the $767,997 baseline land cost in the OM&A of the test year and use the deferral account to record the costs when they are incurred in the incentive period. Please provide the pros and cons of this approach as compared to the approach proposed by Algoma.
c) Please elaborate further on how the $767,997 is derived.
d) Please explain why Algoma Power has included some potential capital expenditures in the OM&A expenses.
e) Please confirm the land use payment amounts to be recorded in the requested new variance account will include both OM&A expenses and capital expenditures.
    i. If confirmed, please clarify that Algoma is to record the revenue requirement impact on the capital expenditure and the OM&A expense to be incurred in the requested DVA and the total amount is then compared to the $767,909 OM&A that is embedded in the test year’s revenue requirement.
    ii. Please update the journal entries in the draft accounting order by separating the capital expenditure and OM&A
    iii. Please describe how and when the capital expenditures portion of the actual land use payments will be added to the rate base and provide the related journal entries.
    iv. Please clarify that the requested DVA will be disposed of in the next cost of service application along with other Group 2 DVAs. If so, please explain why a separate rate rider is needed for this DVA.
    v. Please provide a revised draft accounting order accordingly.

API Response:

a) API believes there is a high likelihood that the actual payments incurred can be materially different than the baseline proposed, based on a number of factors including the cost of the agreements, the term of the agreements and the nature of the agreements (what proportion of one-time versus ongoing payments). Additionally, material legal, consulting and/or surveying fees will follow these costs, which may also be either capitalized or expensed based on the nature of the agreement they are related to.
b) Given cost uncertainty, API would open to the approach of removing the $767,997 baseline land cost in the OM&A of the test year and use the deferral account to record the costs when they are incurred in the incentive period. Despite this, API’s preference/recommendation continues to be to include the baseline land cost. As

outlined below, API believes this approach will reduce customer bill impacts over time, mitigate the next COS bill impacts, and better maintain intergenerational equity.

Pro of this approach (as compared to API recommended approach):

- Ability to more clearly identify the magnitude of the actual land use costs incurred during the rebase period when all costs are being captured in specific deferral sub-accounts

Some cons of this approach (as compared to API recommended approach):

- There is a higher likelihood of higher bill impacts upon the next rebasing with a higher debit expected upon disposition of the requested account.
- Furthermore, excluding the Land Use baseline from base rates means exclusion from RRRP and DRP funding, resulting in a long-term net bill increase to API's RRRP and DRP eligible customers (as opposed to the proposed option);
- The disposition of the costs upon rebasing in 2030 will increase the amount of time between when the costs are incurred and when the customer's rates reflect these costs.
- There is certainty around the existence of land use costs during the forecast period; however, the total magnitude remains unknown primarily for those agreements not yet finalized, and so removing all land use costs in OM&A from 2025 Test Year revenue requirement will understate the true cost of API's on-going operations during the forecast period;
- API will have negative cash flow during the rebasing period as payments will be made with no offset recovery built into the 2025 Test Year revenue requirement;
- With the use of multiple additional sub-accounts, there will be a heavier administrative burden to separately track all of these costs

c) Please refer to the information provided in 4-SEC-25 a).

d) API has included the revenue requirement associated with some of the land payments that are forecasted to be capitalized. Since the proposed variance account would capture both capital and OM&A impacts of the land use costs, a baseline on the basis of an OM&A equivalent is relatively simple to apply when completing variance account entries as API would calculate the revenue requirement equivalent of the actual payments and compare them against the amount included as the baseline in OM&A, which is equivalent to the baseline revenue requirement. Since OM&A is generally a 1:1 basis with Revenue Requirement, the adjustment has been made directly in OM&A.

e) Confirmed.

  i. Confirmed. Only, the variance between the sum of the revenue requirement impact of the capital expenditure and the OM&A expense incurred, as compared to the total amount included in 2025 Test Year of $767,909 OM&A will be recorded in the proposed deferral and variance sub-accounts.

  ii. Please refer to the attachment provided with the response to e) v below.

iii. The actual land use payments which are capitalized would be added to rate base in the year that they are capitalized, subject to OEB approval, consistent with other capital expenditures during the rebase period.
iv. Confirmed. API agrees that no separate rate rider would be necessary and rather the account balance approved for disposition would be included with the Group 2 Rate Riders.
v. Please see Attachment 9-Staff-75.

9-Staff-76

Defined Benefit Pension Plan Variance Account
Ref 1: Exhibit 9, Section 9.4.1, pages 36-37
Ref 2: Exhibit 4, pages 37 – 38
Ref 3: Report of the Ontario Energy Board, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (the OEB Report), EB-2015-0040, September 14, 2017

Preamble:
In Reference 1, Algoma Power proposes a Defined Benefit Pension Plan Variance Account to capture variances in the coming COS cycle. Algoma Power states that "API has based a portion of its Section 3461 pension expense forecasts on a forecast prepared by Mercer for API in February of 2024 for the 2025 test year. The forecast provided by Mercer is influenced by a discount rate assumption of 4.9%, which is higher than past historical trending. On this basis, API anticipates that the test year budgets for the Defined Benefit Pension Plan are relatively low, and the actual Defined Benefit pension costs will materially increase in future years of the COS (ex: 2026-2029), as discount rates will trend back in line with past historical levels."

Page 13 of Reference 3 states that, no set-aside mechanism is necessary for pensions at this time.

Question(s):

a) Please provide the rationale of the requested variance account, considering the guidance provided in the OEB Report of regulatory treatment of Pension and OPEB costs.
b) Has Algoma Power considered forecasting the pension expense for the 2025 Test Year based on a discount rate aligned with the past historical levels expected during the 2026-2029 term?

API Response:

a) In accordance with the guidance, Algoma Power uses the accrual method in recognition of pension expense. As well, DVA sub-accounts have been established and used to track the difference between the forecasted accrual amount in rates and actual cash payment made.
However, as interest rates play a major role in actual and forecasted accrual amount, the recent fluctuations in interest rates have demonstrated that such fluctuations can have a significant impact on actual pension expense realized and forecasted amounts. For example, a significant decline in pension expense is noted from $400k in 2022 to $43k forecasted for 2025, which represents an almost 10 times decline. Algoma Power anticipates that interest rates will decline over time in the next five years which may have a material impact on pension expense. The proposed variance account will be used so as to mitigate against the risk of potential material pension expense fluctuations.
b) Algoma Power has utilized Mercer's expertise in providing the pension expense projections for several years and will continue to do so. Although API had considered using a lower discount rate that is more aligned with the historical trend, it was decided

that API would rely on Mercers in-house modeling to determine the appropriate discount rate to be used in API's projections given current market conditions at the time of estimation. Given the expected change in economic conditions to come which in turn will drive changes in underlying assumptions for the future year pension expense calculations, API has made the request for the variance account in Reference 2 above.

9-Staff-77

1508-Other Regulatory Assets – Pension and OPEBs Deferral and Variance Sub-Accounts
Ref 1: EB-2013-0368 and EB-2013-0369 Accounting Order
Ref 2: Exhibit 9, page 11
Ref 3: EB-2014-0055 Exhibit 1, Tab 1, Schedule 10, page 3 of 3

Preamble:
In Reference 1, the OEB directed Algoma Power to establish four Group 2 Accounts related to pension and other post-employment benefits costs that resulted from Algoma Power's adoption of Accounting Standards for Private Enterprises Section 3462 (which disallowed amortization to income of actuarial gains and losses), starting on January 1, 2013. These include two accounts for the transitional amounts upon adoption, as well as two accounts for the annual expense differences between Section 3462 and 3461 (3461, the standard that underpinned rates at the time, previously allowed certain actuarial gains/losses to be amortized to net income).

In Reference 2, Algoma Power states the following with respect to Account 1508 – Other Regulatory Assets – Pension Deferral Sub-Account:

> Due to the reasons outlined in the EB-2013-0368/EB-2013-0369 proceeding requesting the creation of these variance accounts, API is not requesting disposition of the balance of this Sub-Account in this proceeding.

The Accounting Order for the proceeding referred to above was approved as filed on January 9, 2014. In that Accounting Order, the following statements were made by the applicants:

"Disposition of the accounts is proposed to occur in a future cost of service proceeding and will be subject to the Board's prudence review. The proposed recovery through a rate rider will be based on the average remaining service lives of employees in each respective company…No carrying charges will be recorded on these accounts."

In the pre-filed evidence, under Exhibit 1, Tab 1, Schedule 10 (page 3 of 3) in API's subsequent 2015 Cost of Service application (EB-2014-0055), Algoma Power made the following statements:

"The 2014 Bridge and 2015 Test Year revenue requirement model was developed assuming Section 3461 utilizing the corridor method to smooth P&OPEB expenses. Therefore, within this Application, API is not seeking recovery of any transitional balances, nor is it requesting recovery of any variances calculated for 2013. Instead, API will continue to assess the balances within the established deferral and variance accounts and will look to seek disposition of these balances in a future proceeding."

Question(s):

a) Please confirm that the same approach has been utilized for the 2024 bridge and 2025 test years for estimating Pension and OPEB expenses (using the corridor method prescribed in the previous Section 3461 rules).
b) please elobarate on the reasons that Algoma Power does not request the disposition of the four sub-accounts that were established in EB-2013-0368/0369.
c) Please Algoma Power's thought of discontinuing these four sub-accounts. If not, please explain why not.

API Response:

a) Confirmed.
b) As outline in EB-2013-0368/0369, the four sub-accounts were established to capture the difference between the pension and OPEB expense under section 3461 and 3462. These differences are a result of different accounting treatments. They are not associated with actual cash flow. The balances in these accounts have materially varied from year to year and this volatility is why API has not put forth any of these balances for disposition.
c) Please see responses above in b. API proposes to continue to use these sub-accounts.

1-SEC-1

[Ex. 1, p. 14] Algoma states that it intends to file an application to extend its license extension related to implementation of time of use billing, and provisions of the Distribution System Code related to billing accuracy and limiting estimated bills. Please provide an update on the status of this application.

API Response:

The Application has not yet been filed.

1-SEC-2

[Ex. 1] Please provide copies of all benchmarking studies, reports, and analyses that Algoma has undertaken or participated in since the filing of its last rebasing application, that are not already included in the Application.

API Response:

API is unaware of any further such reports that API has participated in.

1-SEC-3

[Ex. 1, Attachment 1B] Algoma has provided a copy of its 2025 Business Plan.

a. When was the 2025 Business Plan prepared?
b. Does Algoma prepare a Business Plan for each year? If so, please provide the plan prepared for 2024. If not, please provide any planning documents prepared by Algoma for 2024.
c. Please outline any changes that were made between the 2025 Business Plan and the 2025 cost-of-service Application.
d. Please provide any other materials provided to Algoma's Board of Directors regarding its approval of the Application and the underlying budgets.

API Response:

a) The 2025 Business Plan attached as Attachment 1B was completed in May 2024. API notes that in the normal course it presents a business plan in Q4 of the year prior to the subject year, i.e. a 2025-2029 Business Plan will be presented to the Board of Directors in Q4 of 2024 (similar to the 2024-2028 business plan provided in subsection b) below). In order to comply with the filing requirements for a Cost of Service Application with a Test Year of 2025 , the attached Business Plan for the Test Year was completed in Q2 2024 for inclusion with this Application.

b) Yes, API completes business plans on an annual basis. As noted in part a) the plan is typically prepared and presented to the Board of Directors in Q4 of each year, focussing on detailed budgeting for the subject year with inflationary and other assumptions underpinning a forecast for the following 4 years. In December 2023, API presented its 2024 Business Plan to its Board of Directors. Please see Attachment 1-SEC-3b for a copy of this presentation.

c) There were no changes made between the 2025 Business Plan in Ref.1 and the Application.

d) Please see Attachment 1-SEC-3d, which represents an update provided to the API Board in June of 2024 regarding the application and management's actions to file the application.

1-SEC-4

[Ex. 1, Table 20 and p 74-75].

a. Please provide details of all productivity and efficiency measures Algoma has undertaken over the last five years, and any it plans to undertake in the test year and subsequent four years. Please quantify the forecasted savings and explain how they were calculated.
b. Table 20 states that Algoma has incorporated cost efficiency targets into its 2025 budget for Vegetation Management. Please provide the details.

API Response:

a)Please see the listing below:

Action	Description	Achievements before 2025	Future Plans - Test year and Subsequent Years	Measurement Methods & Prorated Savings
Customer Service				
Digitization of Customer Accounts in SAP	API has digitized and saved all paper-based customer files into customer accounts in SAP	API eliminated the storage of approximately 12,000 paper file folders/associated documents. This project was completed in Q1-2023.	API continue to review record retention and other opportunities to digitize records	All departments purged and/or digitized any unnecessary physical documents prior to the moved from the old SSM Facility, thereby reducing moving volume and costs. Customer Service's time & productivity improvement when interacting with Customers as digitized documents are easier to find & search.
Automation of Noticing Process	API has an automated noticing process that alleviates the current manual process.	API has automated reminder calls, 7-day notice calls & 48-hour disconnection notice calls. Target end of 2024.	API will maintain in future	Automation helps to minimizes chance of error and ensure notices are completed on time

Elimination of Walk-In Traffic	API has been eliminating walk-in traffic after the office closure due to COVID-19	This decision has reduced time for customer service staff and prevented interruptions from non-customer service-related occurrences caused by walk-in traffic	API will maintain the in the future and may consider appointment only face-to-face interactions with customers while further developing e-tools for our customers to access remotely	Enhancing customer experience through online tools and ease of access. Improvement to Customer Service's staff time and avoiding distraction not related to Customer inquiries.
Electrical/Metering				
Annual Water Sampling Approved	API requested and received approval in 2023 to change their ECA,	This approval allowed containment water sample testing to change from quarterly to annual sampling. The change in testing frequency mitigates both testing and labor costs.	API will maintain this in the future	Three sites were impacted by this change which is estimated to save approximately $3000/year in time and sampling test fees
Finance				
Automation of Accounts Payable - SAP Concur	New software (SAP Concur) improves visibility and timeliness of accounts payable processes for approvers, A/P department, and vendors.	API has improved vendor relationships by submitting payments on time and enhanced planning for future expenditures through real-time tracking of vendor spending. This increases invoice visibility, reduced employee search time and electronic storage space by centralizing invoices, and minimized the time spent tracing emails.	SAP Concur would continue to reduce management time spent on A/P (ex: approvals), freeing up time to focus on other priority work.	Automation helps to minimizes chance of error and helps to ensure timely payment. Enhances visibility, real-time tracking and ease of the electronic review and approval process. Enhances vendor relationships
		API can demonstrate adherence to purchasing and payment policies through query reports, allow electronic approvals from any		Enhances auditing and reporting requirements

		location, and have improved records management by knowing what to retain, destroy, and where everything is located.		
Forestry/VM (Additional items see response 4-SEC-4 b))				
New Version of VM software implementation plan for 2025	The new software will allow for efficient tracking of vegetation work and progress of completion	API's software vendor has recently released a new version of their solution that is geared towards crew activity, progress tracking and data collection. API has made the investment to move to the new version to support efforts related to progress and data collection, tracking and reporting.	Full implementation planned for 2025 API will also obtain better future estimations of vegetation work values by tracking different types of work and improve VM program monitoring.	Enhance visibility, accuracy, tracking and reporting Enhance data collection and timeliness for review and approval for work progress and completion.
Fleet, Stores and Material Management				
Task Management App for Streamlined Workflows	Fleet Facilities and Materials have created a cloud-based tool (app) to improve task efficiency. Employees use QR codes to submit requests, and the tool tracks tasks.	Fleet Facilities and Materials have developed a cloud-based product called Operations Summary, which enhances the efficiency of various tasks. All workers can submit requests using QR code technology. This tool serves as a tracking system, collecting tasks with one common location for worker to access and track completion.	Full implementation planned for 2025 Ongoing development will further improve workflow efficiency, record-keeping, and reporting.	Enhance overall visibility, tracking, prioritization, workflow efficiency and reporting

		This process change has been applied to: • Civil Maintenance requests & tasks • Fleet repair requests • Tool repair requests • Employee lone worker check ins • Forklift circle check • Waste tracking		
Efficient Delivery Management	Deliveries are managed through the shipping/receiving department, and payments, documents, and mail are deposited in the building's customer service drop box.	This decision effectively prevented customer service staff from being interrupted by deliveries and improved their work efficiency.	API will maintain this decision in the future	Enhances productivity and workflow for Customer Service and the Stores & Receiving area
IT				
Utilizations of Remote Workforce Tools	API has been utilizing teleconferencing solutions to support remote meeting.	Teleconferencing solution effectively reduce the travel and commuting time for API employees by holding virtual meetings.	API will maintain this decision in the future	Saves on driving time and enhances communication and collaboration
	API has been deploying remote workforce tools to encourage paperless work order	API has successfully implemented outage management systems (OMS) for field crews to use and operation in the field.	This action will continue to be promoted and implemented in more areas from 2025-2029	Saves driving time by mobilizing remote crews and avoiding return trips
	API has enabled secure, remote access to	Remote and safe access reduce/eliminate the need to travel to substations to check or	Continue to advance SCADA implementation	Saves on driving time and dispatching crew to collect device data on-site

	SCADA and other Operational Technology devices from corporate offices or VPN-connected laptops	change device settings. This approach reduces travel, fuel usage, pollution, and other associated costs		
	API has been deploying Starlink satellite internet equipment	Starlink satellite internet equipment reduce/eliminate the need to drive to remote sites for meter reading and other functions	Continuing to review communication options for API service territory	Saves on driving time for remote meter reading
Lines				
Cost Management	API has implemented different approaches to improve management tools, material and resources	API conducted ground equipment testing internally to avoid high laboratory costs and the shipping of tools.	API will maintain this approach	Ensure repairs are made in a timely fashion and tool availability is maximized
		Prepared material lists for capital projects early the previous year to prevent delays to due supply chain concerns	API will continue to review supply chain concerns	Enhance continued project productivity and completion
		Added additional vendors to the preferred contractors list to promote competition	API will maintain this approach	Enhances resource availability and pricing
Employee Engagement Communicatio n	API has implemented different approaches to improve safety, efficiency, and employee engagement	API has purchased small tools to reduce lost time injuries and increase production.	API will maintain this approach	Enhances productivity and available work hours
		API have built a positive workplace environment by promoting employee engagement and	API will continue to encourage	Enhances teamwork and positive work environment

recognition. Safety meetings were hosted with all three areas simultaneously, with Wawa attending via Teams.		
Additionally, API collaborated with the electrical department on fleet sharing, rentals, and maintenance programs for reclosers, air breaks, and load breaks.	API will continue this approach	Enhances teamwork, positive work environment and resourcing sharing

General Building - Sault Ste. Marie Facility Efficiencies			
Area	**Description**	**Efficiency Achieved**	**Measurement Methods & Prorated Savings**
Customer Service	Customer Service staff now have easier access to departments and storage, improving overall efficiency and communication. The new building also eliminates previous issues with deliveries and visitor management.	Customer Service staff now have immediate indoor access to key departments (Lines, Metering, Forestry etc.), improving communication and workflow.	Enhances communication and working efficiency.
		The archival storage room is now on the same floor and closer to the Customer Service area, eliminating the need to retrieve supplies or files from the basement.	Enhances productivity
		Customer Service staff no longer face issues with mistaken deliveries, mail receipt, or redirecting visitors, which occurred in the previous shared facility.	Enhances focus and productivity

Engineering	Engineering staff now have easier access to other API groups. The new facility centralizes Engineering's operation.	Engineering staff now have immediate indoor access to other API groups. This improves communication, staff relations, and information exchange. Previously, departments were spread across different levels or buildings, making accessibility difficult.	Enhances communication and working efficiency.
		In the old facility, the Engineering department was segmented, with archival storage in the basement, the plotter and scanner near Customer Service, and vegetation management staff on the west side. Now, the Engineering department is centralized, with an archival storage room located centrally within the department.	Enhances productivity and team collaboration
Lines and Forestry	Lines and Forestry staff now have improved facilities and access.	Staff now have immediate indoor access to other operational groups (Stores, Engineering, Customer Services etc.). This improves communication, staff relations, and information exchange.	Enhances communication, organization, teamwork and workflow
		Staff now have a dedicated drying room for wet clothing, an improvement from the previous facility's locker room.	Enhances care and daily preparedness for work
		Staff have a dedicated work area with benches for better organization, storage, and maintenance of trade tools.	Enhances care and maintenance of tools and equipment
		Lines and Forestry staff are in the same building as their supervisors, with a room for daily	Enhances communication, organization,

		discussions, job planning, and meetings, which improves their communication and working efficiency.	teamwork and workflow
		Staff now have an indoor heated space for tools, equipment, and fleet vehicles. This reduces truck idle time and prevents tools from freezing, improving efficiency and saving time and costs.	Enhance work efficiency while reducing costs and environmental impact.
Stores	Stores staff now work in a climate-controlled area with improved storage, site security and delivery processes Stores can also provide materials to various departments without leaving the facility.	Stores staff now work in a climate-controlled area with improved secure storage and material management. They can receive deliveries through a dedicated door, preventing deliveries vehicles from entering the secured compound.	Enhances site security, inventory management, care and storage of material.
		Stores staff can now provide materials to the Lines, Electrical, and Forestry departments without leaving the facility. This saves time and improves efficiency by avoiding the need to deliver packages to different buildings	Enhances workflow and improves access and security of materials and inventory
Electrical and Metering	Electrical and Metering staff now have improved facilities and access.	Electrical staff have their own area for repair and maintenance, rather than a shared space. As a result, recloser maintenance can be completed safety in an isolated environment. Testing can be set-up over a multiple day period allowing crews to more time working, rather than taking additional time to set up work and put work away daily.	Enhances workflow and security of test equipment
		The overhead crane as a shared resource between the mechanic and electrical allows one major investment to be divided over	Enhances utilization of work equipment

multiple work groups and utilized more frequently.	

b) Please see the listing of measures below:

- **Increase in mechanical brush cutting:** API continues to work towards reducing the volume of tall growing brush species by targeting additional suitable locations for mechanical brush cutting. Mechanical brush cutting is more efficient than hand cutting requiring less labour hours, covers more area in less time and results in the immediate elimination of all vegetation (non-selective). Although, mechanical cutting does not provide long-term control of tall growing tree species and in some cases can increase densities (resprouting or seed exposure), it is typically more cost effective and practical than only hand cutting high density areas where herbicide is not permitted.
- **Increase public awareness and landowner consent for herbicide application:** API has a thorough notification process that provides direct communication with individual landowners. Although landowner consent has been declining with permission to apply herbicide, API is working to reverse this trend by targeting formal agreements with larger landowners, investing in public relations with industry partners, local community groups, townships and forest management companies to provide resource material on how selective herbicide applications are used in protecting assets (ROW) and meet environmental and social governance objectives.
- **Implement contracting provisions and working closely with contractors:** API has built incentive based work into its contracts to promote work efficiencies that encourage contractors to find the most efficient way to safely and productively complete work. API continues to release bulk work (multi-year) to allow contractors time to plan and organize for the upcoming work and consider scheduling, labour hours required, equipment type and best work practices to achieve targets and objectives for completing the work. API ensures competitive market pricing by having multiple bid submissions as part of a tender and works directly with contractors at a pre-bid meeting to review API specifications and standards for vegetation management.

1-SEC-5

[Ex. 1, Scorecard] Please file on the record Algoma's preliminary scorecard for 2023.

API Response:

Please see API's preliminary 2023 scorecard below.

Scorecard - Algoma Power Inc.

8/13/2024

Performance Outcomes	Performance Categories	Measures		2019	2020	2021	2022	2023	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		97.10%	100.00%	100.00%	98.64%	100.00%		90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time		81.61%	84.84%	88.36%	85.46%	78.32%		65.00%	
	Customer Satisfaction	First Contact Resolution		99.96%	99.93%	99.95%	99.99%	99.91			
		Billing Accuracy		99.87%	99.87%	99.82%	99.92%	99.95%		98.00%	
		Customer Satisfaction Survey Results		95%	94%	93%	97%	90			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness		83.00%	83.00%	83.00%	82.00%	82.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0			0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		7.33	6.79	3.61	4.43	5.28			7.36
		Average Number of Times that Power to a Customer is Interrupted [2]		3.39	2.93	1.77	2.08	2.28			3.16
	Asset Management	Distribution System Plan Implementation Progress		Completed	Completed	Completed	Completed	Completed			
	Cost Control	Efficiency Assessment		5	5	5	5	5			
		Total Cost per Customer [3]		$2,235	$2,212	$2,338	$2,479	$2,804			
		Total Cost per Km of Line [3]		$12,107	$12,203	$13,025	$14,501	$16,501			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Connection of Renewable Generation	New Micro-embedded Generation Facilities Connected On Time					100.00%			90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.69	0.77	0.43	0.26	0.20			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.36	1.30	1.32	1.44	1.39			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.30%	8.52%	8.52%	8.52%	8.52%			
			Achieved	8.44%	9.25%	9.38%	10.53%	10.54%			

1-SEC-6

[Ex. 1, Table 20] For Distribution and Subtransmission Line Rebuild, the table refers to proactive replacement and life span optimization.

a. Please describe these two approaches and how they differ.
b. For each major asset type, which of the two approaches is Algoma currently using?

API Response:

a) A proactive asset replacement means replacing an asset in a controlled and planned settings and is generally done so in order to avoid a costlier reactive replacement resulting from an asset failure.

   Asset life span optimization, which can also be described as asset lifecycle optimization is a strategic approach to manage and optimize the useful life an asset.

b) Algoma Power has described its Asset Lifecycle policies and practices in Section 5.3.3 of the DSP.

1-SEC-7

[Ex. 1, p. 67] Does Algoma have a corporate scorecard or similar document used by its Board of Directors to monitor and measure performance? If so, please provide a copy of each annual document from 2020.

API Response:

As demonstrated in 1-SEC-3, API shares the OEB Scorecards with its Board of Directors as a measure of its corporate performance.

Below are links the OEB Scorecards from 2020-2022 (for 2023, please see 1-SEC-7).

2020: Scorecard - Algoma Power Inc..pdf

2021: Scorecard - Algoma Power Inc..pdf

2022: Scorecard - Algoma Power Inc..pdf

Please also refer to response 4-SEC-26 that outlines Corporate targets from 2020.

2-SEC-8

[Ex. 2, Appendices 2-AA, 2-AB and 2-BA]

a. Please update 2-AA and 2-AB showing actuals to date for 2024, and an updated forecast for 2024 and 2025, if required. Please note if the dollars shown are capital expenditures or in-service additions.
b. If the forecast for either year changes, please update 2-BA.
c. Please provide actuals for 2022 and 2023 to the same date as provided in part a.
d. Please provide the source for the planned amounts for 2020 to 2024 (e.g. internal budget documents).

API Response:

a) Please see the response to 2-Staff-5.
b) Please see the response to 2-Staff-5.
c) Please see the attachment included with 2-Staff-5.
d) Please see screenshots below which represent the annual internal budgets. API notes that these budgets differ from the "Plan" entries in Appendix 2-AA/2-AB which were presented on the basis of the 2020-2024 DSP from API's 2020 COS.
API notes that as API plans the execution of its capital plan on an annual basis it prepares annual budgets to reflect updates to its planned spending relative to the budgets contemplated in the DSP; accordingly, in addition to confirming that source of the planned amounts in the various appendices, we have provided the annual budgets for the 2020 to 2024 period, which reflects the most recent budgeting exercise for each year prior to execution of the capital budget.

APPENDIX B

	2020 Budget
Algoma Power	
Substation Upgrades	1,246
Line Replacements and Customer Extensions	5,461
Meters	69
Tools and Equipment	105
Distribution Rebuilds - Storms	222
Scada System Development	96
Land Easement and R.O.W. Procurement	152
R.O.W. Expansions	-
Vehicles	662
Buildings & Service Centre	87
Distribution Transformers/Reclosers/Regulators	274
IT	294
Total Algoma Power	**8,668**
Contributions	**102**
Grand Total (Net)	**8,566**

APPENDIX B

	2021 Budget
Algoma Power	
Substation Upgrades	7,972
Line Replacements and Customer Extensions	6,021
Meters	100
Tools and Equipment	95
Distribution Rebuilds - Storms	189
Scada System Development	126
Land Easement and R.O.W. Procurement	38
R.O.W. Expansions	102
Vehicles	676
Buildings & Service Centre	6,202
Distribution Transformers/Reclosers/Regulators	252
IT	109
Total Algoma Power	**21,882**
Contributions	**120**
Grand Total (Net)	**21,762**

APPENDIX B

	2022 Budget
Algoma Power	
Substation Upgrades	156
Line Replacements and Customer Extensions	25,846
Meters	67
Tools and Equipment	95
Distribution Rebuilds - Storms	162
Scada System Development	149
Land Easement and R.O.W. Procurement	37
R.O.W. Expansions	101
Vehicles	658
Buildings & Service Centre	5,164
Distribution Transformers/Reclosers/Regulators	252
IT	104
Total Algoma Power	**32,793**
Contributions	**120**
Grand Total (Net)	**32,673**

APPENDIX B

	2023 Budget
Algoma Power	
Substation Upgrades	354
Line Replacements and Customer Extensions	9,516
Meters	115
Tools and Equipment	95
Distribution Rebuilds - Storms	95
Scada System Development	77
Land Easement and R.O.W. Procurement	36
R.O.W. Expansions	100
Vehicles	630
Buildings & Service Centre	99
Distribution Transformers/Reclosers/Regulators	192
IT	148
Total Algoma Power	**11,456**
Contributions	**1,144**
Grand Total (Net)	**10,312**

APPENDIX B

	2024 Budget
Algoma Power	
Substation Upgrades [1]	3,905
Line Replacements and Customer Extensions	5,244
Meters	133
Tools and Equipment	110
Distribution Rebuilds - Storms	-
Scada System Development	140
Land Easement and R.O.W. Procurement	39
R.O.W. Expansions	122
Vehicles	585
Buildings & Service Centre [1]	134
Distribution Transformers/Reclosers/Regulators	326
IT	152
Total Algoma Power	**10,890**
Contributions	**385**
Grand Total (Net)	**10,505**

2-SEC-9

[Ex. 2, Appendix 2-BA] For Construction Work in Progress (CWIP), Algoma shows the following in 2-BA:

$000	2020	2021	2022	2023	2024	2025
Opening Balance	5,620	6,015	17,318	12,855	5,091	-1,540
Net Additions	395	11,302	-4,463	-7,764	-6,631	0
Closing Balance	6,015	17,318	12,855	5,091	-1,540	-1,540

a. Please explain the negative closing balance in 2024 and 2025.
b. Please provide details on what assets were included in the 2020 CWIP Opening Balance and for each year's Net Additions.

API Response:

a) API has forecasted the in-service assets for the bridge and test years, as well as the movement of assets out of CWIP and into service in 2024 (from 2023 and prior), but not any additional additions into CWIP in the bridge and test years. This has led to a calculated negative closing CWIP balance, however in reality API expects some level of CWIP balance at the end of 2024 and 2025.
b) Please see the table below which outlines the net change in CWIP corresponding with each of the projects in Table 2-AA. API's records with respect to the assets in CWIP at the 2020 Opening Balance are recorded by asset number rather than by project(100s of lines) and would not provide a meaningful basis for analysis.

	2020	2021	2022	2023	2024	2025
System Access						
Meters	-$ 11,008.70	-$ 4,130.64	-$ 4,704.80	$ 691.73	$ -	$ -
Service Connections	$ 135,449.34	$ 1,598,407.03	$ 2,417,467.84	-$ 2,135,290.47	-$ 1,856,535.76	$ -
Transformers - SA	-$ 4,474.29	$ 42,456.45	-$ 44,667.00	$ 50,288.78	$ -	$ -
Relocation/Joint-Use	$ 595,044.63	-$ 394,501.11	-$ 188,875.93	-$ 2,365.74	$ -	$ -
System Access Gross Expenditures	**$ 715,010.98**	**$ 1,242,231.73**	**$ 2,179,220.11**	**-$ 2,086,675.70**	**-$ 1,856,535.76**	**$ -**
System Access Capital Contributions						
Sub-Total	**$ 715,010.98**	**$ 1,242,231.73**	**$ 2,179,220.11**	**-$ 2,086,675.70**	**-$ 1,856,535.76**	**$ -**
System Renewal						
Storm Capital	-$ 9,651.49	$ 25,582.12	-$ 25,893.30	-$ 6,285.96	$ -	$ -
Small Lines/Station Capital	$ 196,815.49	$ 2,411,998.87	-$ 2,724,960.68	$ 159,623.26	$ -	$ -
Recloser, Regulator Replacements	-$ 48,730.30	$ -	$ 3,553.82	-$ 3,553.82	$ -	$ -
Distribution Line Rebuilds	-$ 306,773.21	-$ 662,864.15	$ 451,052.15	$ 176,275.68	-$ 1,171,715.06	$ -
Subtransmission Line Rebuilds	$ 165,055.99	-$ 160,778.54	$ 29,650.28	$ 818,217.38	-$ 938,810.88	$ -
Transformers - SR	$ -	$ -	$ 17,965.97	$ 14,633.80	$ -	$ -
Dubreuilville DS Rebuild	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Replacements	$ -	$ -	$ 145,246.70	$ 512,301.42	-$ 1,122,000.12	$ -
Bruce Mines DS Rebuild	$ -	$ -	$ -	$ -	$ -	$ -
Wawa #2 DS Rebuild	$ -	$ -	$ -	$ -	$ -	$ -
System Renewal Gross Expenditures	**-$ 3,283.52**	**$ 1,613,938.30**	**-$ 2,103,385.06**	**$ 1,671,211.76**	**-$ 3,232,526.06**	**$ -**
System Renewal Capital Contributions						
Sub-Total	**-$ 3,283.52**	**$ 1,613,938.30**	**-$ 2,103,385.06**	**$ 1,671,211.76**	**-$ 3,232,526.06**	**$ -**
System Service						
Transformers - SS	$ -	$ -	$ -	$ -	$ -	$ -
Hawk Junction DS	$ -	$ 698.97	-$ 698.97	$ -	$ -	$ -
Goulais Voltage Conversion	$ -	$ -	$ -	$ -	$ -	$ -
Protection, Automation, Reliability	$ 8,323.29	$ 3,795,833.37	$ 4,187,793.06	-$ 8,027,929.88	-$ 1,124,620.08	$ -
Desbarats DS Upgrades	$ 782.19	$ 3,483.79	$ 64,350.51	$ 500.25	$ -	$ -
Goulais TS Refurbishment	$ -	$ -	$ 18,052.28	$ 34,084.21	$ -	$ -
System Service Gross Expenditures	**$ 9,105.48**	**$ 3,800,016.13**	**$ 4,269,496.88**	**-$ 7,993,345.42**	**-$ 1,124,620.08**	**$ -**
System Service Capital Contributions						
Sub-Total	**$ 9,105.48**	**$ 3,800,016.13**	**$ 4,269,496.88**	**-$ 7,993,345.42**	**-$ 1,124,620.08**	**$ -**
General Plant						
ROW Expansion	-$ 101,561.28	$ -	$ -	$ -	$ -	$ -
Tools & Equipment	$ 24,816.37	-$ 27,504.27	$ 9,936.17	-$ 1,163.74	$ -	$ -
Business Systems	$ 5,804.60	-$ 15,575.49	-$ 9,179.00	$ 603.33	$ -	$ -
Land Rights	$ 9,960.47	-$ 2,756.94	-$ 8,514.64	$ 27,072.98	$ -	$ -
Communication & SCADA	$ 9,123.76	$ 91,841.33	$ 66,441.03	$ 71,436.79	-$ 251,445.97	$ -
Transportation & Work Equipment	-$ 100,574.27	-$ 386,339.23	$ 442,180.08	-$ 443,428.08	$ -	$ -
IT Hardware/Software	$ -	-$ 42,828.58	$ 19,275.18	$ 2,360.17	$ -	$ -
Buildings, Facilities & Yards	$ 154,227.83	$ 6,161,405.75	-$ 6,653,617.50	-$ 20,591.17	$ -	$ -
Sault Facility	$ -	$ -	$ -	$ -	$ -	$ -
ROW Access Program	-$ 261,408.85	$ 74,083.79	$ 103,867.57	-$ 10,502.86	-$ 166,504.25	$ -
General Plant Gross Expenditures	**-$ 259,611.37**	**$ 5,852,326.36**	**-$ 6,029,611.11**	**-$ 374,212.58**	**-$ 417,950.22**	**$ -**
General Plant Capital Contributions						
Sub-Total	**-$ 259,611.37**	**$ 5,852,326.36**	**-$ 6,029,611.11**	**-$ 374,212.58**	**-$ 417,950.22**	**$ -**
Miscellaneous						
Total	**$ 461,221.57**	**$ 12,508,512.52**	**-$ 1,684,279.18**	**-$ 8,783,021.94**	**-$ 6,631,632.12**	**$ -**
Additional CWIP- Inventory Clearing	*$ 175,910.45*	*$ 273,795.91*	*$ 307,189.15*	*$ 334,276.87*	$ -	
Adjust for CIAC in WIP	*-$ 242,184.17*	*-$ 1,479,962.85*	*-$ 3,098,926.60*	*$ 684,905.59*	$ -	
Other n/m adj.	*$ -*	*$ -*	*$ 13,478.34*	*$ -*	*$ 632.12*	
Adjusted Value	*$ 394,947.85*	*$ 11,302,345.58*	*-$ 4,462,538.29*	*-$ 7,763,839.48*	*-$ 6,631,000.00*	

2-SEC-10

[Ex. 2, Section 2.5.5]

a. Table 40 provides a comparison between the final cost of the SSM Facility and the Original Budget of $14.118M. Please provide the same table, but add columns for the settled amount of $12.69M, and the updated estimate of $14.86M.
b. Please also add to the above table the basis of the amount of land in acres for each estimate/final cost.
b. Please explain why the cost of the land for the SSM Facility increased from $1M for 12.08 acres to $1.1M for 7.94 acres, an increase of 61%.
c. Please provide an itemized listing and reasons for the increase from $1.2M to $1.7M for Internal Labour and Moving/Fixtures/Furniture.
d. Please file on the record of this proceeding a copy of Exhibit 2 (including the Distribution System Plan “DSP”), filed as part of Algoma’s 2020 rate application, and any interrogatory responses related to the SSM Facility. (Note: It is sufficient for the Applicant to simply agree to deem the EB-2019-0019 Exhibit 2 and interrogatory responses on the record for this proceeding and provide a link to the OEB’s Regulatory Document Search, as opposed to re-filing.)

API Response:

a) Please see the table below. In considering how to allocate the downwards adjustment from Original Application (2020 to Settlement, API did not expect to achieve the savings through a reduction in Land or Consulting/Labour costs, and therefore the savings were allocated to the Construction portion of the budget, given the pending issuance of the construction RFP.

The timing of the updated budget of $14.86M provided in API’s 2022 IRM application occurred after the land had been purchased, and the construction contract had been accepted as well as Change Orders #1 (savings) and #2. At this time API had also expected an increase in the consulting and labour budget due to the project progress and unexpected challenges such as COVID.

The table below compares the final cost to the various versions of the project budget, as requested. The table also includes the acreage of land included in each of the budgets as requested in (b1).

	Final Costs	Comparison - 2019 COS Budget			Comparison - 2020 Settlement			Comparison - 2021		
		Budget	Variance	% Variance	Budget	Variance	% Variance	Budget	Variance	% Variance
Land	$ 1,059,623.00	$ 1,000,000	$ 59,623	6%	$ 1,000,000	$ 59,623	6%	$ 854,586	$ 205,037	24%
Construction	$ 13,891,064.00	$ 11,918,285	$ 1,972,779	17%	$ 10,490,000	$ 3,401,064	32%	$ 12,507,869	$ 1,383,195	11%
Consulting & Labour	$ 1,703,976.00	$ 1,200,000	$ 503,976	42%	$ 1,200,000	$ 503,976	42%	$ 1,498,000	$ 205,976	14%
Total	$ 16,654,663.00	$ 14,118,285	$ 2,536,378	18%	$ 12,690,000	$ 3,964,663	31%	$ 14,860,455	$ 1,794,208	12%
Acreage	7.94	Approx. 8			Approx. 8			7.94		

b2) The land estimate of $1.0M in table 35 is an estimate of land costs exclusive of Site Development, based on the estimated land requirements for API, as well as real estate market information at the time of the ACM Application. As outlined on page 70 of Exhibit 2, the Land Purchase occurred in September 2020, while API’s budget for the 2020 rate application was developed in 2018/2019.

The $1.0M budget was not the budget associated with 12.08 Acres, 12.08 acres represents the total land available to be purchased at the current site by API, prior to severance and reconveyance, with a total associated cost of $1,208,460.

API notes the $1.059M quoted as the current land estimate from table 39 of Exhibit 2 includes costs other than the (reduced) price of the land. These include roughly $200k in costs for site development (which per Table 35 were included as a separate line item), as well as legal and other fees to enable the severance and reconveyance of a portion of the land.

API suggests the following table provides a more appropriate comparison of land cost and price per acre in the 2020 ACM budget versus the updated costs:

	Incl. in 14.1M Est, 2019	Actual Costs	% Change
Budget Excl. Site Prep	$ 1,000,000	$ 859,000.84	-14%
Estimated Acres	8	7.94	
Estimated Cost Per Acre	$ 125,000	$ 108,187	-13%

c) The original budget for Labour and Consulting was $200k, while the Move, Furniture, Fixtures and Equipment budget was $1.0. Actual costs were $1.2M on labour and consulting, and $525k on Moving, Furniture, Fixtures and Equipment. The sources of the variances from budget are outlined below:

Labour and Consulting: Increase of $1.0M

The original budget for Labour and Consulting was $200k, while actual costs incurred are $1.2M. The Increased cost is explained through the following factors:

API Labour

The increase in API labour was due to additional time; meetings with the contractor to discuss potential escalating cost impacts to the project, budget management, change order analysis, involvement with geotechnical issues with the contractor and more unscheduled meetings.

Owner’s Engineer

The Owner’s Engineer additional time dealing with; meetings with the contractor to discuss potential escalating cost impacts to the project, performing change order analysis and finalizing the approved change orders between contractor and client, involvement with geotechnical issues and independent analysis, and more unscheduled meeting and on-site meetings with API and the contractor.

Other Consultants

This category dealt mainly with the contractor developing the Strategic Facilities Plan (SFP) and the Master Facility Plan (MFP). The costs of these studies were incurred prior to 2019 and did not factor into the $14.1M budget presented in the application, as the costs presented in the 2020 application were on a forward-looking basis.

Environmental Consultants

Environmental Consultants were used to identify any API environmental impacts at the Sackville site and also property assessments at the property located at 251 Industrial Park Crescent.

Legal

These are costs related to the contract development, any environmental issues and the severance and reconveyance issues. API notes that higher legal fees were necessary as a result of the efforts to reduce the land purchase.

Move/Furniture and Fixtures: Decrease of $0.5M

The original budget for Furniture, Fixtures and Moving was $1.0M while actual costs incurred were $525 k.

The actuals for furniture/fixtures, moving and other items were lower than budget.

API repurposed as much as possible of its office furniture and other fixtures to the new facility and therefore limited new costs were incurred. Some fixtures such as racking for the stores were required to be purchased new.

API also completed some of the move work internally in order to minimize moving costs and the overall budget.

d) API agrees to deem the EB-2019-00019 evidence as part of the record in this Application.

2-SEC-11

[Ex. 2, Section 2.5.5 and DSP Section 5.4.1.1.3]

a. Please provide a copy of the connection and cost recovery agreement (CCRA) for Echo River, including any forecast of increased load that was used to offset the cost of the project.
b. Please describe any agreements that Algoma had with Hydro One or safeguards in the CCRA with respect to increases in costs that were caused by Hydro One.
c. Please provide any correspondence Algoma had with Hydro One with respect to determining the prudence of the increased costs for the Echo River project.

API Response:

a) Algoma Power has included a copy of the executed CCRA as Attachment 2-SEC-11a.

b) Included in the CCRA are clauses pertaining to final true-up cost as well as dispute clauses. Under Part B of the CCRA, a final true-up of actual cost would occur within 180 days after the ready-for-service date is met. Under Part D of the agreement, Algoma Power had the ability to dispute cost and the allocation of costs.

   The CCRA did not require notices of cost increases, however. Hydro One did provide notice of cost increases When these notices were received, Algoma Power proceeded to challenge Hydro One on the prudency of the cost and appropriateness of the cost increases and allocation.

c) The correspondence between Algoma Power and Hydro One with respect to the cost increases has been included in the uploaded responses.

2-SEC-12

[Ex. 2, p. 10]

a. Please provide an update on the status of work for the Bruce Mines DS rebuild.
b. Please confirm that the Bruce Mines DS Rebuild/Expansion was included in the DSP submitted with Algoma's 2020 rate application, as follows: 2022- $150k, 2023-$1,850k.
c. Please explain why the cost of this project increased from $2,000k to $4,346k.

API Response:

a) The construction of the project is ongoing, with final commissioning planned in late September with an October 2024 in-service date.
b) Yes, it was included in the DSP with 2022 for engineering/planning and 2023 for construction.
c) The cost of the project was estimated prior to the pandemic, not aware of rising costs for material and labour due to the challenges of the covid pandemic. API performed two competitive bids in 2023, one for the station construction and another for the power transformer. In both cases all bids were reviewed and awarded to the lowest bidder. A breakdown of the overspend variance cost drivers has been included in the response to 2-VECC-7.

2-SEC-13

[Ex. 2, DSP, p. 67]

a. Please provide the details of the costs that Algoma has recorded in subaccount 1508 for Broadband projects.
b. How many poles will be replaced as a result of work related to Broadband projects?

API Response:

a) Algoma Power has not yet recorded costs in subaccount 1508 for Broadband projects.

b) As of August 2024, Algoma Power has received about 120 permits to connect to 3,274 Algoma Power poles in which 89 poles would require replacement. Based on the feedback from the internet service providers, Algoma Power is expecting another 400-500 permits to connect to an additional 12,000 Algoma Power poles.

2-SEC-14

[Ex. 2, Distribution System Plan (DSP) Figure 3.6 and Appendix D]

a. For each asset included in Figure 3.6, please provide a table showing the number (or kms) of assets replaced or forecasted to be replaced for 2020 to 2029.
b. What is Algoma doing to improve the health data it has for those assets for which it cannot determine a Health Index, e.g., distribution transformers?

API Response:

a) A table summarizing the replaced asset from 2020 to 2024 and planned replacement from 2025 to 2029 has been included in response to 2-Vecc-17.

b) API has outlined its plan for improving its health in response to 2-Staff-7 for those assets in which a Health index could not be derived.

2-SEC-15

[Ex. 2, DSP, Appendix C]

a. Table 1 of The Area Planning Study 2025-2029 lists 12 major capital projects recommended to be completed during the study period. Please indicate which of the projects Algoma has included in its capital budget in this Application, and for those that are not included, please explain why.
b. For those projects included in the Application, please explain any variance in cost or schedule from the Area Planning Study.

API Response:

a) All the projects that were outlined in the Area Planning Study have been included in Algoma Power's Distribution System Plan except for the Miscellaneous Engineering Studies & Investigations. While there was a consideration to include this effort, Algoma Power opted not to include this as a project in its expenditure plan because there was not a clearly defined project and investment justification.

b)

Goulais Area Voltage Conversion & Goulais TS Refurbishment

Area Planning Study $7,363k

Distribution System Plan $2,151k

The recommended project in the Area Planning Study, which was labelled the Batch and Goulais Voltage Conversion originally contemplated a larger scale voltage conversion in the Batchawana Bay and Goulais River regions at a significantly higher investment requirement. The proposed plan included in the DSP is based on a smaller scale conversion in the Goulais Area only and would take advantage of the Refurbishment project at the Goulais River TS. Algoma Power has not included a voltage conversion in the Batchawana Bay area as part of this Cost of Service but expects that it would be included in a future plan.

Protection, Automation, Reliability

Area Planning Study $5,442k

Distribution System Plan $2,655k

The variance in cost under this program is associated with the East of Sault 12.5kV voltage and phase balance reinforcement. In the Area Planning Study, the upgrades proposed originally contemplated larger line upgrade and expansion work to resolve the noted voltage performing risk. Algoma Power has proposed a scaled back plan, with the incorporation of regulating devices to ensure that the voltage is maintained to appropriate level. The result was a lower investment requirement.

Overall, while Algoma Power considered the schedule of proposed projects in the Area Planning Study, it was decided to make slight adjustments year over year with the aim of leveling the overall capital expenditures in each year.

2-SEC-16

[Ex. 2, DSP, Appendix B] Appendix B refers to a 'declining landowner permission issue outlined below', however there does not appear to be an explanation. Please explain how declining landowner permissions is not allowing Algoma to move to the 3-year cycle.

API Response:

Please refer to the explanation provided beginning with page 29 of Exhibit 4, including the example provided in the table on page 30.

Herbicide reduces the density/volume of work to a steady-state level after consistent application over multiple cycles. Under the current conditions, API has not been able to achieve these efficiencies because herbicide permissions are decreasing, and therefore growth levels continue to exceed steady state levels. A 3-year cycle is not achievable under the current herbicide application levels. However, API is ensuring to apply herbicide when permitted at the time of cutting brush using a cut stump treatment to maximize opportunities to demonstrate outcomes to landowners and reduce high density of non-compatible vegetation.

A 3-year cycle would be achievable if API were able to increase locations and consistently apply herbicide in order to enter a "control" scenario, where growth levels of non-compatible species are minimized. This would be achievable after multiple cycles of subsequent herbicide application to reduce non-compatible species.

2-SEC-17

[Ex. 2, DSP, p. 150 and 159, Table 3.6] Algoma states it is planning to replace 400 poles per year at a cost of $9,300/pole as part of the Distribution Line Rebuild program, and 100 poles per year at a cost of $10,000/pole as part of the Subtransmission Line Rebuild Program, for a total of 500 poles per year or 2500 over five years. The current total Poor and Very Poor poles is 718+157=875.

a. Please explain why Algoma believes that 2500-875= 1,625/4440 Fair poles (37%) will deteriorate to Poor or Very Poor in the next five years.
b. How many poles are replaced per year as part of new services or service upgrades done under System Access?

API Response:

a) The objective of Algoma Power's line rebuild program is to achieve a sustainable asset replacement rate that is centered around proactively replacing poles near and at end of life, but prior to failure. The program's annual target replacement rate is based on the number, age, and overall condition of in-service poles as determined through pole testing and condition assessment.

   API isn't necessarily of the belief that upwards to 1,625 poles in fair condition will deteriorate to poor or very poor condition. While API considers the results of the ACA in planning for and as part of the justification for the targeted replacement rate, there is also other factors that influence the requirements to replace poles, such as cost efficiencies associated with the replacement of groups of poles vs individual poles, line imbalance constraints associated with neighbouring poles remaining at the same height, lessened environmental impacts associated with decreased mobilization requirements, etc.

b) API has included a summary of pole replacements, including those that were required as part of new services or service upgrades in response to 2-Staff-15.

2-SEC-18

[Ex. 2, p. 6]

a. Please provide any planning documents, e.g. section of a previous DSP, where the replacement of the 9.2 km of #4 Circuit project was included.
b. Is Algoma's decision to replace the line based on useful life and/or on condition?
c. Please provide details of the Rebuild Cost per km.
d. Please provide details of the total cost of the project of $11.2M (e.g. how much for new construction, how much for replacement, etc.).
e. Did the customer make a capital contribution towards the portion of the new construction reserved for them? If so, what was the amount?

API Response:

a) The customer developments were mentioned at Page 72 (Limer/No. 4 Circuit 44 kV Supply)and page 131 (Express Feeder Rebuilds- Category Specific Requirements) of the 2020 Distribution System Plan, however due to the yet unknown customer requirements related to the level of incremental load to be addressed through "wires" investments, as well as the timing of the forecasted load increases, nor did API have a formal request from the customer(s) at the time of drafting the Application.

b) The decision was based on the existing capacity on the existing line being insufficient to meet the customers' requirements due to conductor thermal capacity limitations. By replacing the existing small conductors with a larger conductor, the structural capacity was insufficient, causing the existing poles to need to be replaced with upgraded poles. Additionally, API was required to relocate a portion of the line due to the customer's development plans.

c) The actual rebuild cost per km was $539,883/km for the section of line which was only rebuilt (section A-B). Other sections of the line were newly built (section C-E) or relocated *and* rebuilt (section B-C), costing $1,802,043/km. This cost was higher due to multiple factors, including additional land rights and consultation requirements, a water crossing, as well as geotechnical conditions.

For the purpose of the advancement credit, API has considered the rebuild costs for the rebuild-only section, as it represents the cost per km of line to rebuild in the project area without any complications specific to the project that are unrelated to a traditional rebuild.

Without the customers' request, API expects that the line replacement decision in 2033 would have been to provide similarly upgraded from 2/O ACSR to 556 ACSR; for which the price differential is small. This would have occurred because the line will be reaching its end-of-life at that time and is already reaching its maximum capacity, and the incremental upgrade would have enabled long term load growth and would have also improved line losses, at a relatively low incremental cost.

d) Please see Table below for breakdown:

1	Rebuild (A to B Section)	$ 3,239,298
2	New Construction (B to C Section Relocation and Watercrossing)	$ 5,766,537
3	New Construction (C to E Section for the new Demarcation Point)	$ 1,091,709
4	Rebuild (C to D Section for the existing Demarcation Point)	$ 315,803
5	Removal of existing B to C Section	$ 166,280
6	Incremental Premium for one customer	$ 653,852
	Total	$ 11,233,479

e) API received a capital contribution of $3,461,610. A total of $4,573,816 expansion deposit was also provided which will be subject to further review within the 5-year connection horizon.

2-SEC-19

[Ex. 2, DSP, p. 85 and 184]

a. Please provide details of the number of vehicles owned by Algoma, year purchased, condition assessment, and year proposed for replacement.
b. How does Algoma determine when a vehicle should be replaced?

API Response:

a) The following table categorizes the quantity of vehicles by type owned by Algoma Power. Due to the nature of Algoma Power's service territory, the ½ ton, ¾ ton and service trucks are 4-wheel drive. A copy of the fleet listing has been included as Attachment 2-SEC-19, and includes all vehicles owned by Algoma Power including their year of manufacture and other details. A condition assessment is not readily available for all vehicles. Proposed replacements from 2025 to 2029 are outlined in the spreadsheet included as part of this response.

Fleet Type	Quantity
Light pick-ups (1/2 Ton)	11
Heavy pick-ups (3/4 ton) with CVOR rating	8
Service Trucks (3 to 5 ton)	2
Material Handlers (Bucket truck)	6
Radial Boom Derrick (RBD lifting device)	3
Forestry Lift (Bucket truck)	2
Brush Chipper	2
Pole Trailer	3
Landscape Trailer	6
Enclosed Trailer	5
Reel Trailer	2
Snowmobile	8
Off-Road Vehicle	5
Forklift	2

b) Algoma Power's fleet replacement strategy is initially based on the lifecycle of, 10 years for the heavy fleet (radial boom derrick, material handler, etc.) and 5 years for all other fleet. Once a vehicle is identified for potential replacement, a vehicle assessment is completed to determine the overall condition of the vehicle and the priority for replacement. As part of the assessment, Algoma Power considers the age, mileage, wear, condition, and impact from corrosion. Once the assessments are complete, then an updated fleet plan is finalized.

3-SEC-20

[Ex. 3, Table 1]

a. Please provide an update on actual customer numbers to date, for each class in 2024.
b. Please rerun the regression models using actual data (customer numbers and billing determinants) to date for 2024.

API Response:

a) Please see 3-Staff-20.
b) Please see attachment 3-SEC-20. API notes the billing units/power purchases in the model have been entered on an accrual/estimate basis. Furthermore, API has maintained the same manual adjustment for industrial customer load, however the "actual period" now contains some months where the incremental load has materialized (thereby creating some element of double-counting).

3-SEC-21

[Ex. 3, p. Table 1 and DSP, Appendix C, p. 12]

a. Please reconcile the 0.31% increase in total billed kWh for 2025 from 2024 in the load forecast with the 0.92% general load growth forecasted in Appendix C.
b. Has Algoma made any adjustment to its load forecast to account for electric vehicles and/or heat pumps?

API Response:

a) Please see the response to 3-Staff-35.

b) No API, has not made any specific adjustment to the load forecast to account for EVs or heat pumps.

4-SEC- 22

[Appendices 2-JA, 2-JD, and 2-K]

a. Please update Appendices 2-JA, 2-JD and 2-K for 2024 actuals to date and provide actuals for the same date in 2022 and 2023.
b. Please provide the internal budget for OM&A for 2019 to 2024.

API Response:

a) Please see updated Appendices below. API has provided 2-JC (not 2-JD) for consistency with original application submission.

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	2020 OEB Approved	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year	2022-06 YTD Actuals	2023-06 YTD Actuals	2024-06 YTD Actuals
Reporting Basis	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE
Operations	$ 1,732,837	$ 1,481,440	$ 1,624,753	$ 1,891,114	$ 2,001,412	$ 2,049,080	$ 2,563,055	$ 979,226	$ 1,052,574	$ 1,313,551
Maintenance	$ 5,282,210	$ 5,596,378	$ 5,546,052	$ 5,496,523	$ 5,603,445	$ 5,834,295	$ 6,711,543	$ 2,026,670	$ 1,992,463	$ 2,714,863
SubTotal	**$ 7,015,047**	**$ 7,077,818**	**$ 7,170,805**	**$ 7,387,637**	**$ 7,604,856**	**$ 7,883,376**	**$ 9,274,598**	**$ 3,005,897**	**$ 3,045,037**	**$ 4,028,414**
%Change (year over year)		0.9%	1.3%	3.0%	2.9%	3.7%	17.6%			
%Change (Test Year vs Last Rebasing Year - Actual)							31.0%			
Billing and Collecting	$ 986,414	$ 951,794	$ 907,175	$ 891,233	$ 959,849	$ 1,039,479	$ 1,085,080	$ 458,596	$ 490,355	$ 565,998
Community Relations	$ 96,558	$ 34,402	$ 52,871	$ 70,420	$ 68,681	$ 69,488	$ 75,220	$ 25,842	$ 25,649	$ 17,597
Administrative and General	$ 5,589,735	$ 5,292,720	$ 5,477,479	$ 5,556,465	$ 5,360,101	$ 5,614,130	$ 5,884,116	$ 2,776,973	$ 2,666,881	$ 2,728,779
SubTotal	**$ 6,672,707**	**$ 6,278,917**	**$ 6,437,525**	**$ 6,518,119**	**$ 6,388,631**	**$ 6,723,097**	**$ 7,044,416**	**$ 3,261,410**	**$ 3,182,885**	**$ 3,312,374**
%Change (year over year)		-5.9%	2.5%	1.3%	-2.0%	5.2%	4.8%			
%Change (Test Year vs Last Rebasing Year - Actual)							12.2%			
Total	**$ 13,687,754**	**$ 13,356,735**	**$ 13,608,330**	**$ 13,905,756**	**$ 13,993,487**	**$ 14,606,472**	**$ 16,319,014**	**$ 6,267,307**	**$ 6,227,922**	**$ 7,340,788**
%Change (year over year)		-2.4%	1.9%	2.2%	0.6%	4.4%	11.7%			

	2020 OEB Approved	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year	2022-06 YTD Actuals	2023-06 YTD Actuals	2024-06 YTD Actuals
Operations[4]	$ 1,732,837	$ 1,481,440	$ 1,624,753	$ 1,891,114	$ 2,001,412	$ 2,049,080	$ 2,563,055	$ 979,226	$ 1,052,574	$ 1,313,551
Maintenance[5]	$ 5,282,210	$ 5,596,378	$ 5,546,052	$ 5,496,523	$ 5,603,445	$ 5,834,295	$ 6,711,543	$ 2,026,670	$ 1,992,463	$ 2,714,863
Billing and Collecting[6]	$ 986,414	$ 951,794	$ 907,175	$ 891,233	$ 959,849	$ 1,039,479	$ 1,085,080	$ 458,596	$ 490,355	$ 565,998
Community Relations[7]	$ 96,558	$ 34,402	$ 52,871	$ 70,420	$ 68,681	$ 69,488	$ 75,220	$ 25,842	$ 25,649	$ 17,597
Administrative and General[8]	$ 5,589,735	$ 5,292,720	$ 5,477,479	$ 5,556,465	$ 5,360,101	$ 5,614,130	$ 5,884,116	$ 2,776,973	$ 2,666,881	$ 2,728,779
Total	**$ 13,687,754**	**$ 13,356,735**	**$ 13,608,330**	**$ 13,905,756**	**$ 13,993,487**	**$ 14,606,472**	**$ 16,319,014**	**$ 6,267,307**	**$ 6,227,922**	**$ 7,340,788**
%Change (year over year)		-2.4%	1.9%	2.2%	0.6%	4.4%	11.7%			

Appendix 2-JC
OM&A Programs Table

Programs	Last Rebasing Year (2020 OEB-Approved)	Last Rebasing Year (2020 Actuals)	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year	Variance (Test Year vs. 2023 Actuals)	Variance (Test Year vs. Last Rebasing Year (2020 OEB-Approved)	2022-06 YTD Actuals	2023-06 YTD Actuals	2024-06 YTD Actuals
Reporting Basis	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE
Customer Focus												
Customer Service, Mailing Costs	842,496	747,347	784,594	757,743	773,436	878,542	904,372	130,936	61,876	400,762	376,796	430,300
Community Relations	96,558	34,402	52,871	70,420	68,681	69,488	75,220	6,539	-21,338	25,842	25,649	17,597
Bad Debts	71,000	98,828	24,171	5,730	66,606	50,000	75,000	8,394	4,000	8,859	49,618	81,039
Meter Reading	104,058	136,232	129,023	158,373	150,419	141,549	147,708	-2,711	43,649	83,483	83,941	77,047
Sub-Total	1,114,112	1,016,809	990,658	992,266	1,059,142	1,139,579	1,202,300	143,158	88,188	518,946	536,004	605,983
Operational Effectiveness												
Stations	197,425	109,846	192,702	214,222	183,035	217,480	258,684	75,649	61,258	107,841	86,161	94,270
Load Dispatching	142,302	131,697	138,200	128,953	153,248	132,322	196,581	43,333	54,279	70,923	73,631	64,544
Supervision and Engineering	246,582	219,436	221,590	230,336	223,808	238,607	258,583	34,774	12,000	114,503	141,586	133,884
Meters Maintenance	836,103	776,125	734,669	748,724	831,049	840,128	795,363	-35,686	-40,740	394,513	417,014	436,166
Overhead Lines and Feeders	1,306,533	1,535,748	1,265,781	1,538,670	1,279,721	1,616,589	2,112,707	832,987	806,174	769,489	716,761	843,315
Distribution Transformers	17,446	29,103	14,135	111	29,515	13,367	13,657	-15,857	-3,789	0	0	-1,183
Right of Way Maintenance Program	3,571,764	3,595,162	3,839,055	3,821,811	4,024,179	4,000,882	4,816,434	792,254	1,244,670	1,230,003	1,227,939	1,886,644
Underground Lines, Feeders, and Services	14,466	16,599	21,048	14,105	13,435	15,633	15,763	2,328	1,296	11,520	10,574	7,340
Poles Towers & Fixtures	130,195	113,694	122,309	89,308	62,042	154,217	147,142	85,100	16,947	20,465	11,468	18,890
Salaries, Wages and Benefits for Administrative Services	3,064,412	2,966,989	3,221,036	3,031,327	3,162,490	3,141,109	3,400,789	238,299	336,377	1,475,038	1,443,538	1,607,817
Other External Administrative Services	441,194	497,881	435,668	490,569	491,704	463,152	480,479	-11,225	39,285	282,035	291,897	205,904
Rent and Maintenance of Genera	1,512,169	1,414,549	1,395,544	1,429,134	1,116,011	1,292,125	1,221,591	105,579	-290,579	706,250	600,873	559,163
Other Operating and Maintenanc	548,133	547,617	615,854	597,064	802,581	648,886	654,311	-148,271	106,177	285,678	357,660	542,256
Other General and Admin	358,266	249,972	248,087	373,653	341,406	462,832	436,190	94,784	77,924	176,902	202,357	221,144
Sub-Total	12,386,991	12,204,417	12,465,675	12,707,988	12,714,224	13,237,330	14,808,272	2,094,048	2,421,281	5,645,159	5,581,459	6,620,155
Public and Regulatory Responsiveness												
Regulatory & Compliance	187,179	135,510	151,997	201,605	220,121	229,563	308,442	88,321	121,263	103,202	110,459	114,651
Sub-Total	187,179	135,510	151,997	201,605	220,121	229,563	308,442	88,321	121,263	103,202	110,459	114,651
Miscellaneous								0	0			
Total	**13,688,282**	**13,356,735**	**13,608,330**	**13,901,859**	**13,993,487**	**14,606,472**	**16,319,014**	**2,325,527**	**2,630,732**	**6,267,307**	**6,227,922**	**7,340,788**

Appendix 2-K
Employee Costs

	Last Rebasing Year 2020 - OEB Approved	Last Rebasing Year (2020 Actuals)	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year	2022-06 YTD Actuals	2023-06 YTD Actuals	2024-06 YTD Actuals
Number of Employees (FTEs including Part-Time)[1]										
Management (including executive)	12	11	12	11	12	11	11	11	11	11
Non-Management (union and non-union)	58	54	56	57	59	63	63	55	57	57
Total	70	65	68	68	71	74	74	66	68	68
Total Salary and Wages including ovetime and incentive pay										
Management (including executive)	$1,745,282	$1,745,599	$1,806,968	$1,809,000	$1,771,244	$ 1,806,045	$ 1,892,538	$ 872,484	$ 841,120	$ 944,449
Non-Management (union and non-union)	$5,566,645	$5,278,914	$5,465,122	$5,715,777	$6,012,789	$ 6,579,988	$ 6,789,512	$ 2,700,109	$ 2,895,073	$ 2,932,469
Total	$7,311,927	$7,024,513	$7,272,090	$7,524,777	$7,784,033	$ 8,386,033	$ 8,682,050	$ 3,572,593	$ 3,736,193	$ 3,876,918
Total Benefits (Current + Accrued)										
Management (including executive)	$ 414,774	$ 420,195	$ 496,355	$ 431,840	$ 409,061	$ 362,805	$ 382,519	$ 232,922	$ 211,630	$ 236,361
Non-Management (union and non-union)	$1,711,110	$1,737,448	$2,057,219	$1,745,003	$1,576,206	$ 1,584,703	$ 1,651,103	$ 961,922	$ 863,623	$ 883,578
Total	$2,125,884	$2,157,643	$2,553,574	$2,176,843	$1,985,267	$ 1,947,508	$ 2,033,622	$ 1,194,844	$ 1,075,253	$ 1,119,939
Total Compensation (Salary, Wages, & Benefits)										
Management (including executive)	$2,160,056	$2,165,794	$2,303,323	$2,240,840	$2,180,305	$ 2,168,850	$ 2,275,057	$ 1,105,406	$ 1,052,750	$ 1,180,810
Non-Management (union and non-union)	$7,277,755	$7,016,362	$7,522,341	$7,460,780	$7,588,995	$ 8,164,691	$ 8,440,615	$ 3,662,031	$ 3,758,696	$ 3,816,047
Total	$9,437,811	$9,182,156	$9,825,664	$9,701,620	$9,769,300	$ 10,333,541	$10,715,672	$ 4,767,437	$ 4,811,446	$ 4,996,857
Total Compensation Breakdown (Capital, OM&A)										
OM&A	$6,655,084	$6,473,496	$6,489,504	$6,521,797	$6,489,520	$ 6,972,852	$ 7,152,603	$ 3,321,168	$ 3,336,566	$ 3,556,319
Capital	$2,782,727	$2,708,660	$3,336,160	$3,179,823	$3,279,780	$ 3,360,689	$ 3,563,069	$ 1,446,269	$ 1,474,880	$ 1,440,538
Total	$9,437,811	$9,182,156	$9,825,664	$9,701,620	$9,769,300	$10,333,541	$10,715,672	$ 4,767,437	$ 4,811,446	$ 4,996,857

b) Please see below for the internal budget amounts for OM&A for 2019 to 2024.

	2019	2020	2021	2022	2023	2024
API OM&A Internal Budget	13,461,000	13,836,000	13,865,000	13,943,000	14,030,000	14,633,000

4-SEC- 23

[Ex. 4, Table 7] Please confirm that Algoma has not included any increased costs related to the Getting Ontario Connected Act, and does not plan to make use of the generic DVA account set up by the OEB.

API Response:

Please refer to API's response to 9-Staff-74.

4-SEC- 24

[Ex. 4, Tables 7 and 8]

a. Algoma is forecasting an increase in vegetation management costs of $816k for 2025 over 2024. Please break down the increase into the following cost drivers: increase in planned km, decrease in density & complexity, higher contractor costs, higher skilled workers, etc.
b. Does Algoma require a landowner to provide authorization to use herbicides when it pays Right of Way Land Fees? If not, why not?

API Response:

a) Please see the table below and the explanations that follow

2024 Budget	**$ 4,000,882**
Impact of Internal Labour	-$ 16,224
Estimated Impact of Km of Contract Work	$ 1,020,166
Estimated Impact of Complexity/Density	-$ 51,503
Estimated Impact of Other Factors Incl. Contractor Costs	-$ 136,889
2025 Budget	**$ 4,816,433**

Internal Labour Costs

Consistent with the response to 4-Staff-42e) ii), API's budgeting process for Vegetation Management (VM) typically considers that internal API staff will complete relatively consistent functions each year. The functions covered by internal staff include administration, demand work (ex: customer driven), and off-cycle required work. The table below compares the internal labour portion of the 2024 and 2025 budgets. As seen below, there are no material variances expected between the bridge and test years. API notes the complement of high-skilled Utility Arborists allocating time to the VM expense budget is relatively stable and is not a cost driver between the bridge and test years.

Internal staff support the cycle program activities completed through contracted services (ex: API Utility Arborists may complete the higher complexity work closer to powerlines). Additionally, some VM parts in the line clearing/brush control (LC/BC) cyclical program are assigned to API internal resources annually. Internal staff also support capital projects, and therefore a portion of the internal staff budget is allocated to capital, rather than the VM expense budget.

		2024		2025	Variance
nternal Costs- Administrative Functions	$	482,300	$	529,130	$ 46,831
nternal Costs- Demand Work, Off-Cycle Required Work, Support Cyclical Program & Complete Some Cycle Parts	$	1,456,714	$	1,393,659	-$ 63,055
Total Internal Costs	**$**	**1,939,013**	**$**	**1,922,789**	-$ 16,224

Contractor Costs for Line Clearing and Brush Control

API has focused the cost driver analysis on the costs associated with contract services for planned Line Clearing (LC) and Brush Control (BC) work.

The costs for contractor completion of LC and BC work vary with the km of work to be completed, the nature of work (LC, BC, or both LC and BC), and the complexity of the spans to be covered (including access to the area and density of the vegetation).

The table below shows summary statistics regarding the km of line, average difficulty per km, and estimated cost per km for each of 2024 and 2025. Km listed below represent “contract km” and exclude those spans planned to be completed using in house resources.

Difficulty was assessed on a scale of 1(light) to 6 (very heavy). Average difficulty per km was assessed by multiplying the difficulty of each span by the km, then dividing by the number of km.

	contract km 2024	contract km 2025	Avg Complexity / Km 2024	Avg Complexity /km 2025	Contractor Cost/km 2024	Contractor Cost / km 2025	Adj. Factor Complexity 24 to 25	2024 price adj for 2025 complexity
			A	*B*	*C*		*D=B/A*	*E=C*D*
BC	52.7	190	2.5	4.4	$ 3,991	$ 6,901	177%	$ 7,080
LC,BC	96.25	120.8	4.1	3.0	$ 19,237	$ 13,099	73%	$ 13,951

Using the statistics in the table above, API has estimated the impacts of the km of line and difficulty/complexity cost drivers, as depicted in the table below. For example, to estimate the impact of km of line change from 2024 to 2025, API assessed a scenario where the 2025 km of line were completed applying the 2024 complexity/pricing. This scenario represents a contract service budget of $3.08M, indicating the km of line driver contributed $1.02M of the 2024 to 2025 change.

Similarly, the relative density/difficulty of work contributed a -$52k decrease, while other factors including vendor pricing contributed a further decrease of -$137k.

	2024 Plan	2025 km using 2024 Rates	2025 km using 2024 rts adjusted for 2025 Complexity	2025 Plan
BC	$ 210,299	$ 758,196	$ 1,345,216	$ 1,311,266
LC,BC	$ 1,851,570	$ 2,323,840	$ 1,685,317	$ 1,582,378
Total	$ 2,061,869	$ 3,082,035	$ 3,030,533	$ 2,893,644
		Impact of Km	Impact of Complexity	Impact of Other Factors incl. Pricing
BC		$ 547,896	$ 587,021	-$ 33,951
LC,BC		$ 472,270	-$ 638,523	-$ 102,938
Total		$ 1,020,166	-$ 51,503	-$ 136,889

b) No, API does not currently require a landowner to provide authorization to use herbicide when securing Right of Way land rights. API notes it has attempted to include such provisions during past discussions, however interest holders/landowners are unwilling to provide such permissions.

4-SEC-25

[Ex. 4, p. 6 and 37] Right of Way Land Use Fees are forecast to increase by $386k in 2025. In addition, Algoma is requesting the establishment of a new DVA.

a. Please explain how Algoma determined the forecast for 2025 of $767,909 for Right of Way Land Use Fees, in light of the uncertainty of forecasting and the request for a new DVA.
b. Please explain what is meant by ''the OM&A equivalent of the current revenue requirement estimate … for negotiations with various entities.'
c. Algoma notes that these Fees can either be OM&A or capital. Please explain how Algoma records these fees if they are capital.

API Response:

a) API has assessed the areas expected to be subject to new and renewed land use agreements over the upcoming period, and made an estimate of the associated acres of land affected by such permits.

   These acreages were then multiplied by the most relevant available comparable rates, however as discussed in the Application, the "comparable rates" may be from other interest holders, and may not reflect the preferences and requirements of the parties API would ultimately negotiate with, or they may not be an apples-to-apples comparison with the nature of the land under negotiation. Furthermore, changes in market and other conditions may impact land use rates over time.

   For those areas where it is an option, for estimating purposes, API has reflected its preference, which is to obtain permanent easements or long term (10+ year) permits, in its forecast. In order to arrive at the annual revenue requirement estimate, API assessed the following:

   - Total value of capitalized assets =
     - Prior Year's assets; +
     - Cost of Easement and/or long-term permit; +
     - Cost of any Surveys, agreement fees, legal fees.

   1) The average 2024-2028 revenue requirement of capitalized agreements, with each year's revenue requirement calculated as:
   - Depreciation expense of each capitalized agreement; plus
     - Depreciation Useful Life is the duration of the long-term permit (10 years) or 40 years for Permanent Easement;
   - Return on capital considering value of capitalized assets calculated above at the applied-for WACC of 7.06%; plus
   - Grossed Up PILS estimate.

   2) Plus annual fees on existing agreements and forecasted new annual payments.

b) As outlined in the response to subsection a), the Test Year OM&A forecast in account 5095 includes a provision for the revenue requirement associated with agreements assumed to be capitalized in API's forecasts.

c) Capital Right of Way Land use fees are capitalized to the OEB asset class 1612 (Land Rights) and have an associated depreciation rate of 40 years.

4-SEC- 26

[Ex. 4, p. 59]

a. Please provide a list of Corporate Targets for 2020 to 2025, and the three performance levels for each target.
b. Please provide the results for 2020-2023 with respect to the Corporate Targets.

API Response:

a) FortisOntario operates various regulated utilities in Ontario, one of which is Algoma Power. FortisOntario's corporate targets are based on consolidated operating and capital expenditures, safety performance measures, customer satisfaction results and reliability targets. Each of the corporate targets benefits the ratepayers. Below are FortisOntario's corporate targets (and results) from 2020-2024. The 2025 Corporate Targets have not yet been developed.

2020

Category	Weight	Measure	(50%) Minimum	(100%) Target	(150%) Maximum
Financial	20%	Consolidated Operating Expenses ($'000)	Budget +10% $38,223	Budget $34,748	Budget -15% $29,536
	15%	Effectively Manage/Optimize Consolidated Capital Plan (Net) ($'000)	Target -15% $24,183	Budget $28,451	Subjective
	15%	Cash Flow from Operations Before Working Capital ($'000)	Target -3% $28,410	Budget $29,289	Budget +5% $30,753
Customer Service	15%	Customer Satisfaction [1]	Subjective	Ontario Benchmark +2%	Ontario Benchmark +5%
Safety	15%	All Injury Frequency Rate (AIFR) [2]	2.41	Target 1.45	0.00
	5%	Planned Work Observations & Workplace Inspections	Target -10% 374	Target 415	Target +20% 498
Reliability	15%	The average duration of outages per customer (SAIDI) for FortisOntario [3]	Target +20% 2.93	Target 2.44	Target -20% 2.00

[1] 2020 Target is Ontario Benchmark conducted by UtilityPULSE +2%.

[2] 2020 AIFR 100% target was calculated based on 3 incidents (i.e., medical aids and/or lost time injuries). The minimum is equivalent to 5 incidents, and 150% is 0 incidents. There were 4 recordable incidents in 2020 and the AIFR is 2.0.

[3] 2020 SAIDI 100% target was calculated based on the past 3-year's rolling average less 5%. In calculating the rolling average, the adjusted 2019 result of 2.26 was used instead of the actual SAIDI of 3.31. The acutal 2020 SAIDI was 2.90. After adjusting the planned outages due to major construction work, the adjusted SAIDI for 2020 is 2.44.

2021

Category	Weight	Measure	(50%) Minimum	(100%) Target	(150%) Maximum
Financial	20%	Consolidated Operating Expenses ($'000)	Budget +10% $38,214	Budget $34,740	Budget -15% $29,529
	15%	Effectively Manage/Optimize Consolidated Capital Plan (Net) ($'000)	Target -15% $37,983	Budget $44,686	Subjective
	15%	Cash Flow from Operations Before Working Capital ($'000)	Target -3% $25,423	Budget $26,209	Budget +5% $27,519
Customer Service	10%	Customer Satisfaction [1]	Subjective	Ontario Benchmark +1%	Ontario Benchmark +3%
	5%	E-Billing Enrolment [2]	30% (24%+6%)	36% (24%+12%)	50% (24%+26%)
Safety	15%	All Injury Frequency Rate (AIFR) [3]	2.67	1.60	0.00
	5%	Planned Work Observations & Workplace Inspections	Target -10% 374	Target 434	Target +20% 521
Reliability	15%	The average duration of outages per customer (SAIDI) for FortisOntario [4]	Target +20% 2.61	Target 2.18	Target -20% 1.74

[1] 2021 Target is Ontario Benchmark conducted by UtilityPULSE +1%.

[2] Current e-billing is at 24%, and target is based on increasing current number by 50%.

[3] 2021 AIFR 100% target was calculated based on 3 incidents (i.e., medical aids and/or lost time injuries), and 2020 actual working hours (FON+Watay PM). The minimum is equivalent to 5 incidents, and 150% is 0 incidents.

[4] 2021 target was calculated using past 3 year's rolling average less 5%.

2022

Category	Weight	Measure	(50%) Minimum	(100%) Target	(150%) Maximum
Financial	20%	Consolidated Operating Expenses ($'000)	Budget +10% $39,872	Budget $36,247	Budget -15% $30,810
	20%	Effectively Manage/Optimize Consolidated Capital Plan (Gross) ($'000) [5]	Subjective	Budget $53,665	Subjective
	10%	Cash Flow from Operations Before Working Capital ($'000)	Budget -3% $30,581	Budget $31,527	Budget +5% $33,103
Customer Service	10%	Customer Satisfaction [1]	Subjective	Ontario Benchmark +1%	Ontario Benchmark +3%
	5%	E-Billing Enrolment [2]	Target -15% 3,400	4,000 e-billing enrolments	Target +15% 4,600
Safety	15%	All Injury Frequency Rate (AIFR) [3]	2.67	Target 1.60	0.00
	5%	Planned Work Observations & Workplace Inspections	Target -10% 390	Target 433	Target +20% 520
Reliability	15%	The average duration of outages per customer (SAIDI) for FortisOntario [4]	Target +20% 2.50	Target 2.08	Target -10% 1.87

[1] 2022 Target is Ontario Benchmark conducted by UtilityPULSE +1%.

[2] Current e-billing is at 31%, and target is based on 36%.

[3] 2022 AIFR 100% target was calculated based on 3 incidents (i.e., medical aids and/or lost time injuries), and 2020 actual working hours (FON+Watay PM). The minimum is equivalent to 5 incidents, and 150% is 0 incidents.

[4] 2022 target was calculated using past 3 year's rolling average less 5%.

[5] 2022 Consolidated Capital Plan (Gross) target will consider completing projects on the scheduled timelines, quality of construction, effective project management especially with third party contractors, safety of construction, and consideration of distribution system plans.

2023

Category	Weight	Measure	(50%) Minimum	(100%) Target	(150%) Maximum
Financial	20%	Consolidated Operating Expenses ($'000)	Budget +10% $40,634	Budget $36,940	Budget -15% $31,399
	20%	Effectively Manage/Optimize Consolidated Capital Plan (Net) ($'000) [4]	Subjective	Budget $32,549	Subjective
	10%	Cash Flow from Operations Before Working Capital ($'000)	Target -3% $28,695	Budget $29,582	Budget +5% $31,061
Customer Service	15%	Customer Satisfaction [1]	Subjective	Ontario Benchmark +1%	Ontario Benchmark +3%
Safety	15%	All Injury Frequency Rate (AIFR) [2]	2.44	1.48	0.00
	5%	Planned Work Observations & Workplace Inspections	Target -10% 396	Target 440	Target +20% 528
Reliability	15%	Average Duration of Outages per Customer (SAIDI) for FortisOntario [3]	Target +20% 2.36	Target 1.97	Target -10% 1.77

[1] 2023 target is Ontario Benchmark conducted by UtilityPULSE +1.

[2] 2023 AIFR 100% target was calculated based on 3 incidents (i.e., medical aids and/or lost time injuries) and 2023 actual working hours (FON+Watay PM). The minimum is equivalent to 2 incidents, and the maximum is equivalent to 0 incidents.

[3] 2023 target was calculated using the past 3 year's rolling average.

[4] Consolidated Capital Plan target will consider completing projects on the scheduled timelines, quality of construction, effective project management especially with third party contractors, safety of construction, and consideration of distribution system plans.

2024

FortisOntario Inc.

2024 Corporate Short-Term Incentive Plan Targets

Category	Weight	Measure	(50%) Minimum	(100%) Target	(150%) Maximum
Financial	25%	Consolidated Operating Expenses ($'000)	Budget +10% $42,571	Budget $38,701	Budget -15% $32,896
	25%	Effectively Manage/Optimize Consolidated Capital Plan (Net) ($'000) [4]	Subjective	Budget $32,605	Subjective
Customer Service	15%	Customer Satisfaction [1]	Subjective	Ontario Benchmark +1%	Ontario Benchmark +3%
Safety	15%	All Injury Frequency Rate (AIFR) [2]	2.44	1.46	0.00
	5%	Planned Work Observations & Workplace Inspections	Target -10% 391	Target 434	Target +20% 521
Reliability	15%	Average Duration of Outages per Customer (SAIDI) for FortisOntario [3]	Target +20% 2.77	Target 2.31	Target -10% 2.08

[1] 2024 Target is Ontario Benchmark conducted by UtilityPULSE +1%.

[2] 2024 AIFR 100% target was calculated based on 3 incidents (i.e., medical aids and/or lost time injuries) and 2024 estimated working hours (FON+Watay PM). The minimum is equivalent to 5 incidents, and maximum 150% is equivalent to 0 incidents.

[3] In the past, FON used adjusted SAIDI, excluding non-controllable outages such as outages during major storms and major planned outages, to calculate the reliability targets. Beginning in 2024, all outages, excluding loss of supply and major event days, were used to calculate the reliability target. The 2024 target is the past 3-year average SAIDI less 5%.

[4] 2024 Consolidated Capital Plan (Gross) target will consider completing projects on the scheduled timelines, quality of construction, effective project management especially with third party contractors, safety of construction, and consideration of distribution system plans.

b) Corporate Targets Results are as follows:

Year	Result
2020	104.3%
2021	96.2%
2022	123.0%
2023	111.0%

4-SEC-27

[Ex. 4, p. 62, Appendix 2-K] Please breakout Appendix 2-K to show employees of Algoma and the allocation of FTEs included in the shared services, allocation of FTEs included in corporate cost allocations and FTEs related to time directly charged to Algoma from its affiliates within the FortisOntario group, such as customer service and engineering support which are not already covered under the shared services allocations.

API Response:

Please see 2-K updated below.

Appendix 2-K
Employee Costs

	Last Rebasing Year 2020 - OEB Approved	Last Rebasing Year (2020 Actuals)	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management - API	8.0	7.0	7.5	7.4	7.4	7.0	7.0
Management (including executive) - Shared Services/Corporate Allocation	3.8	3.4	3.7	3.5	3.6	3.5	3.5
Management - Direct Time from Affiliates	0.2	0.4	0.4	0.4	0.6	0.5	0.5
Non-Management (union and non-union) - API	50.0	44.9	45.8	46.8	48.0	52.0	51.6
Non-Management (union and non-union) - Shared Services/Corporate Allocation	6.9	7.0	8.0	8.0	8.3	8.0	8.6
Non-Management (union and non-union) - Direct Time from Affiliates	1.3	2.3	2.3	1.9	2.8	3.3	3.2
Total	70.2	65.0	67.7	68.0	70.7	74.3	74.4

Appendix 2-K
Employee Costs

	Last Rebasing Year 2020 - OEB Approved	Last Rebasing Year (2020 Actuals)	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Number of Employees (FTEs including Part-Time)							
Management - API	8.0	7.0	7.5	7.4	7.4	7.0	7.0
Management (including executive) - Shared Services/Corporate Allocation	3.8	3.4	3.7	3.5	3.6	3.5	3.5
Management - Direct Time from Affiliates	0.2	0.4	0.4	0.4	0.6	0.5	0.5
Non-Management (union and non-union) - API	50.0	44.9	45.8	46.8	48.0	52.0	51.6
Non-Management (union and non-union) - Shared Services/Corporate Allocation	6.9	7.0	8.0	8.0	8.3	8.0	8.6
Non-Management (union and non-union) - Direct Time from Affiliates	1.3	2.3	2.3	1.9	2.8	3.3	3.2
Total	70.2	65.0	67.7	68.0	70.7	74.3	74.4

Appendix 2-K
Employee Costs

Total Salary and Wages including overtime and incentive pay							
Management - API	$1,068,341	$1,052,633	$1,094,016	$1,095,437	$1,054,547	$ 995,240	$ 1,019,274
Management (including executive) - Shared Services/Corporate Allocation	$ 657,690	$ 659,975	$ 673,271	$ 666,123	$ 656,696	$ 738,490	$ 782,445
Management - Direct Time from Affiliates	$ 19,251	$ 32,991	$ 39,681	$ 47,440	$ 60,001	$ 72,315	$ 90,819
Non-Management (union and non-union) - API	$4,832,737	$4,427,515	$4,518,953	$4,796,680	$5,018,218	$ 5,471,556	$ 5,600,482
Non-Management (union and non-union) - Shared Services/Corporate Allocation	$ 646,066	$ 693,427	$ 781,605	$ 750,293	$ 783,968	$ 825,960	$ 876,121
Non-Management (union and non-union) - Direct Time from Affiliates	$ 87,842	$ 157,972	$ 164,564	$ 168,804	$ 210,603	$ 282,472	$ 312,909
Total	$7,311,927	$7,024,513	$7,272,090	$7,524,777	$7,784,033	$ 8,386,033	$ 8,682,050
Total Benefits (Current + Accrued)							
Management - API	$ 257,484	$ 267,023	$ 324,207	$ 265,998	$ 212,529	$ 169,083	$ 176,072
Management (including executive) - Shared Services/Corporate Allocation	$ 152,416	$ 144,848	$ 162,028	$ 155,585	$ 181,021	$ 176,481	$ 185,306
Management - Direct Time from Affiliates	$ 4,874	$ 8,324	$ 10,120	$ 10,257	$ 15,511	$ 17,241	$ 21,141
Non-Management (union and non-union) - API	$1,520,756	$1,520,754	$1,802,510	$1,540,674	$1,319,136	$ 1,320,571	$ 1,373,511
Non-Management (union and non-union) - Shared Services/Corporate Allocation	$ 168,112	$ 176,802	$ 212,763	$ 167,691	$ 202,403	$ 196,788	$ 204,752
Non-Management (union and non-union) - Direct Time from Affiliates	$ 22,242	$ 39,892	$ 41,946	$ 36,638	$ 54,667	$ 67,344	$ 72,840
Total	$2,125,884	$2,157,643	$2,553,574	$2,176,843	$1,985,267	$ 1,947,508	$ 2,033,622
Total Compensation (Salary, Wages, & Benefits)							
Management - API	$1,325,825	$1,319,656	$1,418,223	$1,361,435	$1,267,076	$ 1,164,323	$ 1,195,346
Management (including Executive) - Shared Services/Corporate Allocation	$ 810,106	$ 804,823	$ 835,299	$ 821,708	$ 837,717	$ 914,971	$ 967,751
Management - Direct Time from Affiliates	$ 24,125	$ 41,315	$ 49,801	$ 57,697	$ 75,512	$ 89,556	$ 111,960
Non-Management (union and non-union) - API	$6,353,493	$5,948,269	$6,321,463	$6,337,354	$6,337,354	$ 6,792,127	$ 6,973,993
Non-Management (union and non-union) - Shared Services/Corporate Allocation	$ 814,178	$ 870,229	$ 994,368	$ 917,984	$ 986,371	$ 1,022,748	$ 1,080,873
Non-Management (union and non-union) - Direct Time from Affiliates	$ 110,084	$ 197,864	$ 206,510	$ 205,442	$ 265,270	$ 349,816	$ 385,749
Total	$9,437,811	$9,182,156	$9,825,664	$9,701,620	$9,769,300	$ 10,333,541	$10,715,672

Appendix 2-K
Employee Costs

Total Compensation Breakdown (Capital, OM&A)							
OM&A - API	$4,940,326	$4,571,401	$4,468,027	$4,637,081	$4,442,462	$ 4,762,263	$ 4,799,663
OM&A - Shared Services/Corporate Allocation	$1,624,284	$1,675,052	$1,829,667	$1,739,692	$1,824,088	$ 1,937,719	$ 2,048,624
OM&A - Direct Time from Affiliates	$ 90,474	$ 227,043	$ 191,810	$ 145,024	$ 222,970	$ 272,870	$ 304,316
Capital - API	$2,738,992	$2,696,524	$3,271,659	$3,061,708	$3,161,968	$ 3,194,187	$ 3,369,676
Capital - Direct Time from Affiliates	$ 43,735	$ 12,136	$ 64,501	$ 118,115	$ 117,812	$ 166,502	$ 193,393
Total	$9,437,811	$9,182,156	$9,825,664	$9,701,620	$9,769,300	$ 10,333,541	$10,715,672

4-SEC- 28

[Ex. 4, p. 65 and Appendix 2-K]

a. Please breakout the union positions information from Non-Management (union and non-union) in Appendix 2-K.
b. Please break out the Short-Term Incentive Pay for Management and Non-union Non-Management.
c. Please break out those FTEs that work for API versus those that are allocated or directly charged from affiliates.
d. Algoma states that the 3 new FTEs in 2024 are temporary vacant positions, seasonal labourers and a co-op student. Please explain why these positions are continuing over into 2025 and becoming a part of the 2025 OM&A request.
e. Please provide an update on the status of the increase in 3 FTEs in 2024.

API Response:

a) See table below.

	Last Rebasing Year 2020 - OEB Approved	Last Rebasing Year (2020 Actuals)	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	12	11	12	11	12	11	11
Non-Management (union)	34	29	30	31	33	33	34
Non-Management (non-union)	24	25	26	26	26	30	29
Total	70	65	68	68	71	74	74
Total Salary and Wages including overtime and incentive pay							
Management (including executive)	$ 1,745,282	$ 1,745,599	$ 1,806,968	$ 1,809,000	$ 1,771,244	$ 1,806,045	$ 1,892,538
Non-Management (union)	$ 3,466,098	$ 3,079,879	$ 3,087,658	$ 3,372,365	$ 3,428,991	$ 3,862,795	$ 3,907,641
Non-Management (non-union)	$ 2,100,547	$ 2,199,035	$ 2,377,464	$ 2,343,412	$ 2,583,798	$ 2,717,193	$ 2,881,871
Total	$ 7,311,927	$ 7,024,513	$ 7,272,090	$ 7,524,777	$ 7,784,033	$ 8,386,033	$ 8,682,050
Total Benefits (Current + Accrued)							
Management (including executive)	$ 414,774	$ 420,195	$ 496,355	$ 431,840	$ 409,061	$ 362,805	$ 382,519
Non-Management (union)	$ 1,003,064	$ 933,074	$ 1,102,082	$ 949,037	$ 881,607	$ 830,083	$ 891,071
Non-Management (non-union)	$ 708,046	$ 804,374	$ 955,137	$ 795,966	$ 694,599	$ 754,620	$ 760,032
Total	$ 2,125,884	$ 2,157,643	$ 2,553,574	$ 2,176,843	$ 1,985,267	$ 1,947,508	$ 2,033,622
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 2,160,056	$ 2,165,794	$ 2,303,323	$ 2,240,840	$ 2,180,305	$ 2,168,850	$ 2,275,057
Non-Management (union)	$ 4,469,162	$ 4,012,953	$ 4,189,739	$ 4,321,402	$ 4,310,598	$ 4,692,877	$ 4,798,712
Non-Management (union and non-union)	$ 2,808,593	$ 3,003,409	$ 3,332,602	$ 3,139,378	$ 3,278,397	$ 3,471,814	$ 3,641,903
Total	$ 9,437,811	$ 9,182,156	$ 9,825,664	$ 9,701,620	$ 9,769,300	$ 10,333,541	$ 10,715,672
Total Compensation Breakdown (Capital, OM&A)							
OM&A	$ 6,655,084	$ 6,473,496	$ 6,489,504	$ 6,521,797	$ 6,489,520	$ 6,972,852	$ 7,152,603
Capital	$ 2,782,727	$ 2,708,660	$ 3,336,160	$ 3,179,823	$ 3,279,780	$ 3,360,689	$ 3,563,069
Total	$ 9,437,811	$ 9,182,156	$ 9,825,664	$ 9,701,620	$ 9,769,300	$ 10,333,541	$ 10,715,672

b) See 4-VECC-27.
c) See 4-SEC-27.
d) There was temporarily vacant position in 2023 filled in 2024 and so in turn expected to remain filled into 2025. In 2023, API had 2.5 FTE in seasonal labours supporting the vegetation management program and planned to have 4.5 FTE in 2024 and 2025.
e) Seasonal labourers and a co-op student position have been filled in 2024. In addition, two (2) PLT positions that were temporarily vacant in 2023 have since been filled.

4-SEC- 29

[Ex. 4, Appendix 2-M]

a. Please provide the details for the $20,904 + $307,000k = $327,904k consultant costs forecast for the 2025 cost of service application.
b. Please explain why Algoma has forecast total intervenor costs of $7,488 + $126,996 = $134,482 for the 2025 cost of service application, given the forecasted intervenor costs for the 2020 application were $97,000 and the actual costs were $37,440.

API Response:

a) The $20,904 in bridge year costs are related to the amortization of consultants' costs from the 2020 COS application, and are not included in the total $504k forecasted for the 2025 COS Application. API provides the following breakout of forecasting consulting costs among "main COS" versus DSP consulting:

COS Consulting		
Customer Engagement Rate Consulting (possible offset to Legal) Accounting Studies	$	183,500.00
DSP Consulting		
Asset Condition Assessment Area Planning Study Vegetation Management	$	123,500.00
Total	$	307,000.00

b) Since intervenor costs primarily vary based on the number of intervenors, which was unknown at the time of the application, and can change from one COS to another, API estimated 4-5 intervenors plus OEB costs. The $7,488 in bridge year intervenor costs represent 1/5th of the intervenor costs form the 2020 COS application.

4-SEC-30

[Ex. 4, p. 71 and Appendix 2-N]

a. Please provide the details of the corporate services ($639,570 in 2025) provided by Fortis Ontario, including the cost for each service, a description of the corporate cost allocation methodology and the percentage allocated to Algoma for each service for the test/ bridge years, and the 2020 to 2023 actuals.
b. Please explain the 2022 updated methodology for corporate services allocation.
c. Please provide a breakdown of all administrative services provided by CNPI Distribution, including the cost for each service, a description of the corporate cost allocation methodology and the percentage allocated to Algoma for each service for the test/ bridge years, and the 2020 to 2023 actuals.
d. Please provide the calculation including the return on the shared assets, the depreciation expense, and the grossed up for taxes totalling the $431,621 forecasted for 2025 for IT.

API Response:

a) The $639,570 for 2025 represents the Executive Services fee allocated to API by FortisOntario. Rather than each FortisOntario subsidiary having its own Executive level staffing compliment, for cost efficiencies, one central corporate Executive level team was previously established (President & CEO, VP Operations, VP Finance and CFO, VP Corporate Services & Indigenous Relations, and Executive Assistant). The allocation methodology is based on the relative time and effort providing Executive level support services to both FortisOntario and its regulated subsidiaries (Algoma Power Inc. Canadian Niagara Power Inc, Cornwall Electric). The allocation methodology including the overall allocation percentages are reviewed every 5 years when Canadian Niagara Power distribution rebases (last reviewed and updated in 2022, see part b below). During the years in between rebasing, although the allocation percentages do not change, the total dollars allocated will fluctuate depending on actual total dollars incurred that are to be shared. Executive costs that are shared through shared service allocations are costs directly associated with the employment of the Executive group (salaries, benefits, bonuses, training and conferences, professional dues, vehicle costs, travel and accommodations, meals, and other supplies). Appendix 2-N as presented (the version uploaded to the proceeding dated July 19, 2024) provides, by year, of both the percentage of the allocation as well as the dollar costs allocated to API (i.e. $639,570 for 2025).
b) To supplement the explanation provided in a) above, both administrative shared service and corporate allocation methodologies are reviewed in advance of Canadian Niagara Power rebasing, which most recently was for rates effective 2022. During the review exercise, allocation methodology is reviewed for reasonableness and updates are made to the methodology where appropriate. The approach for allocating corporate services is outlined in a) above was reviewed for 2022 and the outcome resulted in a negligible change in the relative percentage allocation to API, from 21.8% (for the years 2017 to 2021) to 21.5% (for the years 2022 to 2026).
c) A breakdown, by the main functional areas (Finance & Purchasing, IT, HR, Health, Safety, Environment, and Regulatory), of the shared administrative services provided

CNPI to API has been provided in Appendix 2-N (the version uploaded to the proceeding dated July 19, 2024). From an internal accounting perspective, all costs directly related to each of these functions is captured in a set of internal financial records for tracking, but records are not maintained at a further level of detail within each function (i.e. not by individual sub-activities within the various functions). For example, accounting records are not maintained at a level of detail to separately identify and track all of the costs directly associated with the management of Accounts Payable processing within the Finance corporate function; rather those costs are included in one set of financial accounting records alongside all direct costs associated with the Finance function as a whole. The types of sub-activities/services provided within each corporate function, which are tracked and then shared through allocations, can be found in The Service Agreement which was provided in Attachment 4B of Exhibit 4 of the Application. Additional commentary on services that are shared can be found in Section 4.1.1 of Exhibit 4. Both the percentage and dollar allocations by function have been provided in Appendix 2-N. Below is a table outlining the allocation methodology drivers, highlighted by function.

Shared Functional Area	Cost Allocation Methodology
Finance & Purchasing	A review of the sub-activities and/or positions performed within Finance & Purchasing functions by respective staff which included a combination of equally splitting the effort, using an estimate of the relative amount of effort for certain sub-activities by company, and/or using historical relative spend for allocation percentages, to then arrive at total Finance & Purchasing functions percentage allocation to each company. Examples of sub-activities/positions individually reviewed were payroll processing, accounts receivable, accounts payable, financial reporting and planning, management of capital asset accounting, general accounting support, financial controls oversight and Internal Audit.
IT	Based on a weighted scoring system that considers the relative weighting of support/effort provided by IT to FortisOntario (including subsidiary) employees.
HR	Weighting based on the relative number of employees.
Health, Safety, Environment	Weighting based on the relative number of employees.
Regulatory	Based on estimate of relative amount of effort/support provided to each FortisOntario subsidiary.

d) See table below.

	2025 Test Total	
CNPI Shared IT Total Avg NBV	4,144,000	**A**
Depreciation Estimate	1,097,800	**B**
CNPI Cost of Capital Rate	5.75%	**C**
CNPI Return on Avg NBV	238,300	**D = A * C**
Equity	40.00%	**E**
CNPI ROE	8.66%	**D**
CNPI Corporate Tax Rate	26.50%	**G**
CNPI PILS	38,000	**H = A * E * D * G**
CNPI Grossed-up PILs	51,700	**I = H / (1 - G)**
Total Shared IT Assets Including Return and Grossed-up PILs	1,387,800	**J = B + D + I**
API IT Shared Allocation %	31%	**K**
API Shared IT Allocated $	431,600	**L = J * K**
Per 2-N	431,621	
Difference	- 21	rounding

5-SEC-31

[Ex. 5, Table 5 and Appendix 2-OB]

a. Please provide an update on the new $55M debt which was to be secured July 1, 2024.
b. Please explain why Algoma is retiring its affiliate debt, which in Table 5 is shown at 4.13% and in Appendix 2-OB is shown at 3.21%, and taking on new debt at 6%?

API Response:

a) Please refer to the response provided in 5-Staff-52
b) Please refer to the response provided in 5-Staff-52.

6-SEC-32

[Ex. 6, p. 18-19] What is the dollar impact to 2025 PILs from Algoma's proposal to smooth the effect of the accelerated CCC being phased out as of 2028?

API Response:

For the 2025 calculated PILs, an increase to taxable income of $212,000 has been added to the PILs model which has been labeled as "Addition for Smoothing of Enhanced CCA Impact" under the Total Additions section of the T1 Sch 1 Taxable Income Test tab.

6-SEC-33

[Ex. 6, Appendix 2-H] Please explain the forecasted reduction in Account 4210 Rent from Electric Property in 2025.

API Response:

The value relates to pole attachment revenues. API has been tracking the difference between pole attachment rates included in API's 2020 approved revenue requirement ($44.50 per attacher per pole per year) and the OEB's subsequent change in approved pole attachment rates throughout the historical through bridge years. See Exhibit 9, Sections 9.3.2 and 9.3.10. The 2025 Test Year value is a reflection of the 2024 OEB published rate $37.78 per attacher per pole, plus an estimate for inflationary increases (API estimated rate of $40.00 for 2025 per attacher per pole per 6-VECC-33), along with an estimate of 11,100 pole attachers, which is in line with the historical number of pole attachers.

7-SEC-34

[Ex. 7, p. 11-12] Please provide the backup data and analysis that was used to calculate:

a. The Weighting Factor for Services of 10 for the R2 class.
b. The Weighting Factor for Billing and Collecting of 10 for the R2 class.

API Response:

a) The weight factor for services for the R2 class is unchanged from the 2020 COS. Please see the explanations below from Exhibit 7 of the 2020 Application (EB-2019-0019, filed May 17, 2019).

> **Weighting Factor for Services Account 1855**
>
> Due to the very rural nature of the API distribution system, the ongoing practice has all customers providing their own service assets which are connected to API's distribution system by API personnel using API's connection assets. The weighting factors are based on an estimated of time and materials required to complete these connections.

Residential – R2: the weighting factor is set to 10 to reflect that connection assets must be suited to larger services and to reflect that these connections are often more complex, and that additional labour is often required to coordinate connection and commissioning activities with the customer's contractor.

b) The tables below summarize the derivation of the Billing and collecting Weight Factors. The weight factor of 10 was assessed for the R2 Class, based on an allocated $443.63/customer in the R2 class, compared to $44.53 in the R1 class, leading to a relative weighting of 10. Please also refer to the methodology outlined in 7-Staff-60.
API estimated the allocation per class of 6 major cost drivers in the Billing and Collecting Accounts (Billing Labour, Postage and Print, Meter communications, Customer Service Labour and Outage Call Service). Each of these costs items was allocated among the classes based on an appropriate allocator. The cost per customer for each driver was then estimated by dividing by the number of customers in each class, to arrive at the above-mentioned estimated costs per customer (ie: $443.63/customer for R2 vs. $44.53 for R1).

Average Cost per Customer Class - R2 vs. R1			
Number of Customers		9,611	41
Cost Per Customer		$ 44.53	$ 443.63
Relative Cost per Customer (Weght factor)		1	10

Allocation of Billing $ Collecting Costs to R2 Class

	Total Cost	Allocator	R2 Allocation	Number of Customers	Cost Per Customer	Allocator Basis
Billing- Labour	$ 70,869.36	6%	$ 4,489.59	41	$ 108.25	Staff time spent on billing interval * interval meters/class +Staff time spent on smart meter billing*smart meters/class
Billing- Postage and Print	$ 119,216.69	0%	$ 105.59	41	$ 2.55	Number of paper bills per month
Collecting- Labour	$ 158,545.32	0%	$ 530.79	41	$ 12.80	Estimate of effort and frequency of collections activities
Meter Comms	$ 11,171.79	100%	$ 11,171.79	41	$ 269.36	Interval/MIST cost only
Customer Service Labour	$ 205,878.93	1%	$ 2,058.79	41	$ 49.64	Allocation primarily based on number of customer, with "judgement based" adjustments based on frequency and length of typical call from each class.
Outage Calls	$ 12,790.08	0%	$ 42.82	41	$ 1.03	number of customers per class
Total of Above					**$ 443.63**	

9-SEC-35

[Ex. 9, p. 26 and Table 9-8, DVA Continuity Schedule and Proposed Tariff] As per the 2020 approved settlement, funding for the two ACMs for the R1 and R2 classes was provided through the RRRP. Please explain why the over-collection of funds shown in Table 9-8 is being refunded directly back to the customers in these two classes and not being applied to offset RRRP funding?

API Response:

API notes that all credits and debits in deferral or variance accounts that track variances between API's actual revenue requirement relative to the revenue requirement underpinning API's rates are collected from/returned to API's customers, both in the proposed clearances of accounts in this proceeding and in previous proceedings. To API's knowledge, the same is true for all distributors that receive RRRP and/or DRP funding against their distribution rates; variances against base distribution rates, both positive and negative, are cleared to customers, not the source of RRRP or DRP funding.

9-SEC-36

[Ex. 9, p. 34]

a. Please provide the yearly actual/forecast amounts for 2020 to 2024 in Account 5095 Operations Overhead Distribution Lines and Feeders- Rental Paid.
b. Please provide details for the entries to the proposed DVA, should an agreement consist of a lump sum payment instead of annual payments.

API Response

a) See table below.

OEB Acct	OEB Acct Description	2020 Last Rebasing Year Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2024 June YTD Actuals
5095	Overhead Distribution Lines and Feeders - Rental Paid	20,318	153,074	288,354	268,746	381,876	238,862

b) Please see 9-Staff-75 part e.

9-SEC-37

[Ex. 9, p. 36] Algoma references a number of cases where the OEB has approved 'similar variance accounts' to Algoma's requested Defined Benefit Pension Plan Variance Account. For each case, e.g., Enbridge Gas (EB-2022-0200), Hydro One Transmission and Distribution (EB-2021-0110) and Ontario Power Generation (EB-2020-0290), please provide a comparison table to Algoma's request. Please include in the comparisons such things as; is there a deadband, what specifically is being recorded in the account, accrual versus cash or change in discount rate, etc.

API Response:

Please see the table below:

	Most Recent Approval	Accounting Methodology	Variance Tracked	Reference	Deadband	Scope of Vairance
Ontario Power Generation	EB-2020-0290	Accrual	This account records the difference between (i) the pension and other post employment benefit ("OPEB") costs, plus related income tax PILs, reflected in the revenue requirement approved by the OEB; and (ii) OPG's actual pension and OPEB costs, and associated tax impacts, for the prescribed generation facilities. Actual pension and OPEB costs used in the calculation of the difference are calculated on an accrual basis using the same accounting standards as those used to derive the reference amount.	EB-2020-0290 Exhibit H1, Tab 1, Schedule 1 page 23	N/A	Full Pension and OPEB costs, both OMA and Capital impacts
Hydro One Networks Inc.	EB-2021-0110	Cash	This account tracks the difference between the OM&A portion of pension cost estimates based on actuarial assessments used in the approved revenue pension cost estimates based on actuarial assessments used in the approved revenue requirement and the actual OM&A portion of pension contributions.	EB-2021-0110 Exhibit G1, Tab 1, Schedule 1 page 47	N/A	Pension Costs, OMA only
Enbridge Gas Inc.	EB-2022-0200	Accrual and Cash	This account records the difference, in excess of a $10 million deadband (debit or credit), between the revenue requirement impact of actual pension and other post-employment benefits (OPEB) costs (accrual and cash-based amounts) and the revenue requirement impact of pension and OPEB costs (accrual and cash-based amounts) included in rates.	EB-2022-0200 Exhibit O1 Tab 1 Schedule 2 page 46	$10M	Full Pension and OPEB costs, both OMA and Capital
Algoma Power Inc.	N/A	Accrual	Any variances recorded in the proposed variance account will reflect the difference between the 2025 Test Year forecasted Defined Benefit Pension OM&A and actual.	EB-2024-0007 Exhibit 9, page 36	N/A	Defined Benefit Pension only, OMA only

1.0-VECC-1

Reference: Exhibit 1, page 42

API indicates variances in overall spending during the historical period were driven by several one-time projects.

a) Please provide a cost variance analysis for the #4 Circuit Project (System Access, 2023).

API Response:

API did not include any project budget for this project in the prior DSP, due to the uncertain nature of the project at the time of drafting the DSP. API had mentioned the request for new capacity in its last Application, however the incremental load requirements and timing had not been confirmed by the customer.

The following variance analysis compares the project budget by category based on the initial Economic Evaluation versus the Final Economic Evaluation. Several Change Orders were required to the project budget, the most significant of which was driven by a customer requirement to include a costly water crossing. Overall, the estimated distribution cost was $9,907,097, and the actual spending for distribution is $11,233,479.

Project Component	Total Estimated Cost (excl. HST)	Actual Costs
Contractor General Costs	$ 483,593	$ 914,518
Land	$ 115,592	$ 788,451
Line Construction	$ 7,021,330	$ 7,258,755
Premium	$ 93,571	$ 653,851
Project Management and Studies	$ 900,781	$ 1,617,904
SubTotal	**$ 8,614,867**	**$ 11,233,479**
Contingency (15% of Subtotal)	$ 1,292,230	$ -
Total	**$ 9,907,097**	**$ 11,233,479**

2.0-VECC-2

Reference: Exhibit 2

a) Appendix 2-AA: please provide on the basis of in-service additions and include excel version.

b) Appendix 2-AB: please provide on the basis of in-service additions and include excel version.

API Response:

a) Appendix 2-AA was already provided on the basis of in-service additions; the excel version was included as part of the Application Chapter 2 Appendix document.
b) Appendix 2-AB was already provided on the basis of in-service additions; the excel version was included as part of the Application Chapter 2 Appendix document.

2.0-VECC-3

Reference: **Exhibit 2, Appendix 2-AA**

a) Please add columns in Appendix 2-AA for 2024 year to date expenditures and provide in excel format.

API Response:

Please refer to 2-Staff-5.

2.0-VECC-4

Reference: Exhibit 2, Appendix 2-AB

a) Please provide the Accounts included in System O&M.

API Response:

Consistent with the formulas in the Chapter 2 Appendix document, the accounts included are listed below:

"System O&M contains the following accounts: 5005, 5010, 5012, 5014, 5015, 5016, 5017, 5020, 5025, 5030, 5035, 5040, 5045, 5050, 5055, 5060, 5065, 5070, 5075, 5085, 5090, 5095, 5096, 5105, 5110, 5112, 5114, 5120, 5125, 5130, 5135, 5145, 5150, 5155, 5160, 5165, 5170, 5172, 5175, 5178, 5195"

2.0-VECC-5

Reference: Exhibit 2, Attachment 2A, DSP

a) Page 55 (Table 2.13): Please provide a breakdown of Defective equipment outages by equipment cause code for the years 2019 to 2023.

b) Page 56 (Table 2.14): Please provide a breakdown of Defective Equipment Customers Interrupted by equipment type for the years 2019 to 2023.

c) Page 58 (Table 2.15): Please provide a breakdown of Defective Equipment Customers-Hours Interrupted by equipment type for the years 2019 to 2023.

API Response:

a) Algoma Power has provided a breakdown of outages by asset class from 2019 to 2023 in response to 2-Staff-8 (b).

b) Algoma Power has provided a breakdown of defective equipment customer interrupted by asset class from 2019 to 2023 in response to 2-Staff-8 (b).

c) Algoma Power has provided a breakdown of defective equipment customer-hours of interruption by asset class from 2019 to 2023 in response to 2-Staff-8 (b).

2.0-VECC-6

Reference: Exhibit 2, Attachment 2A, DSP, page 112

a) Please provide the derivation of the calculation of Contributed Capital in Figure 4.2 for the years 2025 to 2029.

API Response:

The forecasted contributed capital is based on a 2025 forecast of $100,000, and adjusted annually by a 2% level for expected inflation. API believes $100,000 is a reasonable forecast taking into consideration that typically only System Access projects are expected to feature a CIAC, and the average CIAC in 2020, 2022, 2023 is approximately $106k. 2021 was excluded from this analysis due to unusually high levels of third-party relocation work and #4 Circuit Project. Without these specific 2021 projects, the System Access CIAC is $102k, in line with API's expectations.

2.0-VECC-7

Reference: Exhibit 2, Attachment 2A, DSP

a) Page 115: For 2024 AGI estimates 8 permits to connect to 297 API poles (as of March 2024). Please update.

b) Page 116: Please provide API's final project cost variance reports or equivalent for the following projects:
- Distribution Line Rebuilds
- Dubreuilville Station Rebuild
- Bruce Mines DS Rebuild

c) Page 117: Please allocate Distribution Lines Rebuild total overspend variance of $5.6 M to the three cost drivers.

d) Page 118: Please allocate Dubreuilville Sub 86 Rebuild total overspend variance of about $1.3 M to the cost drivers.

e) Page 119: Please allocate Bruce DS Mines Rebuild total overspend variance of $2.3 M to the cost drivers.

f) Page 119: Please allocate Bruce DS Mines Rebuild total overspend variance of $2.3 M to the cost drivers

API Response:

a) As of August 2024, Algoma Power has received about 120 permits to connect to 3,274 Algoma Power poles in which 89 poles would require replacement. Based on the feedback from the internet service providers, Algoma Power is expecting another 400-500 permits to connect to an additional 12,000 Algoma Power poles.

b) The following is the updated Project cost variances for the three programs/projects:

Project	Net Plan ($000's)	Net Actual ($000's)	Net Variance ($000's)
Distribution Line Rebuilds	14,783	20,377	5,594
Dubreuilville Sub 86 Rebuild	1,496	2,856	1,360
Bruce Mines DS Rebuild	2,000	4,346	2,346

c) Please see the table below for the allocation of cost driver overspend variances for the Distribution Line Rebuilds:

Distribution Line Rebuilds

Cost Drivers	Overspend Variance ($000's)	Overspend Variance (%)
Material Cost Increases	$ 1,543	27.59%
Contractor Cost Increases	$ 1,009	18.03%
Line Upgrade (1-Phase to 3-Phase)	$ 995	17.78%
One-time in-service addition of Dubreuilville Line assets	$ 272	4.86%

d) Please see the table below for the allocation of cost driver overspend variances for the Dubreuilville DS Project:

Dubreuilville Sub 86 Rebuild

Cost Drivers	Overspend Variance ($000's)	Overspend Variance (%)
Incremental Site Preparation	$ 50	3.7%
Additional Distribution Pole Relocations (part of feeder egress)	$ 69	5.1%
Reconfiguration of 44kV Incoming Line	$ 55	4.1%
Additional Project Management & Engineering	$ 307	22.6%
Higher design-build contractor, third-party & material costs	$ 864	63.5%

e) Please see the table below for the allocation of cost drivers overspend variance for the Bruce Mines DS Project:

Bruce Mines DS Rebuild

Cost Drivers	Overspend Variance	
	($000's)	(%)
Higher than anticipated Design-build cost & Material Cost increases	$ 1,510	64.4%
Increases in Major Material Costs	$ 127	5.4%
Land purchase was higher than planned	$ 130	5.5%
Reconfiguration of 34.5kV Line to Site	$ 212	9.0%
Additional Project Management & Engineering	$ 197	8.4%

f) API notes that 2-Vecc-7(f) is a duplicate question for which the response is provided in 2-Vecc-7(e).

2.0-VECC-8

Reference: Exhibit 2, Attachment 2A DSP

a) Page 122: Regarding the Echo River TS project, in May 2021, API proceeded to execute the connection and cost recovery agreement (“CCRA”) with HOSSM for $7.76 M. Please provide a copy of the CCRA.

a) Page 122: Please provide the notices from HOSSM In July 2022 and September 2022 for additional funding.

b) Page 123: Please provide the original business case and subsequent business cases for this project.

c) Page 123: Please provide a copy of the July 2022 cost benefit analysis.

d) Page 121: In December 2020, API received the HOSSM estimate for the procurement and installation of a second transformer at the Echo River TS. HOSSM provided a final class 3 estimate of $7.76 M. Please provide a copy of the final class 3 estimate.

e) Page 124: Please provide copies of the quarterly project reports in Table 4.6 and any subsequent reports.

f) Page 124: In an email report, HOSSM indicated that further additional funds would be required to cover increased cost for commissioning. Overall, HOSSM indicated that an additional $99k would be required.
Please provide a copy of the email report.

API Response:

a) Algoma Power has included a copy of the executed CCRA in the uploaded responses

a) Algoma Power has included copies of the email notices in the uploaded responses.

b) The original business case was included in Algoma Power previous DSP (Please see Exhibit 2, page 201 in EB-2019- 0019). As part of the settlement of API’s 2020 Cost of Service, Algoma Power committed to provide a business case analysis that incorporates the updated forecast cost responsibility for the project based on the outcome of Hydro One’s detailed engineering study and cost estimate process. This business case analysis was included as Appendix J to the DSP.

c) Algoma Power did not create a new cost benefit analysis per se, but rather revisited the one that was previously drafted and proceeded on the basis of understanding the cost implications had Algoma Power proceeded with cancelling the project with Hydro One. This is further described in detail in Section 5.4.1.1.2 of the DSP under the Echo River TS heading.

d) HOSSM included the final class 3 estimate as part of issuing their CCRA. The breakdown of the estimate can be found on Page 14 of the CCRA.

e) Algoma Power has included copies of the quarterly project reports in the uploaded responses.

f) Algoma Power has included a copy of this email notice in the uploaded responses.

2.0-VECC-9

Reference: Exhibit 2, Attachment 2A, DSP, page 127

a) For the Sault Ste. Marie Facility (SSM Facility) project, please provide a breakdown of approved project costs compared to actuals and provide a detailed explanation of the cost overruns.

b) Please provide copies of all Change Orders for the project.

c) Please provide copies of the quarterly project status reports.

API Response:

a) Please refer to the explanation provided in 2-SEC-10 regarding the ACM approved facility cost budget adjustment. Additionally, please refer to Table 41 and the associated narrative in the Application for an outline of the changes to the project costs.

Following the reduction from $14.1M in the Application to $12.69M approved for ACM purposes, API investigated its options to reduce the overall project budget. By arranging for the severance and reconveyance of a large portion of the land purchased, API was able to achieve reductions to the Land budget of approximately $370k. For the construction contract, which was awarded to the lowest bid, through a competitive bidding process, API was unable to obtain any bids to achieve the target project cost.

b) Please refer to Attachment 2-VECC-9b

c) API and its Owner's Engineer had bi-weekly meetings with the Constructor reviewing civil, structural, architectural, mechanical, electrical and security design and progress to date. The meeting typically involved verbal updates, with limited formal reports.

2.0-VECC-10

Reference: Exhibit 2, Attachment 2A, DSP, page 129

a) Please provide the number of service connections for each of the years 2020 to 2029.

API Response:

a) The table below provides a quantitative summary of new and upgraded service connections from 2020 to 2023 and the forecasted new and upgraded service connections from 2024 to 2029:

	Actual				Forecast					
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Qty of Service Connections	198	262	217	233	242	232	232	232	232	232

2.0-VECC-11

Reference: Exhibit 2, Attachment 2A, DSP

a) Page 150: With respect to Distribution Line Rebuilds please explain the increase in spending in 2024 and the scope/volume of work in 2024 compared to 2020-2023.

b) Page 155: With respect to Subtransmission Line Rebuilds please explain the increase in spending in 2024 and 2025 to 2029 compared to the years 2020-2023 and provide the scope/volume of work in 2024.

c) Page 159: With respect to Smart Meter Replacements, please provide the business case.

d) Page 159: With respect to Smart Meter Replacements, please explain why the program does not commence in 2027.

e) Page 164: With respect to Wawa #2 DS Rebuild, please provide a breakdown of the $4.584 million in costs in 2027.

API Response:

a) The increase in spending in 2024 with respect to the Distribution Line Rebuild program is associated with a larger level of in-service additions coming online compared to 2020-2023.

b) The increase in spending in 2024 with respect to the Subtransmission Line Rebuild program is associated with a larger level of in-service additions coming online compared to 2020-2023.

c) API's current population of Smart Electric meters were installed in 2009. With this meter population aging API risks an exponential failure rate of our existing meter population. With this in consideration, along with lengthy procurement lead times, API weighed the risks associated with having meter failures without adequate replacement inventory. By creating a staggered changeout plan we are mitigating failure risk. Furthermore, the bulk of our existing meter population is up for seal renewal in 2027. Should failures be present during this time, or sample grouping requirements not be met, API would not have sufficient time to source replacements and meet Measurement Canada requirements.

   Since the inception of Smart Metering in 2009, technology in Smart Metering has evolved. Our current outage management system at API utilizes smart meter information for both voltage and outage monitoring telemetry. By transitioning towards a newer meter technology, it will allow for better telemetry and other data from our electrical infrastructure on our electrical infrastructure, allowing API to monitor more accurately end of line power quality to our customers.

d) With the inception of Smart Metering in 2009, Government Mandates for installation timeframe required utilities to purchase meters in a bulk lot to meet the required deadline. This approach places the bulk of installed meters under the same manufacturer order, and Measurement Canada Seal requirement.

By taking a staggered approach to meter installation, API is breaking down our meter population into smaller manageable lots. Should there be a manufacturing issue or recall, the lot size is manageable for the RMA (Return Merchandise Authorization) process. Furthermore, this staggered approach tiers Measurement Canada Seal requirements over multiple years, allow manageable lot sizing for future testing and replacement.

The intent is to start this process early as a proactive rather than reactive approach. This allows labor cost to be spread over multiple years, and API not to risk being non-compliant with Measurement Canada should adequate time not be available in a one-year approach.

e) Please see the breakdown in the table below:

Project Management	$ 84,000
Owner's Engineer	$ 130,000
10MVA 34.5kV : 4.8/8.32kV Transformer	$ 520,000
5MVA 34.5kV : 7.2/12.5kV Transformer	$ 360,000
Major Switch Materials	$ 200,000
Engineering/Design	$ 250,000
Mobilization/Demobilization	$ 100,000
Construciton -Civil/Structural	$ 1,200,000
Construction - Electrical	$ 1,000,000
Construction - Commissioning	$ 150,000
Construction - Decommissioning	$ 50,000
Construction - Material Cost	$ 525,000
Station Energization and Cut-Over	$ 15,000
Total	$ 4,584,000.00

2.0-VECC-12

Reference: Exhibit 2, Attachment 2A, DSP, page 169

With respect to Goulais Area Voltage Conversion, API developed a Greenfield TS report, that considered different supply options with the objective of identifying API's long term supply needs. The recommendation from this report was to refurbish the existing Goulais TS and convert its distribution system to 25kV within the next 10-15 years.

a) Please provide the scope and volume of work for the period 2025 to 2029.

b) Please provide the remaining scope and volume of work beyond 2029.

c) Please confirm the investment alternative selected and why.

API Response:

a) Algoma Power has proposed to complete the scope and volume defined in Alternative B, described in Section 5.4.2.4.3.1 and includes the following:
   a. Reinsulate 532 primary distribution poles
   b. Upgrade 205 distribution transformers, including the fuse link and arrester
   c. Convert approximately 76km of primary distribution lines in the Goulais River area
   d. Install 7 step-down transformers that will bridge the 25kV system to the 12.5kV system.
   e. Once the Goulais River TS refurbishment is complete and ready to supply the Algoma Power distribution system, convert the 76km of primary distribution lines and the associated distribution equipment.

b) The remaining scope and volume of work beyond 2029 would include approximately the following:
   a. Reinsulate 1,416 primary distribution poles
   b. Upgrade 686 distribution transformers, including the fuse link and arrester
   c. Convert approximately 126 km of primary distribution lines
   d. Remove the 7 step-down transformers that were previously used to bridge the 25kV system to the 12.5kV system
   e. Once the Goulais River TS refurbishment is complete and ready to supply the Algoma Power distribution system, convert the 126km of primary distribution lines and the associated distribution equipment.

c) Algoma Power has identified three alternatives that were defined approximately by the area of coverage, either 25%, 50% or 100%. This area of coverage would begin at the Goulais River TS and expands outwards. As described in the alternative analysis, Alternative A and Alternative B were similar in net-present value cost and Alternative C substantially higher. Alternative C would also require substantial logistical coordination and potential challenges with regards to actually switching the distribution from the lower voltage to the higher voltage once the Goulais River TS refurbishment is complete. Alternative A and B would require significant effort and logistical coordination in this regard. Both Alternative A and B are similar in cost and effort involved, however Alternative B would have better system loss improvements. It is for this reason that Algoma Power selected Alternative B as the preferred and proposed alternative.

Algoma Power has also included further details and explanations in the response to 2-Staff-26.

2.0-VECC-13

Reference: Exhibit 2, Attachment 2A, DSP page 173

With respect to Protection, Automation, Reliability:

a) Please provide a breakdown of the costs of $11,213 million in 2023 and $1.485 million in 2024.

API Response:

a) The following is a breakdown of the costs under Protection, Automation, Reliability in 2023 and 2024:

Project Description	2023	2024
Echo River TS 2nd Transformer	$ 10,851,932	$ 154,279
Bar River Contingency Upgrade	$ 276,001	$ -
Maclennan Rd Recloser Upgrade	$ 85,311	$ -
Desbarats DS Contingency Upgrade	$ -	$ 463,494
Batchawana TS Refurbishment/Feeder Relocation	$ -	$ 724,669
Dubreuilville LV Inter-tie Switch	$ -	$ 50,339
Bar River DS 12.5kV Switch Install	$ -	$ 92,189
Total	$ 11,213,244	$ 1,484,971

2.0-VECC -14

Reference: Exhibit 2, Attachment 2A, DSP, page 184

With respect to Transportation & Work:

a) Please provide a breakdown of fleet vehicles replaced for each of the years 2020 to 2023 and include the age and mileage of each vehicle.

b) Please provide a breakdown of fleet vehicles to be replaced in each of the years 2025 to 2029 and include the age and mileage of each vehicle.

API Response:

a) Please see the table below:

Replacement Year	Vehicle Unit#	Year Purchased	Description	Mileage
2020	09.23	2009	Freightliner c/w RBD	165,453
	12.34	2012	Dodge RAM 1500	239,999
	13.38	2013	Ford F250	285,620
	51.35	2011	Vermeer BC1000 Chipper	NA
2021	09.25	2009	Dodge RAM 5500	306,251
	12.32	2012	International c/w Forestry Lift	201,505
	12.33	2012	Dodge RAM 1500	193,778
	11.31	2011	Landscape Trailer	NA
2022	47.16	2012	Arctic Cat Snowmobile	N/A
	15.49	2015	Chevrolet 2500	252,334
2023	14.41	2014	Ford F250	261,656
	50.32	2010	Polaris Snowmobile	N/A
	14.43	2014	Ford F150	192,901
	16.56	2017	Chevrolet Traverse	76,886
	16.53	2012	Dodge RAM 1500	315,505

b) Please see the table below:

Replacement Year	Vehicle Unit#	Year Purchased	Description	Mileage
2025	11.30	2011	Freightliner with Posi 400-46 MHD	214,000
	13.40	2013	Freightliner with Posi 400-46 MHD	243,000
2026	14.47	2014	Freightliner with Altec AM55E MHD	182,811
	15.50	2015	Freightliner with Altec LR7-60E70 Forestry Lift	193,750
2027	16.55	2017	Freightliner with Posi 500-55AUE	125,341
	15.51	2015	Dodge 3500 Forestry Service	234,294
	15.52	2015	Ford F150	163,000
	17.60	2018	Chevrolet 2500 HD	215,000
	18.65	2019	Ford F250	192,000
	52.38	2011	PoleTrailer	NA
	55.50	2016	Landscape Trialer	NA
	44.76	1993	Strining Trailer	NA
	55.44	2015	SkiDoo Snowmobile	NA
2028	17.58	2018	Freightliner with Posi 500-55AUE	190,791
	19.69	2019	Dodge Ram 1500	125,275
	19.70	2019	Ford F150	126,000
	19.71	2019	Ford F250	176,022
	20.76	2020	Ford F150	103,989
	20.77	2020	Ford F250	NA
	55.57	2017	Vermeer BC1500 Chipper	NA
	48.24	2008	Polaris Snowmobile	NA
2029	19.67	2019	Freightliner with Wajax RBD	61,279
	21.81	2021	Ford F150	48,667
	22.87	2022	Ford F250	43,071
	22.88	2022	RAM 2500	46,732
	55.75	2020	Vermeer BC1500 Chipper	NA
	43.10	1990	Caterpillar R80 Fork Lift	NA
	55.47	2015	Enclosed Trailer	NA
	54.43	2013	Argo 8 Wheel ORV	NA

2.0-VECC-15

Reference: Exhibit 2, Attachment 2A, DSP. page 184

With respect to Buildings, Facilities & Yards, please provide a breakdown of the work program and associated costs in each of the years 2025 to 2029.

API Response:

A breakdown of 2025 project expenditures by area of investment under the Buildings, Facilities & Yards has been included in response to 2-Staff-24.

API has planned for similar capital expenditures amount from 2026-2029 but is not able to provide any specific project at this time.

2.0-VECC-16

Reference: Exhibit 2, Attachment 2A, DSP

Please provide the number of failures for each of the following assets in each of the years 2020 to 2023:

-Wood Poles
-Distribution Transformers
-Overhead Switches
-Overhead Conductors
-Underground Cables
-Substations

API Response:

Algoma Power has provided a breakdown of outages by asset class from 2019 to 2023 in response to 2-Staff-8 (b).

2.0-VECC-17

Reference: Exhibit 2, Attachment 2A, DSP, Appendix D

a) Please provide API's previous Asset Condition Assessment.

b) Page 26: For each of the asset categories in Table 4-1, please provide the number of assets replaced in each of the years 2020 to 2024.

c) Page 26: For each of the asset categories in Table 4-1, Please provide the forecast assets to be replaced for each of the years 2025 to 2029.

d) Please discuss the percentage of assets replaced over the period 2020-2023 in poor or very poor condition and the forecast for 2025.

API Response:

a) API's previous Asset Condition Assessment has been included as Attachment 2-VECC-17.

b)

	2020	2021	2022	2023	2024
Station Power Transformers & Voltage Regulators	0	0	3	0	0
Station Reclosers	0	0	0	0	1
Station Switches	0	0	4	0	4
Station Yards	0	0	1	0	1
Poles	338	634	518	587	652
Ratio-Bank Transformers	0	0	0	0	0
Capacitor Banks	0	0	0	0	0
Voltage Regulators	0	0	0	0	0
Overhead Conductor (km)	10	8	7	11	10
Underground Cable (km)	0	0	0	0	0
Distribution Transformers	21	18	34	25	10
Reclosers	0	0	0	1	0

API did not include transformers that were replaced as a result of customer connections. In these instances, the existing transformers would have been returned to inventory.

The station equipment and yard replaced in 2022 refers to the Dubreuilville #2 DS rebuild and retitled Dubreuilville Sub 86, the new name for the station.

c)

	2025	2026	2027	2028	2029
Station Power Transformers & Voltage Regulators	0	0	1	0	0
Station Reclosers	0	0	2	0	0
Station Switches	0	0	2	0	0
Station Yards	0	0	0	0	0
Poles	500	500	500	500	500
Ratio-Bank Transformers	0	0	0	0	0
Capacitor Banks	0	0	0	0	0
Voltage Regulators	0	0	0	0	0
Overhead Conductor (km)	See Note				
Underground Cable (km)	0	0	0	0	0
Distribution Transformers	65	63	62	29	30
Reclosers	0	0	0	0	0

Conductor replacement is determined on a project-by-project basis based on age and size. As a result, API does not have the exact quantity of conductor that would be replaced.

d) The results of the asset condition assessment provide a more generalized snapshot of the overall condition and health of the various asset group. It does not provide specific asset health and condition, and so it is not possible to confirm at this time the percentage of assets that have been or plan to be replaced with a poor to very poor condition.

Through API's maintenance and inspection programs, such as testing and inspections, identifies assets for priority replacement. As an example, API perform non-destructive pole testing to approximately 10% to the pole population annually. API receives a pole testing report with recommendations based on the test results. For any poles that were recommended to the replaced, API prioritizes these poles for replacements, typically within the following year.

3.0 OPERATING REVENUE (EXHIBIT 3)

3.0-VECC-18

Reference: **Exhibit 3, pages 5 & 6**

Preamble: The Application states:

"The variables selected are consistent with API's most recent (2020 COS) load forecast, with the exception of the employment variable which was replaced with a number of customers variable, and the days in month which improved the statistical outputs of the equation." (page 5)

And

"While the regression used in API's last load forecast included an employment variable, API found the number of customers variable to be statistically strong." (page 6)

a) How did replacing the employment variable with a number of customers variable improve the statistical outputs of the equation?

API Response:

In API's 2020 COS application, the employment variable used in API's 2020 load forecast had a T-stat of -2.795 along with a coefficient of –(34,494.856) as per API_2020 CoS_Exh 3_Revenues_20190517, Table 5 - Correlation/Regression Results. In preparing API's 2025 load forecast and reviewing the 2020 load forecast the statistical results of the employment variable appeared to be non-intuitive. The results suggest that as employment increases energy usage decreases which does not appear to be intuitive. As a result, the employment variable was replaced with the number of customers variable which resulted in a T-stat of 21.55 and a coefficient of 6,967.04. This T-stat result suggest number of customers is statistically more significant than the employment variable and with a positive coefficient the number of customers variable is intuitive which means as customers increase usage increases. The employment variable is typically used to reflect the economic conditions of the service area. However, number of customers, to a certain degree, also reflects the economic conditions of the service area.

3.0-VECC-19

Reference: Exhibit 3, page 14

a) Did API specifically test any COVID-related variables?

i. If not, why not?

ii. If yes, what COVID-related variables were tested and why were they rejected?

b) What other explanatory variables were tested and why were they rejected.

API Response:

a) Please refer to the response in 3-Staff-34 b

b) The number of days in the month was tested and added as a variable since the T-stat was 6.39 and the coefficient was 688,833.56 which is an intuitive result. No other variables were tested. Overall, the regression results produced a Adjusted R Square of 93.59% which was slightly better than the Adjusted R Square in API's 2020 load forecast.

3.0-VECC-20

Reference: **Exhibit 3, page 20**
Load Forecast Model, Rate Class Customer Model Tab

Preamble: The Application states:

"The formula is reasonably representative of API's natural customer growth. For the 2024 forecast customers counts, the 2023 averages were used as a starting point increased by the geomean from 2015 to 2019. During the COVID-19 pandemic, API observed above-average customer growth due to individuals relocating from other areas of the province. API believes this trend was limited to the COVID-19 pandemic, and is unlikely to continue. API considers that the geomean excluding 2020, 2021 and 2022 presents a more accurate viewpoint of the typical customer growth expected in future years, now that COVID impacts are slowing."

And

"Additionally, 2020 had an above normal increase due to the acquisition of a new service area, ie: the customers of the former Dubreuil Lumber Inc. (DLI)"

a) Please reconcile the concern about including data post 2019 in the determination of the growth rate due to COVID-19 impacts with the fact the customer growth for the each of the Residential and GS classes has continued in 2023 at higher rate than that seen pre-2020.

b) If the post-2019 years are excluded due to presumably residential customers relocating to API's service area, please explain why these years should be excluded when calculating the customer growth rates for the GS classes.

c) Please provide the actual customer count for each class as of June 30, 2024.

d) How many customers were added to each customer class as a result of the acquisition of the new service area?

API Response:

a) API made the assumptions in light of the fact that customer growth in 2023 -2025 is expected to slow down compared to the growth levels experienced in 2020 and 2021. This is confirmed by the 2022, 2023 and 2024 YTD growth rates.

b) The existing growth that occurred during the 2019-2023 period has been captured in the customer forecast as the forecasted growth rate is applied to 2023 customer numbers as the starting point. API does not believe future growth will occur at similar rates to the 2020-2021 period because of the one-time nature of customer relocations and the addition of the DLI customers.

c) Please Refer to 3-Staff-33.

d) Please see the table below:

	Changes to API customers as of August 7, 2019 (EB-2018-0271)
Residential	312
GS<50	47
GS>50	-1
Seasonal	0
Street Lights	50

3.0-VECC-21

Reference: Exhibit 3, pages 21-22

a) Please confirm that in Table 8 the historical counts for Street Lights represent the average number of devices in each year. If not confirmed, please provide the historical number of devices for each year.

API Response:

API confirms that the historical counts for Street Lights in Table 8 of Exhibit 3 represent the average number of device connections in each year.

3.0-VECC-22

Reference: **Exhibit 3, page 23**

Preamble: The. Application states:

"For both the 2024 bridge year and the 2025 test year, the historical loss factor employed is the five-year average total loss factor of 1.0873."

a) Please explain why API did not use the average loss factor for the entire historical period that was used in regression analysis (i.e., 2014-2023).

API Response:

a) API believes the more recent years' history to be a more appropriate forecast for the loss factor, due to the reflection of more recent customer and system conditions. The timeframe selected also aligns with the timeframe applied in the Loss Factor calculation used in Appendix 2-R.

3.0-VECC-23

Reference: **Exhibit 3, page 25**

Exhibit 2, DSP, page 72 (pdf page 131)

Load Forecast Model, Rate Class Energy Model Tab &

Rate Class Load Model Tab

Preamble: The Application states:
"For the R2 commercial class, API has made a manual adjustment to increase the forecast for the anticipated load associated with increased customer usage from the #4 Circuit project which is detailed in Exhibit 2. The project will bring 8MW in increased maximum customer load." (Exhibit 3)
And
"API subsequently received a deposit to proceed with CIA/SIA processes for a new 21 MW distribution load addition." (DSP)

a) Please explain the basis for the 8 MW referenced in Exhibit 3 and reconcile with the 21 MW reference in the DSP.

b) Please explain how the 51,899,643 kWh and 86,880 kW adjustments for this increased customer load were determined.

API Response:

a) API has been in discussions with two large commercial customers for several years. The original customer requests were for a larger level of additional capacity. API has investigated and presented offers to connect for multiple project configurations. Due to the nature of the requests and the characteristics of the delivery system (Transmission and Distribution) in the region, the solutions available to bring significant increases in capacity to the area can have long timelines and high cost levels.

The CIA/SIA targeted for 21 MW of incremental load was completed as part of an offer to connect associated with this higher level of requested capacity, which was not ultimately accepted by the customer. Upon further fine-tuning of requirements, considering costs, timing and other considerations, the #4 Circuit 10 MW project was developed, at the request of the customer(s) and accepted by the customer(s). Out of the 10MW incremental capacity, 8MW is assigned to the industrial customers and 2MW is reserved for the general distributed growth along #4 Circuit.

b) The starting point for the kW adjustment is the incremental 8 MW associated with the project. API then applied an adjustment factor to account for the differential between a customer's annual peak load and average monthly load. API then adjusted the kW forecast by an appropriate kW-kWh ratio to arrive at the incremental kWh forecast. Both the kW-kWh ratio and the annual peak vs. average monthly peak ratio were based on appropriate estimates specific to the nature of the customers.

OM&A (EXHIBIT 4)

4.0 -VECC-24

Reference: Exhibit 4, page 11

API indicates it tracks the program progress in API's vegetation management software and reports on the progress of the annual program.

a) Please provide the data tracked in the software and provide the annual vegetation management results for each of the years 2020-2024.

API Response:

API's software solution primarily focuses on landowner records and work prescriptions (specific instructions) pertaining to each property impacted by VM work activities. Progress of the annual program is currently tracked through excel spreadsheets and is used to capture program related information. This information is collected on a kilometer basis and includes kms completed, tree trims, removals, danger trees, litres of herbicide and work activity type (see Annual VM Tracking Sheet below for 2020-2024). API's software vendor has recently released a new version of their solution that is geared towards crew activity, progress tracking and data collection. API has made the investment to move to the new version to support efforts related to progress and program data collection, tracking and reporting.

Year	Circuit	Kms	Work Type	ROW Width (ft.)	Trims (# of)	Removals (#of)	Brushing	Mechanical (km)	Line Clearing	Danger Tree	Herbicide Litres
2020	No. 4 Circuit	49.60	BC	100	0	0	x		0	0	124.00
2020	Bruce Mines Part 1	48.40	LCBC	30	345	330	x	20.00	x	115	25.00
2020	Bruce Mines Part 4	35.00	LCBC	30				10.00			
2020	Garden River First Nation	13.00	BC	30	0	0	x		0	0	0.00
2020	Garden River First Nation	6.00	LC	30	40	100			x	25	0.00
2020	Goulais Part 4	32.00	LCBC	30	1,541	975	x	15.00	x	353	203.00
2020	Bar River Part 1	22.00	LCBC	30	1,833	1,500	x	20.00	x	425	0.00
2020	St Joe Part 4	74.00	BC	30	0	0	x	8.09	0	0	318.50
	Total Kms	280.00									
Year	**Circuit**	**Kms**	**Work Type**	**ROW Width (ft.)**	**Trims (# of)**	**Removals (#of)**	**Brushing**	**Mechanical (km)**	**Line Clearing**	**Danger Tree**	**Herbicide Litres**
2021	Bar River Part 1	37.37	LCBC	30	3,468	1,266	x	20.00	x	236	0.00

2021	Bruce Mines Part 1	48.40	LCBC	30	346	225	x		x	182	0.00
2021	Bruce Mines Part 2	72.00	LC	30	902	220		30.00	x	168	
2021	Bruce Mines Part 4	44.00	LCBC	30	2,800	1,975	x	15.00	x	248	406.00
2021	Garden River Part 3	4.70	BC	30	0	0	x		0	0	0.00
2021	Garden River Part 3	4.70	LC	30	3	2			x	4	0.00
2021	Goulais Part 2	63.30	BC	30	0	0	x	20.00	0	0	0.00
2021	Goulais Part 3	32.80	BC	30	0	0	x	10.00	0	0	40.00
2021	HWY 101 Part 1	49.90	BC	30	0	0	x	20.00	x	0	30.00
2021	St. Joes Part 4	50.00	LC	30	740	183			x	63	0.00
	Total Kms	407.17									

Year	Circuit	Kms	Work Type	ROW Width (ft.)	Trims (# of)	Removals (#of)	Brushing	Mechanical (km)	Line Clearing	Danger Tree	Herbicide Litres
2022	Bar River Part 3	58.80	LC	30	817	285			x	110	0.00
2022	Bar River Part 3	58.80	BC	30	0	0	x	22.80	0	0	100.65
2022	Batchawana Part 2	21.80	LCBC	30	0	0	x	10.00	x	28	0.00
2022	Bruce Mines Part 2	72.00	LC	30	902	220	x		x	336	0.00
2022	HWY 101 Part 1	36.60	LC	30	3,060	748	x		x	362	x
2022	Garden River Cycle 3&4	17.00	BC	30	0	0	x	9.00	x	0	0.00
2022	Garden River Cycle 3&4	17.00	LC	30	48	106			x	36	0.00
2022	No. 4 Circuit	43.12	BC	100	0	0	x	20.00	0	0	179.00
2022	Wawa Part 3	46.00	LC	30							
2022	Wawa 1&2	15.00	BC	100	0	0	x	10.00	0	0	73.00
2022	St. Joseph Island Part 1	73.60	LCBC	30	8,821	2,370	x	35.00	x	379	48.00
2022	Goulais Part 3	20.00	LC	30							
	Total Kms	479.72									

Year	Circuit	Kms	Work Type	ROW Width (ft.)	Trims (# of)	Removals (#of)	Brushing	Mechanical (km)	Line Clearing	Danger Tree	Herbicide Litres
2023	Batchawana Part 1	31.80	LC,BC	30	2,614.00	976.00	x	20.67	x	38	3.6

2023	34.5kv Off Road	45.00	BC	100	0.00	0	x	15.3	0	0	TBD
2023	Wawa Part 3	20.00	BC	30	0.00	0	x	4.4	0	0	TBD
2023	Bruce Mines Part 3	55.00	BC	30	0.00	0	0	13.75	0	0	363
2023	Bar River Part 2	40.00	LC,BC	30	890.00	837	x	20	x	96	0
2023	Batchawana Part 2	34.40	LC	30	819	290			x	110	0
2023	Batchawana Part 1	7.00	LC	30	606.00	675	x		x	34	0
2023	Goulais Part 3	10.00	LC	30	826.00	778	0		x	28	0
2023	No. 4 Circuit	0.00	LC	30	0.00	157	0		x	68	0
	Total Kms	243.20									

Year	Circuit	Kms	Work Type	ROW Width (ft.)	Trims (# of)	Removals (#of)	Brushing	Mechanical (km)	Line Clearing	Danger Tree	Herbicide Litres
2024	Dubreuilville	13.00	BC	30			x	1.85			92
2024	Missanabie	6.40	BC	30			x	0.9			
2024	Hawk Part 1	13.00	BC	30			x	2.35			78
2024	Localsh	4.30	BC	30			x	3.87			110
2024	Goudreau	16.00	BC	30			x	0.5			
2024	Goulais Part 1	54.70	LC,BC	30			x	13.3			
2024	Desbarats Part 1	41.55	LC,BC	30							
2024	Bruce Mines Part 3	20.00	LC	30							
2024	Goulais Part 3	9.00	LC	30							
2024	Goulais Reserve	20.00	BC	30							
2024	Batchawana Reserve	15.00	BC	30							
	Total Kms	212.95									

4.0 -VECC-25

Reference: Exhibit 4, page 41

The Appendix 2-K impact on OM&A is as follows: Decrease of $182,000, Increase of $17,000, Increase of $32,000, Decrease of $32,000, Increase of $483,000, Increase of $180,000

Please provide the derivation of these amounts.

API Response:

This is the change in the OM&A value at the bottom of the 2-K table, rounded to thousands. Explanations around the drivers of these fluctuations are discussed in Exhibit 4 as well as throughout these interrogatories and are impacted by a variety of factors which can be summarized as resulting from changes in FTE's, salary and benefit changes, and a shift in relative effort between capital and OM&A year-over-year.

4.0 -VECC-26

Reference: Exhibit 4, Appendix 2-K

The 2025 Test year total FTE of 74 is an addition of four FTE as compared to 2020 Board Approved.

Please provide a schedule that identifies the positions that have been added, removed and not filled since 2020 Board Approved.

API Response:

Response provided in 4-Staff-46 a provides a summary of the change in the 4 FTEs from 2020 Board Approved to 2025 Test Year.

4.0 -VECC-27

Reference: Exhibit 4, Appendix 2-K

a) Please provide data for Executive, Management, Union and Non-Union FTEs separately.

b) With respect to Total Salary and Wages, please provide the data for salary, overtime and incentives separately by FTEs in part (a).

c) Please an excel version of the response.

API Response:

a) See 4-SEC-28 for break-out. The Executive information has not been separated out as providing quantum for this specific allocation would mean providing a quantum for three FTE or fewer employees. Therefore, in accordance with Chapter 2 filing requirements, the Executive information has been included with the Management values as presented in 4-SEC-28.

b) See table below.

Appendix 2-K
Employee Costs

	Last Rebasing Year 2020 - OEB Approved	Last Rebasing Year (2020 Actuals)	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	12	11	12	11	12	11	11
Non-Management (union)	34	29	30	31	33	33	34
Non-Management (non-union)	24	25	26	26	26	30	29
Total	70	65	68	68	71	74	74
Salary and Wages							
Management (including executive)	$ 1,408,596	$ 1,394,922	$ 1,456,432	$ 1,468,081	$ 1,447,668	$ 1,434,734	$ 1,510,872
Non-Management (union)	$ 3,091,187	$ 2,715,014	$ 2,796,531	$ 2,994,453	$ 3,142,195	$ 3,459,775	$ 3,532,323
Non-Management (non-union)	$ 1,937,423	$ 2,025,466	$ 2,198,820	$ 2,175,633	$ 2,427,527	$ 2,532,510	$ 2,692,996
Total	$ 6,437,207	$ 6,135,402	$ 6,451,783	$ 6,638,167	$ 7,017,389	$ 7,427,019	$ 7,736,191
Overtime							
Management (including executive)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non-Management (union)	$ 374,910	$ 364,864	$ 291,127	$ 377,912	$ 286,796	$ 403,020	$ 375,318
Non-Management (non-union)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 374,910	$ 364,864	$ 291,127	$ 377,912	$ 286,796	$ 403,020	$ 375,318
Incentive Pay							
Management (including executive)	$ 336,686	$ 350,677	$ 350,536	$ 340,919	$ 323,576	$ 371,311	$ 381,666
Non-Management (union)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non-Management (non-union)	$ 163,124	$ 173,570	$ 178,645	$ 167,779	$ 156,271	$ 184,683	$ 188,875
Total	$ 499,810	$ 524,247	$ 529,181	$ 508,698	$ 479,847	$ 555,995	$ 570,540

c) Please see Attachment 4-VECC-27 .

4.0 -VECC-28

Reference: Exhibit 4

Please provide a schedule that sets out a description of API's contracted services and amounts for each of the years 2020 to 2024 and forecasted for 2025-2029,

API Response:

API has made best efforts to provide the requested information however due to data limitations, the response provided was prepared on a "best efforts" basis and does not represent a robust and 100% accurate data set. Below are some of the factors affecting the complexity of the request.

- 2020-2023 data is provided on the basis of actual payments to vendors.
  - API obtained a vendor list and payments for each year, and manually identified which vendors provide contracted services. Some vendors, which primarily provide materials were excluded; however some of the amounts in the table may relate partially to the provision of materials rather than services.
  - API only considered vendors where 3-year purchase level exceeded ~$10,000.
  - The listing provided includes contracted services that were either expensed or capitalized.
- 2024-2025 data is provided on the basis of planned contracted services;
  - The amounts included are for both capital and OM&A.
  - Amounts by area represent those budgets where the external vendor payments are primarily related to contracted services (rather than materials), however some of the budgets provided may relate to materials.
  - Different methodologies were used to determine the 2024-2025 versus 2020-2023 data and therefore an "apples to apples" comparison would not necessarily be appropriate.
- API's forecasts for 2026-2029 were not prepared at a level that details the breakout of internal vs. Contract services vs. Other. Accordingly API does not have reasonably appropriate data to provide.
- API has considered only the services purchased directly through API in this response; services purchased from affiliates have not been taken into consideration, including any third party contracted services purchased by an affiliate and then shared with API through shared service allocations.

	Actual 2020	Actual 2021	Actual 2022	Actual 2023
Facility Maintenance and General Snow Removal	$ 467,894	$ 587,982	$ 592,633	$ 735,832
Financial Services	$ 712,951	$ 824,949	$ 859,663	$ 770,450
Communications	$ 106,714	$ 78,037	$ 80,645	$ 76,309
Training	$ 10,116	$ 16,159	$ 95,402	$ 86,363
Facility Move Support	$ 1,791	$ 172	$ 20,187	$ 319,238
Vegetation Management	$ 1,701,978	$ 3,844,125	$ 2,208,786	$ 2,373,685
Construction	$ 1,245,338	$ 7,389,283	$ 11,421,251	$ 10,217,110
Engineering	$ 373,861	$ 1,142,792	$ 1,087,361	$ 1,120,679
Customer Communication	$ 101,155	$ 112,792	$ 129,676	$ 152,232
Vehicle Rentals, Fleet Services	$ 439,577	$ 491,044	$ 657,260	$ 616,463
Asset Maintenance and Repairs	$ 29,084	$ 79,676	$ 199,465	$ 138,337
Legal/Regulatory	$ 84,901	$ 1,556,112	$ 798,219	$ 183,754
Construction	$ 136,010	$ 234,916	$ 66,024	$ 534,135
Customer Billing and Communications	$ 25,612	$ 5,663	$ 12,420	$ 21,258
Asset Assessment	$ 150,290	$ 192,202	$ 287,973	$ 232,226
Metering Support	$ 560,439	$ 592,238	$ 483,597	$ 610,361
Other	$ 107,139	$ 164,970	$ 238,886	$ 134,132
TOTAL	**$ 6,254,851**	**$ 17,313,113**	**$ 19,239,448**	**$ 18,322,564**

	Budget 2024	Budget 2025
Facility Maintenance and General Snow Removal	$ 404,500	$ 386,250
Financial Services	$ 161,398	$ 185,396
Communications	$ 127,628	$ 133,344
Training	$ 96,620	$ 76,893
Facility Move Support		
Vegetation Management	$ 1,914,917	$ 2,769,539
Construction	$ 3,757,348	$ 2,677,245
Engineering		
Customer Communication		
Vehicle Rentals, Fleet Services	$ 27,252	$ 10,130
Asset Maintenance and Repairs	$ 128,110	$ 389,685
Legal/Regulatory	$ 60,455	$ 67,058
Construction		
Customer Billing and Communications		
Asset Assessment	$ 26,080	$ 37,018
Metering Support	$ 55,116	$ 47,116
Easements/Rental Agreements	$ 508,435	$ 891,422
Benefits	$ 386,008	$ 394,186
Information Technology	$ 98,585	$ 149,904
Other	$ 328,268	$ 372,472
TOTAL	**$ 8,080,720**	**$ 8,587,657**

4.0 -VECC-29

Reference: Exhibit 4, page 26

With respect to Vegetation Management:

a) Please provide the accomplishments tracked and reported on under Line Clearing and Brush Control.

b) Please provide the Line Clearing and Brush Control costs for each of the years 2020 to 2023, and forecast budgets for 2025 to 2029.

c) Please provide unit cost data for the years 2020 to 2024 and forecast for 2025 to 2029 related to Line Clearing and Brush Control.

API Response:

a) Please refer to the tables provided in 4-VECC-24 and see Annual VM Tracking sheet.

b) The following table presents the costs for line clearing and brush control contracts entered into in each year. Due to timing differences these figures do not reconcile perfectly with annual spending. API does not track internal staff time spent on line clearing and brush control, but rather captures staff time spent on all activities by various sections of the service territory (ex: line clearing, brush control, demand work, inspections, etc all together). At this time, API has not yet forecasted the 2026-2029 budgets for line clearing and brush control.

Contractor Costs	2020	2021	2022	2023	2024	2025
LC	$ -	$ -	$ 328,494	$ 416,381	$ -	$ -
BC	$ 637,042	$ 659,794	$ 830,564	$ 385,869	$ 210,299	$ 1,311,266
LC,BC	$ 1,819,979	$ 1,677,380	$ 919,336	$ 1,219,947	$ 1,851,570	$ 1,582,378
0	**$ 2,457,021**	**$ 2,337,174**	**$ 2,078,394**	**$2,022,197**	**$2,061,869**	**$2,893,644**

c)The table below shows the 2020 to 2023 actual and 2024 to 2025 forecast contractor cost per km of line for Line Clearing, Brush Control and both Line Clearing and Brush Control km. API does not have forecasted costs per km for the 2026-2029 period.

Contractor Costs/Contractor Km	2020	2021	2022	2023	2024	2025
LC	N/A	N/A	$ 1,962.33	$ 12,104.09	N/A	N/A
BC	$ 4,633.03	$ 2,962.70	$ 4,616.30	$ 5,936.45	$ 3,990.50	$ 6,901.40
LC,BC	$ 13,197.82	$ 12,925.79	$ 9,636.65	$ 16,990.90	$ 19,237.09	$ 13,099.16

4.0-VECC-30

Reference: Exhibit 4

a) Please provide the number of API's vacancy rate for each of the years 2020-2024.

b) Please provide API's assumptions with respect to vacancies in the 2025 budget.

API Response:

a) Below is API's vacancy rate for 2020-2024. It should be noted that there are additional costs related to employee turnover and recruitment, such as vacation payout and recruitment costs.

2020	2.96%
2021	1.38%
2022	1.78%
2023	1.59%
2024	2.67%

b) API has not forecasted any vacancies in the 2025 budget.

4.0-VECC-31

Reference: Exhibit 4, page 58

API budgets for incentive payments at target payment levels.

a) Please provide API's budgets versus actuals for incentive payments for the years 2020 to 2023.

API Response:

A) See Chart below

Year	Incentive Payment Budget	Incentive Payment Actual
2020	$ 502,567	$524,247
2021	$ 520,400	$529,180
2022	$ 504,491	$508,698
2023	$ 508,684	$479,847

4.0-VECC-32

Reference: Exhibit 4, page 61

For Union employees, wage increases are in line with other industry adjustments and are 3.75%, 3.25% and 3% for 2024-2026 respectively.

a) Please provide the Union wage increases for the years 2020 to 2023.

b) Please provide the wage increases for other FTE groups for the years 2020 to 2026.

API Response:

a) Union increases for 2020-2023 were 2.25%, 2.25%, 2.25% and 2.20% respectively.
b) Wage increases for other FTE groups which include market increases and step increases as salaries for some positions progress to the salary line midpoint of the salary policy line, recommended by Korn Ferry management consultants:

Year	Increase
2020	3.52%
2021	2.81%
2022	3.66%
2023	3.56%
2024	4.19%
2025	TBD
2026	TBD

6.0 REVENUE REQUIREMENT (EXHIBIT 6)

6.0-VECC-33

Reference: Exhibit 6, pages 22-23
Chapter 2 Appendices, Appendix 2-H

a) In the main Appendix 2-H table (also shown in Exhibit 6, page 23) there are no entries for Account #4245. However, in Appendix 2-H, the supporting tables below the main table show -$365,033 for 2025. Please reconcile.

b) Please provide the basis for the Joint Use Pole Attachments revenue for 2023, 2024 and 2025 (i.e. # of poles, rate per pole, etc.).

API Response:

a) API searched all of Exhibit 6 and was not able to identify a -$365,033 value within its submission. API confirms that OEB 4245 should show a value of $Nil for 2025 Test Year and confirms that this $Nil value is also reflected in Appendix 2-H as originally submitted.

b) See 9-Staff-72 for 2023 and 2024 information. The basis of the 2025 test year revenue was estimating approximately 11,100 poles at $40.00/pole attacher/year. API expects to record any additional pole attachment revenue resulting from the Building Broadband Faster Act, 2021 in a separate deferral and variance account per OEB guidance.

7.0 COST ALLOCATION (EXHIBIT 7)

7.0-VECC-34

Reference: **Exhibit 7, page 6**

Preamble: The Application states:
"API has completed a load profile study for this application which is based on actual API meter reading data. In doing so, API employed three years of meter data from February 2021 to January 2024"

a) Please explain why January 2024 was used instead of January 2021.

API Response:

a) API took into consideration the completion of its MIST meter implementation program in order to ensure robust meter data was utilized in the load profile. January 2021 data was believed to still contain some non-MIST meters which would not have provided the level of detail required for completion of the load profile.

7.0-VECC-35

Reference: **Exhibit 7, page 9**
Cost Allocation Model, Tab I8

Preamble: The Application states:
"For each of the three historical years, demand allocators for that year were produced from the load profiles. Then the demand allocators for the 3 years were averaged to produce the demand allocators used in the cost allocation model. The R1 class data was aggregated, consistent with the format applied in the cost allocation model. API has applied scaling factors to the demand allocators to adjust between the historic load and 20 projected 2025 load forecast."

a) Please provide the details (i.e., working excel models) that show how the CP and NCP value in Tab I8 were determined using the average of the demand allocators for three years developed by Utilis Consulting.

API Response:

Please refer to Attachment API_2025 COS Utilis[t] Load Profile_20240601 filed June 1, 2024 and API_2025 COS_Load Profile Scaling Factors_20240601 filed June 1, 2024. API notes the Cost Allocation model dated July 19, 2024 correctly reflects the scaling factors.

7.0-VECC-35.5

Reference: Exhibit 7, page 11
API's Conditions of Service, Section 3.1.5

Preamble: The Application states:

"Due to the very rural nature of the API distribution system, the <u>ongoing practice has all customers providing their own service assets</u> which are connected to API's distribution system by API personnel using API's connection assets. The weighting factors are based on an estimated of time and materials required to complete these connections." (emphasis added)

Section 3.1.5 of API's Conditions of Service indicates that there is a Standard Connection Allowance (SCA) for all R1 or Seasonal Residential Service Class Customers.

a) Please reconcile the statement that "ongoing practice has all customers providing their own service assets" with the provision for a Standard Connection Allowance in API's Conditions of Service.

API Response:

a) Section 3.1.6 of API's Conditions of Service defines the Operational Demarcation between API and its Customers and is generally located at the Customers property line. As a result, the Customer is responsible for the service conductor ("Customer service assets") from the property line to the service entrance.

Algoma Power has defined a Standard Connection Allowance ("SCA") in order to meet the requirements of Section 3.1.4 of the Distribution System Code. Included in the SCA is a credit for up to 30 meters of applicable overhead secondary voltage conductor and the installation of an overhead pole-mounted transformer.

7.0-VECC-36

Reference: Cost Allocation Model, Tab I6.2 and Tab I8

a) In Tab I6.2 the number of bills calculation for the Street Lighting class uses number of devices times 12. Is a separate bill sent for each device? If not, how many bills are sent monthly with respect to street lighting use (i.e., how many actual Street Lighting customers does API have)?

b) In TabI6.2, please explain why for the Residential class the value for CCS is greater than the value for CCLT. Does this mean there are customers for whom API does not own the transformer but does own the secondary assets on the low side of the transformer? (Note: The same issues exists for Residential in Tab I8 where the SNCP4 value is greater than the LTNCP4 value)

API Response:

a) API confirms that each of the 15 accounts is issued a monthly bill, not each device as depicted in the Cost Allocation model. Please also see the response to 7-Staff-59.

b) API confirms there are some limited situations where a customer may own their own transformer, but are secondary metered. Likewise there are some limited legacy situations where a customer is primary metered but does not own its own transformer.

7.0-VECC-37

Reference: **Exhibit 7, page 19**

Preamble: The Application states:

"API therefore proposes to rebalance its revenue-to-cost ratios such that the ratio for the Seasonal class is gradually increased to the lower limit of the OEB's policy range over a two-year period. API proposes to rebalance the revenue-to-cost ratios such that the ratio for the Street Lighting Class is gradually increase to the lower limit of the OEB's range over a five-year period.

These phased-in proposals have been made in response to bill mitigation measures, to maintain the total bill impacts for the Street Lighting and Seasonal Classes (at the 10th percentile consumption level) below the 10% mitigation threshold."

a) What was the 10th percentile consumption (i.e., the kWh and kW) used for each of the Seasonal and Street Lighting classes?

b) Please provide API's calculation of the monthly total bill impacts (at both the 10th percentile consumption level and an average consumption level) for the Street Lighting class for the years 2026-2029 based on:
   i) the proposed R/C ratio phase-in and
   ii) a phase-in that is completed in 2028.

c) Please provide API's calculation of the 2025 total bill impact for the Seasonal class ((at both the 10th percentile consumption level and an average consumption level) assuming no phase-in of the R/C ratio change to 85%.

API Response:

a) The 10th percentile consumption used to assess the bill impact for Seasonal customers was 15 kWh. API assessed the bill impact at the 10th percentile for seasonal customers as a result of the ongoing phasing-in of fully fixed distribution rates for the seasonal class. API understands the OEB to require this assessment until the seasonal distribution rates are fully fixed.
API clarifies it did not assess the bill impact at the 10th percentile for street lighting class, as the phase in of fixed distribution rates is not applicable to these customers. The Street Light bill impact at average usage exceeded the 10% mitigation threshold.

b) API notes there is no 10th percentile level applicable to the Street Lighting class. For the purposes of assessing the impacts of the bill mitigation alone, API has made the assumption that no other changes are made to the total bill (ie: no IRM increases, changes to rate riders and transmission rates , or any other part of the bill are assumed after 2025).
I)The bill impacts for an average customer at the proposed phase in plane are outlined in the table below

	2026 Proposed	2027 Proposed	2028 Proposed	2029 Proposed
Total Bill Impact	$ 199.58	$ 199.30	$ 199.58	$ 199.58
% Impact	12%	11%	10%	9%

Ii) The bill impacts for the average street lighting customer at a phase in completed by 2028 are shown in the table below . API notes that with the updates provided in 1-Staff-1, the need for the street lighting mitigation (phase in) has been eliminated.

	2026 Proposed	2027 Proposed	2028 Proposed	2029 Proposed
Total Bill Impact	$ 249.62	$ 248.91	$ 249.90	$ -
% Impact	15%	13%	11%	0%

c) The bill impacts for the average and 10th percentile customer under a no-phase in scenario are presented below. API has presented the proposed (phased in) bill impacts for comparison. API notes under both scenarios, the fixed-variable split was kept at the status quo.

		2025 Proposed Plan	2025 No Phase In
$ Bill Impact - Seasonal Average Customer (200 kWh)		$ 8.04	$ 13.77
% Bill Impact- Seasonal Average Customer (200 kWh)		6.8%	11.6%
$Bill Impact - Seasonal 10th p. (15kWh)		$ 7.75	$ 13.03
% Bill Impact - Seasonal 10th p. (15kWh)		9.0%	15.2%

7.0-VECC-38

Reference: **Exhibit 7, page 14**

Cost Allocation Model, Tabs I7.1 and I7.2

Preamble: The Application states:

"API's unmetered scattered load customers are included as general service customers in its R1(ii) rate class."

a) How many unmetered scattered load customers are included as general service customers in the R1(ii) rate class ?

b) Please explain why, in Tabs I7.1 and I7.2, the number of meters and meter reads for the Residential class has not be reduced in order to account for these unmetered customers.

API Response:

a) As of July 2024, API has 9 USL accounts included as General Service customers.
b) API concurs, the number of meters and meter reads should be reduced to account for these customers. This change has been reflected with the models submitted in 1-Staff-1.

8.0 RATE DESIGN (EXHIBIT 8)

8.0-VECC-39

Reference: Exhibit 8, pages 8, 11 and 13

a) Please confirm that API receives external funding to cover the rate reductions (per page 8) arising from the RRRP, the DRP and the FNDC regulation and what the funding source is for each (i.e., who pays for the rate reduction).

b) Please provide a revised version of Table 2 based on 2025.

c) Do the "equivalent rates" set out in Table 2 (page 13) represent the rates that the customers in each class would be charged absent: i) the funding provided under the RRRP, the DRP and the FNDC regulation and ii) the Residential Rate Design Policy as applied to Residential-R1.

i. If not, how do they vary from what such rates would be?

API Response:

a) API confirms it receives external funding for the RRRP, DRP and FNDC. The RRRP is funded through the RRRP charge per kWh on most Ontario electricity customers' electricity bills. The DRP and FNDC are funded through provincial revenues.

b) Please see the table below:

2015 Rate Design Particulars

Customer Class	Metric	Average # of Customers	Billing Determinant kWh	Billing Determinant kW	F/V Split Fixed Allocation	F/V Split Variable Allocation
Residential - R1	kWh	8496	105,791,701		13.6%	86.4%
Residential - R2	kW	50		198,901	12.0%	88.0%
Seasonal	kWh	3138	7,731,414			
Street Lighting	kWh	1018	804,705			

Legend
consistent with 2015 COS Final Rate Design
2025 Test Year Proposals from this Application (as of July 19,2024)
Equivalent Rates/Figures for use in RRRP calculation

2015 Breakout R1 Class Total into Subclasses

Customer Class	Metric	Average # of Customers	Billing Determinant kWh	Billing Determinant kW	F/V Split Fixed Allocation	F/V Split Variable Allocation
Residential - R1(i)	kWh	7531	80,045,884		73.5%	26.5%
Residential - R1(ii)	kWh	965	25,745,817		24.2%	75.8%
Residential - R1 - Combined	**kWh**	**8496**	**105,791,701**		**64.1%**	**35.9%**

Estimated 2025 Equivalent Rates

Customer Class	Metric	Average # of Customers	Billing Determinant kWh	Billing Determinant kW	F/V Split Fixed Allocation	F/V Split Variable Allocation	Distribution Rates Monthly Service Charge	Distribution Rates Variable Charge	Revenues Fixed	Revenues Variable	Revenues Transformer Ownership Allowance	Revenues Revenue Less Transformer Ownership	Allocated Base RR
Residential - R1	kWh	9,674	131,653,365		64.10%	35.90%	128.50	0.0634	14,917,356	8,353,019		23,270,375	23,270,375
Residential - R2	kW	45		372,457	25%	75%	3,701.02	17.5799	1,998,553	6,349,006	$ 198,751	8,148,808	8,148,808
Seasonal	kWh	2,717	5,958,052		92%	8%	96.69	0.0448	3,152,527	267,112		3,419,639	3,419,639
Street Lighting	kWh	1,156	548,977		14%	86%	2.67	0.4312	37,008	236,720		273,728	273,728
Total		13,592										35,112,550	35,112,550
					Note: Seasonal Mthly Rate has rounding diff vs. RRWF							variance	$0

c) The rates represent the rates customers would be charged absent the RRRP and the change in Residential R1 rate design. API notes that as part of the change in Residential R1 rate design, the R1 class was split into the current subclasses (R1(i) and R1(ii)). The FNDC and DRP are applied independently of the calculated rates in the Tariff and therefore these elements have no impact on either the proposed or equivalent rates (consistent with the treatment outlined in 8-VECC-40).

8.0-VECC-40

Reference: **Exhibit 8, pages 8, 11, 15 and 20**

Preamble: The Application states:

"Since July 1, 2023, the maximum monthly base distribution charge has been set at $39.49, as a result of the OEB's decision in EB-2023-0119." (page 8)

And

"For purposes of calculating preliminary proposed rates, bill impacts and a 2025 RRRP Payment in this Application, API used the 2024 approved RRRP Adjustment Factor of 3.54% as a placeholder in this Application. API acknowledges that the Board will determine the actual RRRP Adjustment Factor for 2025 electricity distribution rates in due course, and API will update the proposed rate design accordingly." (page11)

a) Please confirm that maximum month base distribution rate set per the DRP has been updated to $41.39 per EB-2024-0133.

b) Has there been any update to the RRRP Adjustment Factor?

c) Please update the proposed rates as required based on the responses to parts (a) and (b).

d) Please explain why, at page 15, the approved 2024 monthly service charge for R1(i) is shown as $64.31 when the base distribution rate at the time of the Application was $39.49 (per page 8).

API Response:

a) Confirmed.
b) The final RRRP adjustment factor applicable for 2025 rate-setting has not yet been approved by the OEB, however please refer to 8-Staff-62.
c) The Distribution Rate Protection does not appear on API's Tariff, however API has reflected the adjustment in the Tariff and Bill Impacts filed with 1-Staff-1. The RRRP has not been approved yet, however API has reflected the draft rate mentioned in 8-Staff-62.
d) In the applicable historical years, API's Tariff has always shown the RRRP-adjusted base distribution rate, while the Distribution Rate Protection maximum has been approved for applicable customers in a separate OEB Decision. API notes that not all Residential R1(i) customers are eligible for the Distribution Rate Protection, as FNDC eligible customers do not receive the DRP reduction (but rather a higher credit based on their entire delivery line).

8.0-VECC-41

Reference: **Exhibit 8, page 16**

Preamble: The Application states:

"API has used the RRWF, with adjustments, to calculate the adjustment for the Seasonal rate class. However, in the scenario where API applied the $4 incremental amount to the fixed rate for the Seasonal Class, the Seasonal bill impact at the 10th percentile of usage (ie: a small Seasonal customer using only 15kWh per month), the total bill impact exceeded the 10% threshold. Despite attempting various approaches, API could not find a reasonable time frame to phase the adjustments to the minimum revenue-to-cost policy range that would bring the bill impact below 10% for the Seasonal customer at the 15th percentile. Therefore, API is proposing to defer the 2025 adjustment to the fixed-variable split for the Seasonal Class, in addition to a phased- in revenue-to-cost ratio increase (which is outlined in Exhibit 7). API proposes to continue with the transition to fully fixed distribution rates in its 2026 IRM application, and extend the phase-in to a nine-year period." (emphasis added)

a) Is the second highlighted portion of the preamble mean to refer to the 15th or the 10th percentile?

API Response:

a) The correct reference is to the 10th percentile.

8.0-VECC-42

Reference: Exhibit 8, pages 20-21

a) Does the $21,206,759 in RRRP funding include funding required under the DRP and/or the FNDC regulation? If not please provide the calculations of the additional funding required under these regulations.

API Response:

No, the quoted amount only includes the amounts related to RRRP funding. The sections below outline the expected funding requirements for DRP and FNDC, based on the number of eligible customers in each classification, as well as the Bill Impacts filed with the updated Application on July 19th.

Eligible Number of Customer Estimates		**Calc Ref**	**Source Ref**
Current Seasonal FNDC Recipients	6	A	internal data
Current R1(i) of FNDC Recipients	561	B	internal data
Forecasted Res R 1(i)	8,621	C	load forecast
Forecasted DRP Recipients (Res R1(i) less FNDC)	8,060	D=C-B	calc
DRP Funding Estimate Calculation			
RRRP Adjusted Distribution Monthly Rate	$ 66.59	E	bill impact
DRP Maximum Monthly Rate	$ 41.39	F	bill impact
Differential - per Customer per Month	$ 25.20	G=E-F	calc
Number of DRP Eligible Customers	8,060	D	
Monthly DRP Funding Requirement	$ 203,107	H=G*D	calc
Annual DRP Funding Requirement	**$ 2,437,286**	I=H*12	calc
FNDC Funding Estimate			
Forecasted Delivery Charges- Residential R1(i), after RRRP ar	$ 56.69	J	subtotal C, Bill Impact
Add Back DRP (not applicable with FNDC)	25.2	G	
Total Monthly Delivery Charges for FNDC Eligible Customers (	$ 81.89	K=J+G	calc
FNDC Eligible R1(i) customers	561	B	
Monthly FNDC R1(i)	$ 45,939.34	L=K*B	calc
Annual FNDC R1(i)	**$ 551,272.06**	M=L*12	calc
Forecasted Delivery Charges- Seasonal	111.17	N	Subtotal C, Bill impact
FNDC Eligible Seasonal customers	6	C	
Monthly FNDC Seasonal	667.02	O=N*C	calc
Annual FNDC Seasonal	**8,004.24**	P=O*12	calc
Total Estimated Annual FNDC Funding	**$ 559,276.30**	Q=M+P	calc

8.0–VECC-43

Reference: **Exhibit 8, pages 23-24**
RTSR Model, Tabs 3 & 5

Preamble: The Application states:
"API notes the proposed 2025 RTSRs generally represent a decrease compared the 2024 approved RTSRs. API attributes this to the following assumptions included in the calculations:
• The wholesale volume applied to the Uniform Transmission Rates is based on 2023 actual, consistent with the OEB's methodology.
• The RTSRs are calculated based on API's load forecast, which includes a significant forecasted increase for the R2 class that has not been consistently factored into the UTR forecast."

a) Please confirm that the usage data in Tab 3 of the RTSR model is based on the 2025 load forecast whereas the data in Tab 5 is based 2023 IESO billing quantities.

b) Please provide a revised RTSR Model where the usage data in Tab 3 is based on 2023 actuals.

API Response:

a) API confirms the usage data in Tab 3 of the RTSR model is based on the 2025 Load Forecast, while the data in Tab 5 is based on the 2023 IESO wholesale purchase data.
b) Please see the RTSR model provided as Attachment 8-VECC-43. API notes for comparison purposes it has maintained the same rates as the original Application UTR current and forecast rates.
The table below compares the original application proposed RTSRs and the updated RTSRs calculated on the basis of the 2023 RRR data. Upon review, API believes the 2023 data is the appropriate data set to use, as this approach will maintain the appropriate relationship between wholesale and retail billings in the RTSR model, and therefore has reflected this update in the models filed with 1-Staff-1 The Application model inappropriately forecasts an increase in retail billings without any commensurate increase in wholesale billings forecast. This approach would likely result in a future debit balance accumulating in the Transmission RSVAs.

Rate Class	Rate Description	Unit	Proposed RTSR-Network Using 2023 Actual Retail Data	Proposed RTSR-Network Using 2025 Forecasted Retail Data
RESIDENTIAL R1 SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kWh	$ 0.0108	$ 0.0092
RESIDENTIAL R2 SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kW	$ 4.1294	$ 3.5192
SEASONAL CUSTOMERS SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kWh	$ 0.0108	$ 0.0092
STREET LIGHTING SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kW	$ 2.9902	$ 2.5483

Rate Class	Rate Description	Unit	Proposed RTSR-Connection Using 2023 Actual Retail Data	Proposed RTSR-Connection Using 2025 Forecasted Retail Data
RESIDENTIAL R1 SERVICE CLASSIFICATION	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	$ 0.0081	$ 0.0069
RESIDENTIAL R2 SERVICE CLASSIFICATION	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	$ 3.0628	$ 2.6105
SEASONAL CUSTOMERS SERVICE CLASSIFICATION	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	$ 0.0081	$ 0.0069
STREET LIGHTING SERVICE CLASSIFICATION	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	$ 2.2094	$ 1.8832

8.0-VECC-44

Reference: **Exhibit 8, pages 24-25 and Attachment 8-D**

Preamble: The Application states:
"The following table, reproduced from the OEB's February 14, 2019 Decision and Order in EB-2015-0304 shows the Retail Service Charges in effect May 1, 2019, and sought for approval in this proceeding."

a) Please confirm that the Retail Service Charges set out in API's proposed 2025 tariffs are those approved for 2024 per EB-2023-0193 and not those approved in EB-2015-0304.

API Response:

API confirms the Retail Service charges set out in API's proposed 2025 tariffs are those approved per EB-2023-0193 which are featured below in the updated charge column.

Service Charge	Current Charge	Updated Charge, Effective January 1, 2024
One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$111.66	$117.02
Monthly fixed charge, per retailer	$44.67	$46.81
Monthly variable charge, per customer, per retailer	$1.11	$1.16
Distributor-consolidated billing monthly charge, per customer, per retailer	$0.66	$0.69
Retailer-consolidated billing monthly credit, per customer, per retailer	($0.66)	($0.69)
Service Transaction Requests – Request fee, per request, applied to the requesting party	$0.56	$0.59
Service Transaction Requests – Processing fee, per request, applied to the requesting party	$1.11	$1.16

8.0-VECC-45

Reference: **Exhibit 8, page 29**

Preamble: The Application states:
"API is proposing to use the OEB approved province wide service charge for pole rentals. The current charge is set at $37.78 for 2024, and is updated annually by the OEB's inflation factor. Consistent with the methodology in the Tariff and Bill Impact model, API has used the inflation factor of 4.8% for 2024 rates as a placeholder, resulting in a placeholder 2025 rate of $39.59. API acknowledges that this rate will be adjusted annually based on the OEB's inflation factor when it becomes available."

a) Please update the 2025 pole attachment rate for the OEB's 2025 inflation factor.

b) Does this update impact API's proposed 2025 Revenue Offsets?

API Response:

a) Please see the updated Proposed 2025 Pole Attachment Charge using the updated inflation factor of 3.6%. This update is reflected with the responses to 1-Staff-1.

Wireline Pole Attachment Charge	Unit	Current charge	Inflation factor [2]	Propose
Specific charge for access to the power poles - per pole/year	$	37.78	3.60%	39.14

b) Yes. This has been provided with the updates in 1-Staff-1.