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

BY EMAIL

November 5, 2024

Ms. Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4
Registrar@oeb.ca

Dear Ms. Marconi:

Re: Ontario Energy Board (OEB) Staff Submission
Algoma Power Inc.
2025 Cost of Service Application
OEB File Number: EB-2024-0007

Please find attached OEB staff's submission in the above referenced proceeding, pursuant to the direction provided in the Procedural Order No. 2 dated September 27, 2024.

Yours truly,

Birgit M. Armstrong
Digitally signed by Birgit M. Armstrong
Date: 2024.11.05 14:27:28 -05'00'

Birgit Armstrong
Senior Advisor – Major Applications - Electricity Distribution

Encl.

cc: All parties in EB-2024-0007

ONTARIO ENERGY BOARD

OEB Staff Submission

Algoma Power Inc.

Cost of Service Application

EB-2024-0007

November 5, 2024

1. Introduction

This is OEB staff's submission on the settlement proposal filed by Algoma Power Inc. (Algoma Power) related to its application for January 1, 2025 electricity distribution rates (Application). On August 2, 2024, the OEB issued a decision on the proposed Issues List, which excluded issue 6.2 from settlement. Issue 6.2 is being heard via a written hearing. The settlement proposal represents a complete settlement on all eligible issues on the OEB-approved issues list.

The settlement proposal was arrived at during a settlement conference on September 18, 19, 20, 23, 24 and 25, 2024. The parties to the settlement proposal are Algoma Power and all approved intervenors, namely: School Energy Coalition (SEC), Vulnerable Energy Consumers Coalition (VECC) and the Independent Electricity System Operator (IESO) (collectively, the Parties). OEB staff attended the settlement conference; however, it was not a party to the settlement proposal.

If the settlement proposal is approved, a typical residential customer with a monthly consumption of 750 kWh would see a monthly distribution charge decrease of $3.28 (2.25%).[1]

OEB staff notes that the above bill impacts exclude any bill impacts resulting from the disposition of the commodity accounts 1588 and 1589 as Issue 6.2 pertaining these accounts and Algoma Power's request to require the IESO to settle past Class A submission was excluded from settlement.

[1] Before taxes and the Ontario Electricity Rebate

2. Overview

OEB staff submits that the explanations and rationale provided by the parties support the settlement proposal and that the outcomes arising from the OEB's approval of the settlement proposal would reflect the public interest and would result in just and reasonable rates for customers.

OEB staff's position was developed in consideration of the objectives of the *Renewed Regulatory Framework*[2] (RRF), the *Handbook for Utility Rate Applications*[3], applicable OEB policies, relevant OEB decisions, and the OEB's statutory obligations.

Below, OEB staff provides specific submissions on the issues as they appear on the OEB-approved issues list, as shown below.[4]

- Issue 1: Capital Spending and Rate Base
- Issue 2: Operating, Maintenance and Administration (OM&A)
- Issue 3: Cost of Capital, PILs, and Revenue Requirement
- Issue 4: Load Forecast
- Issue 5: Cost Allocation, Rate Design, Other Charges and Rural and Remote Rate Protection
- Issue 6: Deferral and Variance Accounts (DVAs)
- Issue 7: Other

The approved issues list also contains two additional sub-issues to issue 1 related to an Advanced Capital Module (ACM) proposal for a new facility in Sault St. Marie and a transmission station build at Echo River.

[2] Report of the Board – *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012
[3] *Handbook for Utility Rate Applications*, October 13, 2016
[4] EB-2024-0007, Decision on Issues List, August 2, 2024

3. OEB Staff Submissions on the Settlement Proposal

Issue 1: Capital Spending and Rate Base

1.1 Are the proposed capital expenditures and in-service additions appropriate?

OEB staff supports the proposed capital expenditures and in-service additions.

In the Application, Algoma Power proposed capital in-service additions budget of 14.0M for the 2024 Bridge Year (inclusive of ACMs) and $10.2M for the 2025 Test Year.[5]

As a result of the settlement agreement, the proposed net in-service additions for the 2024 Bridge Year will be $14.6M (inclusive of ACMs) and $12.4M for the 2025 Test Year.[6] The reasons for the net increase of $600k in 2024 and $2.2M in 2025 are as follows:

- The Parties agreed to move $400k from 2024 Bridge Year additions to 2024 Construction Work in Progress to reflect the timing difference of various projects and instead recognize this capital spending in 2025.
- The Parties also agreed to reduce the 2025 test year net service additions by $1.5M.
- The Parties also agreed to include incremental capital additions of $1M in 2024 and $3.327M in 2025 to reflect potential land use agreements over the IRM term as a baseline amount against which Algoma Power will track the actual costs of the agreements.

Algoma originally proposed to include a total of $768k in OM&A cost related to future land use agreements regardless of whether these costs would be capitalized or treated as OM&A costs. Of this total amount, $643k was the estimated revenue requirement related to new agreements that would be capitalized. As part of this settlement agreement, the Parties agreed to establish two sub-accounts to track a) the revenue requirement related to land use agreement that are capitalized and b) OM&A cost associated with land use agreements. As a result, Algoma Power removed $643k related to capitalized costs from its overall OM&A budget and reflect updates to forecasted in-service additions of $1M in 2024 rate base and $3.327M in 2025 rate base as a base line amount in capital.

Due to the uncertainty of costs, the revenue requirement associated with additions related to Land Use Agreements will be tracked in a variance account against actual revenue requirements in the Land Use Revenue Requirement Variance Account (LURR

[5] API_IRR_1-Staff-1 Chapter 2 App_2024-0904, Tab App.2-AA_Capital Projects
[6] EB-2024-0007, Settlement Agreement, p. 11

VA). Algoma Power will calculate the revenue requirement impact of any capitalized land use agreements based on annual amortization expense, return on rate base using the OEB-approved weighted average cost of capital (WACC), and grossed-up PILS impact.[7] The Land Use Revenue Requirement Variance Account will be subject to a prudence review at the next rebasing application. Further details regarding this new variance account are discussed under Issue 6.1.

OEB staff supports the agreed upon capital expenditures and agrees with the inclusion of a forecasted capital budget for Land Use Agreements and subsequent tracking due to Algoma Power's unique circumstances and funding mechanism. Algoma Power's eligible customers receive rate protection under O. Reg. 442/01 for ratemaking purposes based on forecasted amounts, called Rural and Remote Rate Protection (RRRP). As RRRP funding is based on the test year forecast, OEB staff submits that the inclusion of a capital budget in rate base and tracking of the related revenue requirement for anticipated Land Use Agreements is appropriate despite the uncertainty of the forecasts.

As part of the settlement proposal, Algoma Power has also agreed to:

- file an updated Asset Condition Assessment and report back on the steps it has taken to address the data gaps identified by METSCO in its previous Asset Condition Assessments.
- provide project cost variance reports for any capital project with an estimate of $1.5M or over during the rate term that has a cost variance of 10% or greater.
- provide a description and explanation of its Project Management process in its Distribution System Plan and any modification or improvements made over the rate term.
- provide a description of its project estimating process and any modification or improvements made over the rate term.

OEB staff agrees with the pacing proposed by the Parties in the settlement proposal as well as the agreements above. OEB staff submits that the proposed in-service additions budgets for 2024 and 2025 are sufficient for Algoma Power to continue operating its system reliably.

1.2 Are the proposed rate base and depreciation amounts appropriate?

The proposed 2025 rate base is $179M, a $1.5M (1.1%) increase from $177M from the Application. The rate base includes the addition of the #4 circuit line project in which Algoma Power constructed 11.2km of new and replacement 44kV lines and removed 9.2km of existing line to facilitate a customer request to provide 8MW in incremental

[7] EB-2024-0007, Application, Exhibit 4, p. 38

load. The project cost of $11.2M in 2023 was offset by a capital contribution of $3.5M in 2024 which represents the cost of replacing assets before the end of their useful life.

The adjustments agreed to by the Parties in the following areas contribute to the adjusted rate base: adjustment to 2024 closing rate base, capital additions, depreciation, and allowance for working capital.

The proposed 2025 depreciation expense is $5.7M, which is a $72k (12.7%) increase from $5.6M in the Application. The adjustment to the depreciation expense reflects the changes made to the 2024 and 2025 in-service additions, as indicated above under Issue 1.1.

OEB staff supports the proposed rate base, including the addition of the #4 circuit project, and depreciation amounts which have been calculated in accordance with the settlement proposal.

1.3 Is the in-service addition of the Sault St. Marie Facility ACM project appropriate

The Sault St. Marie Facility was approved as part of Algoma Power's last rebasing application through an ACM at a budget of $12.69M. The facility was put into service in 2022 at a cost of $15.7M. Algoma Power added incremental amounts of $640k in 2023 and $200k in 2024. Algoma Power has added the total cost of the project of $16.7M less accumulated depreciation of $735k into rate base for 2024. The Parties agreed to the proposed in-service addition of $15.9M as proposed by Algoma Power.

OEB staff supports the proposed rate base addition for the Sault St. Marie Facility. OEB staff notes that several of the cost overruns were uncontrollable by Algoma Power, such as delays and change orders due to the COVID-19 pandemic as well as due to unanticipated geotechnical issues. However, OEB staff is of the view that Algoma Power's overall estimation and planning methodology can improve and believes that the agreements made by the Parties as part of section 1.1 will result in more accurate estimates going forward.

1.4 Is the in-service addition of the Echo River TS ACM project appropriate?

The Echo River TS was approved as part of Algoma Power's last rebasing application through an ACM at a budget of $7.5M. The project was constructed by Hydro One Sault Ste. Marie (HOSSM) and put into service in 2023 at a cost of $10.9M with incremental work of $154k in 2024. As part of the settlement proposal, the parties agreed to in-service additions of $11.0M less accumulated depreciation of $343k in 2024. In the settlement agreement, the Parties noted their concerns regarding HOSSM's reluctance to respond to information requests pertaining to cost overruns and project delays.

OEB staff supports the proposed rate base addition for the Echo River TS project. OEB staff believes that the cost increases and project delays were outside Algoma Power's control as the project was planned and constructed by HOSSM. OEB staff also believes that Algoma Power adequately questioned HOSSM on change orders throughout the stages of the project.

Issue 2: OM&A

2.1 Are the proposed OM&A expenditures appropriate?

OEB staff considers the agreement reached by the Parties with respect to 2025 OM&A expenses reasonable and appropriate.

Algoma Power proposed total OM&A expenses of $16.3M for the 2025 Test Year in the Application, an increase of 19.2% (or 3.6% compounded annually) compared to the 2020 OEB-approved OM&A spending of $13.7M. In the Application, Algoma Power stated that the OM&A cost increases since 2020 have been driven by increased right of way maintenance cost, right of way land fees, inflation, labour related costs and increased shared service and corporate cost allocation.[8]

Through settlement, the Parties agreed to a 2025 OM&A envelope reduction of $327k and the removal of the Right of Way Land Fees of $643k (discussed under Issue 1.1) for a total of $970k, resulting in OM&A expenses of $15.3M. The revised 2025 OM&A spending represents an increase of 12.1% (or 2.3% compounded annually) compared to the 2020 OEB-approved OM&A amount.[9]

OEB staff notes that the reduction related to the transfer of the revenue requirement associated with capitalized land use agreements (discussed under Issue 1.1) is subject to a variance account. Algoma originally proposed to include a total amount of $646k related to future Land Use Agreements in its OM&A budget as a revenue requirement placeholder regardless of whether these costs would be capitalized or treated as OM&A costs. This amount is incremental to $122k of OM&A cost for serving existing agreements. As part of this settlement agreement, the Parties agreed to establish two sub-accounts to track a) the revenue requirement related to Land Use Agreement that are capitalized and b) OM&A cost associated with Land Use Agreements.[10]

OM&A costs related to Land Use Agreement can include one-time implementation costs such as legal fees, up-front payments, and/or other expenses incurred during the negotiations. OEB staff notes that the agreed upon base line for Land Use fees as part of the OM&A budget is set at $124k[11] ($122k for existing land use agreements and 2k

[8] Exhibit 4, p. 6,
[9] Settlement Proposal, p. 19
[10] Settlement Proposal, p. 39
[11] Settlement Proposal, p. 19

of incremental costs). The variance account will be discussed in more detail under Issue 6.1.

OEB staff supports the proposed OM&A budget for the 2025 test year. OEB staff submits that the envelope reduction of $327k in OM&A, as well as the removal of $643k and the inclusion of a baseline amount of $124k for Land Use Agreement costs are reasonable. The settled OM&A budget of $15.3M should ensure that Algoma Power has sufficient resources to maintain a safe and reliable distribution system.

2.2 *Is the proposed shared services cost allocation methodology and the quantum appropriate?*

OEB staff supports the proposed shared services cost allocation methodology and quantum.

Issue 3: Cost of Capital, PILs, and Revenue Requirement

3.1 Is the proposed cost of capital (interest on debt, return on equity) and capital structure appropriate?

In the application, Algoma Power proposed to use the OEB capital structure and the OEB's cost of capital parameters for the Short-Term debt rate and Return-on-Equity. For the Long-Term debt rate, Algoma Power proposed a rate of 5.59%, which is the weighted average of its existing $52 million third-party debt at a rate of 5.12% and the forecasted rate of 6.00% for a new $55 million third-party debt. Algoma Power indicated plans to repay an existing affiliated debt of $12.75 million at the time it issues the new debt.

In response to interrogatories,[12] Algoma Power confirmed that the new loan was funded on August 22, 2024, with an interest rate of 5.054%, and that the $12.75 million affiliated debt was paid down. Algoma Power updated the rate of the new $55 million third-party loan to reflect the actual rate of 5.05%, which results in a weighted Long-Term debt rate of 5.12%.

Through settlement,[13] the Parties agreed that Algoma Power will update the cost of Short-Term debt and Return on Equity once the OEB releases the 2025 "Cost of Capital Parameter Updates". On October 31, 2024, the OEB issued the 2025 Cost of Capital parameters.[14] OEB staff submits that Algoma Power should update its cost of capital through the Draft Rate Order process and file updated models at that time.

[12] 5-Staff-52(a) IRR
[13] Settlement Proposal, pp. 29
[14] 2025 Cost of Capital Parameters, issued October 31, 2025

As part of their interrogatory responses,[15] Algoma Power agreed to implement the outcomes of the generic proceeding on Cost of Capital and Other Matters, EB-2024-0063, as applicable to Algoma Power. Algoma Power stated that it will comply with the direction set out in the OEB's Letter and Accounting Order issued on July 26, 2024[16] which included setting the Deemed Short-Term debt rate on an interim basis. On October 31, 2024, the OEB issued Accounting Orders (002-2024 and 003-2024)[17], along with the 2025 Cost of Capital parameters letter in Schedule B, which indicated the Deemed Long-Term debt rate and Return on Equity are also being set now on an interim basis. It is OEB staff's expectation that Algoma Power will establish and record entries in the new generic variance accounts for the interim Deemed Short-Term debt rate, Deemed Long-Term debt rate, and Return on Equity, given that the Parties agreed that Algoma Power will implement the outcomes from the OEB's generic proceeding on Cost of Capital and Other Matters.

OEB staff submits that the agreed upon cost of capital calculations have been appropriately determined in accordance with OEB policies and practices.

3.2 Is the proposed PILs (or Tax) amount appropriate?

OEB staff takes no issue with the proposed PILs amount of $962k as shows in Table 9 of the settlement agreement.[18] The PILs also reflected a five-year smoothing method for capital cost allowance (CCA) to address the phase-out of the accelerated CCA rules in 2028.

The smoothing adjustment added to test year regulatory net income before taxes of $212k, as set out under Issue 3.2 of the settlement proposal,[19] is calculated based on forecasted capital additions in 2028 and 2029. Without the smoothing adjustment, the regulatory net income would have been $886k.

Regarding the CCA smoothing method, OEB staff notes that in its July 25, 2019 letter titled Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance, the OEB stated that it may consider a smoothing mechanism to address any timing differences that could lead to volatility in tax deductions over the rate-setting term. OEB staff also notes that CCA smoothing proposals have been previously accepted by the OEB in settlement proposals of other

[15] 5-Staff-50, 5-Staff-51 IRR
[16] EB-2024-0063, OEB Letter and Accounting Order – DVA Rate and DSTDR, July 26, 2024
[17] EB-2024-0063,OEB Letter and Accounting Orders –Deemed Long-Term debt rate and Return on Equity set on interim basis and new variance accounts, Schedule B, October 31, 2024
[18] Settlement Proposal, p. 23, Table 9
[19] Settlement Proposal, p. 23, Table 8

proceedings.[20] In OEB staff's view, the agreed-upon smoothing adjustment calculation is an appropriate method to address the phase-out of accelerated CCA. Therefore, OEB staff does not take issue with Algoma Power' smoothing adjustment calculation.

Additional details of Account 1592, Sub-account CCA Changes are discussed under Issue 6.1

3.3 Is the proposed Other Revenue forecast appropriate?

OEB staff has no issues with the revised 2025 Test Year Other Revenue of $786k, an increase of $140k compared to $646k in the Application (as set out in Table 10 of the settlement proposal). The adjustment was made in the context of the settlement proposal as a whole.[21]

3.4 Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?

OEB staff agrees with the Parties that the impacts of any changes in accounting standards, policies, estimates and adjustments have been properly identified and recorded, and the rate-making treatment of these impacts is appropriate.[22]

3.5 Is the proposed calculation of the Revenue Requirement appropriate?

OEB staff supports the proposed revenue requirement which has been calculated in accordance with the settlement proposal and referenced documents.

Table 8 of the settlement proposal shows the change in revenue requirement between the Application, interrogatory response, and the settlement proposal.

As indicated on page 28 of the settlement agreement, the Parties agreed to a service revenue requirement of $34.5M and a base revenue requirement of $33.7M. These values reflect the impact of an increase in the 2025 Test Year capital additions of 2.2M (discussed under Issue 1.1) and the reduction of OM&A expenditures of $970k (discussed under Issue 2.1), compared to the Application. The values also reflect changes to revenue offsets, depreciation, cost of capital, and working capital allowance.

Issue 4: Load Forecast

4.1 Is the proposed load forecast methodologies and the resulting load forecasts

[20] Brantford Power Inc. 2022 Cost of Service Decision and Rate Order, EB-2021-0009, November 25, 2021, PUC Distribution Inc. 2023 Cost of Service Decision and Rate Order, EB-2022-0058, April 6, 2023
[21] Settlement Agreement, p. 25
[22] Settlement Agreement, p. 27

appropriate?

OEB staff submits that the agreed upon Load Forecast Model is appropriate.

The Parties agreed to update the load forecast to incorporate data to the end of 2023 and to account for new load associated with the #4 Circuit Line through a manual adjustment. For the customer forecast, the Parties agreed to incorporate more recent historical data up to June 2024.[23] In response to interrogatories,[24] Algoma Power updated its load forecast and this updated forecast was agreed upon by all the Parties, as indicated in the tables shown on page 29 of the settlement proposal.

OEB staff supports the proposed consumption, demand and customer forecasts of 307 GWh, 347 MW, and 13,599 customers respectively. Relative to the Application, this reflects a decrease of 10 GWh for consumption and 26 MW for demand. The proposed customer forecast increases by 7 customers compared to the Application.

Issue 5: Cost Allocation, Rate Design, and Other Charges

5.1 Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios, appropriate?

As updated through interrogatory responses, pre-settlement conference clarification question responses and the settlement proposal, the Parties accepted the results of Algoma Power's cost allocation methodology and its proposed revenue-to-cost ratios.[25]

The revenue-to-cost ratios for all classes except for the seasonal rate class fell within the OEB policy range. Algoma Power proposed and the Parties accepted that the revenue to cost ratio for the seasonal rate class would be increased from 76.77% to 85%, the lower end of the OEB's policy range, in 2025. To maintain revenue neutrality, the revenue-to-cost ratio for residential R1 rate class is reduced to 106.3% from 107.92%. No further adjustments are proposed outside of the test year.

OEB staff has no concerns with the cost allocation methodology as agreed to by the Parties, or with the resulting revenue-to-cost ratios.

5.2 Is the proposed rate design, including fixed/variable splits, appropriate?

In its application, Algoma Power noted that the analysis of fixed/variable splits is based on consideration of equivalent rates for the R1 and R2 rate classes determined for cost allocation purposes. However, actual rates for the R1 and R2 are set outside of the standard cost allocation and rate design processes, by applying the RRRP Adjustment

[23] Interrogatory response 3-SEC-20
[24] Pre-ADR clarification questions, 3-SEC-20
[25] Settlement Proposal, p. 31

Factor to the most recently approved fixed and variable rates. As a result, fix/variable analysis has no impact on rate setting for the R1 and R2 rate classes. Through the RRRP adjustment process (discussed under Issue 5.7), the existing fixed variable split is naturally maintained, as both the fixed and variable split are adjusted by the same percentage.[26]

Algoma Power noted that while it has transitioned its residential customer to a fully fixed rate design, the transition for its season rate class is ongoing. In its application, Algoma Power stated that if it would apply the $4 incremental amount to the fixed rates for the season class, a customer at the 10th percentile of usage would exceed the 10% threshold. As part of its rate mitigation plan, Algoma Power requested to pause the transition to fully fixed rates for this rate class for one year,[27] and maintain the current fixed/variable split of 92% fixed/8% variable.

The Parties accepted Algoma Power's approach to rate design including the proposed fixed/variable splits.

OEB staff submits that the proposed rate design, including the fixed/variable splits is appropriate.

5.3 Are the proposed Retail Transmission Service Rates (RTSR) and Low Voltage (LV) Service rates appropriate?

The Parties accepted that the RTSR rates are appropriate. Algoma Power stated that it commits to updating its RTSR rates once the OEB approves preliminary or final Uniform Transmission Rates.[28]

OEB staff notes that Algoma Power is transmission connected. OEB staff has no concerns with the RTSR as agreed to by the Parties subject to an update of the RTSRs based on preliminary UTRs, which were issued by the OEB on November 1, 2024.[29] OEB staff submits that Algoma Power should update its RTSRs through the Draft Rate Order process and file updated models at that time

5.4 Are the proposed loss factors appropriate?

OEB staff takes no issue with the proposed total loss factor of 1.0873. This is based on a supply facilities loss factor of 1.0067 and a distribution loss factor of 1.0801.

5.5 Are the Specific Service Charges and Retail Service Charges appropriate?

[26] Exhibit 8, pp. 18-19
[27] Exhibit 8, p. 16
[28] Settlement Proposal, p. 33
[29] OEB Letter: 2025 Preliminary Uniform Transmission Rates and Hydro One Sub-Transmission Rates, November 1, 2024

The Parties accepted that Algoma Power's proposed Specific Service Charges and Retail Service Charges are appropriate.[30] OEB staff supports the parties' agreement.

5.6 Are rate mitigation proposals required and appropriate?

In the Application, Algoma Power stated that the total bill impacts for Seasonal and Street Lighting rate classes were above 10% and proposed a rate mitigation plan for both rate classes. Through interrogatories and pre-ADR questions, Algoma Power adjusted its cost allocation for its Seasonal and Street Lighting rate classes, which corrected some of the rate impact. No further rate mitigation for the Street Lighting rate class is required.

For the seasonal rate class, Algoma Power requests to pause the transition to fully fixed rates by one year to eliminate the incremental $4 step increase to fixed rates for the 2026 rate year. Algoma Power requested to continue its transition as part of its 2027 rate application. OEB staff takes no issue with this approach but submits that Algoma Power should provide a schedule that outlines the remaining transition to fully fixed rates for the seasonal rate class.

OEB staff considers the bill impacts of the proposed revenue requirement (as set out in Issue 3.5) to be reasonable. Overall, the settlement proposal results in total bill impacts that range between -4.79% and 6.80%. For residential (R1(i)) and GS<50kW (R1(ii)) rate classes, the monthly bill impacts including taxes and rebates are -2.25% and -0.34% respectively on a total bill basis.[31]

5.7 Is the proposed request for Rural and Remote Rate Protection (RRRP) funding appropriate?

The OEB established the methodology for determining Algoma Power's funding mechanism in the 2007 proceeding. This methodology gave effect to O. Reg. 442/01 titled "Rural or Remote Electricity Rate Protection" (RRRP Regulation) made under the *Ontario Energy Board Act*, *1998.*

RRRP Funding

OEB staff supports the parties agreed upon RRRP base funding of 19.7M and an adjustment to RRRP funding for the ACM true-up amount of $1.2M, resulting in a 2025 RRRP funding amount of $18.6M. The parties agreed that these amounts shall be updated to reflect the cost of capital parameters, which was issued on October 31, 2024 and/or cost of power changes.[32] OEB staff submits that these updates should be made

[30] Ibid, p. 35
[31] Ibid, Table 2, p. 9
[32] Settlement Proposal, p. 37

as part of a draft rate order process.

The methodology to calculate forecasted consumer revenue is set out in subsection 4(3.2) of the RRRP Regulation as follows:

> 4.(3.2) For the purpose of subsection (3.1), the distributor's forecasted consumer revenues for a year shall be based on the rate classes and on the rates set out for those classes in the most recent rate order made by the Board and shall be adjusted in line with the average, as calculated by the Board, of any adjustment to rates approved by the Board for other distributors for the same rate year. O.Reg. 335/07, s. 1(2)

Under that provision, forecasted consumer revenue for a year is based upon the current rates adjusted for the average increase or decrease in rates approved by the OEB for the same rate year. This average adjustment reflects the ratepayers' contribution to the recovery of any revenue deficiency.[33] This annual adjustment is referred to as the RRRP Adjustment Factor.

In its 2010 rebasing Decision and Order,[34] the OEB refined the methodology for calculating the RRRP funding. Included was the OEB's finding that RRRP adjustments should be based on comparators' base distribution rates and not take into account retail transmission rates, rate riders and rate adders. As part of interrogatories, Algoma Power confirmed that the appropriate RRRP adjustment factor is 4.75%.[35] As part of this settlement, Algoma Power filed the Revenue Requirement Work Form (RRWF), showing total revenues collected from RRRP eligible class to be $10.2M[36] resulting in a base RRRP funding amount of $19.7M.

<u>ACM True-up Amounts</u>

In the last rebasing application, the OEB approved the recovery of the ACM revenue requirement for the Sault Ste. Marie facility and the Echo River TS through allocating ACM revenue requirement to the RRRP-eligible classes (R1 and R2), during the IRM period, through a revenue requirement adjustment rather than a rate rider.[37]

This request constituted a further refinement of the RRRP framework under which Algoma Power operates. The Parties noted that a rate rider cost recovery for a typical

[33] The appropriate method of calculating the average rate adjustments of other distributors in order to calculate the rate increase for the customers of Algoma Power, and the remaining amount that is payable under RRRP funding was decided in the OEB's Decision and Order (EB-2009-0278), issued November 11, 2010.
[34] EB-2009-0278
[35] EB-2024-0007, Interrogatory Response 8-Staff-62(a)
[36] RRWF, Tab API-RRRP
[37] EB-2019-0019

utility approximates what would have occurred had the investment been included in rate base in the test year and been subject to an annual base rate adjustment during the IRM period.

In the case of Algoma Power, the majority of customers are eligible for rate protection under the RRRP and DRP programs. As part of the previous settlement agreement, the parties agreed that it was appropriate that Algoma Power's ratepayers should receive the benefit of the RRRP and/or DRP for the capital related costs in the context of an ACM cost recovery. The Parties noted that it was the intent of the ACM policy to allow recovery of incremental revenue requirement during non-rebasing years with bill impacts that approximate a situation where the project costs had been included in base rates.

As part of the true-up calculation in this application, Algoma Power stated that it had over-collected $1.6M for both projects (Sub-account 1508 credit balance of $1.3M and 1592 Sub-account credit balance of $286k). Typically, Group 2 account balances are disposed of through a rate rider. OEB staff notes that for the Seasonal and Street Lighting rate classes, a credit rate rider will be applied. But for the R1 and R2 rate classes, the parties agreed to dispose of $1.2M, which is allocated to the RRRP eligible rate classes, through a one-time adjustment to the 2025 RRRP funding. The resulting 2025 RRRP funding amount is $18.6M as shown in the table below.

Table 2: ACM True-up for R1 and R2 Customer Classes[38]

	Allocated Base Revenue Requirement
Residential R1(i)	$ 22,513,464
Residential R1(ii)	
Residential R2	$ 7,484,994
Total	$ 29,998,458
Total Revenue Requirement from RRRP Classes	$ 29,998,458
Less: Revenue From RRRP Reduced Rates	$ 10,248,676
Proposed 2025 Annual RRRP Funding- 2025 Test Year	**$ 19,749,782**
2025 ACM True Up Disposition to RRRP (One-time adjustment)	-$ 1,163,128
Adjusted 2025 RRRP Funding	**$ 18,586,653**

OEB staff submits that this approach is fair and reasonable as the proposed methodology to refund the over-collection matches the methodology used to fund the ACM projects. OEB staff further submits that the quantum and cost recovery

[38] Settlement Proposal, RRRW, Tab API-RRRP,

mechanism are appropriate, subject to updates for any cost of capital parameter and/or cost of power changes. OEB staff is of the view that the proposed disposition of the credit balances through an annual revenue requirement adjustment is reasonable in light of Algoma Power's unique circumstances.

5.8. Is Algoma's proposal to change the billing determinant for Street Lights from "connections" to "devices" appropriate?

In its application, Algoma Power requested to change the billing determinants for Street Lights from "connections" to "devices" is appropriate. The Parties agreed that this change is appropriate.

OEB staff notes that the quantum of connection vs. devices is approximately similar and therefore take no issue with the proposal.

Issue 6: Deferral and Variance Accounts

6.1 Are the proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for new accounts, requests for discontinuation of accounts, and the continuation of existing accounts, appropriate?

OEB staff supports the agreement reached by the Parties related to the DVAs.

The Parties agreed to the disposition of the following DVA balances as of December 31, 2023 and forecasted interest through to December 31, 2024, over a one-year disposition period: [39]

- Group 1 DVAs of a total credit balance of $224,727, excluding Accounts 1588 and 1589
- Group 2 DVAs of a total credit balance of $1,885,219

Some of the Group 2 DVA balances also include forecasted principal amounts up to December 31, 2024.[40]

Through settlement, the Parties agreed to the following[41]:

a) The 2025 budget amounts for cloud computing-related costs as set out in 4-Staff-41 provide an appropriate baseline amount for cloud computing costs concerning any future use of the - Incremental Cloud Computing Implementation Costs DVA.
b) The 2025 budget amount for locates as set out in 9-Staff-74 provides an

[39] Ibid, Table xx, p. xx
[40] Settlement Proposal, DVA Continuity Schedule, tab 2b
[41] Settlement Proposal, pages 39-43

appropriate baseline amount of locate costs concerning any future use of the Getting Ontario Connected Act (GOCA) Variance Account. This baseline locate amount does not reflect the impact of Bill 93.

c) The credit balance of $1,163,051 from the ACM rider revenue collected for the Sault St. Marie Facility and the Echo River TS will be credited to the RRRP program as an offset to the funding that API receives from the RRRP program in 2025. The amounts are further described under Issue 5.7.
d) The establishment of the proposed Defined Benefit Pension Variance Account.
e) The establishment of a 1508 Sub-Account, #4 Circuit Section C-E Sale Deferral Account.
f) The establishment of the proposed Land Use Revenue Requirement Variance Account, subject to the account operating in the following fashion:
    i. The account will track variance in the revenue requirement related to Algoma Power's land use rights costs in two separate sub-accounts, one for OM&A costs and one for capital-related revenue requirement amounts
    ii. The 2025 baseline OM&A amount will be $124,122
    iii. The baseline capital related revenue requirement amount will be 2,067,985, which includes the revenue requirement impact associated with the forecast of $1M in 2024 in-service additions and $3.327M in 2025 in-service additions. The in-service additions are described under issues 1.1 and 1.2.
    iv. On clearing the OM&A sub-account, Algoma Power will clear 100% of the net cumulative OM&A account, whether it is a credit to be paid to customers or a debit to be collected from customers, subject to a prudence review
    v. On clearing the capital related revenue requirement sub-account, Algoma Power will dispose of 100% of the net cumulative capital related revenue requirement if that net cumulative amount is a credit to customers. If the if that net cumulative amount is a debit only 70% of the net cumulative capital related revenue requirement will be recovered from customers. In either case, the account balances are subject to a prudence review

Continuation of the Incremental Cloud Computing Implementation Costs DVA

The OEB Accounting Order issued for the establishment of a deferral account to record Incremental Cloud Computing Arrangement Implementation Costs specified that the deferral account is generally intended to record cloud computing implementation costs when utilities first transition from on-premises solutions to cloud computing.[42]

In response to interrogatories, Algoma Power clarified that its operating budget includes

[42] OEB Accounting Order for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs, November 2, 2023, pages 3-4

the use of FortisOntario on-premises and cloud based software, allocated through the shared service and corporate allocation from CNPI distribution and the budgeted amount of $19,000 is included in the test year's OM&A for the cloud-based subscription from FortisOntario. [43] Algoma Power also confirmed that it has considered future adoption and expansion of cloud computing solutions in its test year forecast, including consideration of the forecasted allocations from shared services with CNPI. However, Algoma Power states that it "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"[44]. Algoma Power further states that "since there are no immediate adjustments needed in the test year, Algoma Power will assess the applicability of the Cloud Computing DVA if any related costs materialize".[45]

OEB staff does not take issues with the parties' agreement to continue the Incremental Cloud Computing Implementation Variance account in the context of this settlement proposal. Algoma Power is unable to forecast costs beyond 2025 test year related to the future adoption and expansion of cloud computing solutions cost allocations within its shared services setup. OEB staff submits that the Incremental Cloud Computing Implementation Variance Account is not meant to be an on-going variance account to be used by the utilities to true up the cloud related expenditure/expenses that are embedded in rates. Rather, the generic variance account is "intended to record cloud computing implementation costs when utilities first transition from on-premise solutions to cloud computing solutions"[46]

OEB staff is of the view that Algoma Power should use the generic account to record any material cloud computing implementations costs when Algoma Power first transition from on-premises solutions to cloud computing, rather than use the account to true up the budgeted amount of $19,000 embedded in rates for cloud-based subscriptions. .

Continuation of the GOCA Variance Account

The OEB Accounting Order issued for the GOCA variance account specified 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.[47]

[43] 4-Staff-41
[44] 4-Staff-41
[45] 9-Staff-73
[46] Accounting Order for the Cloud Computing Arrangement Implementation Costs, November 2, 2023.
[47] EB-2023-0143, Decision and Order, October 31, 2023

In response to interrogatories,[48] Algoma Power clarified that it has not been able to quantify the impacts of Bill 93 in its test year budget, nor does it have an accurate estimate of how many locates will be required to facilitate the GOCA.

OEB staff supports the parties' agreement to continue the GOCA variance account as the Bill 93 impact is not reflected in the test year OM&A cost. Given the implementation of the GOCA administrative penalty regime was postponed to April 1, 2024,[49] OEB staff takes no issue that Algoma Power will continue the GOCA variance account to record any material locates costs that directly result from Bill 93 and incremental to the current embedded locate costs.

OEB staff submits that the GOCA Account should be closed upon disposition of the balance in Algoma Power's next rebasing application because, with five years (or more) of experience, the utility should be able to forecast the impacts of Bill 93 and any such variances should be handled like variances in any other operating program.

Account 1592 – PILs and Tax Variances, Sub-account CCA Changes

Bill C-97 introduced the Accelerated Investment Incentive Program (AIIP), which provides for a first-year increase in CCA deductions on eligible capital assets acquired after November 20, 2018. The AIIP is expected to be phased out starting in 2024 and fully phased out by 2028. In its July 25, 2019 letter entitled Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance, the OEB provided accounting direction on the treatment of the impacts from accelerated CCA resulting from the AIIP. The OEB established a separate sub-account, Account 1592 – PILs and Tax Variances, Sub-account CCA Changes to track the impact of any differences that result from the CCA change to the tax rate or rules that were used to determine the tax amount that underpins rates.

The credit balance of $587,953 in sub-account CCA Changes of Account 1592 represents the full revenue requirement impact of the application of accelerated CCA as of December 31, 2024, including interest to December 31, 2024.

The parties also agreed to the continuation of Account 1592 – PILs and Tax Variances, Sub-account CCA Changes subsequent to December 31, 2024. Although Algoma Power has smoothed out the AIIP impact in its incentive period in this proceeding and AIIP is going to fully phase out by 2028, OEB staff agrees that Account 1592, Sub-

[48] 9-Staff-74
[49] According to the Decision and Order (EB-2023-0143), the OEB set an effective date of April 1, 2023 for the establishment of the GOCA variance account.

account CCA Changes should remain open to track the impact of any differences that result from a change in the CCA rule used to determine the tax amount that underpins rates.[50]

New DVAs - Account 1508, Sub-Account API Defined Benefit Pension Plan Variance Account (ADBVA)

Parties have agreed to the establishment of the ADBVA and its sub-account for carrying charges to track the variance between the Defined Benefit Pension Plan embedded in 2025 base rates and actuals during the subsequent IRM years.

In the application, Algoma Power stated that the defined benefit pension expense amounts and forecasts are prepared by its third-party consultant. The 2025 forecast is based on market information available as of January 31, 2024, which reflects a higher-than-historical-trending discount rate of 4.9%. Algoma Power noted that the recent pension expenses for the Defined Benefit Pension Plan from 2023 to 2025 have been lower than historical levels due to the increased discount rates in recent years. However, the defined benefit pension expenses are expected to increase significantly as interest rates decline.[51]

OEB staff takes no issue with the parties' agreement to establish the proposed ADBVA and its sub-account. Given the fluctuations in the interest rate in recent years and the declining trend of the interest rate began in 2024, material fluctuations in actual pension accruals are anticipated. The proposed variance account will help mitigate the potential material impact of the variances between the actual and the forecasted pension expense embedded in the base rates. OEB staff also notes that a similar variance account has been previously accepted by the OEB in settlement proposals of another proceeding.[52]

In addition, OEB staff notes that Algoma Power addressed the causation, materiality, and prudence criteria for establishing new accounts in the application.[53] Further, OEB staff reviewed the draft accounting order attached to the settlement proposal and has no concerns.

New DVAs - Account 1508, Sub-Account # 4 Circuit Section C-E Sale Variance Account

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[50] Account 1592, Sub-account CCA Changes was established in the OEB's letter Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance, July 25, 2019
[51] Exhibit 4, page 67
[52] EB-2021-0110, Hydro One Networks Inc, November 9, 2022, page 545
[53] Exhibit 9, page 36

(4CircuitC-E)

Parties have agreed to the establishment of the 4CircuitC-E and its sub-account to track the revenue requirement impact of the potential sale of any part of the #4 Circuit to a third party, should such a sale occur.

OEB staff submits that the parties' agreement to establish Account 1508, Sub-account 4CircuitC-E is reasonable as the status of the potential sale is uncertain. In response to interrogatories,[54] Algoma Power identified the potential for a future sale of a portion (section C-E) of its #4 Circuit line. Algoma Power stated that the purchase/sale of the assets is currently being considered by both Algoma Power and the third party, but there is no confirmation that such a transaction would occur.

OEB staff notes that Algoma Power addressed the causation, materiality, and prudence criteria for establishing new accounts in the settlement proposal.[55] Further, OEB staff reviewed the draft accounting order attached to the settlement proposal and has no concerns.

New DVAs - Account 1508, Sub-Account API Land Use Variance Account (LURR VA)

The Parties have agreed to the establishment of the LURR VA and its sub-accounts (Capital and OMA) to track the variance in revenue requirement between the actual land use rights capital expenditures (Capital) embedded in the rate base and the forecasted amounts, as well as the variance between the actual and forecasted land use rights OM&A expenses (OMA) embedded in the base rates.

OEB staff takes no issue with the parties' agreement to establish LURR VA and its sub-accounts, given the difficulty in determining a reasonable forecast for land use rights Capital and OMA for both the bridge year and test year, as described below.

In the application, Algoma Power stated that there is an increase in land use payments anticipated in the coming years, particularly in the 2024 bridge year and the 2025 test year. Algoma Power further stated that there is a high degree of uncertainty regarding the amount and the associated accounting treatment (whether the costs should be classified as OMA or Capital) pending the outcome of ongoing and future negotiations with a variety of landowners, including municipalities, unorganized townships, First Nations, private landowners, resource companies and the Ministry of Natural Resources

[54] Preamble, page 7
[55] Exhibit 9, page 36

and Forestry. In response to interrogatories,[56] Algoma Power clarified that removing the baseline amount from the base rates and using a deferral account approach instead would negatively impact its RRRP and DRP eligible customers, as it would result in a long-term net bill increase due to the exclusion of this amount from the RRRP and DRP funding. OEB staff notes that due to Algoma Power's unique funding mechanism, only forecasted base rate amounts are eligible to rate protection treatment.

The agreed-upon land use rights baseline amounts in 2025 rates are as follows:

- Capital In-Service Additions: $1M in 2024 and $3.33M in 2025.
- Baseline Revenue Requirement: The baseline 2025 revenue requirement for the capital portion is calculated to be $2.07M, subject to update when the OEB issues the 2025Cost of Capital parameters.[57]
- OM&A costs: $124K.

Furthermore, the Parties agreed on a true-up mechanism for the revenue requirement associated with actual capital in-service addition. If the total capital related revenue requirement variance tracked in the LURR VA Capital sub-account is a credit balance (i.e., the cumulative capital related revenue requirement is less than the annual capital related revenue requirement of $2.07M over the next five years) ,100% of the cumulative revenue requirement will be refunded to customers. However, if the total capital related revenue requirement variance tracked in the LURR VA Capital sub-account is a debit balance (i.e., the cumulative capital related revenue requirement is more than the annual capital related revenue requirement of $2.07M over the next five years), only 70% of the total net amount will be recovered from customers.

In the context of the settlement, OEB staff submits that given the complexity and uncertainty of these transactions as well as the potential negative impact on Algoma Power's RRRP and DRP eligible customers by removing the forecasted capital amount, it is reasonable to establish a baseline in this proceeding and track variances using the proposed new variance account and its sub-accounts. Additional details of the agreed-upon baseline amounts are discussed under Issues 1.1 and 1.2 for the capital in-service additions, and Issue 2.1 for the OM&A baseline costs.

OEB staff also submits that the agreed-upon true-up mechanism is appropriate, as it keeps Algoma Power's customers whole by ensuring they are fully refunded if the actual cumulative revenue requirement is lower than what is embedded in the base rates while limiting their exposure when actual costs exceed forecasts. Furthermore, by capping the recovery at 70% for the net revenue requirement, the mechanism of this new DVA

[56] 9-Staff-75
[57] Settlement Proposal, Table 19

reduces the financial impact on customers while still allowing Algoma Power to recover majority of the costs associated with land use rights.

OEB staff notes that Algoma Power addressed the causation, materiality, and prudence criteria for establishing new accounts in the settlement proposal.[58] Further, OEB staff reviewed the draft accounting order attached to the settlement proposal[59], along with the calculation of the baseline revenue requirement[60], and has no concerns.

Issue 7: Other

7.1 Is the proposed effective date appropriate?

OEB staff supports the settlement proposal with respect to Algoma Power's requested effective date of January 1, 2025.

The Parties agreed that Issue 6.2, which relates to the disposition of Account 1588 and 1589 is subject to a separate approval process outside of this Settlement Proposal. The Parties noted their expectation that in the event Issue 6.2 is not resolved in time to implement a rate rider to dispose of the balances of Accounts 1588 and 1589 for January 1, 2025, the OEB will provide direction regarding this issue.[61]

7.2 Has the applicant responded appropriately to all relevant OEB directions from previous proceedings?

OEB staff supports the Parties' view that Algoma Power has responded appropriately to all previous OEB directions.

~All of which is respectfully submitted~

[58] Exhibit 9, page 36
[59] Settlement Proposal, pages 52-53
[60] Settlement Proposal, Table 19
[61] Settlement Proposal, p. 47