Attachment 1-Staff-1

Chapter 2 Appendix (Excel Only)

Algoma Power Inc.
EB-2024-0007

Attachment 1-Staff-1

Cost Allocation (Excel Only)

Algoma Power Inc.
EB-2024-0007

Attachment 1-Staff-1

DVA Model (Excel Only)

Algoma Power Inc.
EB-2024-0007

Attachment 1-Staff-1

PILS Model (Excel Only)

Algoma Power Inc.
EB-2024-0007

Attachment 1-Staff-1

Revenue Requirement Work Form (Excel Only)

Algoma Power Inc.
EB-2024-0007

Attachment 1-Staff-1

RTSR Model (Excel Only)

Algoma Power Inc.
EB-2024-0007

Attachment 1-Staff-1

Tariff and Bill Impact (Excel Only)

Algoma Power Inc.
EB-2024-0007

Attachment 2-Staff-5

YTD Capital (Excel Only)

Algoma Power Inc.
EB-2024-0007

Attachment 2-Staff-28

Advancement/Replacement Credit(Excel Only)

Algoma Power Inc.
EB-2024-0007

Attachment 2-Staff-29a

HOSSM Correspondence

Algoma Power Inc.
EB-2024-0007

PROJECT STATUS REPORT - 2021 Q4

Project: Echo River TS - New Transformer and EOL 230kV Breaker Removal

Customer: Algoma Power Inc.

Project Description

Algoma Power has requested Hydro One Sault Ste. Marie LP to add a second 230/34.5kV power transformer at the Echo River TS to operate as a "Hot Spare" where it will normally be on potential and ready to carry load should the existing Transformer T1 be taken out of service. The scope of work will consist of installation of this additional transformer and associated work including wave traps, HV circuit switcher, surge arrestors, PT, LV isolation switch, protection scheme additions, modifications and extension of bus work for the 230kV and 34.5kV buses and identified new equipment triggered by this new transformer installation.

PROJECT STATUS

SCHEDULE : ON TRACK

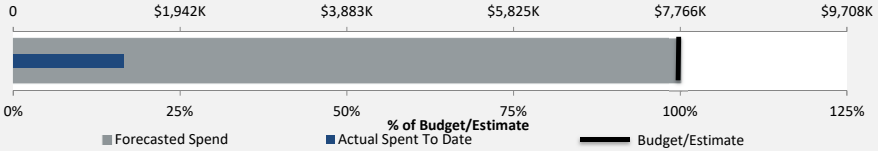
FORECASTED COST : ON BUDGET

Project Costs

Forecasted Cost

0 %

Under / Over Budget

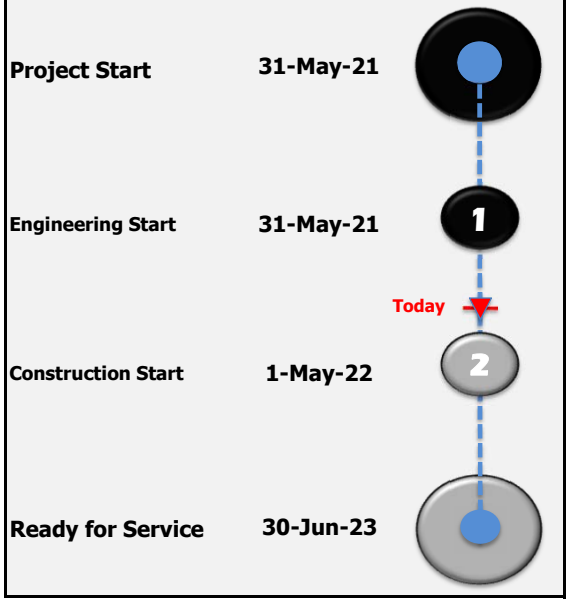


Cost Component	Budget / Estimate	Actual To Date*	Forecast†
Project Management	$ 689,000	$ 395,475	$ 862,405
Engineering	$ 799,000	$ 854,786	$ 1,135,786
Procurement	$ 2,060,000	$ 20,583	$ 2,060,341
Construction	$ 2,320,000	$ 11,361	$ 2,211,622
Commissioning	$ 622,000	$ 1,202	$ 613,109
Other**	$ 1,276,000	$ 4,229	$ 882,737
Total	**$ 7,766,000**	**$ 1,287,636**	**$ 7,766,000**

*Actual costs spent as of Dec 31, 2021.
**Other costs include contingency as applicable.

Customer Capital Contributions excl. HST	$	7,766,000
Forecast of Required Customer Capital Contributions excl. HST	$	7,766,000
Forecast of Additional Contribution (or Refund) excl. HST	**$**	**0**

Project Schedule



Additional Notes

- Past Incurred Cost of $393,000 is included in the Other Cost for Budget/Estimate, however, this Past Incurred Cost has been redistributed for Actual to Date and Forecast
- Engineering is expected to be completed by March 2022
- Power Transformer (230/34.5 kV) has been ordered
- Construction is expected to commence in May 2022
- Schedule is on track to meet agreed In-Service Date of 30-Jun-23
- To support the station expansion, Hydro One is requesting API to upgrade the backup supply to 50 KVA

Threats, Risks, and Scope Changes

- COVID related supply chain risks remain, awaiting confirmation of firm delivery dates for minor equipment and components
- Potential risk of slightly delayed construction start due to adverse weather such as excess snow in the area
- There was a scope change with respect to the location of the phase swap, this has been moved from station to the lines, however, there is no cost or schedule impact due to this

Account Executive	Project Manager
John Blackburn	Kannappan Manickam
Phone: 1 (807) 628-6665	Phone: 1 (647) 354-4175
Email: John.Blackburn@HydroOne.com	Email: Kannappan.Manickam@hydroone.com

†Forecasted costs are a projection of the actual Engineering and Construction Cost of the Work Chargeable to Customer and are subject to change due to internal resource bundling, scheduling, delays in third party invoicing for equipment, materials and services, and other factors. Because of the foregoing, upon Project completion, the customer will pay Hydro One Sault Ste. Marie LP's actual Engineering and Construction Cost (plus applicable Taxes) of the Work Chargeable to Customer in accordance with the terms of the Simplified Customer Connection Cost Recovery Agreement.

PROJECT STATUS REPORT - 2022 Q1

Project: Echo River TS - New Transformer and EOL 230kV Breaker Removal

Customer: Algoma Power Inc.

Project Description

Algoma Power has requested Hydro One Sault Ste. Marie LP to add a second 230/34.5kV power transformer at the Echo River TS to operate as a "Hot Spare" where it will normally be on potential and ready to carry load should the existing Transformer T1 be taken out of service. The scope of work will consist of installation of this additional transformer and associated work including wave traps, HV circuit switcher, surge arrestors, PT, LV isolation switch, protection scheme additions, modifications and extension of bus work for the 230kV and 34.5kV buses and identified new equipment triggered by this new transformer installation.

PROJECT STATUS

SCHEDULE : ON TRACK

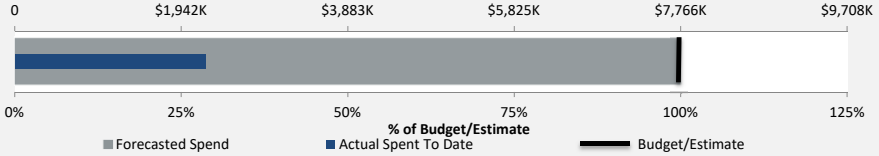
FORECASTED COST : ON BUDGET

Project Costs

Forecasted Cost

0 %

Under / Over Budget

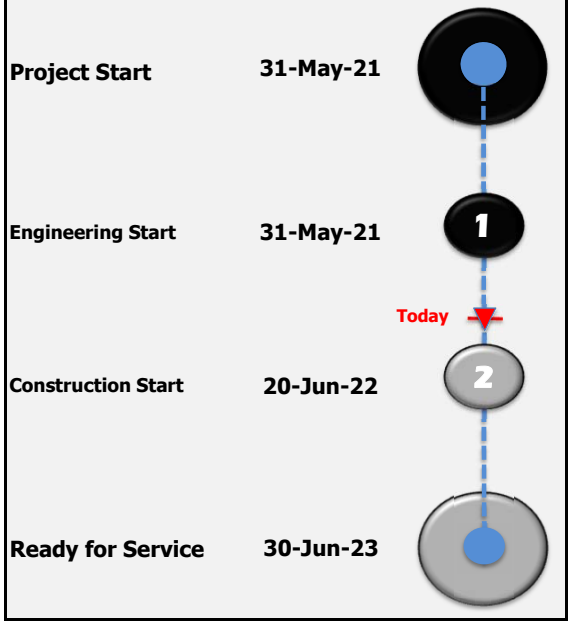


Cost Component	Budget / Estimate	Actual To Date*	Forecast†
Project Management	$ 689,000	$ 408,791	$ 863,162
Engineering	$ 799,000	$ 1,165,433	$ 1,303,433
Procurement	$ 2,060,000	$ 625,209	$ 2,060,512
Construction	$ 2,320,000	$ 19,998	$ 2,237,753
Commissioning	$ 622,000	$ 4,696	$ 618,403
Other**	$ 1,276,000	$ 4,229	$ 682,737
Total	**$ 7,766,000**	**$ 2,228,356**	**$ 7,766,000**

*Actual costs spent as of March 31, 2022.
**Other costs include contingency as applicable.

Customer Capital Contributions excl. HST	$ 7,766,000
Forecast of Required Customer Capital Contributions excl. HST	$ 7,766,000
Forecast of Additional Contribution (or Refund) excl. HST	**$ 0**

Project Schedule



Additional Notes

- Construction is to commence in June instead of May 2022, as Engineering required additional time to process the Power Transformer Manufacturer Drawings, however, no impact to in-service date is anticipated
- Power Transformer (230/34.5 kV) is on track for July delivery
- To support the station expansion, Hydro One is requesting API to upgrade the backup supply to 50 KVA
- Past Incurred Cost of $393,000 is included in the Other Cost for Budget/Estimate, however, this Past Incurred Cost has been redistributed for Actual to Date and Forecast

Threats, Risks, and Scope Changes

- COVID related supply chain risks remain, awaiting confirmation of firm delivery dates for minor equipment and components

Account Executive
Elsy Aceves
Phone: (416) 884-7385
Email: Elsy.Aceves@HydroOne.com

Project Manager
Kannappan Manickam
Phone: 1 (647) 354-4175
Email: Kannappan.Manickam@hydroone.com

†Forecasted costs are a projection of the actual Engineering and Construction Cost of the Work Chargeable to Customer and are subject to change due to internal resource bundling, scheduling, delays in third party invoicing for equipment, materials and services, and other factors. Because of the foregoing, upon Project completion, the customer will pay Hydro One Sault Ste. Marie LP's actual Engineering and Construction Cost (plus applicable Taxes) of the Work Chargeable to Customer in accordance with the terms of the Simplified Customer Connection Cost Recovery Agreement.

PROJECT STATUS REPORT - 2022 Q2

Project: Echo River TS - New Transformer and EOL 230kV Breaker Removal

Customer: Algoma Power Inc.

Project Description

Algoma Power has requested Hydro One Sault Ste. Marie LP to add a second 230/34.5kV power transformer at the Echo River TS to operate as a "Hot Spare" where it will normally be on potential and ready to carry load should the existing Transformer T1 be taken out of service. The scope of work will consist of installation of this additional transformer and associated work including wave traps, HV circuit switcher, surge arrestors, PT, LV isolation switch, protection scheme additions, modifications and extension of bus work for the 230kV and 34.5kV buses and identified new equipment triggered by this new transformer installation.

PROJECT STATUS

SCHEDULE : ON TRACK

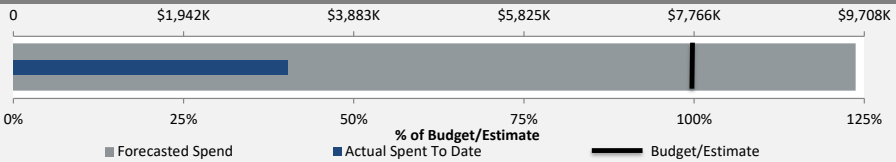
FORECASTED COST : ON BUDGET

Project Costs

Forecasted Cost

24%

Over Budget

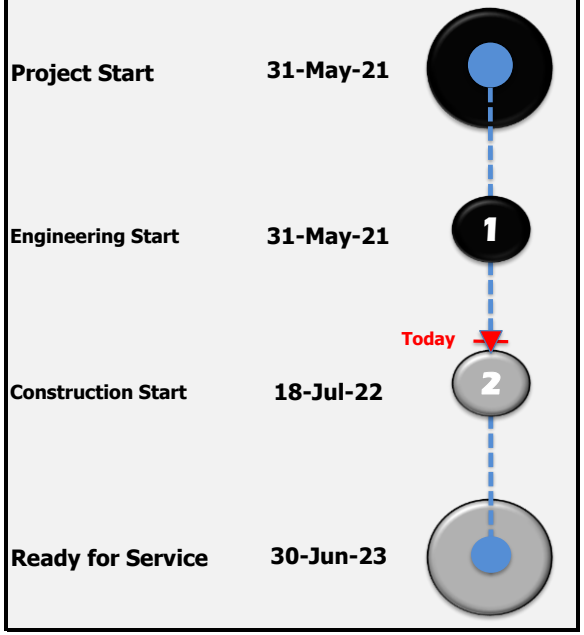


Cost Component	Budget/Estimate	Actual To Date*	Forecast†
Project Management	$ 689,000	$ 508,180	$ 858,316
Engineering	$ 799,000	$ 1,575,878	$ 1,625,878
Procurement	$ 2,060,000	$ 979,815	$ 2,056,018
Construction	$ 2,320,000	$ 28,346	$ 3,787,567
Commissioning	$ 622,000	$ 28,853	$ 621,560
Other**	$ 1,276,000	$ 4,229	$ 650,735
Total	**$ 7,766,000**	**$ 3,125,301**	**$ 9,600,074**

*Actual costs spent as of June 30, 2022.
**Other costs include contingency as applicable.

Customer Capital Contributions excl. HST	**$ 7,766,000**
Forecast of Required Customer Capital Contributions excl. HST	**$ 9,600,074**
Forecast of Additional Contribution (or Refund) excl. HST	**$ 1,834,074**

Project Schedule



Additional Notes

- Construction is scheduled to begin in July 2022
- Project Cost Forecast is 24% above budget, the reasons for this forecast increase have been provided to API
- Power Transformer (230/34.5 kV) and other major equipment deliveries are on track to meet current construction schedule
- To support the station expansion, Hydro One is requesting API to upgrade the backup supply to 50 KVA
- Past Incurred Cost of $393,000 is included in the Other Cost for Budget/Estimate, however, this Past Incurred Cost has been redistributed for Actual to Date and Forecast

Threats, Risks, and Scope Changes

- Supply chain risks remain, awaiting confirmation of firm delivery dates for minor equipment and components

Account Executive
Elsy Aceves
Phone: 1 (416)-884-7385
Email: Elsy.Aceves@HydroOne.com

Project Manager
Kannappan Manickam
Phone: 1 (647) 354-4175
Email: Kannappan.Manickam@hydroone.com

†Forecasted costs are a projection of the actual Engineering and Construction Cost of the Work Chargeable to Customer and are subject to change due to internal resource bundling, scheduling, delays in third party invoicing for equipment, materials and services, and other factors. Because of the foregoing, upon Project completion, the customer will pay Hydro One Sault Ste. Marie LP's actual Engineering and Construction Cost (plus applicable Taxes) of the Work Chargeable to Customer in accordance with the terms of the Simplified Customer Connection Cost Recovery Agreement.

PROJECT STATUS REPORT - 2022 Q3

Project: Echo River TS - New Transformer and EOL 230kV Breaker Removal

Customer: Algoma Power Inc.

Project Description

Algoma Power has requested Hydro One Sault Ste. Marie LP to add a second 230/34.5kV power transformer at the Echo River TS to operate as a "Hot Spare" where it will normally be on potential and ready to carry load should the existing Transformer T1 be taken out of service. The scope of work will consist of installation of this additional transformer and associated work including wave traps, HV circuit switcher, surge arrestors, PT, LV isolation switch, protection scheme additions, modifications and extension of bus work for the 230kV and 34.5kV buses and identified new equipment triggered by this new transformer installation.

PROJECT STATUS

SCHEDULE : ON TRACK

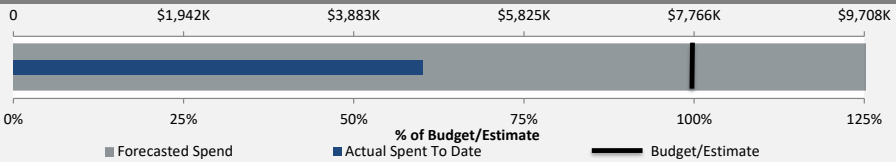
FORECASTED COST : ON BUDGET

Project Costs

Forecasted Cost

33%

Over Budget

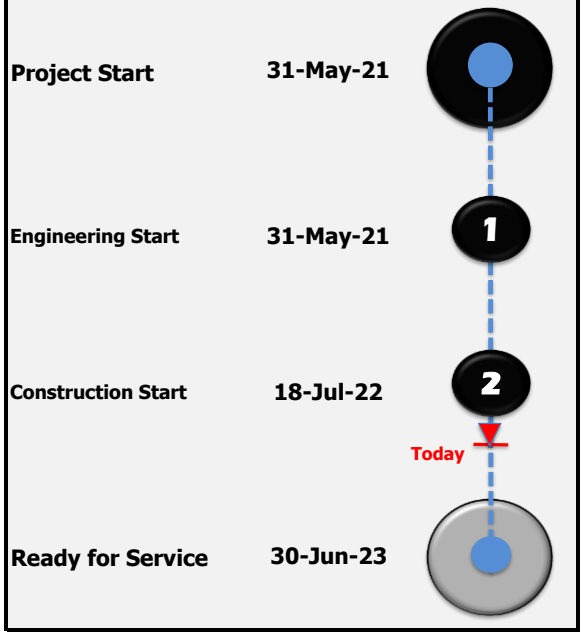


Cost Component	Budget/Estimate	Actual To Date*	Forecast†
Project Management	$ 689,000	$ 639,636	$ 926,307
Engineering	$ 799,000	$ 1,622,920	$ 1,697,046
Procurement	$ 2,060,000	$ 1,934,302	$ 2,609,139
Construction	$ 2,320,000	$ 442,793	$ 3,900,531
Commissioning	$ 622,000	$ 30,963	$ 621,808
Other**	$ 1,276,000	$ 4,229	$ 612,588
Total	**$ 7,766,000**	**$ 4,674,843**	**$ 10,367,419**

*Actual costs spent as of Sep 30, 2022.
**Other costs include contingency as applicable.

Customer Capital Contributions excl. HST	**$ 7,766,000**
Forecast of Required Customer Capital Contributions excl. HST	**$ 10,367,419**
Forecast of Additional Contribution (or Refund) excl. HST	**$ 2,601,419**

Project Schedule



Additional Notes

- Construction commenced in July 2022 and the activites required to complete the first major outage is underway
- Project Cost Forecast is 33.5% above budget, the reasons for this forecast increase have been provided to API
- Power Transformer (230/34.5 kV) has been scheduled to be delivered in October to Echo River TS
- Past Incurred Cost of $393,000 is included in the Other Cost for Budget/Estimate, however, this Past Incurred Cost has been redistributed for Actual to Date and Forecast

Threats, Risks, and Scope Changes

- Supply chain risks remain, awaiting confirmation of firm delivery dates for minor equipment and components
- Potential for weather delays to affect construction schedule
- Higher than currently estimated amount of rock has been found onsite, eventhough majority of the project area has already been daylighted, the risk of encountering additional

Account Executive

Elsy Aceves
Phone: 1 (416) 884-7385
Email: Elsy.Aceves@HydroOne.com

Project Manager

Kannappan Manickam
Phone: 1 (647) 354-4175
Email: Kannappan.Manickam@hydroone.com

†Forecasted costs are a projection of the actual Engineering and Construction Cost of the Work Chargeable to Customer and are subject to change due to internal resource bundling, scheduling, delays in third party invoicing for equipment, materials and services, and other factors. Because of the foregoing, upon Project completion, the customer will pay Hydro One Sault Ste. Marie LP's actual Engineering and Construction Cost (plus applicable Taxes) of the Work Chargeable to Customer in accordance with the terms of the Simplified Customer Connection Cost Recovery Agreement.

PROJECT STATUS REPORT - 2022 Q4

Project: Echo River TS - New Transformer and EOL 230kV Breaker Removal

Customer: Algoma Power Inc.

Project Description

Algoma Power has requested Hydro One Sault Ste. Marie LP to add a second 230/34.5kV power transformer at the Echo River TS to operate as a "Hot Spare" where it will normally be on potential and ready to carry load should the existing Transformer T1 be taken out of service. The scope of work will consist of installation of this additional transformer and associated work including wave traps, HV circuit switcher, surge arrestors, PT, LV isolation switch, protection scheme additions, modifications and extension of bus work for the 230kV and 34.5kV buses and identified new equipment triggered by this new transformer installation.

PROJECT STATUS

SCHEDULE : ON TRACK

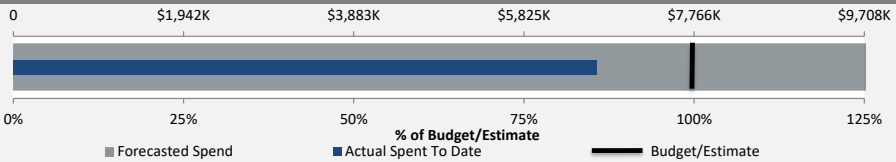
FORECASTED COST : ON BUDGET

Project Costs

Forecasted Cost

33%

Over Budget

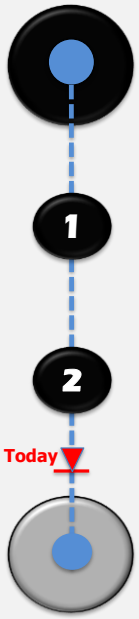


Cost Component	Budget/Estimate	Actual To Date*	Forecast†
Project Management	$ 689,000	$ 654,032	$ 926,305
Engineering	$ 799,000	$ 1,729,488	$ 1,771,488
Procurement	$ 2,060,000	$ 2,686,292	$ 2,998,292
Construction	$ 2,320,000	$ 1,390,977	$ 3,636,938
Commissioning	$ 622,000	$ 193,234	$ 621,607
Other**	$ 1,276,000	$ 4,229	$ 412,558
Total	**$ 7,766,000**	**$ 6,658,252**	**$ 10,367,188**

*Actual costs spent as of December 31, 2022.
**Other costs include contingency as applicable.

Customer Capital Contributions excl. HST	**$ 7,766,000**
Forecast of Required Customer Capital Contributions excl. HST	**$ 10,367,188**
Forecast of Additional Contribution (or Refund) excl. HST	**$ 2,601,188**

Project Schedule



Additional Notes

- Construction is underway, transformer has been received onsite and assembly has been completed
- Certain commissioning activities related to the transformer have been completed
- Project Cost Forecast is 33.5% above budget, the reasons for this forecast increase have been provided to API
- Past Incurred Cost of $393,000 is included in the Other Cost for Budget/Estimate, however, this Past Incurred Cost has been redistributed for Actual to Date and Forecast

Threats, Risks, and Scope Changes

- Supply chain risks remain, awaiting confirmation of firm delivery dates for certain minor equipment and components
- Potential for weather delays to affect construction schedule
- Higher than currently estimated amount of rock has been found onsite, eventhough majority of the project area has already been daylighted, the risk of encountering additional

Account Executive

Elsy Aceves
Phone: 1 (416) 884-7385
Email: Elsy.Aceves@HydroOne.com

Project Manager

Kannappan Manickam
Phone: 1 (647) 354-4175
Email: Kannappan.Manickam@hydroone.com

†Forecasted costs are a projection of the actual Engineering and Construction Cost of the Work Chargeable to Customer and are subject to change due to internal resource bundling, scheduling, delays in third party invoicing for equipment, materials and services, and other factors. Because of the foregoing, upon Project completion, the customer will pay Hydro One Sault Ste. Marie LP's actual Engineering and Construction Cost (plus applicable Taxes) of the Work Chargeable to Customer in accordance with the terms of the Simplified Customer Connection Cost Recovery Agreement.

PROJECT STATUS REPORT - Final for 2023

Project: Echo River TS - New Transformer and EOL 230kV Breaker Removal

Customer: Algoma Power Inc.

Project Description

Algoma Power has requested Hydro One Sault Ste. Marie LP to add a second 230/34.5kV power transformer at the Echo River TS to operate as a "Hot Spare" where it will normally be on potential and ready to carry load should the existing Transformer T1 be taken out of service. The scope of work will consist of installation of this additional transformer and associated work including wave traps, HV circuit switcher, surge arrestors, PT, LV isolation switch, protection scheme additions, modifications and extension of bus work for the 230kV and 34.5kV buses and identified new equipment triggered by this new transformer installation.

PROJECT STATUS

SCHEDULE : ON TRACK

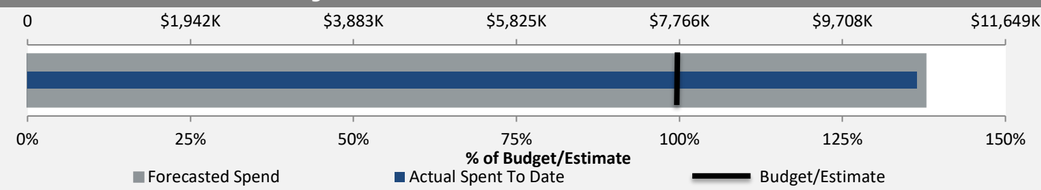
FORECASTED COST : OVER BUDGET

Project Costs

Forecasted Cost

38%

Over Budget



Cost Component	Budget/Estimate	Actual To Date*	Forecast†
Project Management	$ 689,000	$ 1,000,000	$ 1,000,000
Engineering	$ 799,000	$ 1,800,000	$ 1,800,000
Procurement	$ 2,060,000	$ 3,100,000	$ 3,200,000
Construction	$ 2,320,000	$ 3,600,000	$ 3,600,000
Commissioning	$ 622,000	$ 1,100,000	$ 1,100,000
Other**	$ 1,276,000	$ 0	$ 0
Total	**$ 7,766,000**	**$ 10,600,000**	**$ 10,700,000**

*Actual costs spent as of Dec 07, 2023, values have been rounded off to the nearest 100k
**Other costs include contingency as applicable.

Customer Capital Contributions excl. HST	$ 7,766,000
Forecast of Required Customer Capital Contributions excl. HST	$ 10,700,000
Forecast of Additional Contribution (or Refund) excl. HST	**$ 2,934,000**

Project Schedule

Project Start	31-May-21
Engineering Start	31-May-21
Construction Start	18-Jul-22
Project Inserviced	21-Jul-23

Additional Notes

- New transformer T2 has been inserviced and is operational
- Remaining Work: Due to supply chain issues, the new station service scheme was implemented using spare equipment on a temporary basis, however, permanent replacements are required once new equipment is available
- While awaiting completion of the project which is pending due to supply chain issues noted above, Hydro One suggests an interim bill (including Actual plus Forecast) to be sent to the customer, so that further interest would not be accumulated once payment is made
- Final billing is expected to be complete once the delayed equipment are installed, any leftover funds will be refunded
- Project Cost Forecast is 38% above budget, the reasons for this forecast increase have been provided to API
- Past Incurred Cost of $393,000 is included in the Other Cost for Budget/Estimate, however, this Past Incurred Cost has been redistributed for Actual to Date and Forecast

Threats, Risks, and Scope Changes

- Risk of further supply chain delays will impact the timeline of final billing

Account Executive

Elsy Aceves
Phone: 1 (416) 884-7385
Email: Elsy.Aceves@HydroOne.com

Project Manager

Kannappan Manickam
Phone: 1 (647) 354-4175
Email: Kannappan.Manickam@hydroone.com

†Forecasted costs are a projection of the actual Engineering and Construction Cost of the Work Chargeable to Customer and are subject to change due to internal resource bundling, scheduling, delays in third party invoicing for equipment, materials and services, and other factors. Because of the foregoing, upon Project completion, the customer will pay Hydro One Sault Ste. Marie LP's actual Engineering and Construction Cost (plus applicable Taxes) of the Work Chargeable to Customer in accordance with the terms of the Simplified Customer Connection Cost Recovery Agreement.

PROJECT STATUS REPORT - 2023 Q1

Project: Echo River TS - New Transformer and EOL 230kV Breaker Removal

Customer: Algoma Power Inc.

Project Description

Algoma Power has requested Hydro One Sault Ste. Marie LP to add a second 230/34.5kV power transformer at the Echo River TS to operate as a "Hot Spare" where it will normally be on potential and ready to carry load should the existing Transformer T1 be taken out of service. The scope of work will consist of installation of this additional transformer and associated work including wave traps, HV circuit switcher, surge arrestors, PT, LV isolation switch, protection scheme additions, modifications and extension of bus work for the 230kV and 34.5kV buses and identified new equipment triggered by this new transformer installation.

PROJECT STATUS

SCHEDULE : ON TRACK

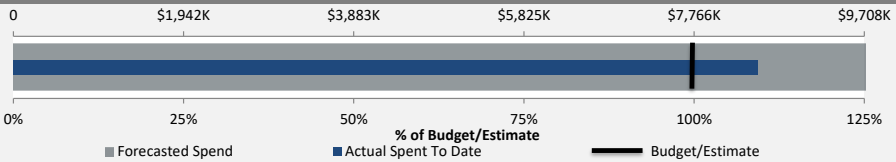
FORECASTED COST : ON BUDGET

Project Costs

Forecasted Cost

33%

Over Budget

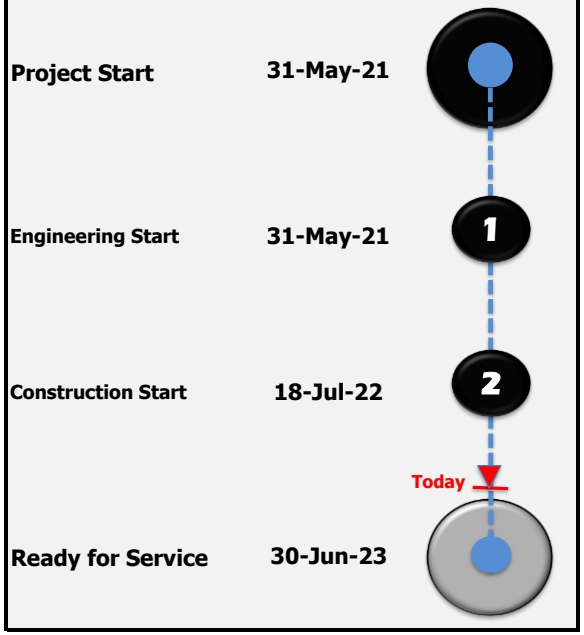


Cost Component	Budget/Estimate	Actual To Date*	Forecast†
Project Management	$ 689,000	$ 885,720	$ 896,123
Engineering	$ 799,000	$ 1,787,325	$ 1,809,846
Procurement	$ 2,060,000	$ 3,016,830	$ 3,209,830
Construction	$ 2,320,000	$ 2,269,306	$ 3,321,452
Commissioning	$ 622,000	$ 525,477	$ 825,477
Other**	$ 1,276,000	$ 4,229	$ 304,460
Total	**$ 7,766,000**	**$ 8,488,887**	**$ 10,367,188**

*Actual costs spent as of March 31, 2023.
**Other costs include contingency as applicable.

Customer Capital Contributions excl. HST	**$ 7,766,000**
Forecast of Required Customer Capital Contributions excl. HST	**$ 10,367,188**
Forecast of Additional Contribution (or Refund) excl. HST	**$ 2,601,188**

Project Schedule



Additional Notes

- Construction and Commissioning underway, transformer assembly has been completed
- Project Cost Forecast is 33.5% above budget, the reasons for this forecast increase have been provided to API
- Past Incurred Cost of $393,000 is included in the Other Cost for Budget/Estimate, however, this Past Incurred Cost has been redistributed for Actual to Date and Forecast

Threats, Risks, and Scope Changes

- Potential for weather delays to affect construction and commissioning schedule
- Higher than currently estimated amount of rock has been found onsite, eventhough majority of the project area has already been daylighted, the risk of encountering additional rock in the yet to be daylighted areas remains

Account Executive
Elsy Aceves
Phone: 1 (416) 884-7385
Email: Elsy.Aceves@HydroOne.com

Project Manager
Kannappan Manickam
Phone: 1 (647) 354-4175
Email: Kannappan.Manickam@hydroone.com

†Forecasted costs are a projection of the actual Engineering and Construction Cost of the Work Chargeable to Customer and are subject to change due to internal resource bundling, scheduling, delays in third party invoicing for equipment, materials and services, and other factors. Because of the foregoing, upon Project completion, the customer will pay Hydro One Sault Ste. Marie LP's actual Engineering and Construction Cost (plus applicable Taxes) of the Work Chargeable to Customer in accordance with the terms of the Simplified Customer Connection Cost Recovery Agreement.

From: ACEVES Elsy
To: Degilio, Michael
Cc: MANICKAM Kannappan; NAIDU Teesin; MUHAMMAD Abdullah
Subject: UPDATE - Echo River TS - Station Reconfiguration - API Feeder
Date: June 29, 2023 1:56:31 PM

Hi Michael,

I'm reaching out to provide you with an update on this project, due to several unexpected circumstances, completion date and estimated commissioning costs changed as follow:

Completion Date:

- HOSSM completion date for API's portion of the project was originally June 30th 2023, based on current schedule we are tracking **July 14th 2023** completion. Transformer T2 was energized and loaded on June 11th, we are currently in the process of relocating the feeder structure.
    - Unfortunately, we had a safety incident onsite mid-June, and we were not able to recover the time lost due to this, as we are in the final stages of the project. We have also had some constructability issues with the feeder structure assembly and hence commissioning has been delayed as a result.

Commissioning higher costs:

- Below the reasons for commissioning cost variance were identified as risks earlier. These risks materialized when teams went through the respective commissioning tasks and a comprehensive understanding of cost implications were only known when commissioning activities were well underway in Q2 2023.
    - Commissioning team had to support heating and hoarding in the winter months, additional equipment, tools and transportation required to support transformer commissioning in winter which was not expected.
    - Vacuum pulling for the transformer was required for a much longer duration than estimated due to weather conditions and longer exposure time (vacuum pulling process being a continuous process it had a material impact).
    - There were issues with the 230 kV Circuit switcher that the commissioning team had to resolve, this item was shipped with the wrong parts, repairs had to be made onsite.
    - Unexpected outage delays caused by equipment failure at the neighboring Mississagi TS resulted in additional rental durations for equipment, crews were already onsite at Echo River TS for transformer soak and then the soak was rescheduled, this caused inefficiencies.

Our current forecast to complete commissioning is estimated to be ~$963K. This is a variance of ~$341K from the original estimate. HOSSM will apply the original contingency (~$240k) against this variance, but HOSSM will still require **additional funding to complete the project in the estimated**

amount of ~$99K.

Please kindly confirm if API would like to have a quick call to review this notice or if above information is acceptable to API.

Thank you

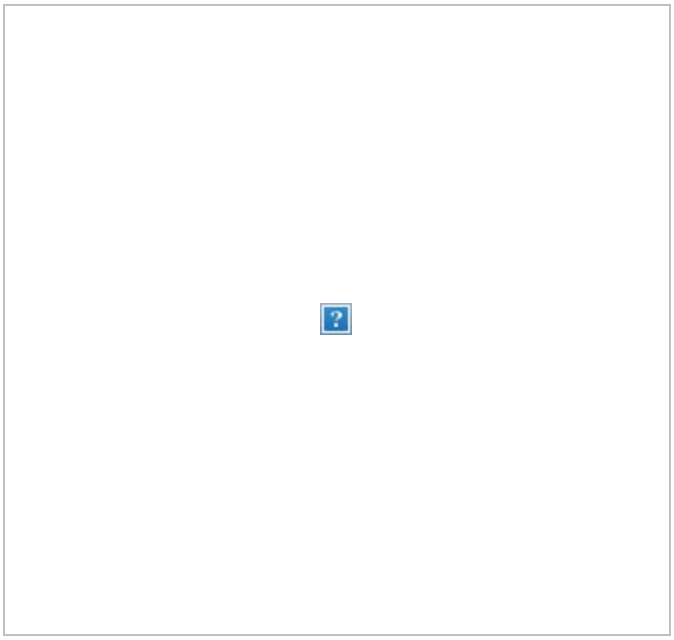
Elsy Aceves
Account Executive, Key Account Management
Hydro One Networks Inc.
Mobile: 416.884.7385

From: ACEVES Elsy
To: Degilio, Michael
Cc: Rose, Jennifer; MANICKAM Kannappan
Subject: API - Echo River TS hot spare project -
Date: July 12, 2022 11:05:19 AM
Attachments: image004.jpg
image005.png
image006.png
image007.jpg
image001.png

Good morning Michael,

With respect to our Class 3 (-20+30%) used to for the existing CCRA, HOSSM/HONI wants to notify API that due to ongoing global supply chain issues, additional funding will be required to cover for engineering and material price increase. This represents a 23.62% increase ($1,834,303.88 (+HST)) on the CCRA estimated cost of $7,766,000.00 (+HST).

Although CCRA estipulate actual costs are charged to the customer, we wanted to give API heads up and requests direction to proceed with this additional expenditure. Also, to ask how API would like to be invoiced for this amount. CCRA will need to be amended to revise below estimate.



Thank you

Elsy Aceves
Account Executive, Key Account Management
Hydro One Networks Inc.

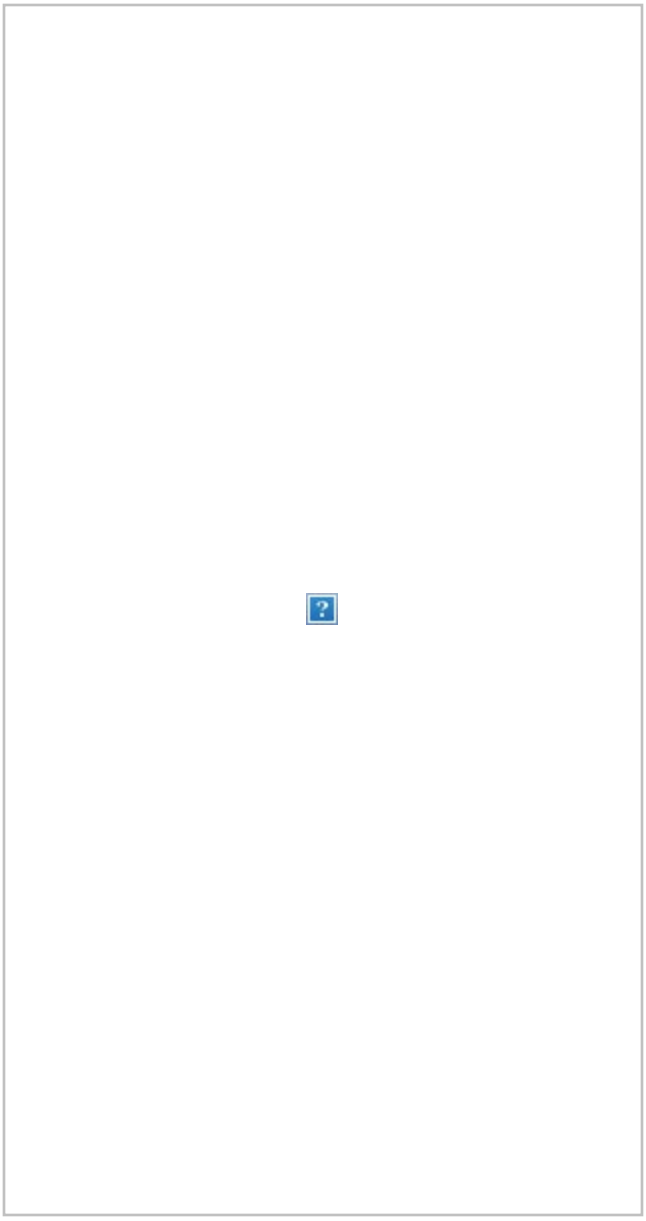
Mobile: 416.884.7385

From: ACEVES Elsy
Sent: Tuesday, April 26, 2022 12:03 PM
To: Degilio, Michael <michael.degilio@algomapower.com>
Cc: Rose, Jennifer <Jennifer.Rose@algomapower.com>; BLACKBURN John <John.Blackburn@HydroOne.com>
Subject: FW: API - Echo River TS hot spare project - Need to confirm-understand when next invoice for remaining 50% will be sent to the customer

Hi Michael,

As per attached Simplified CCRA CBR01618, attached is Inv# 3000350330 Milestone progress payment No 3 in the amount of $3,690,500.00 (+ HST), Invoice is due on **May 25th 2022**.

Please note this is not our final invoice, as per Par B S. 10 of the agreement, HOSSM will provide a final invoice or a credit memorandum specifying actual costs.



Thank you

Elsy Aceves
Account Executive, Key Account Management
Hydro One Networks Inc.
Mobile: 416.884.7385

From: LANDGRAFF Colleen <colleen.landgraff@HydroOne.com>

Sent: Friday, April 22, 2022 1:00 PM
To: ACEVES Elsy <Elsy.Aceves@HydroOne.com>
Cc: BLACKBURN John <John.Blackburn@HydroOne.com>; SAM Allen <Allen.Sam@HydroOne.com>
Subject: FW: API - Echo River TS hot spare project - Need to confirm-understand when next invoice for remaining 50% will be sent to the customer

Thanks Allen

Hi Elsy,

Are you okay with the attached? I've included the previous invoice as well.

Thank you,

Colleen Landgraff
Customer Contracts Coordinator
Process, Reporting & Contracts, Support Services
Hydro One Networks Inc.

From: SAM Allen <Allen.Sam@HydroOne.com>
Sent: Friday, April 22, 2022 9:22 AM
To: LANDGRAFF Colleen <colleen.landgraff@HydroOne.com>
Cc: ACEVES Elsy <Elsy.Aceves@HydroOne.com>; BLACKBURN John <John.Blackburn@HydroOne.com>
Subject: RE: API - Echo River TS hot spare project - Need to confirm-understand when next invoice for remaining 50% will be sent to the customer

Hi Colleen,

Please see attached for the proforma invoice to be generated.

Best,

Allen Sam
Customer Contracts (Co-op), Key Account Management
Hydro One Networks Inc.

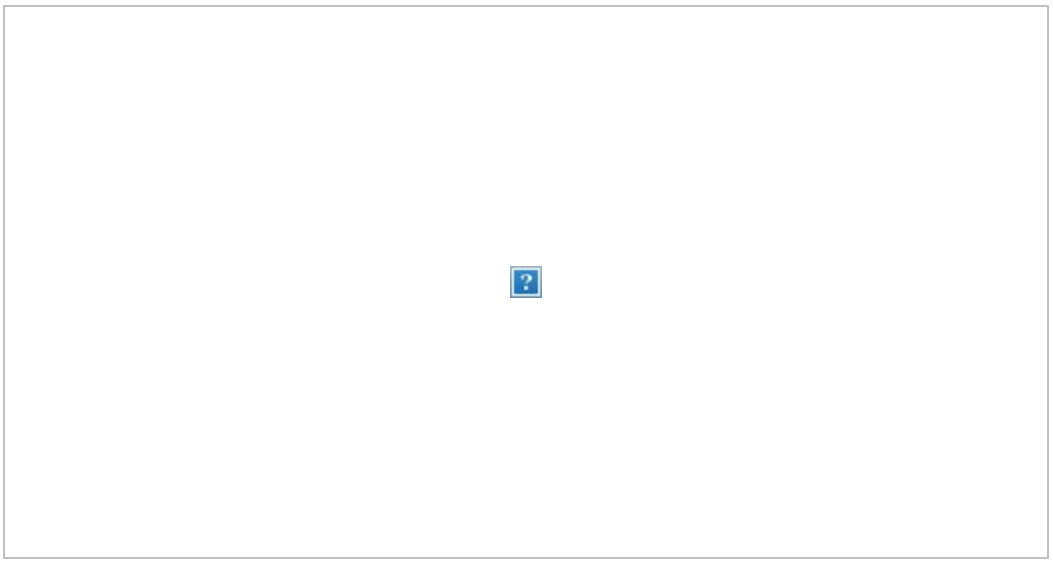
From: LANDGRAFF Colleen <colleen.landgraff@HydroOne.com>
Sent: Thursday, April 21, 2022 3:06 PM
To: SAM Allen <Allen.Sam@HydroOne.com>
Cc: ACEVES Elsy <Elsy.Aceves@HydroOne.com>; BLACKBURN John <John.Blackburn@HydroOne.com>
Subject: FW: API - Echo River TS hot spare project - Need to confirm-understand when next invoice

for remaining 50% will be sent to the customer

Hi Allen,

Can you please create a milestone payment proforma for Algoma Power. The header includes a HOSSM note.

Description: Simplified CCRA_CBR01618
Echo River TS – Addition of a Hot Spare Transformer
Milestone Payment 3.
WBS: 700042938 – please check if you don't mind



Thank you,

Colleen Landgraff
Customer Contracts Coordinator
Process, Reporting & Contracts, Support Services
Hydro One Networks Inc.

From: ACEVES Elsy
To: Degilio, Michael
Cc: MANICKAM Kannappan; Rose, Jennifer
Subject: Cost Increase API - Echo River TS hot spare project
Date: September 23, 2022 11:57:22 AM
Attachments: image001.jpg
image002.png
image003.png
image004.png
image005.png
image006.jpg

Hi Michael,

This is to notify API a cost increase on the subject project, we need API confirmation that we can continue with the work. The revised cost has passed the 30% accuracy of our estimate, projected costs are calculated based on the information available at this time.

Please see below from my HOSSM/HONI PM:

"In July, we had informed the customer of about $1,834,303.88 additional funds required due to incremental engineering and construction costs. At that point of time, the cost impact to project management and equipment procurement were not known as we were in the process of getting quotes from manufacturers and issuing purchase orders.

Now that we understand the costs of procurement items and project management, we can report to the customer that we are forecasting higher than estimated costs for these Lines of Business as well. Overall we are expecting an additional $767,115 to be incurred on the customer portion of the project. I have provided a detailed breakdown below.

Oil-Water Separator Material	76,979
Structural Materials	49,133
Control Materials	136,840
Bus, Hardware & Insulator Materials	96,325
Switches Equipment	23,979
Cable Trench Material	44,723
Power Transformer Equipment	107,698
Instrument Transformer Equipment	13,124
Surge Protecting Devices	5,135
Hired Equipment Electrical	131,291
Civil Foundations Materials	13,760
Project Management (Scheduling, Coordination, Outage Management)	68,128
Total	767,115

I have summarized project financials below, the total cost increment projected for the customer portion is $2,601,419 which is about 33.5% of the CCRA estimate. As of 31 August 2022, we have spent $3,614,484. To date, we retained $612,558.1 in contingency which we are keeping in case any risk materializes down the road. The customer will be only billed the actuals."

	Jul '22 Update	Sep '22 Update		$ Spent (as of 31 Aug 22)	
CCRA	**Increment**	**Increment**	**New Customer Total**	**LTD**	**Contingency Remaining**
$7,766,000.00	$1,834,303.88	$767,115	$10,367,419.00	$3,614,484	$612,558.1
	$2,601,419.00				

Thank you

Elsy Aceves
Account Executive, Key Account Management
Hydro One Networks Inc.
Mobile: 416.884.7385

From: MANICKAM Kannappan <Kannappan.Manickam@hydroone.com>
Sent: Friday, September 23, 2022 10:00 AM
To: ACEVES Elsy <Elsy.Aceves@HydroOne.com>
Subject: RE: API - Echo River TS hot spare project -

Hello Elsy

In line with our internal Major Variance (project budget exceeds 10%) process, I have projected cost comprehensively on all fronts based on the information available at this point of time, so I do not foresee any more cost increments until the completion of the project.

I have made a minor correction to the financials table as shown in red.

	Jul '22 Update	Sep '22 Update		$ Spent (as of 31 Aug 22)	
CCRA	Increment	Increment	New Customer Total	LTD	Contingency Remaining
$7,766,000.00	$1,834,303.88	$767,115	$10,367,419.00	$3,614,484	$612,558.1
	$2,601,419.00				

Thank You
Kanna

From: ACEVES Elsy <Elsy.Aceves@HydroOne.com>
Sent: Friday, September 23, 2022 9:22 AM
To: MANICKAM Kannappan <Kannappan.Manickam@hydroone.com>
Subject: RE: API - Echo River TS hot spare project -

Good morning Kanna,

Thank you for your call and email follow up, your email provides all the details I wanted to communicate this to the customer and get their approval to move forward. I meant to ask yesterday, do you foresee any more cost increments from now until the completion of the project?

Thank you

Elsy Aceves
Account Executive, Key Account Management
Hydro One Networks Inc.
Mobile: 416.884.7385

From: MANICKAM Kannappan <Kannappan.Manickam@hydroone.com>
Sent: Thursday, September 22, 2022 5:02 PM
To: ACEVES Elsy <Elsy.Aceves@HydroOne.com>
Subject: RE: API - Echo River TS hot spare project -

Hello Elsy

As discussed on the phone, in July, we had informed the customer of about $1,834,303.88 additional funds required due to incremental engineering and construction costs. At that point of time, the cost impact to project management and equipment procurement were not known as we were in the process of getting quotes from manufacturers and issuing purchase orders.

Now that we understand the costs of procurement items and project management, we can report to the customer that we are forecasting higher than estimated costs for these Lines of Business as well. Overall we are expecting an additional $767,115 to be incurred on the customer portion of the project. I have provided a detailed breakdown below.

Oil-Water Separator Material	76,979
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Civil Foundations Materials	13,760
Project Management (Scheduling, Coordination, Outage Management)	68,128
Total	767,115

I have summarized project financials below, the total cost increment projected for the customer portion is $2,601,419 which is about 33.5% of the CCRA estimate. As of 31 August 2022, we have spent $3,614,484. To date, we retained $612,558.1 in contingency which we are keeping in case any risk materializes down the road. The customer will be only billed the actuals.

	Jul '22 Update	Sep '22 Update		$ Spent to Date	
CCRA	**Increment**	**Increment**	**New Customer Total**	**LTD**	**Contingency Remaining**
$7,766,000.00	$1,834,303.88	$767,115	$10,367,419.00	$3,614,484	$612,558.1
	$2,601,419.00				

Thank You
Kanna

From: ACEVES Elsy <Elsy.Aceves@HydroOne.com>
Sent: Wednesday, July 20, 2022 11:55 AM
To: Degilio, Michael <michael.degilio@algomapower.com>
Cc: Rose, Jennifer <Jennifer.Rose@algomapower.com>; MANICKAM Kannappan <Kannappan.Manickam@hydroone.com>
Subject: RE: API - Echo River TS hot spare project -

Hi Michael,

Thank you for the email follow up, as discussed, I will discuss this internally and get back to you with our response.

Thank you

Elsy Aceves
Account Executive, Key Account Management
Hydro One Networks Inc.
Mobile: 416.884.7385

From: Degilio, Michael <michael.degilio@algomapower.com>
Sent: Tuesday, July 19, 2022 8:48 PM
To: ACEVES Elsy <Elsy.Aceves@HydroOne.com>
Cc: Rose, Jennifer <Jennifer.Rose@algomapower.com>
Subject: RE: API - Echo River TS hot spare project -

Hi Elsy,

Thank you again for the discussion yesterday regarding the cost increase for this project. As discussed, API agrees in principal to increase in cost with the

understanding that the cost responsibility framework is being reviewed in relation to Hydro One standard practice and that any invoicing would occur at the end of the project, per the terms and conditions of the executed CCRA.

With regards the cost responsibility framework for this project, being given the opportunity to revisit this framework (which up until this point has been 100% paid by API), will help to ensure that we are both writing the same narrative when it comes to this regional need. API also intends on providing an extensive narrative for this project as part of our Cost of Service submission in 2024, given the importance and high cost of the project. So for any cost increases, API will be wanted to lean on Hydro One to help with that narrative.

To give you a bit of background, this project has been in discussion between API and HOSSM since HOSSM acquire GLPT in 2017. Before then, API was in discussion with GLPT since 2015. Originally, API and GLPT had planned the project to be completed in 2017, but with the pending sale of GLPT, it was not possible to pursue. There was a transition period after HOSSM had acquired GLPT, which was around the time of API's 2019 Cost of Service, and at that time we had targeted 2021 as the in-service date. During that transition, API was set on understanding the supply reliability from HOSSM, and so we had requested estimated cost/restoration times for different supply configuration options (I attached the email showing this correspondence). While we understood that cost estimates were very high level, the restoration time for the status quo option was alarming. As a follow-up to this (also in 2019), under the Regional Planning Needs Assessment, it was identified that there existing a transmission supply reliability need at the Echo River TS. This was then followed up in as part of the Scope Assessment, where it was identified that this need would be address through a local planning process.

So really at this point, we want to ensure that were following the standard cost responsibility framework that Hydro One would follow for a project like this, so that we can in turn demonstrate to the OEB why this was the framework that was followed.

To help with the review, the current API customer base that is supplied from the Echo River TS is 6,162.

Let me know if/when you'd like to regroup with the TX planning team to discuss further.

Thanks
Michael

Michael Degilio, P.Eng
Supervisor, Distribution Engineering
Algoma Power Inc.
2 Sackville Road, Suite A | Sault Ste. Marie, ON P6B 6J6
Tel: 705-941-7186
Email: michael.degilio@algomapower.com

From: ACEVES Elsy <Elsy.Aceves@HydroOne.com>
Sent: July 14, 2022 1:54 PM
To: Degilio, Michael <michael.degilio@algomapower.com>
Cc: Rose, Jennifer <Jennifer.Rose@algomapower.com>; MANICKAM Kannappan <Kannappan.Manickam@hydroone.com>
Subject: RE: API - Echo River TS hot spare project -

Hi Michael,

I was trying to call you but you don't seem to be available, the engineering costs are about 15% of the increase costs, please see below. These costs are related to customer work only. HONI uncured in proportional increase on its own work, these costs are not passed onto the customer.

Are you available tomorrow before 1pm or Monday between 1pm and 2pm for a quick call?

Thank you

Elsy Aceves
Account Executive, Key Account Management
Hydro One Networks Inc.
Mobile: 416.884.7385

From: Degilio, Michael <michael.degilio@algomapower.com>
Sent: Thursday, July 14, 2022 12:03 PM
To: ACEVES Elsy <Elsy.Aceves@HydroOne.com>
Cc: Rose, Jennifer <Jennifer.Rose@algomapower.com>; MANICKAM Kannappan <Kannappan.Manickam@hydroone.com>
Subject: RE: API - Echo River TS hot spare project -

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Thank you Elsy, I appreciate the additional details, however there are still some point I'd like to clarify. I

I am not trying to be difficult, but given the magnitude of what's being asked, we need clarity on what is driving these cost, and why Algoma Power is responsible for it.

Can you provide the split between Engineering and Construction for the additional $1.8M?

I've included additional questions, highlighted in red below.

If it would be easier and preferred to discuss over the phone, feel free to reach out and we can discuss.

Thanks
Michael

Michael Degilio, P.Eng
Supervisor, Distribution Engineering
Algoma Power Inc.
2 Sackville Road, Suite A | Sault Ste. Marie, ON P6B 6J6
Tel: 705-941-7186
Email: michael.degilio@algomapower.com

From: ACEVES Elsy <Elsy.Aceves@HydroOne.com>
Sent: July 12, 2022 2:04 PM
To: Degilio, Michael <michael.degilio@algomapower.com>
Cc: Rose, Jennifer <Jennifer.Rose@algomapower.com>; MANICKAM Kannappan <Kannappan.Manickam@hydroone.com>
Subject: RE: API - Echo River TS hot spare project -

CAUTION: This email originated from outside of the organization. Do not click links or open attachments unless you recognize the sender and know the content is safe.

Hi Michael, thank you for the response.

If API prefers to receive a final invoice upon completion of the project we are good with that, I was thinking amending the CCRA to update the payment table but if API rather no to we are good to.

With respect to contingency, we don't use it as it's typically retained in the event that other risks in the project do materialize and require these funds.

Summary of estimate increase factors:

Engineering:

- Grounding study identified more deficiencies to be addressed, additional resources were required to address these deficiencies Can you clarify what is meant by more grounding deficiencies?
- Equipment vendor support and information such as shop drawings were slower than expected:
    - Unexpected delay in transformer drawings and test reports held up completion of engineering, extending schedule and support required from resources What was the cause and magnitude of this delay and why is there an Engineering cost associated with it?

Construction:

- Delay in completion of IFC (Issue For Construction) engineering (as noted in the Engineering section) extended construction schedule into winter seasons, incurring additional heating & preservation expenses
- Quotes received for Hired Equipment rentals - Crane, Scaffolding, Rock Drilling Rig, Generators are significantly higher than the 2020 estimate
- Fuel costs are significantly higher for heating, temp power generators and other equipment noted above
- New soil management regulations introduced additional soil sampling and handling costs
- Incremental scope/quantities of material were added to address deficiencies (as noted in the Engineering section)
- Transformer delivery timeline is not optimal as IFC engineering delays resulted in a delayed construction start
    - Requiring a temporary pad to be built to house the transformer until the transformer foundations are complete Doesn't HONI dictate when the transformer is going to be delivered? It is my understanding that HONI received newly purchased power transformers from manufacturer at a HONI testing facility. Wouldn't this facility have the capability of housing this transformer, negating the need to build a temp pad?
    - Additional craning and lifting costs are incurred as the transformer will have to be rigged into its permanent location from its temp pad
- Laydown area is now outside the compound, as space is required for transformer temporary pad inside compound, requiring additional areas to be prepared and maintained for material handling

Thank you

Elsy Aceves
Account Executive, Key Account Management
Hydro One Networks Inc.
Mobile: 416.884.7385

From: Degilio, Michael <michael.degilio@algomapower.com>
Sent: Tuesday, July 12, 2022 11:31 AM
To: ACEVES Elsy <Elsy.Aceves@HydroOne.com>
Cc: Rose, Jennifer <Jennifer.Rose@algomapower.com>; MANICKAM Kannappan <Kannappan.Manickam@hydroone.com>
Subject: RE: API - Echo River TS hot spare project -

Hi Elsy,

That is a very significant increase. Can you provide additional detail so that the API team is aware of what exactly is driving the cost and so that we can ensure we are both telling the same story to the OEB during our next rebasing. Specifically for the Engineering cost increase, as the scope hasn't changed, what is driving this price increase? Also, as there is Contractor Contingency built into the estimate, wouldn't Engineering cost increase be covered here?

As for the additional payment request, under the current (Part B, Section 10), true-up invoicing or crediting is to occur 180 days after the Ready for Service date, so I would expect that API would receive an invoice sometime after June 30th, 2023. Also, I'm not sure why an amendment to the existing CCRA is required as we are still operating within the terms and conditions of that agreement. Can you please clarify?

Thanks
Michael

Michael Degilio, P.Eng
Supervisor, Distribution Engineering
Algoma Power Inc.
2 Sackville Road, Suite A | Sault Ste. Marie, ON P6B 6J6
Tel: 705-941-7186
Email: michael.degilio@algomapower.com

From: ACEVES Elsy <Elsy.Aceves@HydroOne.com>
Sent: July 12, 2022 11:05 AM
To: Degilio, Michael <michael.degilio@algomapower.com>
Cc: Rose, Jennifer <Jennifer.Rose@algomapower.com>; MANICKAM Kannappan <Kannappan.Manickam@hydroone.com>

Subject: API - Echo River TS hot spare project -

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Good morning Michael,

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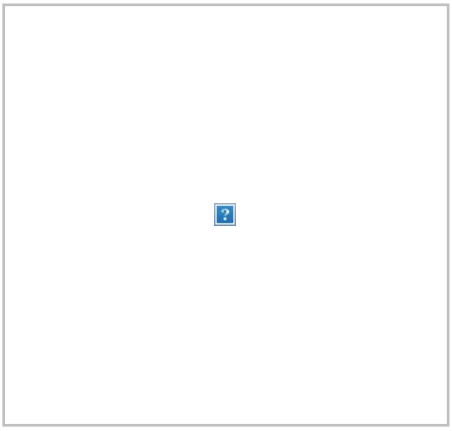

Thank you

Elsy Aceves
Account Executive, Key Account Management
Hydro One Networks Inc.
Mobile: 416.884.7385

From: ACEVES Elsy
Sent: Tuesday, April 26, 2022 12:03 PM
To: Degilio, Michael <michael.degilio@algomapower.com>
Cc: Rose, Jennifer <Jennifer.Rose@algomapower.com>; BLACKBURN John <John.Blackburn@HydroOne.com>
Subject: FW: API - Echo River TS hot spare project - Need to confirm-understand when next invoice for remaining 50% will be sent to the customer

Hi Michael,

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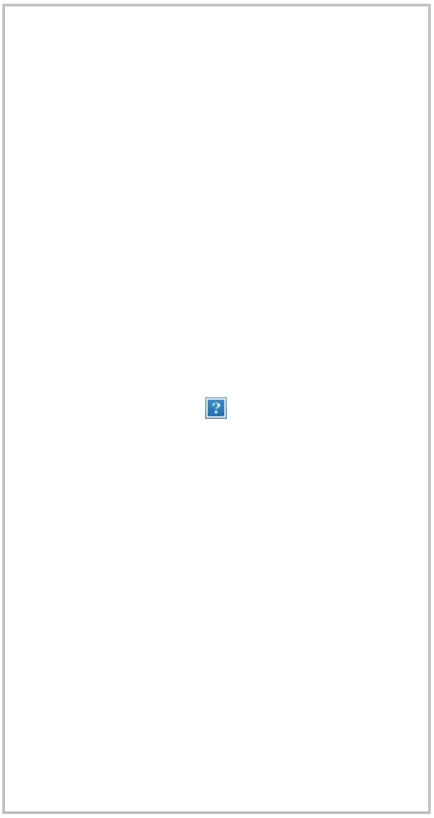
Please note this is not our final invoice, as per Par B S. 10 of the agreement, HOSSM will provide a final invoice or a credit memorandum specifying actual costs.



Thank you

Elsy Aceves
Account Executive, Key Account Management
Hydro One Networks Inc.
Mobile: 416.884.7385

From: LANDGRAFF Colleen <colleen.landgraff@HydroOne.com>
Sent: Friday, April 22, 2022 1:00 PM
To: ACEVES Elsy <Elsy.Aceves@HydroOne.com>
Cc: BLACKBURN John <John.Blackburn@HydroOne.com>; SAM Allen <Allen.Sam@HydroOne.com>
Subject: FW: API - Echo River TS hot spare project - Need to confirm-understand when next invoice for remaining 50% will be sent to the customer

Thanks Allen

Hi Elsy,

Are you okay with the attached? I've included the previous invoice as well.

Thank you,

Colleen Landgraff
Customer Contracts Coordinator
Process, Reporting & Contracts, Support Services
Hydro One Networks Inc.

From: SAM Allen <Allen.Sam@HydroOne.com>
Sent: Friday, April 22, 2022 9:22 AM
To: LANDGRAFF Colleen <colleen.landgraff@HydroOne.com>
Cc: ACEVES Elsy <Elsy.Aceves@HydroOne.com>; BLACKBURN John <John.Blackburn@HydroOne.com>
Subject: RE: API - Echo River TS hot spare project - Need to confirm-understand when next invoice for remaining 50% will be sent to the customer

Hi Colleen,

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Allen Sam
Customer Contracts (Co-op), Key Account Management
Hydro One Networks Inc.

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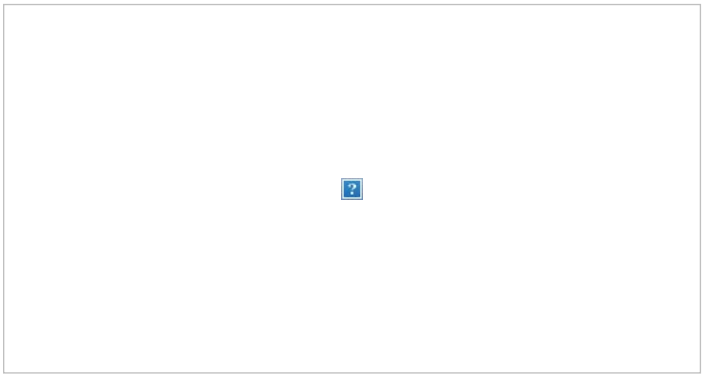
To: SAM Allen <Allen.Sam@HydroOne.com>
Cc: ACEVES Elsy <Elsy.Aceves@HydroOne.com>; BLACKBURN John <John.Blackburn@HydroOne.com>
Subject: FW: API - Echo River TS hot spare project - Need to confirm-understand when next invoice for remaining 50% will be sent to the customer

Hi Allen,

Can you please create a milestone payment proforma for Algoma Power. The header includes a HOSSM note.

Description: Simplified CCRA_CBR01618
Echo River TS – Addition of a Hot Spare Transformer
Milestone Payment 3.
WBS: 700042938 – please check if you don't mind



Thank you,

Colleen Landgraff
Customer Contracts Coordinator
Process, Reporting & Contracts, Support Services
Hydro One Networks Inc.

Hydro One Networks Inc.

483 Bay Street
8th Floor South Tower
Toronto, Ontario M5G 2P5

HydroOne.com

August 30, 2023

Jennifer Rose
Algoma Power Inc. - Regional Manager
251 Industrial Park Crescent• Sault Ste. Marie, Ontario P6B 5P3

Dear Ms. Rose,

In response to your letter dated July 11, 2023 Echo River TS Project Status and Cost, I am providing the following details/response in blue:

General Questions:

1. In terms of overall budget, API has noted a discrepancy between the allocation of the updated budget of $10.5M among cost components (see right-most column above) versus the forecasts in the quarterly project status reports. Please provide further details addressing the discrepancy and final cost.

   The overall discrepancy (variance between Q1 2023 Forecast and the Notices) pointed out is $2,230.88. Please note that both the Q1 2023 Forecast and Notices are forecasted values only, the actual (final) costs are yet to be billed.

2. Further, API requests an outline of the original budget and forecast update between internal and external costs. Has the split among these categories changed since the initial project budget?

   Internal and external cost split is not provided customers, however if this information is required by the regulator to explain the cost variance, Hydro One can directly provide this information to the regulator.

Engineering: +$285k:

3. The engineering budget inclusive of both external consulting and internal staff time? What is the breakdown between these categories and any other categories?

   As noted in Question 2. response above, if this information is required by the regulator to explain the cost variance, Hydro One can directly provide this information to the regulator.

Grounding study identified more deficiencies to be addressed, additional resources were required to address these deficiencies

4. Further explanation- as this is an existing TS.

   Any deficiencies with regards to the existing TS have been addressed and funded by Hydro One. On the customer portion of the project, incremental time and effort was required to resolve grounding issues that were encountered during detailed design – GPR, Touch and Step potential.

5. What budget impact did this have?

In reference to the grounding study details requested, the additional resource requirement details are not provided provided directly to the customer, however if this information is required by the regulator, Hydro One can directly provide this information to the regulator.

Equipment vendor support and information such as shop drawings were slower than expected:

6. Please confirm whether this was internal or external to Hydro One?

Vendors being referred are external.

7. What efforts were made to mitigate the delays?

Regular meetings were held with the vendors to follow up and mitigate the delays to seek resolution.

8. Were there any premiums incurred to address delays?

The level of detail requested is not provided to the customer, however if this information is required by the regulator to explain the cost variance, Hydro One can directly provide this information to the regulator.

Unexpected delay in transformer drawings and test reports held up completion of engineering, extending schedule and support required from resources

9. what is the basis for allocation of internal (HONI staff time)?

Internal staff time had to be allocated to meet with the vendors and review their design, seek resolution and drive outstanding issues to completion, additional engineering reviews/comments were required to ensure the proposed design was per standards.

10. Please describe the impact to schedule vs. and premium cost paid to address delays

A total of a 4-month delay was encountered during detailed design, which was mitigated by carrying out construction activities during the winter months.

Equipment And Materials +$700k:

11. API requests a breakdown of the original budget for each of the individual items below.

Item	Incremental Cost	Category
Oil-Water Separator Material	76,979	Equipment & Materials

Structural Materials	49,133	Equipment & Materials
Control Materials	136,840	Equipment & Materials
Bus, Hardware & Insulator Materials	96,325	Equipment & Materials
Switches Equipment	23,979	Equipment & Materials
Cable Trench Material	44,723	Equipment & Materials
Power Transformer Equipment	107,698	Equipment & Materials
Instrument Transformer Equipment	13,124	Equipment & Materials
Surge Protecting Devices	5,135	Equipment & Materials
Hired Equipment Electrical	131,291	Equipment & Materials
Civil Foundations Materials	13,760	Equipment & Materials

The original budget for Procurement (Equipment & Materials) was $2,060,000.

12. Additionally, API requests further information about the Power Transformer- what was the timing of the procurement, what are the specific delays and increases for the power transformer?

Overall, there was a 4-month delay in the procurement of the power transformer for reasons outlined in the engineering section. The order for this transformer was placed in July 2021 and it was delivered to site in October 2022. Initial budget for the power transformer was $1.3M and final cost was $1.4M.

Construction +$1.55M:

Given the order of magnitude increase in the construction budget, API requires further quantification of the contributing factors to this component

Delay in completion of IFC (Issue For Construction) engineering (as noted in the Engineering section) extended construction schedule into winter seasons, incurring additional heating & preservation expenses

13. Please quantify

This information is not provided to the customer, however if this information is required by the regulator to explain the cost variance, Hydro One can directly provide this information to the regulator.

Quotes received for Hired Equipment rentals - Crane, Scaffolding, Rock Drilling Rig, Generators are significantly higher than the 2020 estimate

14. Please quantify and explain HOSSM procurement process

Please find attached for Exhibit E-05-02 which details the Procurement Process and Warranty Claims process. This exhibit was part of Hydro One's Joint Rate Application.

Fuel costs are significantly higher for heating, temp power generators and other equipment noted above

15. Please quantify.

This information is not provided to the customer, however if this information is required by the regulator to explain the cost variance, Hydro One can directly provide this information to the regulator.

New soil management regulations introduced additional soil sampling and handling costs [Ontario Regulation 406/19 – filed December 4, 2019]

16. Please quantify. We understand the regulation to be effective January 1, 2023. Please confirm if the associated work occured after this date, or whether HOSSM has advanced the requirements to apply in 2022.

HOSSM applied the new soil management regulations to the whole project. It should be noted that construction for this project occurred both in 2022 and 2023.

Incremental scope/quantities of material were added to address deficiencies (as noted in the Engineering section)

17. Please quanitfy.

Any deficiencies with regards to the existing TS has been captured under the Hydro One internal cost. Additions in this case (customer portion) refer to the initial estimate versus final quantities driven by detailed design. The following items had incremental quantities noted: foundations, bus work & insulators, cable trench, oil water separator, structural steel, grounding, control material, station service equipment, power cable.

Transformer delivery timeline is not optimal as IFC engineering delays resulted in a delayed construction start
Requiring a temporary pad to be built to house the transformer until the transformer foundations are complete
Additional craning and lifting costs are incurred as the transformer will have to be rigged into its permanent location from its temp pad

18. Please quantify. Did HONI consider speaking with API about delaying project?

API had been notified about this and acceptance was granted to proceed with the project. Hence, delaying the project was not a consideration.

Laydown area is now outside the compound, as space is required for transformer temporary pad inside compound, requiring additional areas to be prepared and maintained for material handling.

HOSSM also indicated that the construction increase [$1,548,945.88] included a portion due to internal rate increases [$330,033.38]

19. What is the basis for this adjustment? Is it wage increases? How many person-hours are associated with the project to result in such an increase?

This adjustment is driven based on labor rate (wage) increase.

Project Management +$68k:

20. API requests further information on the basis for this increase- what component is related to rates versus the amount of time allocated to the project? What are the major drivers?

Project management efforts are a function of all other aspects of the project. Incremental scope and effort required from other disciplines contributed to this project management increase.

"Third Notice" -Commissioning and Contingency net +$99k :

Commissioning team had to support heating and hoarding in the winter months, additional equipment, tools and transportation required to support transformer commissioning in winter which was not expected.

21. Please quantify and expand on this. As this is a project in Northern Ontario, I'm not sure why was this not expected?

Initial project schedule did not factor transformer commissioning during the winter months.

Vacuum pulling for the transformer was required for a much longer duration than estimated due to weather conditions and longer exposure time (vacuum pulling process being a continuous process it had a material impact).

22. Please provide additional details.
What was the planned vs actual schedule for the vacuum pulling? What were the weather conditions, when did they occur and how did they result in a material impact to the project?

If this information is required by the regulator to explain the cost variance, Hydro One can directly provide this information to the regulator.

There were issues with the 230 kV Circuit switcher that the commissioning team had to resolve, this item was shipped with the wrong parts, repairs had to be made onsite.

23. Please confirm who was responsible for incorrect shipment, HOSSM or the Manufacturer?

Incorrect shipment was the responsibility of the vendor. Replacement parts were furnished by the vendor at no additional cost, however, efforts on the field were required by construction and commissioning team to resolve this in a timely manner.

Unexpected outage delays caused by equipment failure at the neighboring Mississagi TS resulted in additional rental durations for equipment, crews were already onsite at Echo River TS for transformer soak and then the soak was rescheduled, this caused inefficiencies.

24. Please provide API a detailed report explaining the cause of the equipment failure and resource deployment for the Mississagi TSwork.

If this information is required by the regulator to explain the cost variance, Hydro One can directly provide this information to the regulator.

Sincerely,

John Blackburn
Key Account Management – Account Executive

CC: Michael Degilio, Supervisor, Distribution Engineering (API)

Kannappan Manickam, Project Manager, Hydro One (HONI)

Elsy Aceves, Account Executive, Hydro One (HONI)

PROCUREMENT PROCESS AND WARRANTY CLAIMS

1.0 OVERVIEW

This schedule sets out the procurement process that Hydro One employs to source materials and services required to execute the company's investment plan, operations, maintenance and other business activities. It summarizes the principles that underlie the company's procurement process (Section 2.0), Hydro One's approach to sourcing planning (Section 3.0), the execution of the sourcing plan (Section 4.0) and the various sourcing methods that the company employs (Section 5.0). It also summarizes Hydro One's approach to managing warranty claims (Section 6.0).

2.0 SOURCING PRINCIPLES

Hydro One procures materials and services through a framework of policies and procedures that are intended to deliver productivity, buying power, improved services and innovation while building valued supplier relationships that allow the company to achieve greater value in its sourcing.

Hydro One's sourcing activities are based on a set of principles: Financial Stewardship; Supplier Relationships; Health, Safety, Environmental and Sustainability; and Indigenous Procurement. These principles are captured in Hydro One's Supply Chain Policy (included as an attachment to this exhibit) and are described below.

FINANCIAL STEWARDSHIP

- Utilizing a value-for-money approach to source materials and services that helps deliver overall value and lowest total cost of ownership.
- Following negotiation strategies to obtain the lowest possible price from qualified suppliers while not jeopardizing quality and maximizing value.
- Ensuring savings, rebates and volume discounts are captured.
- Ensure the right materials and services are delivered to the right place at the right time in a cost effective manner.

- Achieve operational excellence through continuous improvement in collaboration with Supply Chain's Customers and Suppliers.

SUPPLIER RELATIONSHIPS

- Ensuring that materials and services are acquired from qualified suppliers and establishing consistent expectations for working with suppliers that enhance relationships and the value-for-money proposition.

HEALTH, SAFETY, ENVIRONMENTAL AND SUSTAINABILITY

- Considering responsible ways for sourcing from businesses that conduct operations in a socially responsible manner in accordance with good environmental, health, safety and sustainability practices.

INDIGENOUS PROCUREMENT

- Developing and maintaining relationships with Indigenous Peoples based on mutual respect.
- Encouraging the development and viability of qualified Indigenous businesses, identifying contracting opportunities, conducting workshops, and promoting business networking within Indigenous communities.
- Executing a set-aside process by granting Indigenous businesses more time to complete proposals, directly awarding to qualified Indigenous business, or establishing mandatory Indigenous participation requirements in sourcing events.
- For more information, please refer to Exhibit A-07-02, Section 7.1.

3.0 SOURCING PLANNING

Each year Hydro One develops a sourcing plan that outlines the sourcing priorities for materials and services over the next five years, including a detailed schedule and resourcing plan for the first two years of the plan. The sourcing plan is based on the needs of the business and prioritized based on the expected highest return for productivity savings, operational improvements and service enhancements, organized into categories for different commodities.

For each category, Hydro One develops and executes a sourcing strategy that considers the following factors:

- Identification and engagement of relevant internal stakeholders;
- Defining business requirements;
- Developing an expenditure baseline;
- Analysis of current supply market conditions and trends;
- Analysis of current suppliers' prices, offerings and performance;
- Considerations of category specific circumstances, active contracts, user requirements and specifications, stakeholder analysis, commercial considerations, collaborative planning input, supplier relationship level, key leverage points, bid list, disputes with suppliers, business risks, benefits estimates, qualification requirements, consideration of total value, and market research;
- Selection of an appropriate sourcing method, including open competition, competition directed to a subset of suppliers, or direct negotiation; and
- Encourage opportunities for Indigenous inclusion in the category strategy.

4.0 SOURCING EXECUTION

In 2018, Hydro One developed a Category Management Operations Framework to execute the strategy referred to in Section 3.0. This framework categorizes sourcing efforts into four "Category Teams" that consolidate commodity purchases. This framework is now embedded in the company's supply chain process and polices, including the attached Supply Chain Policy.

Filed: 2021-08-05
EB-2021-0110
Exhibit E
Tab 5
Schedule 2
Page 4 of 10

As illustrated in Figure 1 below, Hydro One's Category Management Operations Framework is based on four objectives:

1. **Align Categories with Business Objectives** - takes a holistic, strategic view of business objectives and becomes primary service line and positions Supply Chain as a sought-after resource to business stakeholders.
2. **Identify Cross-Organizational Opportunities** - broader view enables Supply Chain to incorporate business needs into activities and identify new pockets of value.
3. **Develop Dynamic Sourcing Strategies** - adjusts rhythm to match cadence and lifecycle of stakeholder processes and business needs.
4. **Create Productivity Savings & Operational Efficiency** - integrate multiple value levers to maximize impact such as strategic sourcing, demand planning, and supplier relationship management.

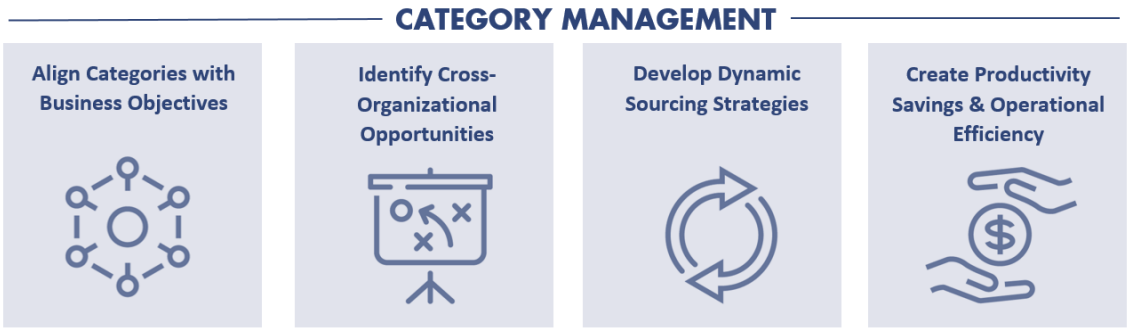


Figure 1: Objectives of Hydro One's Category Management Operations Framework

The category management operations framework organizes spending to accurately represent the distinct categories of sourcing expenditures across the company. The process used to develop spend categorization has three main steps:

- Develop a category structure that segments spend into distinct categories for both internal operations and external supply markets.
- Develop a category structure that aligns to industry best practices and enables the use of category management tools.

Witness: BERARDI Rob

- Align category structure with existing functional material classifications to drive consistency in terminology and classifications across all business units.

The classification into categories is fundamental to the category management operations framework. The category tiers are used to:

- Define the relative importance of each category to Hydro One's system operations.
- Govern category management approval authorities.
- Define category management deliverables.

Once the Sourcing Plan has been approved, sourcing teams begin executing the categories as per the plan's timeline. The lifecycle of a category is as follows:

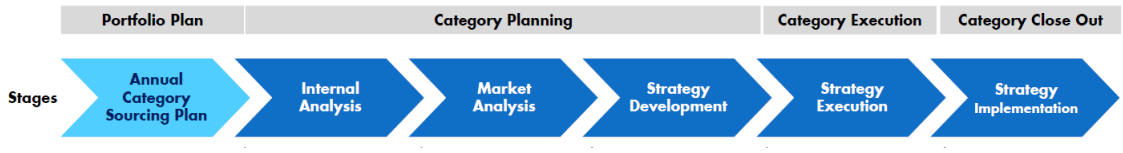


Figure 2: Annual cycle to execute categories

1. **Internal Analysis** – Category Leads in Supply Chain develop a spend profile, engage with key internal stakeholders in impacted Lines of Business and review the current operational model related to the use of the material or service.
2. **Market Analysis** – Category Leads complete an analysis on the cost drivers, trends and complete a marketplace competitive overview. Category Leads conduct research to identify new suppliers or new products/services that could meet the needs of the Line of Business.
3. **Strategy Development** – Leveraging the information learned in the Internal Analysis and Market Analysis phases, the Category Leads will then develop sourcing strategies that will maximize the value to Hydro One based as discussed above in Section 3.0. Strategies are formalized by Category Leads and approved by Supply Chain Management.

4. **Strategy Execution** – Category Leads will execute the strategy using one of the sourcing methods described in Section 5.0 of this exhibit. This phase completes upon the category award and a signed contract with a supplier.
5. **Strategy Implementation** – After a contract has been signed, Category Leads execute a communication plan to all impacted Line of Business stakeholders and ensure a smooth roll out of the new contract.

4.1 ASSURANCE OF SUPPLY

As a result of COVID-19 there were risks of delayed shipments and material availability, especially pandemic related supplies. To address this risk, Supply Chain implemented an Assurance of Supply strategy:

- **Category Management Approach** – As described in Section 4.0 above, Supply Chain has a deep and thorough understanding of the material or service category, its suppliers' industries and end user's needs. Supply Chain relies on market intelligence, transportation expertise, and supplier performance/relationship management to both predict and minimize impact to Hydro One's cost or operation
- **Diversification of Supply Base** – Sourcing strategy development is centered on ensuring redundancy in the supply channels wherever possible. Sole source supply channels are understood and closely managed.
- **Specification Refinement and Consolidation** - Sourcing strategies are executed with Engineering and Technical Service teams to refine specifications to industry standard (as opposed to Hydro One-specific) and to consolidate to as few variations as is possible. This increases market channels, increases manufacturing efficiency, and allows collaboration with peer utilities.
- **Inventory / Strategic Spares** – Hydro One maintains inventory at a central warehouse in Barrie Ontario, and at ~80 Operations Centres across the province. These locations hold inventory on hand to ensure that materials and supplies are available when needed.
- **Collaboration with Peer Utilities** – Hydro One Supply Chain collaborates with several peer utilities, both formally and informally, to identify emerging trends in the marketplace and

collaborate on mitigation strategies, and to pursue collaborative sourcing initiatives where possible.

- **Early Ordering and Committing to Production Slots** – Hydro One Supply Chain and Planning work together to identify opportunities for making early commitments to certain key suppliers in order to guarantee the on time delivery of critical materials.

5.0 SOURCING METHODS

The following are detailed sourcing methods which may be employed:

(1) RFI – Requests for Information

RFI is a process that uses a market research tool sent to a broad base of potential suppliers for a number of purposes, including gathering information, building a supplier database to determine availability of products and services, scoping business requirements, and/or estimating project costs. Responses to RFI questions normally contribute to the content of the eventual RFP, RFPQ, or RFQ document being created but do no result in an award.

(2) RFP - Requests for Proposal

An RFP is a process that uses a document prepared to solicit proposals for the supply of materials or services for which bidders must develop and propose a business application or solution. This competitive bid process is used when one or more of the following criteria are met:

- There is a requirement for custom made/specialized materials or services for which bidders must develop and propose a business application or solution;
- There is a need for engineered equipment and/or construction services, and more than one option exists to address the requirement;
- There are off-the-shelf materials where value added services are required in addition to the materials; and/or
- An alternative solution is sought.

An RFP may result in a Vendor of Record list with pre-established rate cards. These arrangements require a second-stage competitive process, or an award strategy identifying the methodology for determining the award of work.

(3) RFPQ – Request for Pre-Qualification

An RFPQ is a competitive bid process used to solicit supplier capabilities and qualifications, with the intention of establishing a list of pre-qualified suppliers, usually based on financial and/or other technical criteria.

It is used when the following criteria are met:

- There are opportunities to reduce costs for certain categories of materials and services by establishing strategic relationships with a small group of suppliers; and
- There are generally understood technical criteria to pre-qualify the suppliers but specific scopes of work are defined as required.

These arrangements require a second-stage competitive process directed to the pre-qualified suppliers, or an award strategy identifying the methodology for determining the award of work.

(4) RFQ - Requests for Quotation

This competitive bid process is used where a description of exactly what needs to be procured is provided and the evaluation of bidders is made predominantly on price and delivery requirements.

(5) Direct Negotiation

Direct negotiation is used when a competitive process is not feasible or when running a competitive sourcing is not in the best interest of Hydro One. Examples of circumstances when negotiation with a single supplier may be most appropriate include:

- Building key strategic supplier relationships where it is believed that a competitive process may not lead to the best solution or drive the most value for Hydro One;
- A purchase that is of a confidential or privileged nature;
- Where urgency exists and there is only one supplier who can perform the work without causing Hydro One to suffer an unacceptable delay or incur unreasonable costs due to another supplier's learning curve;
- There is only one supplier capable of meeting the requirements;
- To ensure compatibility with existing products, to recognize exclusive rights, such as exclusive licences, copyright and patent rights, or to maintain specialized products that must be maintained by the manufacturer or its representatives;
- Where there is an absence of competition for technical reasons and the materials or services can only be supplied by a particular supplier and no alternative or substitute exists (e.g., original equipment manufacturer, or where the warranty is tied to a particular material and it would be negated by the use of a different supplier’s part);
- The supplier has a statutory monopoly; or
- For the procurement of a prototype, or a first good or service, to be developed in the course of, and for, a particular contract for research, experiment, study, or original development, but not for any subsequent purchases.

6.0 WARRANTY CLAIMS

Hydro One employs a Warranty & Claim Management process that provides a systematic methodology for identifying, assessing and resolving warranty issues and claims, and for seeking compensation, when applicable, from suppliers. The process is tailored to manage warranty issues and claims for major engineered equipment but can be applied to materials and equipment. When materials/equipment fail or are found to be defective, the following process is followed:

- Warranty & Claim Assessment – determine if the materials/equipment are still under warranty, if warranty covers the defect/failure, and Hydro One's cost impact.
- Warranty Claim Form – completed for claims exceeding $25K or where the Line of Business requires assistance from Hydro One's Supply Chain group to manage the warranty issue with the supplier.
- Warranty Claim Support – Hydro One will:
    - Participate in resolution meetings with the team as required.
    - Provide commercial guidance and direction by ensuring the necessary Supply Chain stakeholders are engaged to help resolve the issue.
    - Coordinate internal commercial discussions with Supply Chain, Inergi, and Law, as required.
    - Help coordinate communications with suppliers to ensure the team received the appropriate level of support to quickly resolve the defect/failure.
    - Work with the supplier to negotiate the appropriate compensation.
- Defect or Failure Resolution - develop an action plan, identifying who will complete the work (e.g., Hydro One or supplier).

Where a warranty does not apply, Hydro One may still have reasons to issue a claim such as latent defect, design not to specifications, or breach of contract.

When the repair is complete, applicable costs will be reimbursed by the supplier.

7.0 ATTACHMENTS

Attachment	Description
1	Supply Chain Policy

SP 1231 R3

Filed: 2021-08-05
EB-2021-0110
Exhibit E-5-2
Attachment 1
Page 1 of 3

Supply Chain Policy

Purpose and Scope

The primary purpose of the Supply Chain Policy is to communicate and reinforce desired values and expectations of the supply chain activities of Hydro One Limited, its subsidiaries and the affiliates it controls (referred to in this document as 'Hydro One' or the 'Corporation').

This policy applies to Hydro One and its outsourcing partner.

Revision Statement

This policy has been revised to include additional key Supply Chain functions: Productivity Savings, Supplier Performance Management & Governance. In addition, links in section 3.0 References have been updated.

Principles

Supply Chain will:

- Acquire materials and services through a process that drives value for money, transparency to its internal customers, and builds mutually valuable relationships with key suppliers.
- Ensure the right materials and services are delivered to the right place at the right time in a cost effective manner.
- Source materials and services with consideration to health, safety and the environment and corporate social responsibility.
- Promote business and workforce development for Indigenous Businesses.
- Achieve operational excellence through continuous improvement in collaboration with Supply Chain's Customers and Suppliers.
- Manage its outsourcing partner to align with these principles.

1.0 Requirements

The key requirements of each Supply Chain function are as follows:

Strategy and Oversight:

- Provide a strategic, cost effective, data driven and analytical planning approach to Supply Chain processes.
- Direct continuous improvement initiatives to achieve operational excellence and cost effectiveness.
- Ensure an effective governance process is in place to manage change.

Sourcing:

- Develop and execute a strategic procurement plan to identify materials and services needed to meet business requirements at the best value for money.
- Employ a mix of procurement processes, including sole source, direct negotiation, and bidding processes that provide the best business outcome.
- Identify and attract qualified suppliers that provide quality products and services.
- Provide opportunity for increased Indigenous Business participation in the provision of products and services.

Purchasing:

- Process Purchase Requisitions on a timely basis to ensure that customer's needs are met.
- Promote improved requisitioning through effectively documented processes and education.

SP 1231 R3

Inventory Management:

- Align to the Inventory Policy (SP0732).
- Manage inventory at optimal levels and locations to satisfy operations.
- Monitor and control the accuracy of inventory data.
- Re-deploy, return or dispose of material to maximize cost savings considering environmental impact.

Logistics:

- Determine the most efficient and economical method to store and distribute materials from Suppliers to Customers.
- Facilitate the movement of returnable containers to Suppliers.

Accounts Payable:

- Remit authorized and timely payments to Suppliers in accordance with the terms and conditions of the respective contracts.
- Capture payments accurately and completely in Hydro One systems, and ensure accurate account distributions.

Customer Service:

- Providing Source-to-Pay support for all internal customers
- Delivering value to all its internal customer and dedicated to providing excellent customer service

Productivity Savings:

- Leverage purchasing power across internal organizations and strategic sourcing events to obtain competitive prices and negotiate significant cost savings

Supplier Performance Management & Governance:

- Negotiating terms and contractual language that mitigate risks and ensures Hydro One's interests are protected.
- Ensuring Suppliers meet financial, health & safety, and insurance requirements.
- Providing supplier performance management to ensure Suppliers are fulfilling their contractual commitments to Hydro One.

Data Management

- Utilize business applications, information management methods, and data management tools to implement procedures and an infrastructure to support the integration and shared use of accurate, timely, consistent and complete Supply Chain Master Data.

2.0 Definitions

None

3.0 References

Expenditure Authority Register

Supplier Code of Conduct

SP0829 - Code of Business Conduct

SP0849 - Corporate Disclosure Policy

SP0732 - Inventory Policy

SP0733 - Inventory Procedure

SP1374 - Indigenous Procurement Procedure

SP0327 - Health, Safety and Environmental Policies

SP0312 - HSE Requirements for Purchase of Contractor Services

SP0826 - Sourcing Procedure

Requisitioner's Guideline

SP 1231 R3

4.0 Document Management

Owner/Functional Responsibility	Director, Supply Chain
Approver	Vice President, Shared Services
Approval Date	April 2020
Effective Date	April 28, 2020
Last Reviewed Date	April 28, 2020
Next Review Date	April 28, 2022

5.0 Appendices

None

July 11, 2023

Sent Via Email

Ms. Elsy Aceves
Account Executive, Key Account Management
Hydro One Networks Inc.

Dear Ms. Aceves,

RE: Echo River TS Project Status and Cost

Thank you for your updates on the progress of the Hydro One Sault Ste. Marie (HOSSM) project at Echo River TS. As you are aware, Algoma Power Inc. (API) is a local distribution company regulated by the Ontario Energy Board (OEB).

API notes that the project increase of 35% or $2.7M is material and significant, particularly for a distributor of API's size. For reference API's materiality threshold requires explanation of budget variances in excess of $125,000.

In order to substantiate its understanding of the incremental costs compared to the initial estimate of $7.8M provided in the CCRA, API has developed follow up questions, which are provided in Appendix A. The answers to these questions will also support API's variance explanations in its upcoming rate application, to be filed with the OEB in early 2024. Among the contents of this application, API will need to explain material changes from the budgets and plans which were filed with the prior rate application.

Can you please review these questions and provide your responses before the end of August, 2023.

Please note API intends to use the answers provided, whether verbatim or in summary, in its application to the OEB which will be publicly available online once filed.

Sincerely,

Jennifer Rose,
Regional Manager
jennifer.rose@algomapower.com

CC: Michael Degilio, Supervisor, Distribution Engineering (API)
Oana Stefan, Manager, Regulatory Affairs (API)

Appendix A- API's Questions to HOSSM

Purpose/Introduction

HOSSM has provided project updates via one-page quarterly updates, and via further detail at API's request. Given the magnitude of the change, as it relates to the materiality threshold of API, API requires further information to substantiate and explain the cost increases.

Cost Component	CCRA Estimate	1st Notice (Net Increase)	2nd Notice (Net increase)	3rd Notice (Net Increase)	"Forecasted" Cost based on Increase Explanations	Total Change	Forecast based on Q1 2023 Report	Variance Between Forecasts
Project Management	$ 689,000.00		$ 68,128.00		**$ 757,128.00**	$ 68,128.00	**$ 896,123.00**	$ 138,995.00
Engineering	$ 799,000.00	$ 285,358.00			**$ 1,084,358.00**	$ 285,358.00	**$ 1,809,846.00**	$ 725,488.00
Equipment & Materials	$ 2,060,000.00		$ 698,987.00		**$ 2,758,987.00**	$ 698,987.00	**$ 3,209,830.00**	$ 450,843.00
Construction	$ 2,320,000.00	$ 1,548,945.88			**$ 3,868,945.88**	$ 1,548,945.88	**$ 3,321,452.00**	-$ 547,493.88
Commissioning	$ 622,000.00			$ 341,000.00	**$ 963,000.00**	$ 825,477.00	**$ 825,477.00**	-$ 137,523.00
Past Cost (CCEA)	$ 393,000.00				**$ 393,000.00**	$ -	**$ -**	-$ 393,000.00
Subtotal	**$ 6,883,000.00**	**$ 1,834,303.88**	**$ 767,115.00**	**$ 341,000.00**	**$ 9,825,418.88**	$ 2,942,418.88	**$ 10,062,728.00**	$ 237,309.12
Contractor's Contingency	$ 883,000.00			-$ 240,000.00	**$ 643,000.00**	-$ 240,000.00	**$ 304,460.00**	-$ 338,540.00
Total	**$ 7,766,000.00**	**$ 1,834,303.88**	**$ 767,115.00**	**$ 101,000.00**	**$ 10,468,418.88**	$ 2,702,418.88	**$ 10,367,188.00**	-$ 101,230.88 *

**per email received June 29, 2023 the expected variance is $99,000, however the calculations above indicate over $101,000.*

General Questions:

1. In terms of overall budget, API has noted a discrepancy between the allocation of the updated budget of $10.5M among cost components (see right-most column above) versus the forecasts in the quarterly project status reports. Please provide further details addressing the discrepancy and final cost.
2. Further, API requests an outline of the original budget and forecast update between internal and external costs. Has the split among these categories changed since the initial project budget?

API also has questions about the increases in each cost component, outlined below:

Engineering: +$285k:

3. Is the engineering budget inclusive of both external consulting and internal staff time? What is the breakdown between these categories and any other categories?

Additionally, API has the following follow up questions for the explanations already provided:

Explanation Provided	Follow Up Request
Grounding study identified more deficiencies to be addressed, additional resources were required to address these deficiencies	4. Further explanation- as this is an existing TS. 5. What budget impact did this have?
Equipment vendor support and information such as shop drawings were slower than expected:	6. Please confirm whether this was internal or external to Hydro One? 7. What efforts were made to mitigate the delays? 8. Were there any premiums incured to address delays?
Unexpected delay in transformer drawings and test reports held up completion of engineering, extending schedule and support required from resources	9. what is the basis for allocation of internal (HONI staff time)? 10. Please describe the impact to schedule vs. and premium cost paid to address delays

Equipment And Materials +$700k:

The table below has been provided to explain the change in Equipment and Materials.

The increase represents 34% over the initial component budget.

11. API requests a breakdown of the original budget for each of the individual items below.

Item	Incremental Cost	Category
Oil-Water Separator Material	76,979	Equipment & Materials
Structural Materials	49,133	Equipment & Materials
Control Materials	136,840	Equipment & Materials
Bus, Hardware & Insulator Materials	96,325	Equipment & Materials
Switches Equipment	23,979	Equipment & Materials
Cable Trench Material	44,723	Equipment & Materials
Power Transformer Equipment	107,698	Equipment & Materials
Instrument Transformer Equipment	13,124	Equipment & Materials
Surge Protecting Devices	5,135	Equipment & Materials
Hired Equipment Electrical	131,291	Equipment & Materials
Civil Foundations Materials	13,760	Equipment & Materials
Total	698,987	

12. Additionally, API requests further information about the Power Transformer- what was the timing of the procurement, what are the specific delays and increases for the power transformer?

Construction +$1.55M:

Given the order of magnitude increase in the construction budget, API requires further quantification of the contributing factors to this component.

Escalation Provided	Follow Up Request
Delay in completion of IFC (Issue For Construction) engineering (as noted in the Engineering section) extended construction schedule into winter seasons, incurring additional heating & preservation expenses	11. Please quanitfy.
Quotes received for Hired Equipment rentals - Crane, Scaffolding, Rock Drilling Rig, Generators are significantly higher than the 2020 estimate	12. Please quanitfy and explain HOSSM procurment process
Fuel costs are significantly higher for heating, temp power generators and other equipment noted above	13. Please quanitfy.
New soil management regulations introduced additional soil sampling and handling costs [Ontario Regulation 406/19 – filed December 4, 2019]	14. Please quanitfy. We understand the regulation to be effective January 1, 2023. Please confirm if the associated work occured after this date, or whether HOSSM has advanced the requirements to apply in 2022.
Incremental scope/quantities of material were added to address deficiencies (as noted in the Engineering section)	15.Please quanitfy.
Transformer delivery timeline is not optimal as IFC engineering delays resulted in a delayed construction start Requiring a temporary pad to be built to house the transformer until the transformer foundations are complete Additional craning and lifting costs are incurred as the transformer will have to be rigged into its permanent location from its temp pad	16. Please quantify. Did HONI consider speaking with API about delaying project?

Escalation Provided	Follow Up Request
Laydown area is now outside the compound, as space is required for transformer temporary pad inside compound, requiring additional areas to be prepared and maintained for material handling	
HOSSM also indicated that the construction increase [$1,548,945.88] included a portion due to internal rate increases [$330,033.38]	17.What is the basis for this adjustment? Is it wage increases? How many person-hours are associated with the project to result in such an increase?

Project Management +$68k:

18. API requests further information on the basis for this increase- what component is related to rates versus the amount of time allocated to the project? What are the major drivers?

"Third Notice" -Commissioning and Contingency net +$99k :

Escalation Provided	Follow Up Request
Commissioning team had to support heating and hoarding in the winter months, additional equipment, tools and transportation required to support transformer commissioning in winter which was not expected.	19. Please quantify and expand on this. As this is a project in Northern Ontario, I'm not sure why was this not expected?
Vacuum pulling for the transformer was required for a much longer duration than estimated due to weather conditions and longer exposure time (vacuum pulling process being a continuous process it had a material impact).	20. Please provide additional details. What was the planned vs actual schedule for the vacuum pulling? What were the weather conditions, when did they occur and how did they result in a material impact to the project?
There were issues with the 230 kV Circuit switcher that the commissioning team had to resolve, this item was shipped with the wrong parts, repairs had to be made onsite.	21. Please confirm who was responsible for incorrect shipment, HOSSM or the Manufacturer?
Unexpected outage delays caused by equipment failure at the neighboring Mississagi TS resulted in additional rental durations for equipment, crews were already onsite at Echo River TS for transformer soak and then the soak was rescheduled, this caused inefficiencies.	22. Please provide API a detailed report explaining the cause of the equipment failure and resource deployment for the Mississagi TSwork..

Appendix B- Most Recent Project Status Report

PROJECT STATUS REPORT - 2023 Q1

Project: Echo River TS - New Transformer and EOL 230kV Breaker Removal

Customer: Algoma Power Inc.

Project Description

Algoma Power has requested Hydro One Sault Ste. Marie LP to add a second 230/34.5kV power transformer at the Echo River TS to operate as a "Hot Spare" where it will normally be on potential and ready to carry load should the existing Transformer T1 be taken out of service. The scope of work will consist of installation of this additional transformer and associated work including wave traps, HV circuit switcher, surge arrestors, PT, LV isolation switch, protection scheme additions, modifications and extension of bus work for the 230kV and 34.5kV buses and identified new equipment triggered by this new transformer installation.

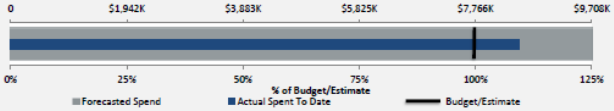
PROJECT STATUS

SCHEDULE : ON TRACK

FORECASTED COST : ON BUDGET

Project Costs

Forecasted Cost
33%
Over Budget

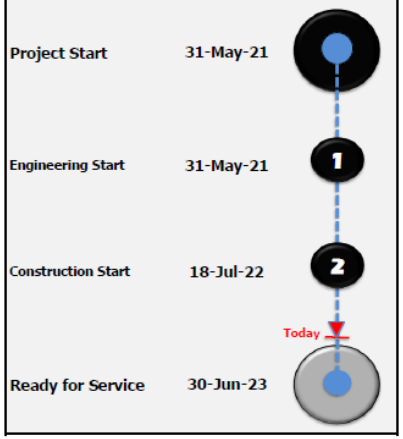


Cost Component	Budget/Estimate	Actual To Date*	Forecast†
Project Management	$ 689,000	$ 885,720	$ 896,123
Engineering	$ 799,000	$ 1,787,325	$ 1,809,846
Procurement	$ 2,060,000	$ 3,016,830	$ 3,209,830
Construction	$ 2,320,000	$ 2,269,306	$ 3,321,452
Commissioning	$ 622,000	$ 525,477	$ 825,477
Other**	$ 1,276,000	$ 4,229	$ 304,460
Total	**$ 7,766,000**	**$ 8,488,887**	**$ 10,367,188**

*Actual costs spent as of March 31, 2023.
**Other costs include contingency as applicable.

Customer Capital Contributions excl. HST	$ 7,766,000
Forecast of Required Customer Capital Contributions excl. HST	$ 10,367,188
Forecast of Additional Contribution (or Refund) excl. HST	**$ 2,601,188**

Project Schedule



Additional Notes

- Construction and Commissioning underway, transformer assembly has been completed
- Project Cost Forecast is 33.5% above budget, the reasons for this forecast increase have been provided to API
- Past Incurred Cost of $393,000 is included in the Other Cost for Budget/Estimate, however, this Past Incurred Cost has been redistributed for Actual to Date and Forecast

Threats, Risks, and Scope Changes

- Potential for weather delays to affect construction and commissioning schedule
- Higher than currently estimated amount of rock has been found onsite, eventhough majority of the project area has already been daylighted, the risk of encountering additional rock in the yet to be daylighted areas remains

Account Executive	Project Manager
Elsy Aceves	Kannappan Manickam
Phone: 1 (416) 884-7385	Phone: 1 (647) 354-4175
Email: Elsy.Aceves@HydroOne.com	Email: Kannappan.Manickam@hydroone.com

†Forecasted costs are a projection of the actual Engineering and Construction Cost of the Work Chargeable to Customer and are subject to change due to internal resource bundling, scheduling, delays in third party invoicing for equipment, materials and services, and other factors. Because of the foregoing, upon Project completion, the customer will pay Hydro One Sault Ste. Marie LP's actual Engineering and Construction Cost (plus applicable Taxes) of the Work Chargeable to Customer in accordance with the terms of the Simplified Customer Connection Cost Recovery Agreement.

CONFIDENTIAL | HYDRO ONE NETWORKS INC

Date: 5/1/2023

Attachment 2-Staff-30

Facility Benchmarking Calculations (Excel Only)

Algoma Power Inc.
EB-2024-0007

Attachment 3-Staff-34

Load Forecast (Excel Only)

Algoma Power Inc.
EB-2024-0007

Attachment 4-Staff-48

Actuarial Reports

Algoma Power Inc.
EB-2024-0007

Mercer

FortisOntario Inc.

2023 Year-End Disclosures and 2024 Pension Expense Estimates under CICA3461

	[redacted]	Algoma RPP	Algoma SERP	TOTAL
Change in benefit obligation				
Benefit obligation - end of prior period	2	26,313,267	87,795	47,939,000
Current service cost (employer)		445,348	-	760,634
Interest cost		1,360,044	4,031	2,466,697
Employee contributions		216,482	-	216,482
Plan amendments		-	-	-
Benefits paid		(1,301,226)	(25,843)	(2,801,160)
Net transfer in (out)*		-	-	-
Acquisitions (divestitures)		-	-	-
Increase (decrease) in obligation due to curt		-	-	-
Obligation being settled		-	-	-
Special Termination Benefit		-	-	-
Actuarial loss (gain)		2,310,172	20,131	3,515,936
Benefit obligation - end	2	29,344,087	86,114	52,097,589
Change in plan assets				
Market value of plan assets - end of prior pe	2	29,929,093	-	57,720,093
Actual return on plan assets		2,902,820	-	5,259,434
Employer contributions		446,062	25,843	502,059
Employee contributions		216,482	-	216,482
Benefits paid		(1,301,226)	(25,843)	(2,801,160)
Net transfer in (out)*		-	-	-
Actual plan expenses		-	-	(213,218)
Market value of plan assets - end	2	32,193,231	-	60,683,690
Reconciliation of funded status				
Benefit obligation - end	2	29,344,087	86,114	52,097,589
Market value of plan assets - end	2	32,193,231	-	60,683,690
Funded status - surplus (deficit)		2,849,144	(86,114)	8,586,101
Employer contributions after measurement d		-	-	-
Unamortized transitional obligation		-	-	-
Unamortized past service costs		-	-	2,478
Unamortized net actuarial loss (gain)		673,925	(963)	2,331,206
Accrued benefit asset (liability)		3,523,069	(87,077)	10,919,785
2023 Components of expense				
Current service cost		445,348	-	935,634
Interest cost		1,360,044	4,031	2,466,697
Expected return on plan assets		(1,705,751)	-	(3,176,391)
Amortization of transitional obliation				-
Amortization of past service costs		-	-	543
Amortization of net actuarial loss (gain)		-	(10,262)	(6,912)
Net expense (income)		99,641	(6,231)	219,571
Assumptions				
At beginning of period				
Discount rate		5.30%	5.30%	
Rate of compensation increase		3.50%	N/A	
Expected rate of return on plan assets		5.75%	N/A	
EARSL		18.60	2.20	
At end of period				
Discount rate		4.60%	4.60%	
Rate of compensation increase		3.50%	N/A	
Expected rate of return on plan assets		5.75%	N/A	
EARSL		18.40	2.90	
Estimated 2024 Components of expense				
Current service cost		550,992	-	912,932
Interest cost		1,319,441	3,431	2,330,442
Expected return on plan assets		(1,829,449)	-	(3,350,423)
Amortization of transitional obliation		-	-	543
Amortization of past service costs		-	-	5,801
Amortization of net actuarial loss (gain)		-	-	-
Net expense (income)		40,984	3,431	(100,705)

Fortis Ontario's Non-Pension Post Retirement Benefit Plans
Estimated 2023 Expense under Section 3461

[redacted]

	Algoma
From	2023-01-01
To	2023-12-31
Change in benefit obligation	
Benefit obligation - end of prior period	5,963,100
Current service cost (employer)	184,100
Interest cost	310,800
Employee contributions	0
Plan amendments	0
Benefits paid	-179,200
Net transfer in (out)	0
Acquisitions (divestitures)	0
Increase (decrease) in obligation due to curtailment	0
Obligation being settled	0
Special termination benefits	0
Actuarial loss (gain)	892,300
Benefit obligation - end	7,171,100
Change in plan assets	
Market value of plan assets - end of prior period	0
Actual return on plan assets	0
Employer contributions	179,200
Employee contributions	0
Benefits paid	-179,200
Surplus paid out to employer	0
Settlement payments	0
Net transfer in (out)	0
Acquisitions (divestitures)	0
Actual plan expenses	0
Market value of plan assets - end	0
Reconciliation of funded status	
Benefit obligation - end	7,171,100
Market value of plan assets - end	0
Funded status - surplus (deficit)	-7,171,100
Employer contributions after measurement date	0
Unamortized transitional obligation (asset)	0
Unamortized past service costs	-0
Unamortized net actuarial loss (gain)	-3,060,560
Accrued benefit asset (liability)	-10,231,660
Unamortized transitional increase (decrease) in valuation allowance	0
Valuation allowance	0
Accrued benefit asset (liability), net of valuation allowance	-10,231,660
Components of expense	
Current service cost (incluuding provision for plan expenses)	184,100
Interest cost	310,800
Expected return on plan assets	0
Amortization of transitional obligation (asset)	0
Amortization of past service costs	-21,940
Amortization of net actuarial loss (gain)	-197,400
Curtailment loss (gain)	0
Settlement loss (gain)	0
Amortization of transitional increase (decrease) in VA	0
Increase (decrease) in valuation allowance	0
Special termination benefits	0
Net expense (income)	275,560
Assumptions	
At beginning of period	
Discount rate	5.30%
Rate of compensation increase	3.50%
Immediate trend rate	4.98%
Ultimate trend rate	4.00%
At end of period	
Discount rate	4.60%
Rate of compensation increase	3.50%
Immediate trend rate	4.83%
Ultimate trend rate	4.00%
EARSL for in-year amortization of actuarial (gain)/loss	18.00

Fortis Ontario's Non-Pension Post Retirement Benefit Plar

Estimated 2023 Expense under Section 3461

	Algoma
From	2024-01-01
To	2024-12-31
Components of expense	
Current service cost (including provision for plan expenses)	240,400
Interest cost	325,200
Expected return on plan assets	0
Amortization of transitional obligation (asset)	0
Amortization of past service costs	0
Amortization of net actuarial loss (gain)	-130,200
Curtailment loss (gain)	0
Settlement loss (gain)	0
Amortization of transitional increase (decrease) in VA	0
Increase (decrease) in valuation allowance	0
Special termination benefits	0
Net expense (income)	435,400
Assumptions	
At beginning of period	
Discount rate	4.60%
Rate of compensation increase	3.50%
Immediate trend rate	4.83%
Ultimate trend rate	4.00%
At end of period	
Discount rate	4.60%
Rate of compensation increase	3.50%
Immediate trend rate	4.77%
Ultimate trend rate	4.00%
EARSL for in-year amortization of actuarial (gain)/loss	18.00

Attachment 6-Staff-56

PILS Model (Excel Only)

Algoma Power Inc.
EB-2024-0007

Attachment 6-Staff-57

DVA Model (Excel Only)

Algoma Power Inc.
EB-2024-0007

Attachment 9-Staff-70

DLI Model (Excel Only)

Algoma Power Inc.
EB-2024-0007

Attachment 9-Staff-75

Updated Accounting Order

Algoma Power Inc.
EB-2024-0007

DRAFT ACCOUNTING ORDER - Land Use Revenue Requirement Variance Account

Account 1508 - Other Regulatory Assets, Sub-Account API Land Use Variance Account

This account includes the variance between land use related revenue requirement included in base rates (currently proposed amount of $767,909 in 2025 Test Year, see Exhibit 4 of proceeding) and actual during the subsequent IRM years. API will track costs at a sufficiently detailed level to assist in a prudence review of the costs incurred, materiality and causation related to new/renewed costs incurred for land use in 2025 and subsequent IRM years.

The following accounts are established to record the amounts described above incurred on or after January 1, 2025 (including the 2025 revenue requirement impacts of capitalized agreements established in 2024).

- Account 1508 - Other Regulatory Assets, API Land Use Variance Account (ALUVA)
- Account 1508 - Other Regulatory Assets, API Land Use Variance Account (ALUVA), Sub-Account Carrying Charges
- Account 1508 - Other Regulatory Assets, API Land Use Variance Account (ALUVA) Rate Rider Revenues

Sample Journal Entries:

Revenue Requirement Variance (2025 Test Year to 2029 Bridge)

Entry below assumes proposed land use amount in base rates is less than actual, entry flipped if proposed amount is greater than actual, entries expected to vary year-to-year.

OMA

Dr. 1508 Other Regulatory Assets, API Land Use Variance Account (ALUVA) OMA

Cr. 4080 Distribution Services Revenue

To record variance between amount included in revenue requirement and actual for OMA.

Capital

Dr. 1508 Other Regulatory Assets, API Land Use Variance Account (ALUVA) Capital

Cr. 4080 Distribution Services Revenue

To record revenue requirement variance between amount included in base rates and actual for capital.

Note: This would be calculated in accordance with revenue requirement calculation methodology and would include consideration for amortization expense, PILs, ROE and interest expense.

Carrying Charges (2025 Test Year to 2029 Bridge)

Entry below assumes net debit balance in Account 1508 - Other Regulatory Assets, ALUVA per above, entry flipped if net credit balance.

Dr. 1508 Other Regulatory Assets, API Land Use Variance Account (ALUVA) OMA, Sub-Account Carrying Charges

Dr. 1508 Other Regulatory Assets, API Land Use Variance Account (ALUVA) Capital, Sub-Account Carrying Charges

Cr. 6035 Other Interest Expense

To record the carrying charges on the net monthly opening balance in Account 1508 - Other Regulatory Assets, API Land Use Variance Accounts (ALUVA).

Rate Rider Recovery (2030 Test Year)

Entry below assumes rate riders collected as net debit balance in Account 1508 - Other Regulatory Assets, ALUVA per above, entry flipped if net credit balance.

Dr. Account 1100 Customer Accounts Receivable

Cr. Account 1508 - Other Regulatory Assets, API Land Use Variance Account (ALUVA) Rate Rider Revenues

To record the collection of rate rider billings.

Carrying Charges (2030 Test Year)

Entry below assumes net debit balance in Account 1508 - Other Regulatory Assets, ALUVA per above, entry flipped if net credit balance.

Dr. 1508 Other Regulatory Assets, API Land Use Variance Account (ALUVA), Sub-Account Carrying Charges

Cr. 6035 Other Interest Expense

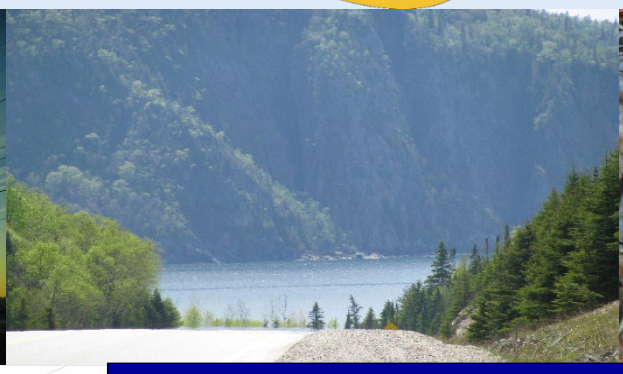
To record the carrying charges on the net monthly opening balance of the sum of in Account 1508 - Other Regulatory Assets, API Land Use Variance Account (ALUVA) OMA, Account 1508 - Other Regulatory Assets, API Land Use Variance Account (ALUVA) Capital, and Account 1508 - Other Regulatory Assets, API Land Use Variance Account (ALUVA) Rate Rider Revenues.

Attachment 1-SEC-3b

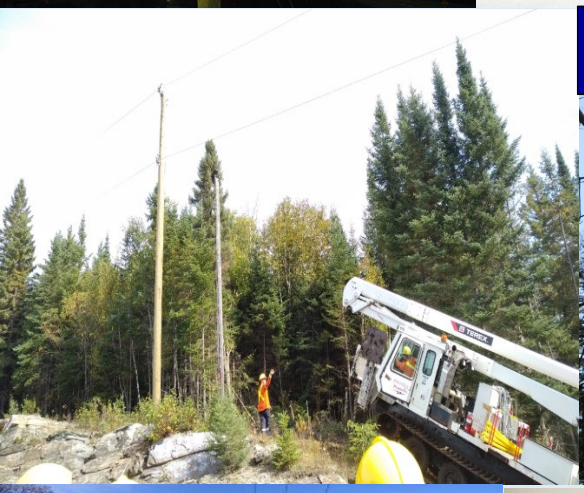
2024-2028 Business Plan

Algoma Power Inc.
EB-2024-0007

Algoma Power Inc.
A FORTIS ONTARIO Company


2024-2028 Five-Year Business Plan













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APPENDICES

1.0 EXECUTIVE SUMMARY

The primary focus of the 2024-2028 Five-Year Business Plan (the "Plan") of Algoma Power Inc. ("API" or the "Company") centers on management achieving continued improvement in overall operational efficiencies, making prudent rate base investments, and driving regulatory performance to enhance earnings while pursuing further expansion of its core regulated distribution business in the Algoma district. The Plan reflects a planning horizon from 2024 to 2028 and includes a comprehensive set of financial forecasts in support of the initiatives for that period.

Management has identified the following areas that represent the most important strategic issues facing the Company over the next five years:

1. Safety and Reliability
2. Financial Performance
3. Operational Performance
4. Regulatory
5. Information Technology
6. Human Resources

The Plan outlines specific objectives and targets in support of API's overall corporate vision of being recognized throughout Ontario as a well-respected, well-managed, and profitable growth vehicle for its parent company, FortisOntario Inc. ("FortisOntario").

2.0 CORPORATE PROFILE

API is a Northern Ontario-based electricity distribution utility, with approximately 1,850 kilometers of lines in a service area of approximately 14,200 square kilometers, which includes Wawa, Goulais River, Desbarats, St. Joseph's Island, Dubreuilville, and Bruce Mines, serving a diverse range of approximately 12,500 customers.

2.1 *CORPORATE VISION*

API will be recognized throughout Ontario as a respected, well managed, and profitable growth vehicle for its parent company, FortisOntario, through its sustained commitment to core business growth and increased returns from existing operations. API will strive to deliver results that

continue to enhance shareholder value while maintaining an unwavering commitment to its Core Values.

OBJECTIVES

The Company will continue to focus on these primary objectives:

i) Earnings: Generate annual net earnings from its distribution business sufficient to achieve a return on equity commensurate with well-run Canadian utilities.

ii) Operational Performance: Ensuring the safe and effective management of its core utility business functions and the achievement of its key performance benchmarks.

CORE VALUES

Our Core Values define what the Company is and how it operates. They reflect the beliefs, philosophy, and commitment of the Company's employees and shareholders. A demonstrated commitment to these values is a prerequisite for individual employee success. Management will treat Respect for People as a condition of employment.

All employees are expected to demonstrate a commitment to the Company's Core Values and will be held accountable for behaving in a manner consistent with these Core Values.

THE CORE VALUES OF ALGOMA POWER INC.

RESPECT FOR PEOPLE: Treat others, as you would have others treat you. Honesty, integrity and ethics are never compromised.

DIVERSITY, EQUITY AND INCLUSION: Create a welcoming environment that encourages and promotes diversity, cross-culture working experiences and strong relationships within our workplace and with our Indigenous communities and partners. Demonstrate leadership and foster a workplace culture where all employees feel empowered to bring their authentic selves to the workplace and do their best work.

SAFETY AND THE ENVIRONMENT: Demonstrate a personal, unrelenting commitment to safety and environmental excellence. Protect yourself, your fellow employees, the public and our environment.

FINANCIAL SUCCESS: Produce solid earnings, with dividends that meet the expectations of shareholders. Grow shareholder value through prudent equity investments and business partnerships. Ensure that debt obligations are always met in a timely manner and to the satisfaction of our creditors.

CUSTOMER SERVICE: Everyone has customers. Determine your customers' needs by listening. When you can meet these needs, do so. When you cannot, tell them that you cannot, or tell them who can. When in doubt about how to treat a customer, do what you believe is right. When serving customers, be pleasant, courteous and accurate; smile, act professionally and enjoy yourself. Attitudes are contagious.

PRODUCTIVITY: Effective teamwork combined with employee innovation produces productivity gains. Employees are encouraged to pursue opportunities to implement new ideas and methods that enhance overall individual and team performance. Remember…if you have a better way to do something – just do it.

COMMUNITY INVOLVEMENT: Each of us has an obligation to support the communities that support us. This means time as much as money. Success is measured by the reaction of community leaders and the opinions expressed by community residents.

3.0 SAFETY AND RELIABILITY

3.1 HEALTH, SAFETY & ENVIRONMENT ("HSE")

MANAGEMENT SYSTEMS

API's integrated Health, Safety and Environmental Management System ("HSEMS") is consistent with ISO 45001 and ISO 14001. A number of ongoing and future initiatives support the HSEMS framework, which is built upon ongoing assessments and continual improvement. To prevent complacency in the workplace, Management is renewing its focus on effectiveness and compliance of leading indicators.

The following are objectives, targets, and initiatives, which are supported through management programs and teams.

NEW MEASUREMENT OF SAFETY

The Fortis Operating Group ("FOG") Safety group has evaluated the newly proposed classification and safety measurement processes for suitability and recommended it for implementation across all Fortis subsidiaries. The FOG Safety group has developed a "Safety Measurement" strategic plan to implement the process. This plan will improve the relevancy of safety performance metrics through Severity-Based Lagging Indicator ("SBLI"), in which the Edison Electric Institute ("EEI") research team has produced a safety event classification model that produces more consistency when classifying incidents and promotes focus on high energy hazards. The Safety Classification and Learning ("SCL") model also provides a framework for using lagging indicators (incidents) as learning opportunities that are more readily shared due to common terminology and format. More importantly, the SCL model seeks to improve leading indicators (work observations, job planning, job safety analyses) through High Energy Control Assessments ("HECA") and a focus on controlling hazards to improve safety capacity. The goal over the next few years is to achieve zero Serious Injury and Fatalities ("SIF's") and integrate a measurement of safety performance using a balanced approach of leading and lagging Indicators that is comparable across all Fortis subsidiaries.

SAFETY LEADING INDICATORS

The Company will be focusing on four leading indicator themes that have been identified as building organizational safety capacity as the Company moves to execute the leading indicators to a higher standard. FortisOntario's levels were determined using a self- assessment tool to provide a baseline that will be used to measure the progress of each element and ensure maturity enhancement.

The four leading indicators are: (1) observation and site visits, (2) safety meetings, (3) safety training and education, and (4) a good catch program. As part of an action plan each leading indicator was evaluated using the Safety Culture Maturity Model and placed in one of four dimensions, which include (1) regulatory, (2) directive; (3) engagement, and (4) collaborative. Each leading indicator had a unique criterion used to place the leading indicator into one of the four dimensions. The level of maturity is a four-step continuum from base level dimension (1) to world class dimension (4). This will enable a consistent approach to measurement, monitoring, and progress across all Fortis companies.

FORTIS OPERATIONS GROUP ("FOG") SAFETY GROUP INITIATIVE BEST PRACTICE REVIEW

The FOG safety team has been engaged in sharing best practice reviews with all Fortis companies. Teams will review, identify, and share best practices, polices, and processes. Topics will consist of technical and cultural safety items, including, safety leadership development, communications, and leading indicators. The FOG safety team will communicate the results and recommendations from the best practice reviews to FortisOntario, which will review and endorse the recommendations that will be implemented at all Fortis companies. The FOG safety team developed a baseline survey of Leading Indicators for all Fortis companies to complete, which identified individual baselines of maturity levels for safety observation and site visits, safety meetings, safety training and education, and good catches.

FOG ENVIRONMENTAL GROUP INITIATIVE BEST PRACTICE INITIATIVES

The FOG environmental team has been focused on sharing environmental issues and best practice initiatives with all Fortis companies. Teams will focus on best practices,

policies, processes, and different legislative requirements. Topics will include biodiversity and greenhouse gas initiatives, sustainability, waste management, Canadian Electricity Association ("CEA") designation. The FOG environmental team will communicate initiatives to FortisOntario for further review and potential future implementation.

EMPLOYEE ENGAGEMENT

Consistent with ISO 14001 and 45001, FortisOntario continues to encourage the participation of workers in our HSE processes including incident investigation as required, significant environmental aspects and impacts, and hazard identification risk assessment controls that are evaluated annually.

3.2 SYSTEM RELIABILITY

The Company's 2023 goal for system reliability (SAIDI) is 3.83. As of September 30, 2023, the SAIDI was 3.77. The future year targets are estimated by using the 'previous 3-year rolling average less 5%' approach. A number of initiatives will be taken to achieve the targets, including improving system protection and control, vegetation management, system automation, reducing outage restoration time, and focusing on sustaining capital investment.

4.0 ECONOMIC OUTLOOK [1]

Ontario's economy will expand by 0.9 per cent this year and 1.4 per cent next year. The slowdown in 2023 compared to last year's robust 3.7 per cent rise is elevated interest rates which takes 18 months to one year to be felt. The economy will expand by 2.7 per cent by 2025, when interest rates moderate. Household spending will be sluggish this year as high interest rates and persistent inflation erode disposable income. Automakers and the province have announced they are investing millions in expansions and in battery plants across the cities, which will give a boost to the construction sector. The tight labour market will ensure employment prospects remain strong and support wage growth. High immigration rate will see Ontario's population expand rapidly sustaining household demand.

[1] Ontario's Three-Year Outlook, Conference Board of Canada June 26, 2023

Based on the 2023 Fall Statement released by Ontario on November 2, 2023, a deficit of $5.6 billion is forecasted for 2023-2024 compared to a deficit of $1.3 billion in the March 2023 Provincial Budget. The decline is attributable to lower tax revenues and less economic growth. The result for 2022-2023 was a deficit of $5.9 billion. Ontario is only forecasting a small surplus of $0.5 billion in 2025-2026.

Ontario's key economic indicators for 2022 to 2025 are as follows:

	2022A	2023F	2024F	2025F
REAL GDP (%Δ)	3.7%	0.9%	1.3%	2.7%
CPI (%Δ)	6.8%	3.6%	2.3%	2.1%
UNEMPLOYMENT	5.6%	5.5%	5.9%	5.9%
HOUSING STARTS (000S)	96	86	88	92

In June 2023, the Independent Electricity System Operator ("IESO") released its Reliability Outlook for the period of July 2023 to December 2024. Ontario's electricity system is expected to be available to meet electricity demand and maintain operating reserves during the 18-month period. Under extreme weather forecast, supply is lower than what is required to meet demand and maintain required reserves during the summer months. If available supply is below requirement, the IESO imports power and/or defers generator maintenance outages to meet the requirement,

In 2023, electricity demand is expected to decreased by 0.4 per cent reaching 136.1 TWh. Energy consumption in 2024 is expected to reach 138.8 TWh representing an increase of 1.9 per cent over 2023.

API is expecting load growth over the forecast period from planned mining developments, community developments and related off-spins.

5.0 REGULATORY

5.1 REGULATORY FRAMEWORK

The OEB's Renewed Regulatory Framework for Electricity Distributors ("RRFE") provides three rate-setting methods for distributors including 4th Generation Incentive Rate-Setting ("4th Generation IR"), Custom Incentive, and an Annual Incentive Rate-Setting Index. The

RRFE is applicable to the API distribution business unit. In 2023, API applied for rates under the 4th Generation IR rate-setting method.

The following table provides a summary of the key regulatory indicators of API:

ALGOMA POWER	
OEB-APPROVED TEST YEAR AMOUNTS	
Most Recent Test Year	2020
Rate Base ($000's)	$119,721
Revenue Requirement ($000's)	$25,510
Return on Equity	8.52%
2024 RATE ADJUSTMENTS	
Rate Setting Method (2022)	4th Generation IR
Inflation Factor	4.8%
Productivity Factor	0%
Stretch Factor	0.6%
Distribution Rate Adjustment	4.2% - IR 3.54% - RRRP [1]
UPCOMING REBASING AND RENEWALS	
Type of Rebasing / Renewal	OEB Cost of Service
Next Rebasing/Renewal Year	2025
Rate Setting Mechanism	4th Generation IR

1- Rate adjustments in all years (Test and IR) for API Residential and General Service customers are prescribed by legislation. The RRRP is an electricity subsidy program applicable to customers in rural and remote areas, funded through a province-wide charge on electricity bills.

5.2 REBASING OUTLOOK

API's next rebasing is planned for rates effective January 1, 2025. In its 2022 and 2023 IRM applications, API requested and was approved for ACM funding for its Sault Ste. Marie Facility ("SSM Facility", $12.7M) and Echo River TS ("ERTS", $7.5M) projects, respectively. The ACM/ICM provides for interim cost recovery of qualifying projects during IRM years that is a proxy for the increased revenue requirement that would result from including these projects in rate base. At the next rebasing, API will apply for the total project costs associated with the SSM Facility and ERTS projects in excess of the amounts currently being recovered.

5.3 OEB INITIATIVES AND GOVERNMENT POLICY

Following the implementation of governance reforms in Q3/Q4 2020, the OEB continues to implement various policy initiatives and other programs, primarily focused on energy transition. Key developments include:

- Distribution Energy Resources ("DERs"): The OEB amended the Distribution System Code to standardize and streamline the connection of DERs. The updates clarified definitions, clarified cost responsibility, and created a separate procedure manual and templates. These changes initially came into force October 1, 2022, with further improvements effective June 7, 2023, and September 18, 2023. Furthermore the OEB released a report permitting distributors to apply for incentives for the use of DERs as non-wires alternatives ("NWAs"). Currently, the OEB is preparing guidelines for a cost-benefit analysis for the use of DERs as NWAs, which will consider both distribution and bulk system benefits.

- Electric Vehicle ("EV") Charging: Currently the OEB's filing requirements require distributors to demonstrate they have planning processes in place to address future capacity needs, including in relation to EVs. The Ministry of Energy made data available to LDCs regarding the purchase of EVs by postal code. The OEB has a policy initiative investigating alternative delivery rate designs for commercial EV charging (public charging stations and fleet charging).

- Resiliency and Reliability: Under separate policy initiatives, the OEB has been reviewing resiliency and reliability. The focus of the resiliency policy consultation is on preparing the electricity system to withstand and recover from extreme weather events caused by climate change, in a manner which balances affordability considerations. The reliability initiatives focus on increased reliability reporting (more detailed cause information, customer-specific reliability metrics, loss of supply reporting), which aim to drive improvements in reliability benchmarking and performance.

6.0 OPERATIONAL PERFORMANCE

6.1 DISTRIBUTION SYSTEM PLAN ("DSP")

API continues to implement the OEB accepted DSP in the Cost of Service application. Major investment areas include:

- Express feeder-rebuilding projects;
- Pole replacement programs;
- System automation projects;
- Rebuild or upgrade three distribution substations; and
- Signed agreement with Hydro One to add another 230/34.5 kV, 25 MVA power transformer in 2023.

API completed several major projects identified in the 2020–2024 DSP filed during the 2019 rate application, including the addition of the Echo River TS (Hydro One owned) second power transformer, construction of the Sault new office building, sub-transmission line upgrades, deteriorated assets replacement, and customer driven projects. Currently, API is preparing a new DSP for the 2025–2029 period for the next rate application. As Hydro One will rebuild Batchawana TS and Goulais TS during the next couple years, API's next major investment areas will include the distribution system upgrade and rebuild supplied by these two new transmission substations, along with customer driven projects and asset replacements. These two substations are located along Trans-Canada Highway 17. Currently the loads in the areas are low and are supplied partially by 7.2 kV single phase lines. API requested Hydro One to supply and install 115 kV to 12.5 and 25 kV dual secondary voltage transformers and make the substation ready to be converted to 25 kV in the future. API will rebuild the lines in these areas to 25 kV, 3-phase system in the future to service the potential EV charging load in the future.

6.2 SYSTEM INSPECTION AND MAINTENANCE

The Company will continue inspection and maintenance programs to minimize equipment life cycle costs, including:

- Equipment inspection and maintenance programs based on OEB and CSA requirements and good utility practice;
- Vegetation management programs; and
- Pole testing programs.

6.3 DISTRIBUTION CAPITAL INVESTMENTS

API will invest approximately $55.56 million over the forecast period in its distribution system. The following table summarizes the net capital investment planned:

	2024	2025	2026	2027	2028	5-Year Total
API DIST	10,506	9,983	10,318	14,100	10,656	55,563

6.4 OPERATIONAL EFFICIENCIES AND INNOVATION

While focusing on sustaining investment and system performance, API is also exploring opportunities in efficiency gain and innovation. One area under development is the system control and automation plan. Following the successful completion of the SCADA pilot project, API intends to pursue full implementation and will develop distribution automation strategy. Alongside the sustainment investment program, API is looking at a medium term voltage conversion, which will ensure API is better positioned to support the forecasted supply requirements, while also reduced system losses. A plan will be developed to electrify its small fleet and install EV charging stations when financially justifiable. API is also looking for projects in areas of micro grid and distributed energy resource to improve operation efficiency and improve system reliability.

6.5 CUSTOMER SERVICE

CUSTOMER SERVICE ANALYSIS

The Company continues to focus on identifying efficiencies and enhancing the customer experience through the consolidation of services and the development of technology. Focus also continues on developing talent within the Company to improve alignment with business requirements and employee retention. Due to the complex nature of the work involved, and SOX based control measures, it is critical that skilled employees are

developed to meet those challenges for entry level positions and support succession planning strategies.

The customer service environment has changed significantly over the past few years. This includes complexity of regulation governing the Ontario utility space as well as customer expectations to support those changes by continuing to provide clear messaging along with complete and accurate billing information in a timely manner. Given the three FortisOntario locations, all with unique requirements and customer demographics, customer service will be reviewing the “as built” environment in terms of major processes with the intent of assessing current deficiencies, risks and where we are getting it right. This project will extend beyond 2023, to properly determine and possibly re-engineer business processes to better align with current company requirements.

CUSTOMER ENGAGEMENT

The Company’s customer engagement plan includes recording and tracking engagement activities and implementing methods to objectively measure the level of engagement with customers and the respective impact the activities are providing.

A customer communication framework is being developed that will accomplish the following objectives:

- Actively encourage customers to register with the new customer self-serve portal, which creates an improved and more independent experience. This will continue to be promoted through annual campaign messaging via social media, and direct customer service team member calls.
- Continued development of new smart forms delivered to customers within the customer self-serve portal allowing easier submission of common activities such as new customer connection, move-out requests, and pre-authorized debit enrollment.
- Actively communicate with customers during major power outages. The Company intends to "push" outage information to customers during major power outages by using customer preferred communication channels. This is being supported by providing line staff with mobile devices and allowing them to actively change the status of an outage in the OMS, which will accurately update information to customers. This technology

deployment has essentially been completed in API and will be used as the corporate model for replication in other FortisOntario locations.

COLLECTIONS

Credit and collection activities have increased. The disconnection moratorium on residential customers required greater focus on managing arrears. Review of the credit and the collection process will be ongoing as part of continuous improvement. Specifically, the responsiveness of customers to all dunning activities is being measured to gauge what is working most effectively to reduce the average days of receivables. Such review looks at developing best practices for all account collection processes and ensuring consistency across FortisOntario. Where possible, configuration to SAP will be made to further increase automation and reduce the need for manual intervention. Receivables are affected during the months of November through April during the disconnection moratorium in Ontario. Arrears increase during this period and will require ongoing recovery efforts. Focus will be on the larger outstanding amounts (>$500) while also encouraging payment arrangements in accordance with the OEB's mandate to work cooperatively with customers.

7.0 INFORMATION TECHNOLOGY ("IT")

API strives to provide high quality and efficient technology solutions that support and enhance corporate and operations' functions. Delivering products and tools that improve accuracy and effectiveness while working closely with stakeholders is a key part of the Company's philosophy.

Between 2024 and 2028, significant investment and growth are expected in the following technology areas:

- Cybersecurity – IT and Operational Technology ("OT");
- SAP CIS & ERP Upgrade Planning and Ongoing Enhancements; and
- Cloud Adoption and Technology Enhancements.

CYBERSECURITY – IT AND OT

In maintaining and striving to exceed compliance in both OEB and Fortis cybersecurity frameworks, which are based upon energy sector-specific sections of the Cybersecurity

Capability Maturity Model ("ES-C2M2"), the Company is working to reduce cybersecurity risk and enhance its maturity in a number of security-related practices.

The Company is continuing with its plan to enhance cybersecurity controls and practices between 2024 and 2028, using its 2019 Cybersecurity Risk Management Program ("CRMP") as the foundation for its cybersecurity risk reduction improvements. A mid-program assessment in 2022 confirmed that significant progress has been made in reducing IT risk, while the next three to five years will focus heavily on integrating OT technology administration and oversight into IT in delivering on the CRMP's commitment to sustainable cybersecurity risk across all technology areas. Some of the next five years' cybersecurity enhancements include:

- Integrate a passive network monitoring solution in the OT network as a first line of defense against network attacks on the SCADA operational network and gain visibility into network performance issues or potential threat vectors.
- Implement a Privileged Identify and Access Management ("PIAM") solution to control and monitor all access to and use of administrative accounts across both IT and OT environments.
- Integrate Data Loss Prevention ("DLP") technology into the Company's corporate network to prevent the leaking and sharing of unauthorized and/or confidential information, and to establish a better classification method for company data.
- Complete an asset inventory of OT equipment and devices, and ensure that a robust mechanism for tracking useful life, patch levels, criticality, and other important information is in place and governed by a documented change management framework.

SAP ERP UPGRADE & ONGOING ENHANCEMENTS

The current release of SAP (called SAP ECC 6.0 with SAP for Utilities) will be at the end of mainstream vendor maintenance in 2027. However, it is possible to contract with SAP for extended maintenance until the end of 2030. Over the next couple of years, the Company will be assessing the viability of SAP's next release (SAP S/4HANA) to determine if an

upgrade can be justified to bring significant value to the Company in comparison to the cost and effort required to upgrade or re-implement the current system.

Ahead of any system upgrades or decisions about future direction, the Company continues to enhance and improve the current system, with the intention of all investments being fully compatible with an upgraded ERP solution over the course of 2024-2028. As business requirements change to meet unpredictable market modifications, planned work is continually reassessed and reprioritized to ensure critical changes are implemented within prescribed deadlines.

CLOUD ADOPTION & TECHNOLOGY ENHANCEMENTS

The IT industry is seeing a rapid move away from on-premise infrastructure to hosted, cloud-based systems. Cloud services offer security, high availability, and redundancy in excess of what most organizations could afford to build on-premise, and reduces the need for hardware and software maintenance tasks. With careful planning, costly on-premise system replacements will be moved to the cloud. While this will shift a large portion of IT capital expenses to operating expenses, the benefits realized by the Company in terms of cybersecurity, reliability, and better use of human resources will justify the cloud adoption. Additionally, software continues to move away from perpetual (i.e., capital cost) licenses to subscription-based models, further decreasing technology capital spending in and shifting it towards annual operating expenses. To help mitigate this industry change, the Company is dedicating resources to evaluating the use of technology across all businesses and finding efficiencies and consolidations of products where possible. Leveraging core capabilities of products available as part of the Microsoft 365 suite and other platforms will help alleviate the shift from capital to operating and minimize the need for standalone, niche software.

8.0 HUMAN RESOURCES ("HR")

8.1 LEADERSHIP DEVELOPMENT

The Company has 59 full-time equivalents ("FTEs") working throughout API, which is expected to remain fairly stable in the coming years. The Company remains committed to retaining and attracting skilled employees to meet ongoing business requirements. API

initiated a practice of hiring co-op students or apprentices in technical areas to facilitate training and assess skills in preparation for anticipated future vacancies due to retirement. This will also provide an opportunity to "retool" the business as required so that skill sets meet future business needs. The Company continues to work with department managers to ensure that future staffing requirements are met. There has been a higher number of retirements in the last few years, becoming increasingly difficult to attract qualified candidates, in particular technical positions. The Company has been working with recruiting firms to assist in recruitment.

API is looking holistically at its leadership development program, and to date, there have been a number of undertakings such as a mentoring program, 360 benchmark programs, and Confident Coach Supervisory training. Together these programs have supported the goal of ensuring the Company has the right people in critical roles to meet the Company's strategic objectives. In 2023, the Company, in conjunction with the Confident Coach facilitator, launched leadership development programs for its people leaders. In addition, the FortisOntario group of companies is working together and has delivered a leadership development program, specific to Fortis for top talent at the manager and director levels across the organization. The Company is committed to ensuring a developmental roadmap it created so there is clear direction for leadership development moving forward.

8.2 SUCCESSION PLANNING

The Company has a succession plan in place for managers and key supervisors, which is updated regularly. As part of the ongoing planning process, the Company enhanced this plan with more detailed supporting work history and biographic information for candidates and identification of gaps where there are no in-house candidates available to be groomed for succession opportunities. In addition, the Company coordinates key information from this process in support of the broader FortisOntario talent management process. A developmental roadmap will be created for high potential candidates.

8.3 LABOUR RELATIONS

Approximately 51 per cent of the workforce is unionized and has an agreement with the PWU union. The Company has harmonious labour relations and is focused on strategies

to maintain positive labour relations. Meetings between labour and management are held semi-annually and as required with the bargaining unit. API's four-year collective agreement expires December 2023, and the Company will look to previous settlements within the FortisOntario group of companies with respect to negotiations.

The Company remains focused and will continue its effort on the benefit administration process, streamlining across FortisOntario where possible. In support of this effort, an analysis of health plans has been undertaken to ensure that the Company's health and medical plans are structured to effectively manage anticipated cost increases due to industry trends. As a result, health and benefit costs have decreased and lower fund management fees (defined contribution pension plan) were renegotiated with the plan sponsor. A harmonized health and medical benefit plan were rolled out to all non-unionized employees in 2022. A benefits committee was established to discuss industry trends and feedback regarding the new harmonized plan.

8.4 DIVERSITY, EQUITY AND INCLUSION ("DEI")

DEI is included in API's Core Values to demonstrate leadership and foster a workplace culture where all employees feel empowered to bring their authentic selves to the workplace and do their best work. It also supports its relationships with FortisOntario's First Nations partners. The Company relaunched its DEI plan to employees and has an established a DEI leadership team comprised of a cross-section of employees throughout the organization to continue to create and maintain a welcoming environment that encourages and promotes diversity, cross-culture working experiences, strong relationships within the Company, and with the Company's Indigenous communities and partners. Ongoing awareness will continue to be generated through the digital bulletin boards, companywide training, and other Company initiatives to encourage 'Starting the Conversation'.

8.5 CORPORATE COMMUNICATIONS

A corporate communications strategy is being designed that will align with its business plans and provide guidance for future communications initiatives. While certain communications efforts tend to be reactive by nature (e.g., responding to a crisis, major outage), other communications require proactive communications. For example,

communications can be used for supporting various operational areas such as health and safety, and infrastructure projects that are part of organic growth.

API continues to focus on improved employee communications to foster consistent messaging across all locations. A communications framework to establish a consistent set of standards was rolled out to managers. These standards include inter/intra departmental communications, regular managers' meetings, and improving dissemination of information through the use of technology, such as the intranet and other IT systems. The new intranet is being leveraged as a consistent means of communicating with all employees. From on-boarding to Company policies, all pertinent information is stored on the intranet. An analysis to optimize the system's capabilities is ongoing and increased use of virtual meetings is expected to continue. Microsoft Teams software is used extensively to facilitate enhanced communication across the organization.

To further enhance communication, digital bulletin boards are being utilized at all work locations, which replaced traditional bulletin boards and enabled information to be disseminated quickly and consistently throughout the Company. Townhall meetings are also scheduled for all locations as well as annual safety awareness days. Further enhancement of the intranet will be ongoing to leverage increased digital engagement throughout the Company.

9.0 CORPORATE TARGETS

API will use the following key corporate targets to measure performance against plan. This objective approach promotes accountability while ensuring focus on key success factors and identifying areas where improvement is required.

CORPORATE TARGETS							
FINANCIAL	**2022 ACTUAL**	**2023 FORECAST**	**2024 TARGET**	**2025 TARGET**	**2026 TARGET**	**2027 TARGET**	**2028 TARGET**
NET EARNINGS ($'MILLIONS)	4.7	5.1	5.3	6.1	6.2	6.2	6.0
OPERATING EXPENSE ($' MILLIONS)	14.1	14.7	15.0	15.3	15.6	15.9	16.2
GROSS CAPITAL EXPENDITURES ($' MILLIONS)	8.9	10.0	10.9	33.1	9.1	11.6	9.2
SYSTEM RELIABILITY							
SAIDI	4.42	4.61	3.79	3.64	3.52	3.43	3.80
HEALTH & SAFETY							
HIGH RISK LOST TIME INJURY	0	0	0	0	0	0	0
PLANNED WORK OBSERVATIONS & WORKPLACE INSPECTIONS (% OF PLAN)	117	100	100	100	100	100	100
CUSTOMER SERVICE							
CUSTOMER SATISFACTION RATING (%)	95	95	95	95	95	95	95
ACCOUNTS RECEIVABLE OVER 30 DAYS (%)	15	15	15	15	15	15	15
SERVICE LEVEL (% CALLS WITHIN 30 SEC.)	86	83	83	83	83	83	83
HUMAN RESOURCES							
ABSENTEEISM (DAYS/EMPLOYEE)	5.71	3.65	3	3	3	3	3
FTE (YEAR-END)	59	59	59	59	59	59	59

10.0 FINANCIAL PERFORMANCE

10.1 FINANCIAL FORECAST

	2022 ACTUAL	2023 FORECAST	2024 PLAN	2025 FORECAST	2026 FORECAST	2027 FORECAST	2028 FORECAST
Sales (GWh)	256	291	299	301	302	304	305
Revenue net of energy purchases	27,223	28,543	30,238	32,501	33,151	33,814	34,490
Operating expenses	14,053	14,719	14,984	15,282	15,589	15,901	16,219
Depreciation	4,188	4,515	4,634	5,089	5,297	5,591	5,842
Operating income	8,982	9,309	10,620	12,131	12,265	12,322	12,429
Other (income) and expense	3,990	3,800	4,955	5,331	5,331	5,331	5,331
Income taxes	259	403	406	696	780	821	1,069
Net Income	4,733	5,106	5,259	6,104	6,154	6,170	6,029
Dividends paid	-	-	3,000	4,000	4,000	5,000	6,000

The 2023 forecast earnings of $5.1 million are expected to be $0.3 million higher than plan due to increases in interest income and decreases in income tax expenses.

The 2024 plan earnings of $5.3 million are up $0.2 million from the 2023 earnings forecast.

The Cost of Service 2020 approved rate base was $119.7 million, an increase of $21.6 million or 4.1 per cent compound annual growth rate ("CAGR") over the 2015 approved rate base. API is expected to rebase again in 2025, and the forecasted rate base is $172.5 million, an increase of $52.8 million or 7.6 per cent CAGR since 2020.

Over the business planning period for goodwill analysis purposes, financial modeling assumes electricity distribution rates in non-rebasing years grow at 5.94 per cent in 2024, 2.00 per cent in 2026, 2.00 per cent in 2027, and 2.00 per cent in 2028 (combination of incentive regulation, load growth and ACM) and operating expenses grow by 2.0 per cent. API will rebase in 2025.

Detailed financial statements for the forecast period have been attached (Appendix A), along with the forecast capital budget (Appendix B) and the major assumptions in the plan (Appendix C).

10.2 FINANCING

API maintains a capital structure of approximately 60 per cent long-term debt and 40 per cent equity, similar to the OEB's deemed capital structure. Financing requirements of the regulated operations will be supported by a combination of short-term borrowings from the non-regulated operations as well as short-term bank borrowings, until the short-term debt is large enough to be replaced by financing from capital markets. The Business Plan assumes the borrowing of the external debt of $50.0 million at API in 2023.

10.3 SCENARIO ANALYSIS

API's most recently approved cost of service application was for rates effective January 1, 2020. The allowed ROE was determined by the OEB in October 2019, to be 8.52 per cent. A one per cent change in the assumed allowed ROE would change API earnings by approximately $590,000.

APPENDIX A

Financial Statements

[*attached*]

Algoma Power Inc.
Balance Sheet
As at December 31

	Actual 2022	Forecast 2023	Budget 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028
Current assets							
Cash and temporary investments	**$ 1,994**	**$ 6,804**	**$ 4,178**	$ 8,107	$ 8,318	$ 5,336	$ 3,705
Accounts receivable	**6,039**	**6,160**	**6,283**	6,409	6,537	6,668	6,801
Inventory	**175**	**178**	**182**	184	186	188	189
Regulatory assets	**978**	**800**	**800**	800	800	800	800
Other current assets	**200**	**204**	**208**	208	208	208	208
	9,483	**14,146**	**11,651**	15,708	16,049	13,200	11,703
Utility plants							
Cost	**202,805**	**212,584**	**223,283**	256,176	265,120	276,548	285,521
Less: accumulated amortization	**(74,259)**	**(78,608)**	**(83,238)**	(88,323)	(93,615)	(99,202)	(105,039)
	128,546	**133,976**	**140,045**	167,853	171,505	177,346	180,482
Accrued pension benefit asset	**9**	**1,000**	**2,000**	2,040	2,081	2,122	2,165
Intangible assets	**14,170**	**13,729**	**13,257**	12,753	12,240	11,717	11,183
Regulatory assets, non current	**26,939**	**37,439**	**35,000**	10,000	10,200	10,404	10,612
Other assets	**65**	**1,200**	**2,500**	-	-	-	-
Total assets	**$ 179,212**	**$ 201,490**	**$ 204,453**	$ 208,354	$ 212,075	$ 214,789	$ 216,145
Current liabilities							
Bank indebtedness	**$ 20,000**	**$ -**	**$ -**	$ -	$ -	$ -	$ -
Accounts payable and accrued liabilities	**6,836**	**6,971**	**7,111**	7,253	7,399	7,546	7,697
Customer deposits	**95**	**124**	**124**	126	129	131	134
Due to affiliates	**5,350**	**1,000**	**1,000**	1,000	1,000	1,000	1,000
	32,281	**8,095**	**8,235**	8,379	8,528	8,677	8,831
Long-term customer deposits	**667**	**576**	**576**	576	576	576	576
Long-term debt	**51,683**	**101,701**	**101,717**	101,734	101,751	101,768	101,785
Affiliate long-term debt	**12,750**	**-**	**-**	-	-	-	-
Accrued post retirement benefit liability	**5,963**	**7,000**	**7,140**	7,283	7,428	7,577	7,729
Future income taxes payable	**9,025**	**10,239**	**10,311**	11,483	12,603	13,693	14,559
Regulatory liabilities	**1,276**	**3,000**	**3,000**	3,060	3,121	3,184	3,247
Contributions	**6,633**	**6,836**	**7,170**	7,434	7,509	7,584	7,659
Shareholder's equity							
Common and preferred shares	**44,008**	**44,008**	**44,008**	44,008	44,008	44,008	44,008
Retained earnings	**14,926**	**20,035**	**22,296**	24,397	26,551	27,722	27,751
Total shareholder's equity and liabilities	**$ 179,212**	**$ 201,490**	**$ 204,453**	$ 208,354	$ 212,075	$ 214,789	$ 216,145
Total debt	**60%**	**62%**	**61%**	**60%**	**59%**	**59%**	**59%**
Shareholder's equity	**40%**	**38%**	**39%**	**40%**	**41%**	**41%**	**41%**

Algoma Power Inc.
Statement of Cash Flows
For the Period Ending December 31

	Actual 2022	Forecast 2023	Budget 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028
Operating activities							
Net earnings for the period	**$ 4,733**	**$ 5,106**	**$ 5,259**	$ 6,104	$ 6,154	$ 6,170	$ 6,029
Amortization	**4,188**	**4,964**	**5,243**	5,711	5,931	6,238	6,502
Change in working capital	**9,550**	**(24,034)**	**9**	14	17	19	17
Deferred pension costs	**7,555**	**(991)**	**(1,000)**	(40)	(41)	(42)	(42)
Future income taxes	**1,401**	**1,214**	**72**	1,172	1,120	1,090	866
Regulatory assets and liabilities	**(22,760)**	**(8,776)**	**2,439**	25,060	(139)	(142)	(144)
Other asset	**(50)**	**(1,130)**	**(1,300)**	-	-	-	-
Loss (gain) on disposal of property, plant and equipment	**(32)**	**-**	**-**	-	-	-	-
Deferred post retirement benefits	**(625)**	**1,037**	**140**	143	146	149	152
Cash from operations	**3,960**	**(22,610)**	**10,862**	38,164	13,188	13,482	13,380
Financing activities							
Dividend paid	**-**	**-**	**(3,000)**	(4,000)	(4,000)	(5,000)	(6,000)
Change in long-term debt	**-**	**37,262**	**17**	17	17	17	17
Affiliate long-term debt	**79**	**(91)**	**-**	-	-	-	-
Contributions	**3,363**	**242**	**385**	315	128	128	130
Cash from (used in) financing activities	**3,442**	**37,413**	**(2,598)**	(3,668)	(3,855)	(4,855)	(5,853)
Investing activities							
Net additions to utility plant	**(8,169)**	**(9,779)**	**(10,699)**	(32,894)	(8,944)	(11,428)	(8,973)
Additions to intangibles	**(195)**	**(214)**	**(192)**	(174)	(178)	(181)	(185)
Proceeds of sale of utility capital assets	**63**	**-**	**-**	-	-	-	-
Change in other assets	**-**	**-**	**-**	2,500	-	-	-
Cash used in investing activities	**(8,301)**	**(9,993)**	**(10,891)**	(30,568)	(9,122)	(11,609)	(9,158)
Increase (decrease) in cash	**(899)**	**4,810**	**(2,626)**	3,928	211	(2,982)	(1,631)
Cash, beginning of period	**2,893**	**1,994**	**6,804**	4,178	8,107	8,318	5,336
Cash (bank indebtedness), end of period	**$ 1,994**	**$ 6,804**	**$ 4,178**	$ 8,107	$ 8,318	$ 5,336	$ 3,705

Algoma Power Inc.
Income Statement
For the Period December 31

	Actual 2022	Forecast 2023	Budget 2024	Forecasted 2025	Forecasted 2026	Forecasted 2027	Forecasted 2028
Revenue							
Sale of energy	**$ 29,361**	**$ 34,718**	**$ 40,339**	$ 40,944	$ 41,558	$ 42,181	$ 42,814
Distribution revenue	**26,500**	**27,925**	**28,330**	31,837	32,474	33,123	33,785
Other revenue	**723**	**618**	**1,908**	664	677	691	705
	56,584	**63,261**	**70,577**	73,445	74,709	75,995	77,304
Purchased power	**29,361**	**34,718**	**40,339**	40,944	41,558	42,181	42,814
	27,223	**28,543**	**30,238**	32,501	33,151	33,814	34,490
Operating expenses							
Distribution	**7,416**	**7,789**	**7,929**	8,088	8,250	8,415	8,583
General	**5,545**	**5,309**	**5,610**	5,722	5,837	5,954	6,073
Customer Service	**950**	**1,157**	**1,094**	1,116	1,138	1,161	1,184
Municipal and other taxes	**142**	**464**	**350**	357	364	371	379
	14,053	**14,719**	**14,984**	15,282	15,589	15,901	16,219
Depreciation and amortization	**4,188**	**4,515**	**4,634**	5,089	5,297	5,591	5,842
Operating income	**8,982**	**9,309**	**10,620**	12,131	12,265	12,322	12,429
Other income							
Interest on Investments	**95**	**902**	**700**	200	200	200	200
Services and miscellaneous revenue	**3**	**1**	**-**	-	-	-	-
Gain (loss) on disposals	**(32)**	**-**	**-**	-	-	-	-
	69	**903**	**700**	200	200	200	200
Other income deductions							
Loan interest expense	**3,494**	**4,347**	**5,483**	5,483	5,483	5,483	5,483
Intercompany interest expense	**441**	**232**	**48**	48	48	48	48
Regulatory expenses	**124**	**124**	**124**	-	-	-	-
	4,059	**4,703**	**5,655**	5,531	5,531	5,531	5,531
Earnings before income taxes	**4,992**	**5,509**	**5,665**	6,800	6,934	6,991	7,098
Provision for income taxes	**259**	**403**	**406**	696	780	821	1,069
Net income	**$ 4,733**	**$ 5,106**	**$ 5,259**	$ 6,104	$ 6,154	$ 6,170	$ 6,029
Return on Equity	**8.4%**	**8.3%**	**8.1%**	**9.1%**	**8.9%**	**8.7%**	**8.4%**

APPENDIX B

Capital Budget

[*attached*]

Algoma Power Inc.
5 Year Capital Budget
(000's)

APPENDIX B

	2022 Actual	2023 Forecast	2024 Budget	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
Algoma Power							
Substation Upgrades [1]	4,438	(4,344)	3,905	11,589	1,723	4,007	1,543
Line Replacements and Customer Extensions	9,376	12,022	5,244	5,307	5,190	5,328	5,470
Meters	133	115	133	150	153	156	159
Tools and Equipment	69	95	110	112	115	117	119
Distribution Rebuilds - Storms	12	95	-	-	-	-	-
Scada System Development	66	90	140	143	146	138	70
Land Easement and R.O.W. Procurement	159	36	39	40	41	42	43
R.O.W. Expansions	-	100	122	124	127	129	132
Vehicles	581	760	585	850	950	1,007	1,027
Buildings & Service Centre [1]	(6,593)	401	134	14,223	138	139	40
Distribution Transformers/Reclosers/Regulators	377	447	326	395	404	411	420
IT	260	178	152	135	135	135	135
Total Algoma Power	**8,878**	**9,995**	**10,890**	**33,068**	**9,122**	**11,609**	**9,158**
Contributions	**3,363**	**242**	**385**	**315**	**128**	**128**	**130**
Grand Total (Net)	**5,515**	**9,753**	**10,505**	**32,753**	**8,994**	**11,481**	**9,028**

APPENDIX C

Forecast Assumption

[*attached*]

ALGOMA POWER INC.

2024-2028 PLAN AND FORECAST

ATTACHMENT C - ASSUMPTIONS

The following assumptions were made in developing the 2024 plan and 2025-2028 forecast:

DISTRIBUTION ENERGY SALES (GWH)

	2022A	2023F	2024P
RESIDENTIAL	105	123	130
COMMERCIAL/OTHER	151	168	169
TOTAL ENERGY SALES	256	291	299
% CHANGE FROM PRIOR YEAR		13.7%	2.7%

DISTRIBUTION – CONNECTED CUSTOMERS

	2022A	2023F	2024P
RESIDENTIAL	11,213	11,759	12,305
COMMERCIAL/OTHER	1,108	1,127	1,146
TOTAL CUSTOMERS	12,321	12,886	13,451
% CHANGE FROM PRIOR YEAR		4.6%	4.4%

T&D RATE INCREASES

	2024	2025	2026	2027	2028
API [(1)]	5.94%	Rebase	2.00%	2.00%	2.00%

(1) In non-rebasing years, combination of IRM, load increase and ACM.

	2024	2025	2026	2027	2028
DIVIDENDS ($'000)	3,000	4,000	4,000	5,000	6,000
CORPORATE INCOME TAX RATE	26.50%	26.50%	26.50%	26.50%	26.50%
RATE BASE ($'M)	148	173	179	183	187
% CHANGE FROM PRIOR YEAR (%)	3.8%	16.8%	3.7%	2.4%	2.2%

EXPENSES

- General expenses rise at an average of 2.0% per annum beyond 2024.
- 2024 annual expense for pension and post- retirement benefits:

($ '000)	
DEFINED BENEFIT	52
DEFINED CONTRIBUTION	148
SERP	3
POST RETIREMENT	517
	720

- Assumptions:

  Investment Rate: 5.75%
  Discount rate: 4.85%

- 2024 composite depreciation rate is 2.1%

APPENDIX D

OEB Scorecard

[*attached*]

Scorecard - Algoma Power Inc.

Performance Outcomes	Performance Categories	Measures		2018	2019	2020	2021	2022	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		98.63%	97.10%	100.00%	100.00%	98.64%	up	90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%	flat	90.00%	
		Telephone Calls Answered On Time		86.06%	81.61%	84.84%	88.36%	85.46%	up	65.00%	
	Customer Satisfaction	First Contact Resolution		99.97%	99.96%	99.93%	99.95%	99.99%			
		Billing Accuracy		99.86%	99.87%	99.87%	99.82%	99.92%	up	98.00%	
		Customer Satisfaction Survey Results		93%	95%	94%	93%	97%			
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		82.00%	83.00%	83.00%	83.00%	82.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	flat		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	flat		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	flat		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		7.51	7.33	6.79	3.61	4.43	down		7.36
		Average Number of Times that Power to a Customer is Interrupted [2]		2.20	3.39	2.93	1.77	2.08	down		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]		$2,182	$2,235	$2,212	$2,338	$2,479			
		Total Cost per Km of Line [3]		$13,831	$12,107	$12,203	$13,025	$14,501			
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**	Renewable Generation Connection Impact Assessments Completed On Time [4]									
		New Micro-embedded Generation Facilities Connected On Time		100.00%				100.00%	flat	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.07	0.69	0.77	0.43	0.26			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.42	1.36	1.30	1.32	1.44			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.30%	9.30%	8.52%	8.52%	8.52%			
			Achieved	8.22%	8.44%	9.25%	9.38%	10.53%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor 's reported information.
4. Value displayed for 2021 reflects data from the first quarter, as the filing requirement was subsequently removed from the Reporting and Record-keeping Requirements (RRR).

Legend:

5-year trend
up down flat

Current year
target met target not met

2022 Scorecard Management Discussion and Analysis ("2022 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2022 Scorecard MD&A:

Scorecard - Performance Measure Descriptions (oeb.ca)

Scorecard MD&A - General Overview

- In 2022, API met or exceeded all of its performance targets, consistent with the strong performance in prior years.
- In 2023, API expects to continue to maintain and improve its overall scorecard performance results. Sustaining and improving performance are expected as a result of enhanced system reliability due to API's investment in its distribution system and continued responsiveness to customer feedback.

Service Quality

- **New Residential/Small Business Services Connected on Time**

In 2022, API connected 99% of the 220 new eligible low-voltage residential and small business customers within the Ontario Energy Board's prescribed five-day timeline. Since 2011, API has consistently exceeded the Ontario Energy Board's target of 90%.

- **Scheduled Appointments Met On Time**

In 2022, API met 100% of its 190 appointments within the prescribed timelines set out by the Ontario Energy Board. Since 2013, API has consistently attended 100% of its schedule appointments on time.

- **Telephone Calls Answered On Time**

In 2022, customer service representatives answered 85.5% of API's 8,769 calls within 30 seconds. This exceeds the Ontario Energy Board's mandated 65% target. Longer call processing times due to the complexity of customer calls are affecting the call answering statistics. API continues to offer and promote self-serve options and utilizes social media to engage and inform customers in an effort

to offer customers additional channels to interact with the Company.

Customer Satisfaction

- **First Contact Resolution**

API measured First Contact Resolution by tracking the number of escalated calls as a percentage of total calls taken by the customer service center. In 2022, only 0.01% of calls were escalated, resulting in a first contact resolution of 99.99%.

- **Billing Accuracy**

For 2022, API issued 149,546 invoices and 99.92% were accurate. This is above the industry target of 98%.

- **Customer Satisfaction Survey Results**

API conducts its customer satisfaction surveys through a third-party survey provider, UtilityPULSE, consistent with many other LDCs in the province. Phone numbers were randomly selected so that 85% per cent of the interviews were conducted with residential customers and 15% with general service customers. API's 2022 satisfaction score was 97%. The Ontario benchmark assessed by UtilityPULSE is 90%.

The survey provides useful information to better meet the needs of API's customers and is incorporated into API's distribution system plan, capital planning and overall company objectives.

Safety

- **Public Safety**
  - **Component A – Public Awareness of Electrical Safety**

The Electrical Safety Authority has developed a survey on public awareness of electrical safety. The Electrical Safety Authority is responsible for developing the survey methodology and questions. The design and scoring are standardized across the province and set by the Electrical Safety Authority. In 2022, API engaged UtilityPulse to complete the survey in relation to "Public Awareness of Electrical Safety". On completion of this survey, UtilityPulse generated a "Public Safety Awareness Index Score" for API. API's score of 82% suggests that members of the public are generally well- informed about the safety hazards associated with electrical distribution systems, but also that further education and engagement would be beneficial. This survey on "Public Awareness of Electrical Safety" is completed on a two-year cycle and will be completed again by API in 2024.

- **Component B – Compliance with Ontario Regulation 22/04**

This component includes the results of an Annual Audit, Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns and Compliance Investigations. All the elements are evaluated as a whole and determine the status of compliance (Non-Compliant, Needs Improvement, or Compliant).

API's status as evaluated by the ESA is Compliant.

- **Component C – Serious Electrical Incident Index**

"Serious electrical incidents", as defined by Regulation 22/04, make up Component C. The metric details the number of and rate of "serious electrical incidents" occurring on a distributor's assets and is normalized per 10, 100 or 1,000 km of line (10km for total lines under 100km, 1000km for total lines over 1000km, and 100km for all the others).

API had zero incidents in 2022.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

API's customers experienced an increase in the average duration of electrical service disruptions in 2022 compared to 2021. The 2022 result is 40% better than API's performance target.

The average number of hours that power to a customer is interrupted, which are adjusted for Loss of Supply and Major Event Days, shows a decreasing trend. This indicates a general improvement in reliability for items within API's control. The four main outage causes in API's service area are Tree Contacts, Loss of Supply, Scheduled Outages and Defective Equipment.

API continues to invest in grid modernization to gain visibility on the state of the distribution system and improve overall response and restoration times. Grid modernization initiatives include the deployment of automated devices, implementation of a SCADA system and further development of API's outage management system. Outages in Northern Ontario can have significant impact to our customers, which is why API has continued to invest in asset contingency planning, ensuring redundancy in critical supplies and equipment. API has also continued to prioritize the management of its right-of-ways through its integrated vegetation management program.

- **Average Number of Times that Power to a Customer is Interrupted**

API's customers experienced a slight increase in the average number of electrical service disruptions in 2022 as compared to 2021, the result is 35% lower than API's performance target of 3.16, and shows an improving trend during the most recent five-year period.

API reviews outage statistics on a monthly basis to identify areas of poor distribution system performance. This process indicates any trends in poor performance and identifies opportunities to improve reliability. API also completes asset condition assessments to identify assets that present a risk of impacting system reliability. API uses reliability indicators and asset condition assessment data as key drivers into the system planning process.

API's outage reduction strategy is based on a cyclical asset preventative maintenance program through inspections and testing, and continues to prioritize management of right-of-ways through it's integrated vegetation management program. API has implemented a renewal based sustainment plan, whereby older, at end-of-life assets are replaced

Asset Management

- **Distribution System Plan Implementation Progress**

In 2022, API continued to see an increase in non-discretionary projects, through customer and third-party requests. API continues to invest in this area as needed in order to provide customers access to electricity services and to ensure ongoing collaboration with third-party entities completing work in our service territory. In particular, API responded to several larger industrial connection requests as well as permit requests associated with the accelerated broadband initiatives.

API's system renewal investments continue to be focused on sustaining asset replacements through our line and express feeder rebuild programs. In 2022, API achieved its planned rebuild plans and began the land acquisition and pre-engineering processes for the Bruce Mines greenfield station project, which is slated to continue in 2023.

API's system service investment continued to be focused on improving system reliability through contingency planning improvements, protection and control upgrades and system configuration upgrades. In 2022, API's main focus continued to be the supply contingency improvements at the Echo River TS. API has also been working with the Transmitter on supply point upgrades at the Goulais TS and Batchawana TS (both led by Hydro One Sault Ste. Marie), ensuring that the refurbishment plans will support long-term projected system capacity needs and improve supply contingency in their respective areas.

API's general plant investments continued to be focused on the new Sault Facility project as well as a sustaining fleet replacement program. In 2022, the construction of the new Sault Facility was completed, and API successfully transitioned its operations to the new building.

Industry supply chain challenges continue to cause procurement delays in our Fleet replacement plan. API achieved other smaller investment plans associated with right-of-way access trail improvements, implementation of a SCADA system, etc.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC on behalf of the Ontario Energy Board to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. In reviewing the Pacific Economics Group benchmarking and report, API management does not believe that the model accurately predicts API's costs. API's unique attributes as a rural and remote distributor, particularly its low customer density, result in API being an extreme outlier in the data set used to develop the model.

Some of API's largest cost drivers, including customer density and the degree of forestation along its distribution line rights of way, are not appropriately reflected in the benchmarking model. As a result of the extremely rural and low-density nature of API's system in relation to other Ontario distributors, API management believes that the total cost per km of line section below provides a more appropriate measure of API's efficiency and cost control.

- **Total Cost per Customer**

The statistical model developed by Pacific Economics Group (PEG) produces total capital and operating costs for each distributor that can be used for the purpose of comparing distributors. This amount is then divided by the total number of customers that API serves to determine Total Cost per Customer. The cost performance result for 2022 is $2,479 per customer which is a 6.0% increase over 2021.

Total cost in 2022, as assessed by PEG, increased 7% over 2021, while API's customer growth in this period was only 1%. API's operating expense component of total cost grew 2%, indicating API was able to manage costs at a rate lower than inflation in 2022. The capital cost component grew at a rate of 12%, driving the increase in total cost. API's Gross Capital Additions in 2022 were substantially *lower* than 2021, and the Capital Quantity assessed by PEG was stable, at 1% growth. The driver of the increase in Capital Cost (and in turn, the increase in total cost) was PEG's assessment of Capital Price, which is consistent across the industry, and grew by 10%, driven by increases in industry-wide inflation and cost of capital parameters.

Over the 2018 to 2022 period covered by the scorecard, API faced both inflationary cost increases, as well as cost increases associated with investments in programs for asset replacement, system improvement, and vegetation management that are sustainable in the long term. From 2018 to 2022, API's total customer count has not grown substantially (11,721 in 2018 vs. 12,332 in 2022), with a result that cost increases are not offset by customer growth.

- **Total Cost per Km of Line**

This measure uses the same total cost that is used in the Cost per Customer calculation above. The total cost is divided by the kilometers of line that API operates to serve its customers. API's 2022 result is $14,501 per km of line, an 11% increase over the result for 2021. The change in 2022 is driven by the increase in total cost, of 7%, as well as a decrease in the km of line (-4%) due to a reporting refinement.

The 7% increase in total costs is explained in the section above(Total Cost per Customer)

Many of API's significant cost drivers are directly related to its total kilometers of line. These cost drivers include most lines and vegetation management related activities, as well as support functions such as engineering and design. As discussed in the Efficiency Assessment section above, API management believes that total cost per km of line is a more accurate assessment of API's cost efficiency than the other measures discussed above.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

The 2022 liquidity current ratio for API per the scorecard is 0.26 (2021 - 0.43). The 2022 liquidity current ratio based on API's audited financial statements, adjusted to exclude due to related parties, is 0.35 (2021 - 0.75), which varied from last year primarily due to an increase in short-term loan payables as a result of cash flow needs associated with several large ongoing capital projects. It is expected that additional long-term debt financing will be secured, and that the liquidity ratio will move back towards a ratio of 1.00.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

The Ontario Energy Board uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5. The combined 2022 debt to equity ratio for API is 1.44 (2021 - 1.32), which has not significantly changed from prior year. The 2022 debt to equity ratio based on API's audited financial statements, adjusted to include due to related parties, is 1.52 (2021 – 1.48). The leverage ratio is expected to be maintained at a level near the 1.5 deemed capital mix noted above.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

API's 2022 distribution rates were approved by the Ontario Energy Board as part of its 4th Generation Incentive Rate-Setting application. API's last Cost of Service application was for rates effective January 1, 2020 and this included an expected (deemed) regulatory return on equity of 8.52%. The Ontario Energy Board allows a distributor to earn within +/- 3% of the expected return on equity. Outside of this range,

the OEB may require a review of the distributor's over-/under- earning.

- **Profitability: Regulatory Return on Equity – Achieved**

API's return achieved in 2022 is 10.53% (2021 - 9.38%), which is within the +/- 3% range allowed by the Ontario Energy Board. API's achieved returns are higher in 2022 as compared to 2021 due to a $0.7 million (15.3%) increase in adjusted regulated net income and a $2.6 million (2.2%) increase in rate base. The primary driver of the increase in adjusted regulated net income was a reduction in the current income tax expense calculated for regulated Return on Equity purposes.

Note to Readers of 2022 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.