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May 29, 2026

Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Mike McNiven
Board Secretary

Re: Quarterly Regulatory Report for the Quarter Ended March 31, 2026

Enclosed is Newfoundland and Labrador Hydro's ("Hydro") Quarterly Regulatory Report for the Quarter Ended March 31, 2026. Hydro has also included its Short-Term Load Forecast Accuracy – Island Interconnected System reports for 2025 and 2026 as Attachments 1 and 2 to Tab 4, consistent with the proposed changes to Hydro's short-term load forecast accuracy reporting.[1]

The Quarterly Regulatory Report is divided into four tabs, as follows:

1) Quarterly Summary;

2) Contribution in Aid of Construction;

3) Customer Damage Claims; and

4) Short-Term Load Forecast Accuracy – Island Interconnected System.

If you have any questions on the enclosed, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW/sk

Encl.

ecc:

Board of Commissioners of Public Utilities
Jacqui H. Glynn
Ryan Oake
Board General

Linde Canada Inc.
Sheryl E. Nisenbaum
Tina Lahey

Teck Resources Limited
Darren Hennessey

[1] "Newfoundland and Labrador Hydro - Short-Term Load Forecasting Accuracy Report – Proposed Changes to Reporting," Board of Commissioners of Public Utilities, November 17, 2025.

Consumer Advocate
Adrienne H.Y. Ding, O'Dea Earle
Justin W. King, O'Dea Earle
Consumer Advocate General

Newfoundland Power Inc.
Dominic J. Foley
Douglas W. Wright
Regulatory Email

Island Industrial Customer Group
Paul L. Coxworthy, Stewart McKelvey
Denis J. Fleming, Cox & Palmer
Glen G. Seaborn, Poole Althouse

Quarterly Regulatory Report

Quarter Ended March 31, 2026

May 29, 2026

A report to the Board of Commissioners of Public Utilities

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TAB 1

Quarterly Summary

Quarter Ended March 31, 2026

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Abbreviations

Term	Definition
AIF	All-Injury Frequency Rate
bbl.	Barrel
Board	Board of Commissioners of Public Utilities
CIAC	Contribution in Aid of Construction
EC	Electricity Canada (Formerly known as the Canadian Electricity Association)
EMS	Environmental Management System
FTE	Full-time equivalent
Holyrood TGS	Holyrood Thermal Generating Station
Hydro	Newfoundland and Labrador Hydro
IDEA	Inclusion, Diversity, Equity and Accessibility
LTIF	Lost-Time Injury Frequency
Newfoundland Power (NP)	Newfoundland Power Inc.
Q1	First Quarter
RSP	Rate Stabilization Plan
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TRIF	Total Recordable Injury Frequency
T-SAIDI	Transmission System Average Interruption Duration Index
T-SAIFI	Transmission System Average Interruption Frequency Index
T-SARI	Transmission System Average Restoration Index

Term	Definition
UFLS	Under Frequency Load Shedding
YTD	Year-to-Date

Definitions

Current Quarter: The period beginning January 1, 2026 and ending March 31, 2026.

EMS Target: An EMS target is an initiative undertaken to improve environmental performance.

End Consumer: End Consumer is a reliability measure of all end consumers of electricity in the province supplied by Hydro, excluding Industrial customers. The measure is a combination of Hydro's service continuity data and Newfoundland Power's service continuity data for loss-of-supply outages resulting from events on Hydro's system.

End-Consumer SAIDI: End-Consumer SAIDI measures reliability to all end customers of electricity in the province who are supplied by Hydro. It is a measure of the duration of service interruptions experienced as a result of Hydro system events, but does not reflect service interruptions that are a result of issues on Newfoundland Power's distribution system.

End-Consumer SAIFI: End-Consumer SAIFI measures reliability to all end customers of electricity in the province who are supplied by Hydro. It is a measure of the frequency of service interruptions experienced as a result of Hydro system events, but does not reflect service interruptions that are a result of issues on Newfoundland Power's distribution system.

FTE: One FTE is the equivalent of actual paid regular hours—2,080 hours per year in the operating environment and 1,950 hours per year in Hydro's head office environment.

Net FTE: Net FTEs are regulated, Hydro-based employees plus time charged to regulated Hydro less the time charged from regulated Hydro to the non-regulated lines of business.

Major Event: EC defines Major Events as "events that exceed reasonable design and/or operational limits of the electrical power system."

Service Continuity SAIDI and SAIFI: Service Continuity SAIDI and SAIFI measure the duration and frequency of service interruptions to Hydro's Isolated and Interconnected systems.

SAIDI: SAIDI is the average interruption duration per customer. It is calculated by dividing the number of customer-outage hours by the total number of customers in an area.

SAIFI: SAIFI is a reliability key performance indicator for distribution service, measuring the average cumulative number of sustained interruptions per customer per year. SAIFI is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.

TRIF: TRIF is a calculation of the rate at which injuries occur.

T-SAIDI: T-SAIDI is a reliability key performance indicator for bulk transmission assets, measuring the average duration of outages in minutes per delivery point.

T-SAIFI: T-SAIFI is a reliability key performance indicator for bulk transmission assets, measuring the average frequency of outages per delivery point.

T-SARI: T-SARI is a reliability key performance indicator for bulk transmission assets, measuring the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.

UFLS: Under-frequency load shedding is the reliability performance indicator that measures the number of events in which shedding of customer load is required to counteract the loss of generation capacity. During a UFLS event, customers are automatically removed from the electrical system. The quantity of customers removed is linearly proportional to the amount of generation lost.

YTD: The period ending March 31 of the applicable year.

1 # 1.0 Highlights

Table 1: Highlights YTD

	Q1			
	2026 Actual	**2026 Target**	**2025 Actual**	**2026 Annual Target**
Safety and Environment				
TRIF Rate[1]	1.38	N/A	1.42	1.25
LTIF Rate[2]	0.92	N/A	0.47	<0.15
Achievement of EMS Targets (%)	2	N/A	2	95
Reliability				
SAIDI	0.66	0.37	0.34	2.66
SAIFI	0.83	0.24	0.16	1.36
Production				
Holyrood No. 6 Fuel Oil Average Cost ($/bbl.)	97	77	116	76
Holyrood Efficiency (kWh/bbl.)	564	583	600	583
Electricity Delivery (GWh)				
Energy Sales	2,745	2,599	2,689	7,699
Financial ($ Millions)[3]				
Revenue	235.7	235.2	234.5	652.4
Operating Expenses	39.9	39.4	38.2	153.2
Net Income	7.9	7.1	13.5	6.1
RSP ($ Millions)[4]				
RSP Balance	10.5	7.6	28.6	0.1
Supply Cost Variance Deferral Account ($ Millions)[5]				
Cumulative Net Balance	96.2	67.8	238.3	206.8
FTE Employees[6]				
Regulated	841.3[7]	N/A	830.1[8]	869.77

[1] TRIF = $\frac{\text{number of recordable injuries x 200,000}}{\text{number of hours worked}}$

[2] LTIF = $\frac{\text{number of lost-time injuries x 200,000}}{\text{exposure hours}}$

[3] Financial figures exclude non-regulated activities.

[4] The RSP report for the current quarter is provided as Attachment 1.

[5] Computed based on methodology presented in "Supply Cost Accounting Compliance Application," Newfoundland and Labrador Hydro, January 21, 2022.

[6] Figures shown are net FTEs.

[7] Figure shown is 2026 Q1 actual annualized to year end.

[8] Figure shown is 2025 Q1 actual annualized to year end.

2.0 Safety and Health

2.1 Safety at Hydro

Safety remains Hydro's priority. Hydro's framework for safety performance includes a balanced focus on culture, people, and process as it continues to ensure its safety management system reflects standards similar to those contained in ISO 45001. Reviewing workplace incidents to prevent future occurrences is a critical part of overall safety management systems. Leading indicators—such as safety meetings, Occupational Health and Safety Committee meetings, leadership safety interactions, and the safety and health monitoring plan, among other performance indicators—continue to be tracked and discussed to ensure safety and health are a continuous part of Hydro's work focus.

Hydro's focus on ensuring the safety of its employees, contractors, and the public continued during the current quarter. The advancement of Hydro's safety and health priorities includes:

- Commence review of Safety Management System to ensure practical and meaningful business application;
- Execute first phase of a multi-year, corporate-wide safety communications campaign;
- Complete Occupational Health and Safety training for lead hands;
- Complete 2026 deliverables identified in safety culture action plan;
- Develop a mental health and psychological safety strategy; and
- Pilot new data analytics tool(s) to support broadly accessible real-time data.

2.2 Safety Performance

An overview of Hydro's safety performance is provided in Table 2.

Table 2: Safety Performance Detail[9]

	YTD 2026	YTD 2025	2025 Annual
Fatalities	0	0	0
Lost-Time Injuries	2	1	2
Medical Treatment Injuries	1	2	2
First Aid with Restrictions	0	0	2
TRIF Rate	1.38	1.42	0.71
LTIF Rate	0.92	0.47	0.24
Severity Rate (Days Lost)	7.85(17)	26.53(56)	7.81(66)
High-Potential Incidents	0	1	3

Hydro experienced two lost-time injuries and one medical treatment injury this quarter. Based on three recordable injuries year to date, Hydro's YTD TRIF rate is 1.38, and its LTIF rate is 0.92. Hydro's lost-time severity rate was 7.85, based on seventeen days of lost time from the two lost-time injuries.

A comparison of Hydro's TRIF and LTIF rates over the past five years to the EC average, along with the 2026 rates, is provided in Chart 1. Hydro's annual lost-time severity rate for the past five years, compared to the EC average and the 2026 rates, is provided in Chart 2.

[9] Injury statistics reflect regulated Hydro employees only.

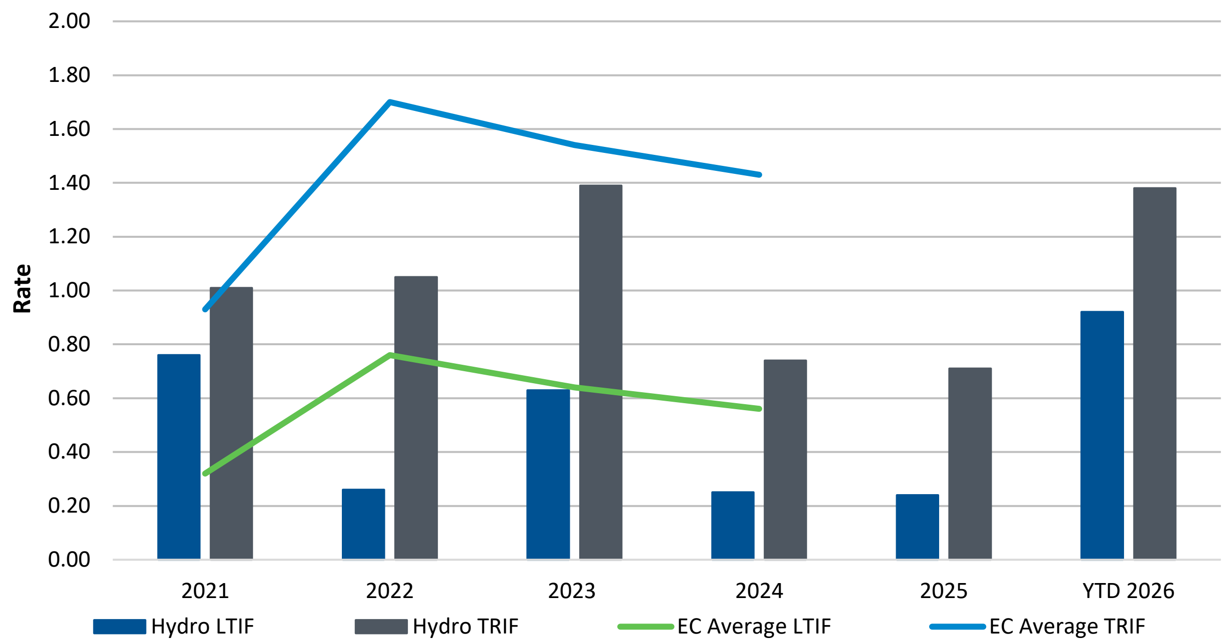

Chart 1: Hydro's TRIF and LTIF Compared to EC Averages[10, 11]

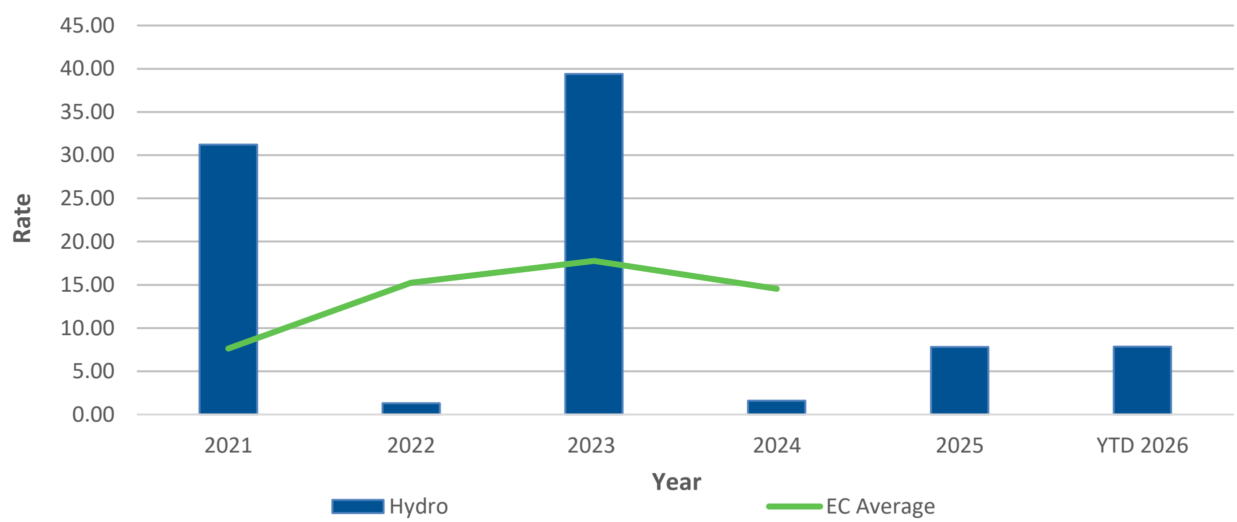

Chart 2: Hydro's Lost-Time Severity Rate Compared to EC Average[12,13]

[10] Safety and Health performance metrics are compared to EC utility members in Group 2 (300–1,500 employees) until 2022, after which Hydro fell into Group 1 (1,500+ employees). The EC comparator group here is the same baseline that Hydro would use for the total Hydro experience, not just regulated operations.
[11] EC reliability data for 2025 is currently not available.
[12] Safety and Health performance metrics are compared to EC utility members in Group 2 (300–1,500 employees) until 2022, upon which Hydro fell into Group 1 (1,500+ employees). The EC comparator group here is the same baseline that Hydro would use for the total Hydro experience, not just regulated operations.
[13] *Supra,* f.n. 11.

2.3 Line Contacts

There was one reportable line contact incident by a third party during the current quarter. There were no injuries as a result of this incident. Hydro continues to work toward reducing line contact incidents by increasing public and contractor awareness of the hazards associated with contacting power lines through education.

3.0 Reliability

3.1 Outage Information

There were five power outages reported to the Board during the current quarter. Information on each of these outages is provided in Appendix A.

A summary of major events from 2021 to 2026, including the impact the major events would have had on performance indicators, is provided in Appendix B. As electrical systems are neither constructed nor expected to fully withstand extreme weather conditions, such as hurricanes and ice storms, the impacts of major events have been removed from the data used in the calculation of each of the electrical system reliability performance indicators in this report.

3.2 Generation Outage Summary

A summary of the status of Hydro's generating units for the current quarter is provided in Appendix C. It classifies which units were available or unavailable and any associated deratings. Further information is provided in Hydro's daily Supply and Demand Status reports filed with the Board.[14]

3.3 Reliability Indicators

For all reliability performance indicators in this report, a year-over-year decrease in reliability indicators indicates an improvement in system performance, and a year-over-year increase in reliability indicators indicates a decline in system performance. Data on reliability indicators, including Service Continuity by Type, Area and Origin, T-SARI, and UFLS, are provided in Appendix D.

[14] Hydro's daily Supply and Demand Status reports can be accessed at http://www.pub.nl.ca/applications/IslandInterconnectedSystem/DemandStatusReports.php.

3.3.1 End-Consumer Performance

The End-Consumer Performance Index data provided in Table 3 are measures of the duration and frequency of service interruptions experienced as a result of Hydro's system events. Hydro uses the averages of its End-Consumer Indices performances for the period 2021–2025 to establish its 2026 annual targets.

Table 3: End-Consumer Performance

	Q1		YTD			2026 Annual Target
	2026	**2025**	**Target**	**2026**	**2025**	**(2021–2025 Average)**
SAIDI	0.66	0.34	0.37	0.66	0.34	2.66
SAIFI	0.83	0.16	0.24	0.83	0.16	1.36

Hydro's End-Consumer SAIDI and SAIFI YTD data (2022–2026) is provided in Chart 3 and Chart 4, respectively.

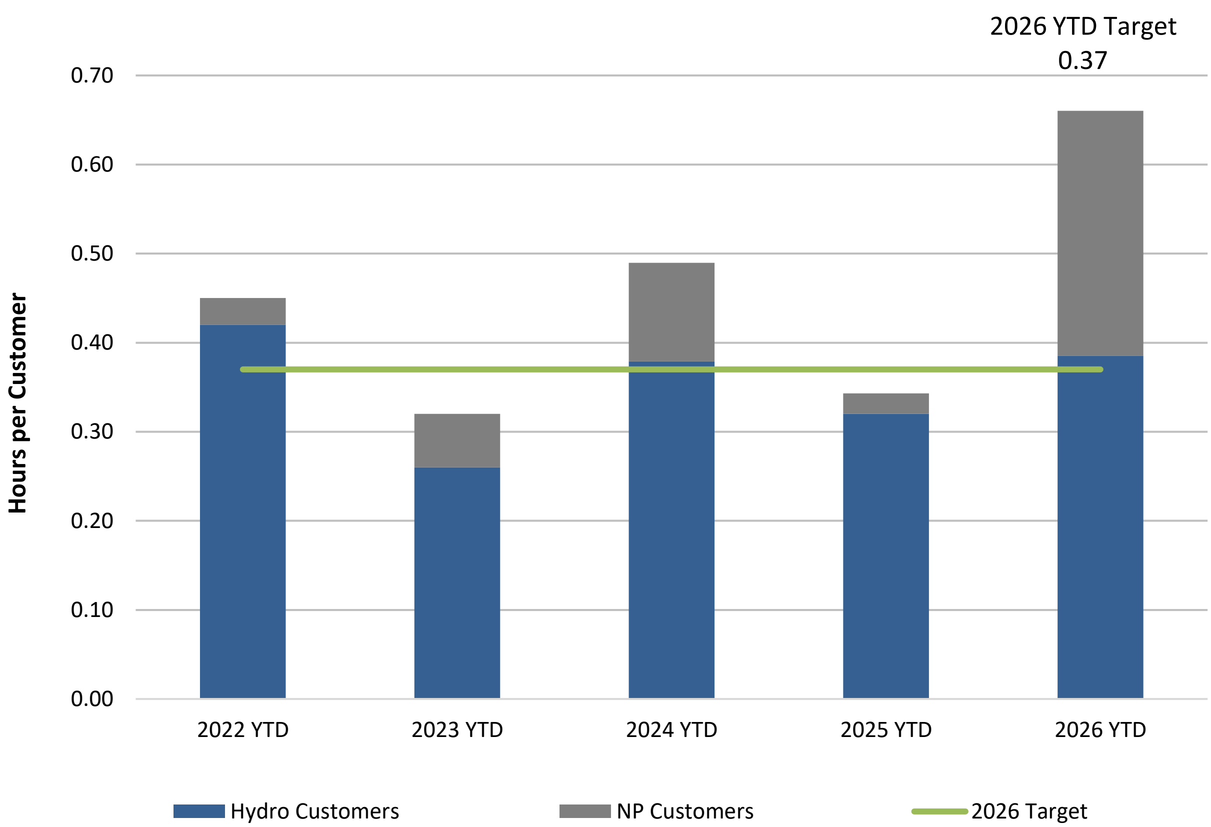

Chart 3: End-Consumer SAIDI

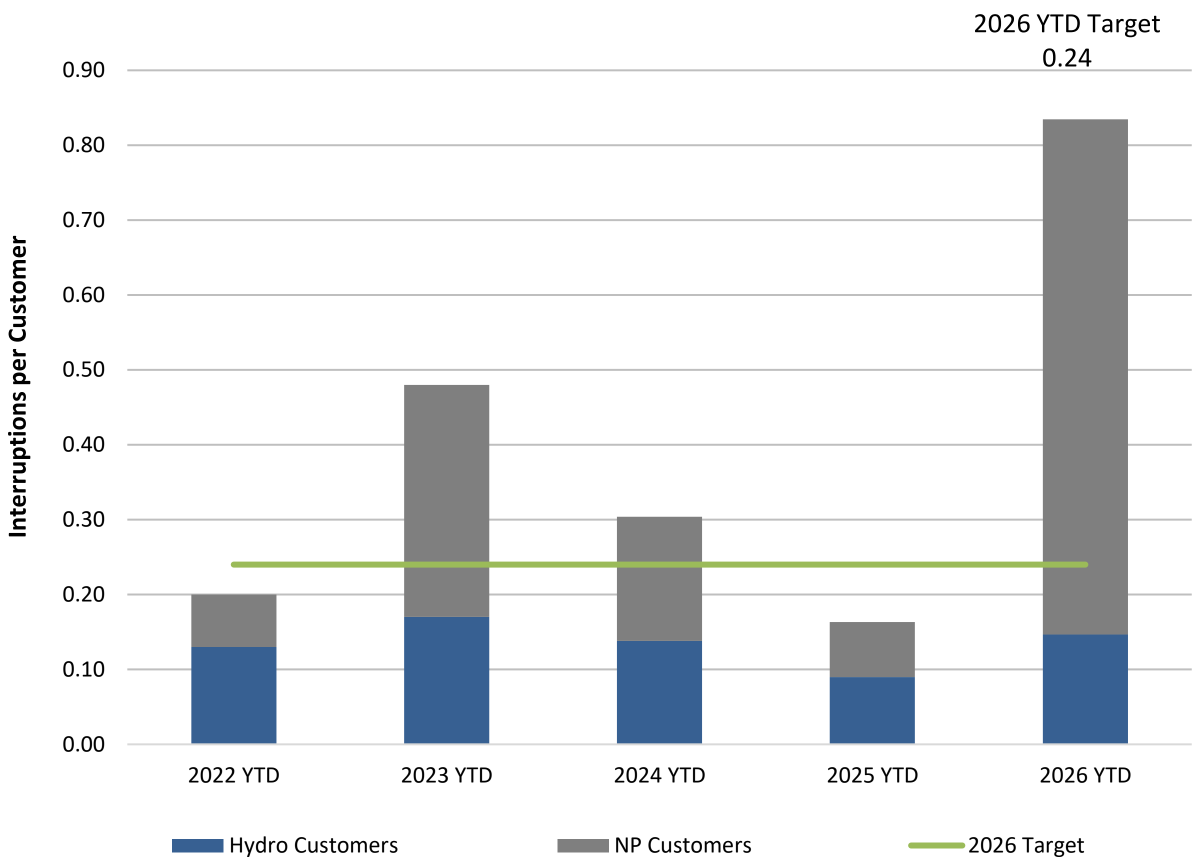

Chart 4: End-Consumer SAIFI

3.3.2 Bulk Power System Delivery Point Interruption Performance

T-SAIDI and T-SAIFI data are provided in Table 4. Hydro uses the averages of each Index for the period 2021–2025 to establish its annual target for 2026. The T-SAIDI and T-SAIFI performance for Hydro, including planned and unplanned outages (2022–2026 YTD), and EC, are provided in Chart 5 and Chart 6, respectively.

Table 4: Transmission Delivery Point Performance

	Q1		YTD			2026 Annual Target
	2026	2025	Target	2026	2025	(2021–2025 Average)
T-SAIDI	57.16	24.51	73.65	57.16	24.51	370.38
T-SAIFI	0.42	0.12	0.52	0.42	0.12	2.48

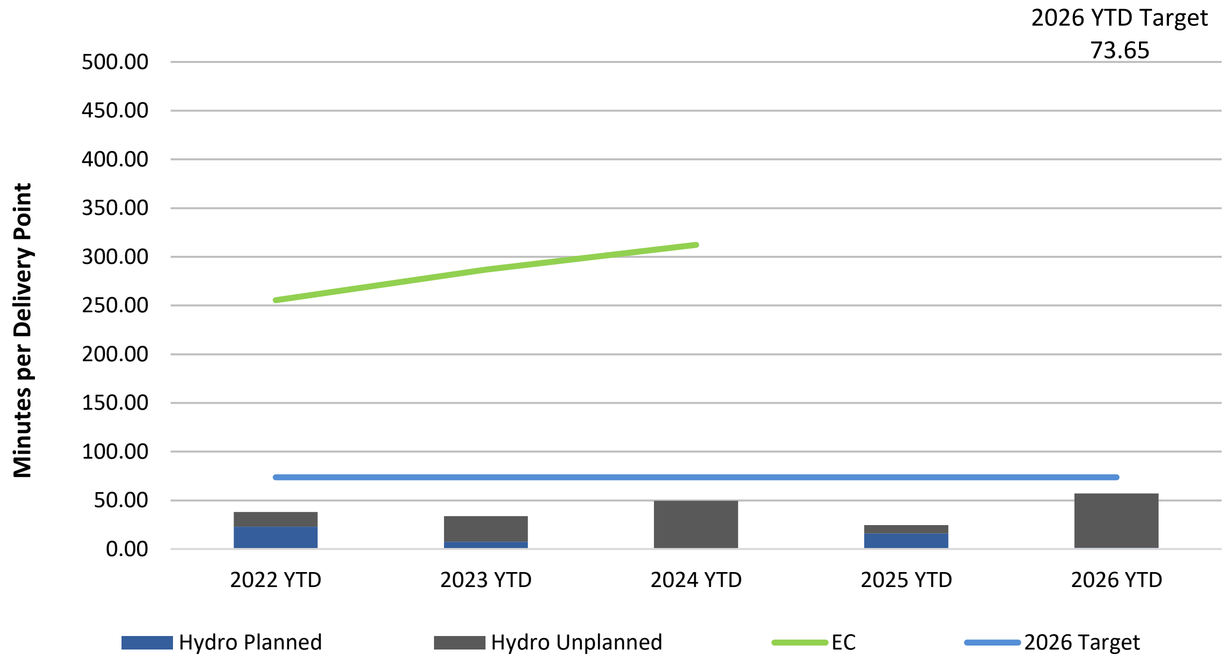

Chart 5: T-SAIDI[15]

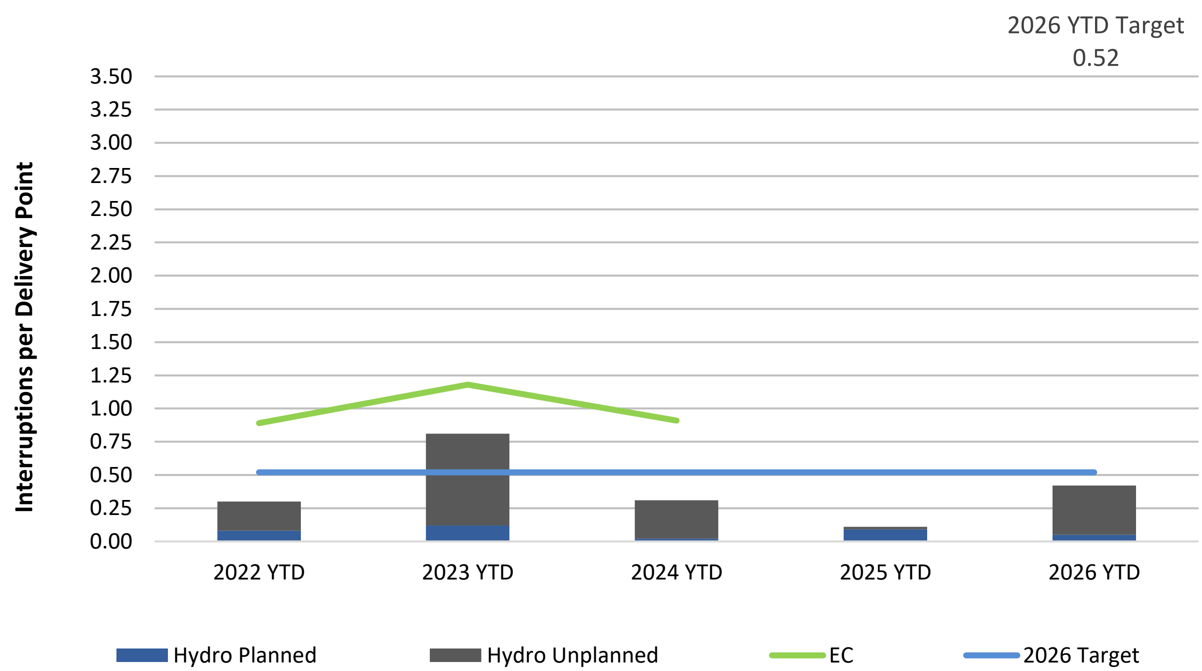

Chart 6: T-SAIFI[16]

[15] *Supra*, f.n. 11.
[16] *Supra*, f.n. 11.

1 ### 3.3.3 Service Continuity Performance

2 Service Continuity SAIDI and SAIFI performance data are provided in Table 5. Hydro uses the average of
3 each index for the period 2021–2025 to establish its annual targets for 2026 for these indices. Service
4 Continuity SAIDI and SAIFI performance data for Hydro (2022–2026 YTD) and EC are provided in Chart 7
5 and Chart 8, respectively.

Table 5: Service Continuity SAIDI and SAIFI

	Q1		YTD			2026 Annual Target
	2026	**2025**	**Target**	**2026**	**2025**	**(2021–2025 Average)**
SAIDI	2.97	2.45	2.49	2.97	2.45	17.94
SAIFI	1.13	0.69	1.00	1.13	0.69	5.61

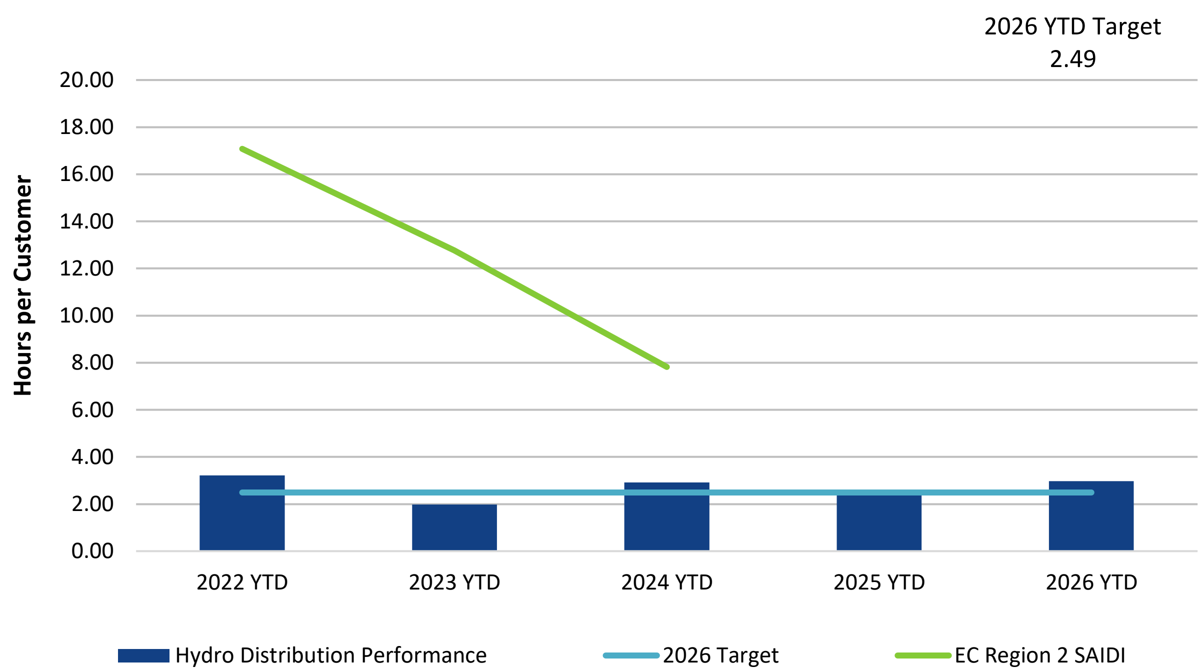

Chart 7: Service Continuity SAIDI[17]

[17] *Supra*, f.n. 11.

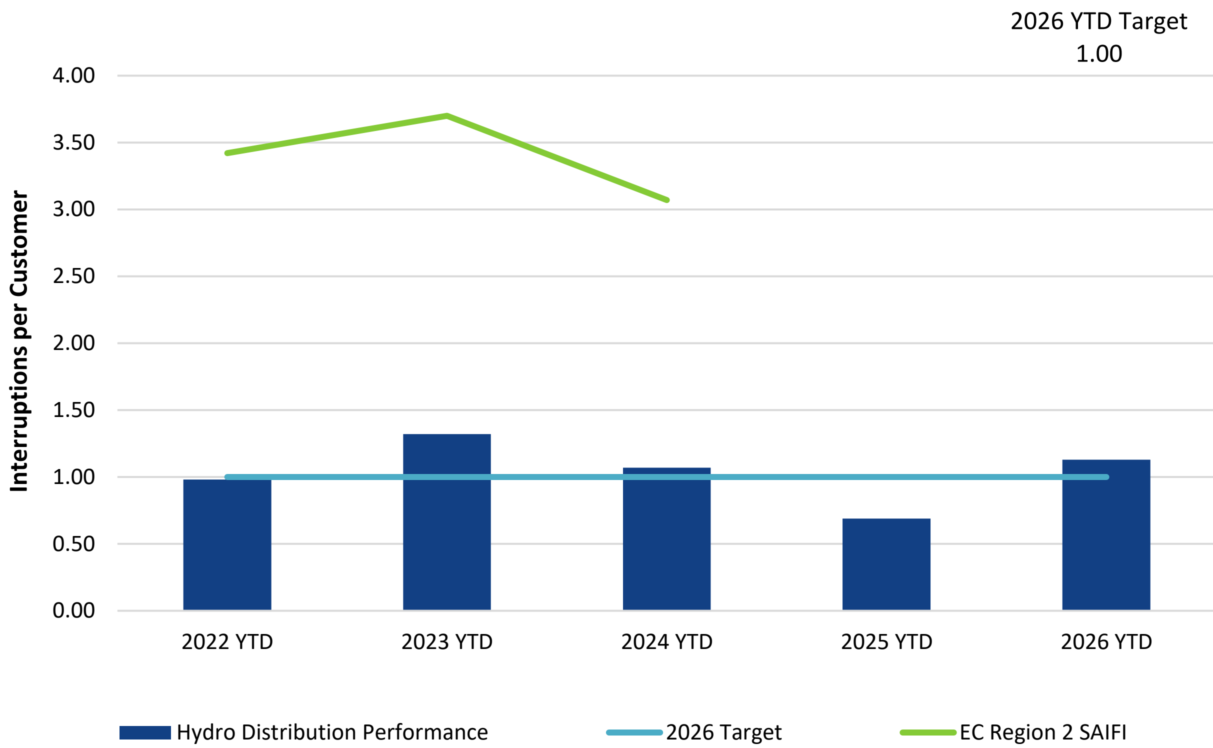

Chart 8: Service Continuity SAIFI[18]

4.0 Customer Service

4.1 Customer Transactional Surveys

Survey results for the current quarter indicate that approximately 87% of customers were satisfied with the service they received when they reached out to Hydro's Customer Service department for assistance. Additionally, 86% of customers felt their concerns were resolved on the first call. A summary of these results is provided in Table 6.

Table 6: Customer Service Transactional Survey Data

Measure	Q1 2026	Q1 2025
Overall Satisfaction	87%	87%
First Call Resolution	87%	86%
Number of Surveys Completed	1,206	1,376

[18] *Supra*, f.n. 11.

4.2 Customer Statistics

A summary of the number of Hydro customers in each customer class, including net metering, is provided in Table 7.

Hydro did not receive any new net metering applications during the current quarter. Hydro's total number of net metering customers remains at three, with a total net metering capacity of 71.6 kW.

Table 7: Customer Statistics

	Q1		Annual	
	2026 Actual	**2025 Actual**	**2026 Budget**	**2025 Actual**
Rural Customers[19]	39,621	39,448	39,625	39,586
Industrial Customers	6	6	6	6
Labrador Industrial Transmission Customers[20]	2	2	2	2
Utility Customers	1	1	1	1
Average Monthly Reading Days	30.2	30.2	N/A	29.9
Net Metering Customers	3	3	N/A	3

5.0 Supply Costs and Energy Sales

5.1 Fuel Prices[21]

Market prices for No. 6 fuel oil reached a high of $164/bbl. at the end of March 2026 and a low of $85/bbl. at the beginning of January 2026. The ending inventory cost for the current quarter was $98/bbl. This compares to the fuel price of $106/bbl. that was reflected in Newfoundland Power's wholesale rates during the current quarter.[22]

There were two shipments of No. 6 fuel oil during the first quarter, as detailed in Table 8. Inventory at the end of the quarter was 186,141 bbl.

[19] Includes net metering customers.
[20] Iron Ore Company of Canada and Tacora Resources Inc.
[21] Prices for No. 6 fuel oil are provided in Canadian ("CDN") dollars.
[22] The price of $105.90/bbl. is reflected in Newfoundland Power's base rates effective October 1, 2019, as per Board Order No. P.U. 30(2019).

Table 8: No. 6 Fuel Oil Shipments

Delivery Date	Quantity (bbl.)	Price/bbl. Delivered ($)
12-Jan-2026	205,147	92
13-Feb-2025	205,813	103

1 A comparison of No. 6 fuel oil prices in 2026, as compared to 2024 and 2025, as well as the fuel oil price
2 reflected in the wholesale rate to Newfoundland Power, is provided in Chart 9.

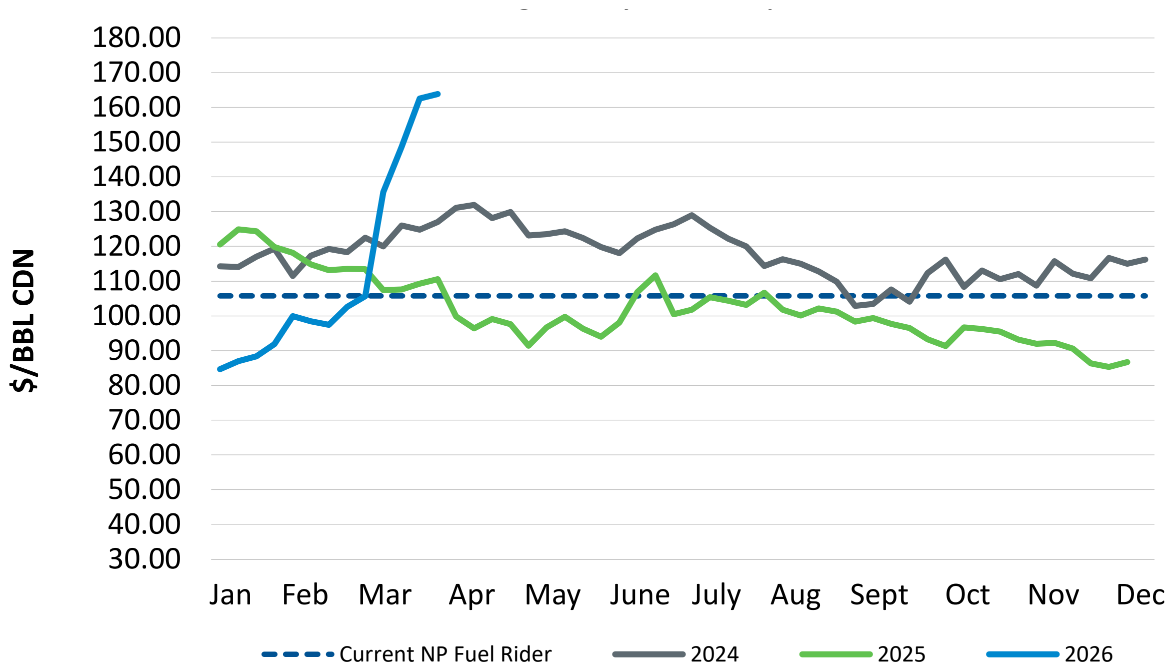

Chart 9: No. 6 Fuel Oil Average Weekly New York Spot Price

The monthly forecast price of No. 6 fuel oil for the next twelve months is provided in Table 9.[23]

Table 9: No. 6 Fuel Oil Forecast Prices ($CDN/bbl.)

Month	Price
Apr-2026	148.60
May-2026	133.80
Jun-2026	123.40
Jul-2026	112.00
Aug-2026	101.10
Sep-2026	97.70
Oct-2026	96.10
Nov-2026	93.80
Dec-2026	91.40
Jan-2027	89.20
Feb-2027	89.80
Mar-2027	89.70

A comparison of the Ultra Low Sulphur Diesel No. 1 (used in diesel generation) fuel oil prices in 2026, as compared to 2024 and 2025, is provided in Chart 10.

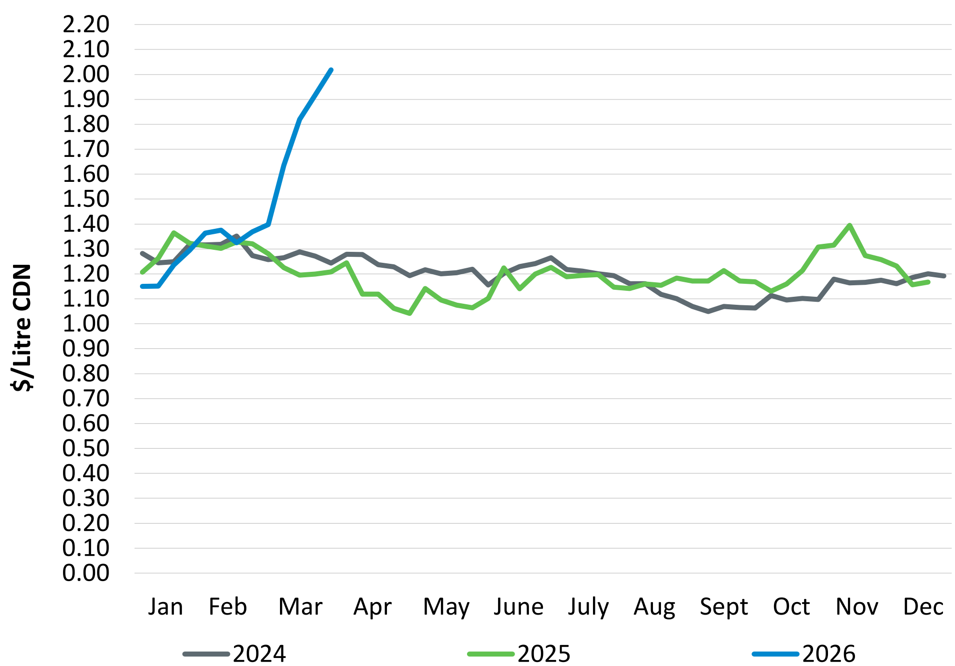

Chart 10: Ultra Low Sulphur No. 1 Diesel Weekly Montreal Rack Price

[23] The price forecast is based on Platts Analytics fuel price outlook, April 2026 World Oil Market Forecast and includes the premium for the No. 6 fuel oil.

5.2 Transfers to Supply Cost Deferral Accounts

5.2.1 Supply Cost Variance Deferral Account Overview

The balances accumulated in the Supply Cost Variance Deferral Account as at March 31, 2026, are reported in Attachment 2.

The 2026 YTD activity in the account decreased the balance by $254.1 million primarily due to rate mitigation funding in March 2026 of $350.3 million. Payments made under the Muskrat Falls Power Purchase Agreement and Transmission Funding Agreement ($189.2 million) was partially offset by fuel savings at the Holyrood TGS ($48.3 million), and payments received from Newfoundland Power and Industrial customers related to the Project Cost Recovery Rider of $30.6 million and $2.9 million, respectively.

As per Order in Council OC2024-062, Hydro has been directed by the Government to retire the 2023 Supply Cost Variance Deferral Account balance of $271.3 million over the 2024–2026 period using its own sources of funding. In March 2026, Hydro transferred $350.3 million of funding to its regulated operations, which includes $90.6 million of rate mitigation funding related to the retirement of the 2023 Supply Cost Variance Deferral Account.

The total balance in the account as of March 31, 2026, is $96.2 million.[24]

5.2.2 Isolated Systems Cost Variance Deferral Account

Hydro accumulated $2.8 million[25] in the Isolated Systems Cost Variance Deferral Account as of March 31, 2026. The current year's actual unit cost of diesel fuel was approximately 17¢/kWh more than the 2019 Test Year unit cost of fuel, which is the primary driver of the YTD transfer of fuel costs to the account this year.

The current year transfers to the Isolated Systems Cost Variance Deferral Account are provided in Table 10. Pursuant to Board Order No. P.U. 30(2019), Hydro has calculated the transfers relative to the 2019 Test Year.

[24] The March 31, 2026 Supply Cost Variance Deferral Account balance of $96.2 million is unaudited.
[25] The March 31, 2026 Isolated System Cost Variance Deferral balance of $2.8 million is unaudited.

Table 10: Isolated Systems Cost Variance Deferral Account Transfers ($ Millions)[26]

Q1 2026 Actual	Q1 2025 Actual	Variance
2.8	1.9	0.9

In accordance with the currently approved account definitions, Hydro filed its application for recovery of the Isolated Systems Cost Variance Deferral Account on March 19, 2026, before the March 31, 2026 deadline. This application included the final transfer amounts as well as detailed information as to the drivers of the transfers. In Order No. P.U. 9(2026), the Board approved Hydro's proposed disposition of $6,338,566 balance in the 2025 Isolated Systems Supply Cost Variance Deferral Account through the transfer, effective March 31, 2026 of a debit of $6,091,362 to the Newfoundland Power RSP Current Plan balance with recovery starting July 1, 2026, and a debit of $247,204 allocated to Hydro Rural Labrador Interconnected System customers to be applied to reduce Hydro's net income as approved.

5.3 Statement of Energy Sold

Table 11 provides a summary of Hydro's energy sales YTD compared to that of other reporting periods.

[26] Net of deadbands.

Table 11: Statement of Energy Sold YTD (GWh)

	2026 Actual	2025 Actual	2026 Budget	2026 Annual Budget
Island Interconnected				
Newfoundland Power	2,017	1,984	2,163	6,032
Island Industrials	167	110	113	472
Export and Other	147	102	-	-
Rural				
Domestic	91	89	87	256
General Service	49	47	48	169
Street Lighting	-	1	1	2
Subtotal Rural	**140**	**137**	**136**	**427**
Subtotal Island Interconnected	**2,471**	**2,333**	**2,412**	**6,931**
Island Isolated				
Domestic	2	2	1	4
General Service	-	-	1	2
Street Lighting	-	-	-	-
Subtotal Island Isolated	**2**	**2**	**2**	**6**
Labrador Interconnected				
Domestic	128	123	127	320
General Service	127	125	126	373
Non-Firm Energy	4	6	-	-
Street Lighting	-	-	-	1
Subtotal Labrador Interconnected	**259**	**254**	**253**	**694**
Labrador Isolated				
Domestic	8	8	8	25
General Service	5	5	5	18
Street Lighting	-	-	-	-
Subtotal Labrador Isolated	**13**	**13**	**13**	**43**
L'Anse-au-Loup				
Domestic	6	6	6	16
General Service	3	3	3	9
Street Lighting	-	-	-	-
Subtotal L'Anse-au-Loup	**9**	**9**	**9**	**25**
Total Energy Sold (Before Rural Accrual)	**2,754**	**2,611**	**2,689**	**7,699**
Rural Accrual	(9)	(12)	N/A	N/A
Total Energy Sold	**2,745**	**2,599**	**2,689**	**7,699**
Non-Regulated Customers[27]				
Labrador Industrials	504	533	542	1,902

[27] Does not include non-regulated sales for export.

6.0 Asset Management and Investment

6.1 2026 Capital Budget

Hydro's 2026 Capital Budget was approved by the Board in Order No. P.U. 2(2026).[28] In addition to approval for an investment of $130 million in capital projects, Hydro carried forward approximately $37 million from its 2025 capital program, of which approximately $15 million is project carryover and $22 million is multi-year cash flow reallocation. As a result, Hydro's opening capital budget for 2026 was $167 million. Additionally, supplemental capital of $8 million has been approved by the Board for 2026, and a total of $2 million has been approved by Hydro for 2026 projects under $750,000. Additionally, Hydro carried forward approximately $28 million related to its 2025 Major Projects, of which approximately $12 million is related to the Avalon Combustion Turbine project and $16 million is related to the Bay d'Espoir Unit 8 project. Additionally, an Early Execution Application related to the Avalon Combustion Turbine project was approved for $29 million. Hydro's revised Board-approved 2026 Capital Budget as of March 31, 2026, was $233 million. Table 12 shows the breakdown of Hydro's capital budget approvals of $233 million by Board Order.

[28] Originally approved on January 30, 2026.

Table 12: Capital Budget by Board Order as of March 31, 2026 ($000)

2026 Capital Budget	**130,343**
Multi-Year Cost Flow Reallocation 2025 to 2026[29]	21,966
Project Carryover 2025 to 2026[30]	14,562
Major Projects Multi-Year Cost Flow Reallocation 2025 to 2026[31]	27,968
Projects Approved by Board:	
Order No. P.U. 25(2024)[32]	3,083
Order No. P.U. 9(2025)[33]	902
Order No. P.U. 11(2025)[34]	196
Order No. P.U. 4(2026)[35]	2,599
Order No. P.U. 6(2026)[36]	334
Order No. P.U. 7(2026)[37]	29,294
Order No. P.U. 8(2026)[38]	582
Total Projects Approved by Board Order	**36,950**
2026 New Projects Under $750,000 approved by Hydro[39]	1,687
Total Approved Capital Budget	**233,477**

1 There were no capital expenditures under $750,000 approved by Hydro during this quarter.

2 In addition, there were CIACs carried forward from the 2025 capital program and supplemental CIACs
3 approved by the Board, totalling $5 million. The 2026 Capital Budget as of March 31, 2026, net of CIACs,
4 was $226 million.

[29] The carryover budget of $36.5 million, of which approximately $14.6 million is project carryover and $22.0 million is multi-year cash flow reallocation, excludes CIACs. Hydro also carried forward CIACs of ($0.4) million, which would result in an estimated net carryover of $36.1 million to be recovered through customer rates.

[30] *Supra*, f.n. 29.

[31] The major projects carryover budget of $28.0 million, of which approximately $12 million is related to the Avalon Combustion Turbine and $16 million is related to the Bay d'Espoir Unit 8 project.

[32] The replacement of Rigolet Unit 2065 and fuel storage upgrades approved was approved for $3.4 million, of which $3.1 million is budgeted for 2026.

[33] The interconnection and integration of the Puffin Wind Inc. renewable energy project was approved for $1.3 million, of which $0.9 million is budgeted for 2026.

[34] The replacement of Hydro’s Learning Management System and Reporting Tools was approved for $1.7 million, of which $0.2 million is budgeted for 2026.

[35] The additions for load growth and customer interconnection – English Harbour West was approved for $3.3 million, of which $2.6 million is budgeted for 2026. $1.8 million of this $3.3 million has an associated contribution from Pennecon.

[36] A contribution from Battle Harbour Data Solutions Inc. of an amount equal to the capital costs of interconnection was approved for approximately $0.6 million, of which $0.3 million is budgeted for 2026.

[37] The Early Works application for the Avalon Combustion Turbine was approved for $29.3 million, of which $29.3 million is budgeted for 2026.

[38] The purchase and installation of a new Pelton runner on Unit 2 at Cat Arm Hydroelectric Generation Station was approved for $4.8 million, of which $0.6 million is budgeted for 2026.

[39] This includes previously reported 2025 under $750,000 projects that had expenditures in 2026 of $1.7 million.

6.2 Capital Expenditures

Table 13 provides an overview of Hydro's capital expenditures for the current quarter.

Table 13: Capital Expenditures Overview for the Quarter Ended March 31, 2026 ($000)[40]

	Board-Approved Budget 2026[41]	Q1 Actual 2026	YTD Actual 2026	Expected Remaining Expenditures 2026
Access	7,175	1,307	1,307	5,869
General Plant	41,180	3,713	3,713	39,224
Mandatory	2,035	165	165	1,870
Renewal	102,613	9,680	9,680	97,618
Service Enhancement	12,885	432	432	10,252
System Growth	9,365	296	296	5,179
Allowance for Unforeseen Expenditures	1,000	-	-	1,000
Total 2026[42, 43, 44]	**176,255**	**15,593**	**15,593**	**161,012**

6.3 2026 Capital Projects and Programs Progress

Hydro's approved regulated capital projects and programs continue to advance through stages of planning, design, procurement, and construction during the year. Notable activities in the first quarter were:

- The completion of the overhaul of the Unit 3 turbine and valves at the Holyrood Thermal Generating Station;
- Delivery of several new light- and heavy-duty vehicles and mobile equipment;
- Completion of various customer service extension connections;
- The delivery of new gate hoist equipment for the Ebbegunbaeg Control Structure, that is scheduled to be installed later in 2026; and

[40] Numbers may not add due to rounding.
[41] Board-approved budget excludes $29 million approved in Order No. P.U. 7(2026) related to Major Projects, as well as $28 million related to Major Projects carryovers as noted in Section 6.1.
[42] Expenditures are before CIACs.
[43] Table 13 does not include modifications to Hydro's infrastructure due to the implementation of the Muskrat Falls Project, given that all aspects of incorporation of the Muskrat Falls Project are fully funded by the project (Labrador Hydro Project Exemption Order in Council OC2000-206 and OC2013-342, NLR 120/13). Expenditures related to these modifications were approximately $42,321 in the current quarter.
[44] Front-End Engineering and Design costs for the current quarter of $0.0 million and YTD of $0.0 million have been excluded.

- Replacement or refurbishment of various distribution system equipment to address in-service failures.

Hydro's actual and forecast expenditures relative to the approved budget are provided in Chart 11.

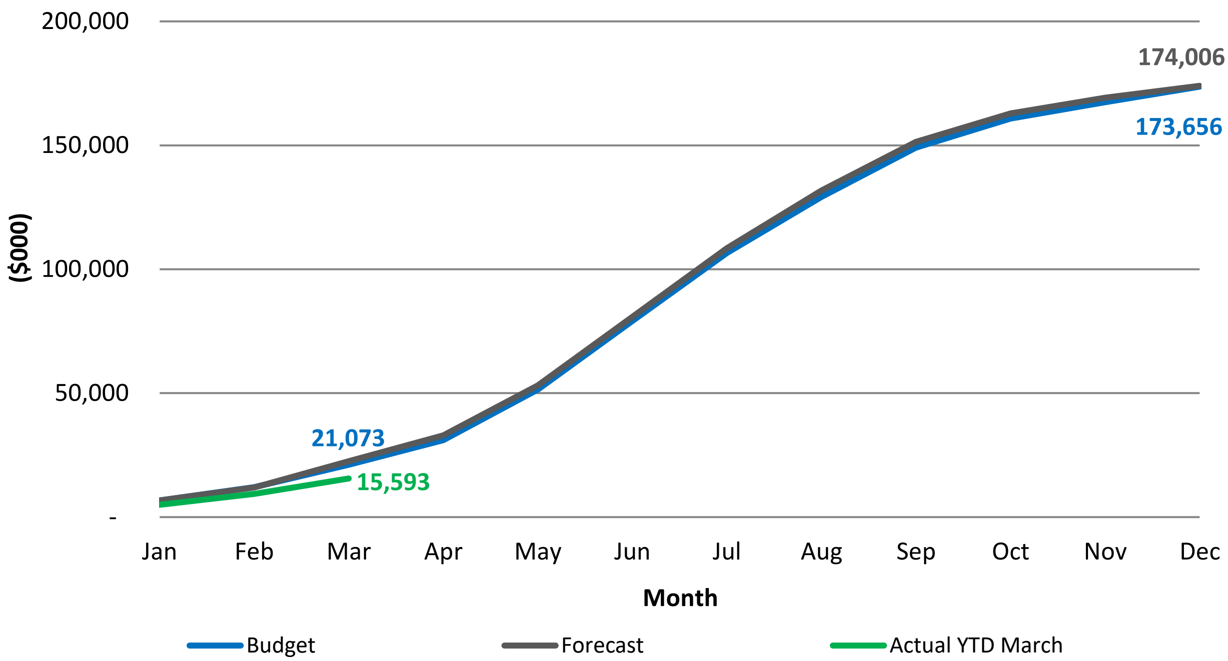

Chart 11: 2026 Capital Projects and Programs Actual and Forecast vs Budget[45]

To the end of the first quarter, Hydro's expenditures were approximately 26% below budget, primarily due to:

- Later-than-forecasted delivery of some equipment and materials;
- Less-than-forecasted expenditures for activities to address in-service failures; and
- Completion of some construction phase activities for less than the budget estimate.

As required by the provisional Capital Budget Application Guidelines,[46] explanations will be provided for projects and programs with variances exceeding 10% and $100,000 at year end, as part of Hydro's Capital Expenditures and Carryover Report.

[45] This chart includes the 2026 cost of the Section Replacement and Weld Refurbishment for the Penstock 1 Project at the Bay d'Espoir Hydroelectric Generating Facility. No other major projects are included.
[46] "Capital Budget Application Guidelines (Provisional)," Board of Commissioners of Public Utilities, January 2022.

6.4 Integrated Annual Work Plan

Hydro has an Integrated Annual Work Plan consisting of capital and maintenance work for its generation, transmission, distribution, and other associated assets. Hydro's 2026 Integrated Annual Work Plan completion target is 90%.[47]

7.0 Financial

7.1 Statement of Income ($000)

Statement of Income - Regulated Operations
for the Three Months Ended March 31, 2026
($000)

Q1 2026 Actual	Q1 2026 Budget	Q1 2025 Actual		YTD 2026 Actual	YTD 2026 Budget	YTD 2025 Actual	Annual 2026 Budget
			Revenue				
233,621	233,732	231,522	Energy Sales	233,621	233,732	231,522	646,292
2,060	1,515	2,955	Other Revenue	2,060	1,515	2,955	6,070
235,681	**235,247**	**234,477**		**235,681**	**235,247**	**234,477**	**652,362**
			Expenses				
114,383	119,053	120,551	Fuels	114,383	119,053	120,551	231,807
24,693	18,782	18,713	Power Purchased	24,693	18,782	18,713	65,934
39,919	39,357	38,221	Operating Costs	39,919	39,357	38,221	153,175
25,885	25,710	22,804	Depreciation and Amortization	25,885	25,710	22,804	102,936
23,305	24,742	20,483	Net Finance Expense	23,305	24,742	20,483	90,248
(365)	539	233	Other (Income) Expense	(365)	539	233	2,157
227,820	**228,183**	**221,005**		**227,820**	**228,183**	**221,005**	**646,257**
7,861	**7,064**	**13,472**	**Net Income**	**7,861**	**7,064**	**13,472**	**6,105**

Net income for the three months ended March 31, 2026 was $7.9 million, which is $5.6 million lower than the $13.5 million for the same period in 2025. The decrease is primarily due to higher depreciation expense due to growth in asset base and lower interest recoveries.

[47] The 2026 Integrated Annual Work Plan statistics are unavailable at the time of filing. Hydro will provide an update on progress against its Integrated Annual Work Plan in its next Quarterly Regulatory Report.

8.0 People and Community

8.1 Diversity and Inclusion

8.1.1 IDEA at Hydro

On February 12, 2026, Hydro hosted its annual IDEA Day—a dedicated day for the company to pause and learn about IDEA-related topics. There were many initiatives throughout the day aimed at engaging employees in different and meaningful ways.

Hydro's President and CEO, Jennifer Williams, kicked off the day with a company-wide address, affirming Hydro's commitment to IDEA and how we can all create an inclusive workplace. Following this address, Ogaga Johnson from Verisault Consulting discussed what inclusion really looks like in a safety-critical workplace. That afternoon, through a virtual session, the IDEA Ambassadors from Hydro Place answered anonymous, pre-submitted questions from their colleagues.

In addition to the informative, engaging sessions, a compilation video of some Hydro employees was shared, expressing what IDEA means to them. Additionally, an updated self-identification survey and a mandatory IDEA course were shared.

Our IDEA Ambassadors located in Churchill Falls and Muskrat Falls also had unique offerings in their areas, which were meaningful to their locations.

8.1.2 Women in Trades Panel

In recognition of International Women's Day, Hydro hosted a session showcasing some of our women in trades. The panel was hosted by Leigh Wall, Industry Partnership Specialist with the Office to Advance Women Apprentices, who provided helpful statistics and anecdotes. During the session, women at Hydro shared their experiences as women in trades, including barriers faced, career path opportunities, and how others can support women in trades.

8.2 Community Initiatives

During the first quarter of 2026, Hydro worked with several community partners across the province in support of initiatives aligned with our strategic focus areas—helping employees spread kindness on Pink Shirt Day and partnering with an organization in Grand Falls-Windsor to provide volunteer opportunities for Hydro Employees. It was also an opportunity to start planning for 2026 events, including Acts of

Kindness Week, the Energy Breakfast in support of Kids Eat Smart, and work with the Community Champions on regional activities.

8.2.1 Supporting Easter Seals & Sharing Safe Winter Snowmobiling Tips

In February 2026, Hydro returned as a Gold Sponsor for Easter Seals Newfoundland and Labrador's Snowarama—an 80 km snowmobile event that raises funds to provide free, accessible recreation equipment to families and communities throughout the province. As a sponsor, Hydro was proud to support the valuable programs and services that Easter Seals provides to people with disabilities in our province.

As part of the sponsorship, Hydro distributed snowmobile safety tips, specifically focused on travel near Hydro structures, including pole lines and dams, to all participants.

8.2.2 Spreading Kindness for Pink Shirt Day

February 25 is Pink Shirt Day in Canada, an opportunity to raise awareness about bullying and to help spread kindness. While originally focused on schools, it's an important message for any organization. This year, Hydro asked employees across the province to spread some kindness with their colleagues using custom pink sticky notes.

The notes, sent to each office and site, were used to thank someone, encourage them or just let them know they were appreciated.

8.2.1 Providing New Volunteer Opportunities to Employees in Central

In January 2026, Hydro was proud to partner with the Lionel Kelland Hospice in Grand Falls-Windsor to provide a new volunteer opportunity for employees in the region. As part of the compassionate palliative care program offered at the hospice, Lionell Kelland Hospice regularly welcome volunteers to its facility to bake for the patients and their families. Each month, two Hydro employees are able to sign up for this worthwhile opportunity.

LIONEL KELLAND HOSPICE

Appendix A

Power Outages Reported to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Power Outages

Table A-1: Power Outages Reported to the Board for the Current Quarter

Date	Area Affected	Cause	Customers Affected	Duration
12-Jan-2026	Great Northern Peninsula	Winter Storm/Equipment Failure (TL244 Broken Crossarm)	3,864	Up to 15 hours
16-Jan-2026	Great Northern Peninsula	Equipment Failure (TL241 Failed Insulator)	5,477	Up to 6 hours, 38 minutes
13-Feb-2026	Newfoundland Power Customers	UFLS (LIL Bipole Trip)	69,387	Up to 52 minutes
27-Feb-2026	Newfoundland Power Customers	UFLS (Unexpected ML Export Ramp)	128,692	Up to 1 hour, 11 minutes
22-Mar-2026	Portion of Northern Peninsula	Tree Contact	1,755	Up to 5 hours, 25 minutes

Appendix B

Major Events Excluded from Performance Index Tables

Major Events

Table B-1: Major Events Excluded from Performance Index Tables[1]

Year	Event Description	End-Consumer SAIDI	End-Consumer SAIFI	Service Continuity SAIDI	Service Continuity SAIFI	Transmission T-SAIDI	Transmission T-SAIFI
2026	January 12 Winter Storm	0.22	0.01	1.68	0.11	63.19	0.09
2025	November 1 Northern Peninsula Outage	0.19	0.02	1.48	0.14	72.09	0.12
	December 5 Winter Storm	0.20	0.01	1.53	0.10	51.30	0.09
	December 15 Winter Storm	0.23	0.01	1.80	0.11	0.00	0.00
	December 25 Winter Storm	0.29	0.01	2.25	0.09	38.26	0.02
2024	Labrador West outage due to Churchill Falls Forest Fires	0.24	0.02	1.64	0.16	64.67	0.05
2023	No major events	N/A	N/A	N/A	N/A	N/A	N/A
2022	TL214 outage due to extreme winds	0.26	0.03	0.00	0.00	35.67	0.03
	Great Northern Peninsula outage	0.38	0.03	2.93	0.20	91.92	0.23
	Connaigre Peninsula outage due to freezing rain	0.24	0.01	1.81	0.06	0.00	0.00
2021	No major events	N/A	N/A	N/A	N/A	N/A	N/A

[1] Data for 2026 reflects major events to the end of the current quarter. Data for 2021–2025 reflects major events experienced throughout the year.

Appendix C

Generation Unit Outages

January 2026

Location	Asset	Capacity	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Island																																	
Bay d'Espoir	G1	76.5 MW																					20	20	20	20							
	G2	76.5 MW																					20	20	20	20							
	G3	76.5 MW																					20	20	20	20							
	G4	76.5 MW																					20	20	20	20							
	G5	76.5 MW																															
	G6	76.5 MW																					20	20	20	20							
	G7	154.4 MW																					50	50	50	50	50	50	50	50	50	50	
Cat Arm	G1	67 MW																															
	G2	67 MW																										57	57	57	57	57	57
Granite Canal	Unit	40 MW																															
Hardwoods	GT	50 MW																															
Hawkes Bay	Unit	5 MW																															
Hinds Lake	Unit	75 MW																															
Holyrood	G1	170 MW	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	125	130	160	160	160	160	160	160	160	160
	G2	170 MW																								40	40	40	40	40	40	40	70
	G3	150 MW																							130	130	130						
	GT	123.5 MW																															
	Diesels	10 MW																															
Soldiers Pond Labrador-Island Link	Monopole ("M") Bipole ("B")	700 MW													450M			450M															
Paradise River	Unit	8 MW																															
Stephenville	GT	50 MW																															
St. Anthony	Unit	9.7 MW	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Upper Salmon	Unit	84 MW																															
Labrador																																	
Happy Valley	GT	25 MW																															
Muskrat Falls	G1	206 MW																															
	G2	206 MW																															
	G3	206 MW																															
	G4	206 MW																															

Available	
Available Derated	
Unavailable	

February 2026

Location	Asset	Capacity	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Island																														
Bay d'Espoir	G1	76.5 MW																												
	G2	76.5 MW																												
	G3	76.5 MW																												
	G4	76.5 MW																												
	G5	76.5 MW																												
	G6	76.5 MW																												
	G7	154.4 MW																												
Cat Arm	G1	67 MW																												
	G2	67 MW	57	57	57	57		57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
Granite Canal	Unit	40 MW																												
Hardwoods	GT	50 MW																												
Hawkes Bay	Unit	5 MW																												
Hinds Lake	Unit	75 MW																												
Holyrood	G1	170 MW	160	160			166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
	G2	170 MW	70	70	70	70	70	70	70	70	70	70						150	150	150	150	163	163	163	163					
	G3	150 MW														70	70	70	100	100	100	100	100				142	40	40	40
	GT	123.5 MW																												
	Diesels	10 MW																												
Soldiers Pond Labrador-Island Link	Monopole ("M") Bipole ("B")	700 MW																										450M		
Paradise River	Unit	8 MW																												
Stephenville	GT	50 MW						25																						
St. Anthony	Unit	9.7 MW	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	6.7	6.7
Upper Salmon	Unit	84 MW																												
Labrador																														
Happy Valley	GT	25 MW																												
Muskrat Falls	G1	206 MW																												
	G2	206 MW																												
	G3	206 MW																												
	G4	206 MW																												

Available
Available Derated
Unavailable

March 2026

Location	Asset	Capacity	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Island																																	
Bay d'Espoir	G1	76.5 MW																															
	G2	76.5 MW																															
	G3	76.5 MW																															
	G4	76.5 MW																															
	G5	76.5 MW																															
	G6	76.5 MW																															
	G7	154.4 MW																															
Cat Arm	G1	67 MW																															
	G2	67 MW	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
Granite Canal	Unit	40 MW																															
Hardwoods	GT	50 MW																															
Hawkes Bay	Unit	5 MW																															
Hinds Lake	Unit	75 MW																															
Holyrood	G1	170 MW	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
	G2	170 MW																															
	G3	150 MW															40	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
	GT	123.5 MW																															
	Diesels	10 MW																								8	8	8	8	8	8	8	
Soldiers Pond Labrador-Island Link	Monopole ("M") Bipole ("B")	700 MW									450M							450M							450M								
Paradise River	Unit	8 MW																															
Stephenville	GT	50 MW																															
St. Anthony	Unit	9.7 MW	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	7.7	7.7	7.7	7.7	7.7	7.7
Upper Salmon	Unit	84 MW																															
Labrador																																	
Happy Valley	GT	25 MW																															
Muskrat Falls	G1	206 MW																															
	G2	206 MW																															
	G3	206 MW																															
	G4	206 MW																															

Available
Available Derated
Unavailable

Appendix D

Supplemental Reliability Information

1.0 Service Continuity Performance

1.1 Service Continuity by Outage Type

Service Continuity SAIDI and SAIFI performance data, by outage type, are provided in Table D-1 and Table D-2, respectively. Hydro uses the average of each index for the period 2021 to 2025 to establish its annual targets for 2026 for these indices.

Table D-1: Service Continuity SAIDI (Hours per Customer)

	Q1		YTD			Annual Target
	2026	2025	Target	2026	2025	2026
Planned	0.18	0.05	N/A	0.18	0.05	N/A
Unplanned	2.79	2.40	N/A	2.79	2.40	N/A
Planned and Unplanned	**2.97**	**2.45**	**2.49**	**2.97**	**2.45**	**17.94**

Table D-2: Service Continuity SAIFI (Interruptions per Customer)

	Q1		YTD			Annual Target
	2026	2025	Target	2026	2025	2026
Planned	0.12	0.05	N/A	0.12	0.05	N/A
Unplanned	1.01	0.64	N/A	1.01	0.64	N/A
Planned and Unplanned	**1.13**	**0.69**	**1.00**	**1.13**	**0.69**	**5.61**

1.2 Service Continuity Performance by Area

Service Continuity SAIDI and SAIFI performance data, broken down by geographical area, are provided in Table D-3 and Table D-4, respectively. The area performance indicators are calculated as a portion of the all-areas value.

Table D-3: Service Continuity SAIDI

	Q1		YTD	
Area	**2026**	**2025**	**2026**	**2025**
Labrador Region	0.82	0.35	0.82	0.35
Island Region	4.43	3.87	4.43	3.87
All Areas	**2.97**	**2.45**	**2.97**	**2.45**

Table D-4: Service Continuity SAIFI

	Q1		YTD	
Area	**2026**	**2025**	**2026**	**2025**
Labrador Region	0.72	0.43	0.72	0.43
Island Region	1.41	0.87	1.41	0.87
All Areas	**1.13**	**0.69**	**1.13**	**0.69**

1 ## 1.3 Service Continuity Performance by Origin

2 Service continuity SAIDI and SAIFI values, broken down by origin, are provided in Table D-5 and
3 Table D-6, respectively.[1]

Table D-5: Service Continuity SAIDI (Hours per Customer)

	Q1		YTD		Average
Origin	**2026**	**2025**	**2026**	**2025**	**2021–2025**
Loss of Supply: Transmission	1.42	0.16	1.42	0.16	N/A
Distribution	1.55	2.29	1.55	2.29	N/A
Overall SAIDI	**2.97**	**2.45**	**2.97**	**2.45**	**17.94**

Table D-6: Service Continuity SAIFI (Interruptions per Customer)

	Q1		YTD		Average
Origin	**2026**	**2025**	**2026**	**2025**	**2021–2025**
Loss of Supply: Transmission	0.48	0.16	0.48	0.16	N/A
Distribution	0.65	0.53	0.65	0.53	N/A
Overall SAIFI	**1.13**	**0.69**	**1.13**	**0.69**	**5.61**

[1] Hydro is updating some reliability tracking processes and is currently unable to provide segmented loss of supply statistics for Newfoundland Power, Isolated, and L'Anse-au-Loup systems. Reporting will resume when available.

1.4 Service Continuity Performance by Type

Service Continuity SAIDI and SAIFI values by type, broken down by geographical area, are provided in Table D-7.

Table D-7: Service Continuity by Interruption Type

	Q1 2026 Planned		Q1 2026 Unplanned		Q1 2026 Total	
Area	**SAIDI**	**SAIFI**	**SAIDI**	**SAIFI**	**SAIDI**	**SAIFI**
Labrador Region	0.25	0.07	0.57	0.64	0.82	0.72
Island Region	0.15	0.15	4.30	1.28	4.43	1.41
All Areas	**0.18**	**0.12**	**2.79**	**1.01**	**2.97**	**1.13**

1.5 Service Continuity Customer Interruptions by Cause

Service Continuity interruptions, grouped by cause, are provided in Table D-8.

Table D-8: Service Continuity by Cause of Interruption[2]

	Q1 2026		YTD	
Cause	**SAIDI**	**SAIFI**	**SAIDI**	**SAIFI**
Adverse Environment	0.03	0.02	0.03	0.02
Adverse Weather	0.32	0.12	0.32	0.12
Equipment Failure	1.65	0.41	1.65	0.41
Foreign Interference	0.00	0.00	0.00	0.00
Human Error	0.00	0.00	0.00	0.00
Loss of Supply	0.20	0.26	0.20	0.26
Lightning	0.00	0.00	0.00	0.00
Distribution Planned Outage	0.16	0.10	0.16	0.10
Tree Contacts	0.56	0.16	0.56	0.16
Undetermined/Other	0.05	0.07	0.05	0.07
Total	**2.97**	**1.13**	**2.97**	**1.13**

2.0 Transmission System Average Restoration Index

Hydro's 2026 YTD T-SARI was 136 minutes per interruption compared to 204 minutes per interruption for 2025 YTD. Hydro does not establish a restoration index target.

[2] Numbers may not add due to rounding.

Chart D-1 shows the YTD T-SARI performance from 2022 to 2026 and the EC 2022 to 2024 annual T-SARI performances.[3]

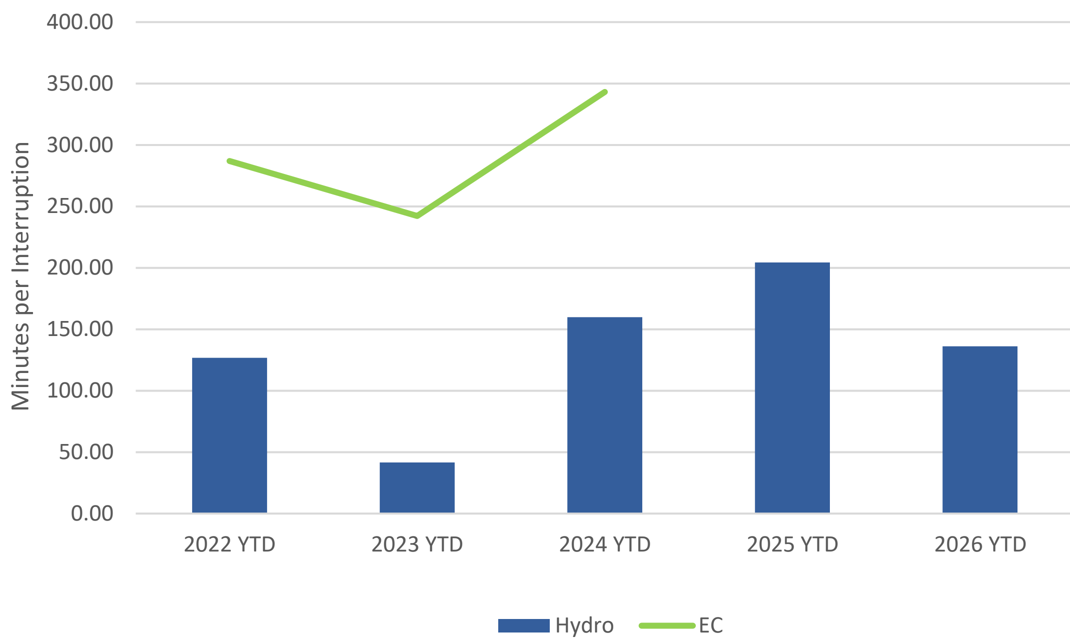

Chart D-1: T-SARI Measurements 2022–2026

3.0 Under Frequency Load Shedding

Performance data for UFLS events and UFLS undersupplied energy, by customer breakdown, are provided in Table D-9 and Table D-10, respectively. The 2026 UFLS target is zero events. Hydro does not establish a UFLS event YTD target or UFLS undersupplied energy targets. Performance data for UFLS events is provided in Chart D-2.

Table D-9: Customer Breakdown of UFLS Events

	Q1		YTD		Annual Target	Average
Customer	**2026**	**2025**	**2026**	**2025**	**2026**	**2021–2025**
Newfoundland Power	2	1	2	1	N/A	2.4
Industrials	1	1	1	1	N/A	2.0
Hydro Rural	1	0	1	0	N/A	0
Total Events[4]	**2**	**1**	**2**	**1**	**0**	**2.4**

[3] EC reliability data is published annually. EC Transmission reliability data is not currently available for 2025.
[4] As individual UFLS events can affect customer types differently, totals may not be the sum of the customer types.

Table D-10: Customer Breakdown of UFLS Undersupplied Energy (MW-min)

	Q1		YTD		Average
Customer	**2026**	**2025**	**2026**	**2025**	**2021–2025**
Newfoundland Power	11,322	1,680	11,322	1,680	3,765
Industrials	2,309	300	2,309	300	297
Hydro Rural	0	0	0	0	0
Total Undersupplied Energy[5]	**21,272**	**1,980**	**21,272**	**1,980**	**4,062**

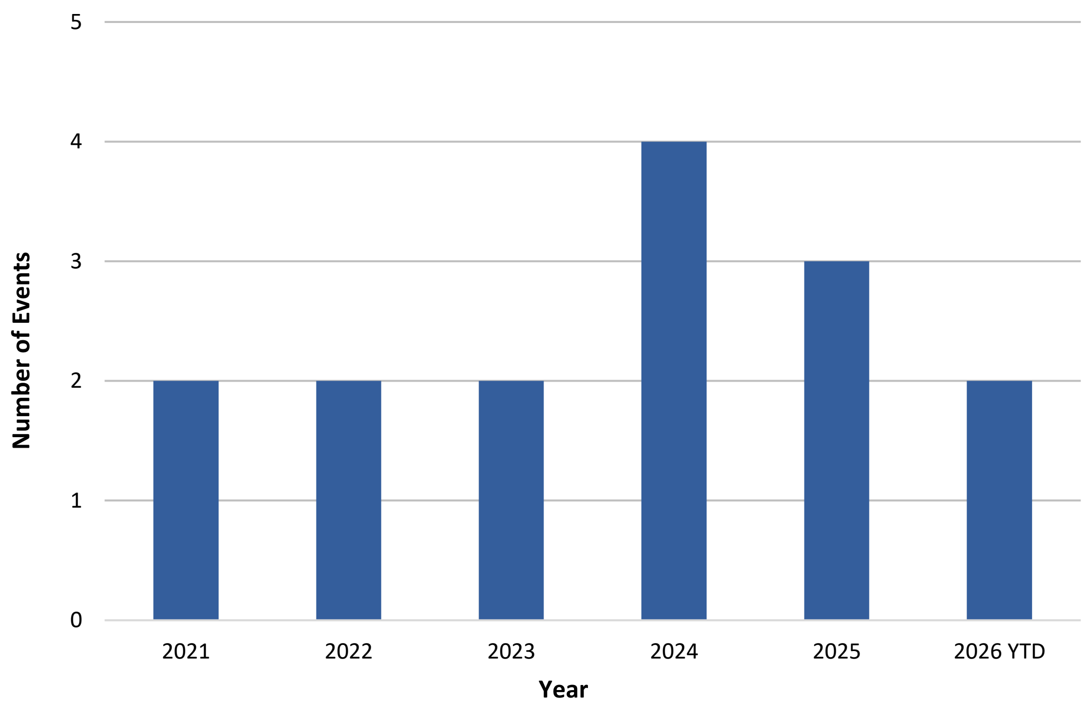

Chart D-2: UFLS Events

[5] As individual UFLS events can affect customer types differently, totals may not be the sum of the customer types.

Appendix E

Financial Schedules

Balance Sheet - Regulated Operations
as at March 31, 2026
($000)

Assets	**March 31, 2026**	**March 31, 2025**
Current Assets		
Cash	1,315	2,734
Accounts Receivable	116,899	112,272
Inventories	84,025	104,258
Current Portion of Sinking Fund Investments	2,297	91,284
Contract Receivable	3,626	2,901
Prepayments	13,319	12,013
Due from Related Parties	1,531	1,536
Promissory Note - Non-Regulated[1]	53,718	21,241
	276,730	**348,239**
Property, Plant, and Equipment	2,571,116	2,407,297
Intangible Assets	4,868	4,502
Sinking Fund Investments	102,555	125,902
Right-of-Use Assets	2,378	2,397
Long-Term Receivable	106	152
Regulatory Assets	1,511,057	1,354,359
Total Assets	**4,468,810**	**4,242,848**

Liabilities and Shareholder's Equity		
Current Liabilities		
Short-Term Borrowings	122,000	244,000
Accounts Payable and Accrued Liabilities	90,905	101,819
Accrued Interest	27,543	23,656
Current Portion of Contract Payable	322,321	299,768
Current Portion of Long-Term Debt	8,750	237,720
Current Portion of Deferred Credits[1]	6,178	7,498
Current Portion of Deferred Contributions	1,347	1,228
Current Portion of Decommissioning Liabilities	979	1,559
Due to Related Parties	21,935	11,244
	601,958	**928,492**
Long-Term Debt	2,050,585	1,770,733
Deferred Contributions	70,014	69,602
Decommissioning Liabilities	33,118	27,110
Employee Future Benefits	85,219	85,634
Contract Payable	980,735	712,888
Long-Term Payable	917	824
Lease Liability	2,646	2,610
Regulatory Liabilities	15,803	21,269
Shareholder Contributions	100,000	100,000
Accumulated Other Comprehensive Income	12,789	9,817
Retained Earnings	515,026	513,869
Total Liabilities and Shareholder's Equity	**4,468,810**	**4,242,848**

[1] Comparative figures for Current Portion of Deferred Credits and Promissory Note in Regulated and Non-Regulated have been restated due to reclassification of a credit from Regulated to Non Regulated. Restated balances are as follows:
Q1 2025 Current Portion of Deferred Credits was restated from $8,271 to $7,948. Decrease of $773.
Q1 2025 Promissory Note - Non-Regulated is restated from $22,014 to $21,241. Decrease of $773.

Statement of Income - Regulated Operations
for the Three Months Ended March 31, 2026
($000)

Q1 2026 Actual	Q1 2026 Budget	Q1 2025 Actual		YTD 2026 Actual	YTD 2026 Budget	YTD 2025 Actual	Annual 2026 Budget
			Revenue				
233,621	233,732	231,522	Energy Sales	233,621	233,732	231,522	646,292
2,060	1,515	2,955	Other Revenue	2,060	1,515	2,955	6,070
235,681	**235,247**	**234,477**		**235,681**	**235,247**	**234,477**	**652,362**
			Expenses				
114,383	119,053	120,551	Fuels	114,383	119,053	120,551	231,807
24,693	18,782	18,713	Power Purchased	24,693	18,782	18,713	65,934
39,919	39,357	38,221	Operating Costs	39,919	39,357	38,221	153,175
25,885	25,710	22,804	Depreciation and Amortization	25,885	25,710	22,804	102,936
23,305	24,742	20,483	Net Finance Expense	23,305	24,742	20,483	90,248
(365)	539	233	Other (Income) Expense	(365)	539	233	2,157
227,820	**228,183**	**221,005**		**227,820**	**228,183**	**221,005**	**646,257**
7,861	**7,064**	**13,472**	**Net Income**	**7,861**	**7,064**	**13,472**	**6,105**

Statement of Comprehensive Income - Regulated Operations
for the Three Months Ended March 31, 2026
($000)

Q1 2026 Actual	Q1 2026 Budget	Q1 2025 Actual		YTD 2026 Actual	YTD 2026 Budget	YTD 2025 Actual
7,861	7,064	13,472	Net Income	7,861	7,064	13,472
			Other Comprehensive Loss			
(225)	-	(163)	Employee Future Benefit Actuarial Loss	(225)	-	(163)
7,636	**7,064**	**13,309**	**Total Comprehensive Income**	**7,636**	**7,064**	**13,309**

Statement of Cash Flows - Regulated Operations
for the Three Months Ended March 31, 2026
($000)

	YTD 2026	YTD 2025
Operating Activities		
Net Income	7,861	13,472
Adjusted for Items not Involving Cash Flow		
Depreciation and Amortization	25,885	22,804
Accretion of Asset Retirement Obligation and Long-Term Debt	602	613
Amortization of Deferred Contributions	(615)	(597)
Employee Future Benefits	1,300	818
Loss on Disposal of Property, Plant and Equipment	(1)	(420)
Other	(3,945)	(4,297)
	31,087	**32,393**
Changes in Non-Cash Working Capital Balances		
Accounts Receivable	19,191	11,708
Inventory	13,197	(511)
Prepaid Expenses	(8,443)	(7,825)
Regulatory Assets	146,867	92,873
Regulatory Liabilities	49	49
Accounts Payable and Accrued Liabilities [3]	(49,681)	(1,408)
Contract Payable	154,860	286,821
Accrued Interest	(655)	(1,707)
Contract Receivable	1,499	26
Due to/from Related Parties [2]	444	(7,314)
	308,415	**405,105**
Financing Activities		
Retirement of Long-Term Debt	(300,000)	-
Decrease in Long-Term Receivable	38	13
Increase (Decrease) in Deferred Credits [1]	96	(51)
Increase in Deferred Capital Contributions	1,034	2,077
Decrease in Promissory Notes [1,2]	(149,912)	(370,015)
	(448,744)	**(367,976)**
Investing Activities		
Additions to Property, Plant and Equipment	(31,945)	(24,729)
Removal Costs	(32)	(15)
Proceeds on Disposal	-	481
Additions to Intangible Assets	(176)	2
Increase in Sinking Funds	184,632	(2,400)
Changes in Non-Cash Working Capital Balances [3]	(13,750)	(10,884)
	138,729	**(37,545)**
Net Decrease in Cash	(1,600)	(416)
Cash Position, Beginning of Period	2,915	3,150
Cash Position, End of Period	**1,315**	**2,734**

[1] Comparative figures for Increase (Decrease) in Deferred Credits and Decrease in Promissory Notes have been restated for transactions reclassified between Regulated and Non-Regulated Hydro.

[2] Comparative figures for Due to/from Related Parties and Decrease in Promissory Notes in Regulated and Non-Regulated Hydro have been restated due to a reclassification. Restated balances are as follows:
Q1 2025 Due to/from Related Parties is restated from ($9,486) to ($7,314). Change of ($2,172).
Q1 2025 Decrease in Promissory Notes is restated from ($367,833) to ($370,015). Change of $2,182, of which $10 pertains to Note 1 above.

[3] Comparative figures for Accounts Payable and Accrued Liabilities and Changes in Non-Cash Working Capital Balances- Investing Activities have been restated to reflect an updated presentation change.

Revenue Summary - Regulated Operations
for the Three Months Ended March 31, 2026
($000)

Q1 2026 Actual	Q1 2026 Budget	Q1 2025 Actual		YTD 2026 Actual	YTD 2026 Budget	YTD 2025 Actual	Annual 2026 Budget
			Industrial				
11,272	8,266	7,887	Industrial	11,272	8,266	7,887	34,385
902	3,157	3,380	Industrial Load[1]	902	3,157	3,380	12,004
12,174	**11,423**	**11,267**	**Total Industrial**	**12,174**	**11,423**	**11,267**	**46,389**
			Utility				
194,811	209,661	191,119	Newfoundland Power Inc.	194,811	209,661	191,119	533,050
(722)	(14,830)	2,494	Utility Load[2]	(722)	(14,830)	2,494	(18,678)
194,089	**194,831**	**193,613**	**Total Utility**	**194,089**	**194,831**	**193,613**	**514,372**
27,358	**27,478**	**26,642**	**Rural**	**27,358**	**27,478**	**26,642**	**85,531**
			Other Revenue				
170	117	338	Sundry	170	117	338	477
411	409	411	Pole Attachments	411	409	411	1,636
614	599	597	Amortization of CIAC[3]	614	599	597	2,397
475	-	1,219	Recovery of Supply Power[4]	475	-	1,219	-
390	390	390	Generation Demand Recovery	390	390	390	1,560
2,060	**1,515**	**2,955**	**Total Other Revenue**	**2,060**	**1,515**	**2,955**	**6,070**
235,681	**235,247**	**234,477**	**Total Revenue**	**235,681**	**235,247**	**234,477**	**652,362**

[1] Industrial load represents the revenue load variance recognized through the Supply Cost Variance Deferral Account ("SCVDA").
[2] Utility load represents the revenue load variance recognized through the SCVDA.
[3] Contribution in aid of Construction ("CIAC").
[4] Recovery of Supply Power includes sales of emergency energy to Nova Scotia Power.

Supplementary Schedule - Regulated Operations
for the Three Months Ended March 31, 2026
($000)

Q1 2026 Actual	Q1 2026 Budget	Q1 2025 Actual		YTD 2026 Actual	YTD 2026 Budget	YTD 2025 Actual	Annual 2026 Budget
			Interest				
			Interest Income				
2,923	3,077	3,882	Interest on Sinking Fund	2,923	3,077	3,882	8,603
616	175	901	Other Interest Income	616	175	901	699
3,539	**3,252**	**4,783**	**Total Interest Income**	**3,539**	**3,252**	**4,783**	**9,302**
			Interest Expense				
25,482	25,841	24,431	Interest on Long-Term Debt	25,482	25,841	24,431	94,704
2,277	2,708	3,810	Interest on Short-Term Debt	2,277	2,708	3,810	6,487
2,565	2,602	2,252	Debt Guarantee Fee	2,565	2,602	2,252	10,406
601	603	613	Accretion	601	603	613	2,056
(131)	(125)	(371)	RSP[1] Interest	(131)	(125)	(371)	(156)
(3,180)	(2,839)	(5,114)	SCVDA[2] Interest	(3,180)	(2,839)	(5,114)	(6,645)
8	12	13	Other	8	12	13	52
27,622	**28,802**	**25,634**	**Total Interest Expense**	**27,622**	**28,802**	**25,634**	**106,904**
(778)	(808)	(368)	Interest Capitalized during Construction	(778)	(808)	(368)	(7,354)
26,844	27,994	25,266		26,844	27,994	25,266	99,550
23,305	**24,742**	**20,483**	**Net Interest Expense**	**23,305**	**24,742**	**20,483**	**90,248**

[1] Rate Stabilization Plan ("RSP").
[2] Supply Cost Variance Deferral Account (SCVDA).

Balance Sheet - Non-Regulated Activities
as at March 31, 2026
($000)

Assets	**March 31, 2026**	**March 31, 2025**
Current Assets		
Cash	477,643	446,877
Accounts Receivable	28,659	29,290
Inventories	1,325	2,193
Current Portion of Sinking Fund Investments	2,174	2,113
Prepayments	2,816	3,144
Deferred Asset	82,333	62,930
Related Party Loan Receivable	555,342	705,342
Due from Related Party	35,937	57,192
Promissory Note Receivable	-	-
	1,186,229	**1,309,081**
Property, Plant, and Equipment	1,886,527	1,885,537
Intangible Assets	19,325	21,312
Sinking Fund	30,766	31,714
Investment in Joint Arrangement	842,050	797,905
Investment in Subsidiaries	5,291,140	5,054,385
Total Assets	**9,256,037**	**9,099,934**

Liabilities and Shareholder's Equity		
Current Liabilities		
Accounts Payable and Accrued Liabilities	53,750	52,745
Current Portion of Decommissioning Liabilities	3	3
Current Portion of Deferred Credits[1]	82,515	97,726
Derivative Liabilities	82,658	76,425
Other Current Liabilities	21,774	21,388
Due to Related Party	4,687	4,560
Promissory Note[1]	53,718	21,241
	299,105	**274,088**
Deferred Credits	1,465,361	1,490,159
Long-Term Payable	416	-
Employee Future Benefits	22,617	20,869
Other Long-Term Liabilities	34,848	37,045
Share Capital	122,504	122,504
Shareholder Contributions	4,658,210	4,658,210
Accumulated Other Comprehensive Income	(31,711)	(38,022)
Retained Earnings	2,684,687	2,535,081
Total Liabilities and Shareholder's Equity	**9,256,037**	**9,099,934**

[1] Comparative figures for Current Portion of Deferred Credits and Promissory Note have been restated due to a reclassification of a credit from Regulated to Non Regulated. Restated balances are as follows:
Q1 2025 Current portion of Deferred Credits was restated from $96,953 to $97,726. Increase of $773.
Q1 2025 Promissory Note was restated from $22,014 to $21,241. Decrease of $773.

Statement of Income - Non-Regulated Activities
for the Three Months Ended March 31, 2026
($000)

Q1 2026 Actual	Q1 2026 Budget	Q1 2025 Actual		YTD 2026 Actual	YTD 2026 Budget	YTD 2025 Actual	Annual 2026 Budget
			Revenue				
21,688	18,100	18,929	Energy Sales	21,688	18,100	18,929	61,053
8,669	8,767	10,104	Other Revenue	8,669	8,767	10,104	39,596
30,357	**26,867**	**29,033**		**30,357**	**26,867**	**29,033**	**100,649**
			Expenses				
35,438	22,635	23,298	Power Purchased	35,438	22,635	23,298	62,644
14,974	9,526	15,420	Operating Costs[2]	14,974	9,526	15,420	41,280
5,156	5,206	6,903	Transmission Rental	5,156	5,206	6,903	20,825
9,805	9,673	9,912	Depreciation and Amortization	9,805	9,673	9,912	38,693
(3,801)	(3,547)	(4,263)	Interest	(3,801)	(3,547)	(4,263)	(8,512)
347,156	346,513	451,081	Other Expense[1,2]	347,156	346,513	451,081	591,022
408,728	**390,006**	**502,351**		**408,728**	**390,006**	**502,351**	**745,952**
(378,371)	**(363,139)**	**(473,318)**	Net Operating Loss	**(378,371)**	**(363,139)**	**(473,318)**	**(645,303)**
			Other Revenue				
18,382	16,909	19,146	Equity in CF(L)Co	18,382	16,909	19,146	39,743
1,813	1,782	1,867	Preferred Dividends	1,813	1,782	1,867	7,129
334,678	242,449	387,665	Equity in Subsidiaries	334,678	242,449	387,665	517,130
354,873	**261,140**	**408,678**		**354,873**	**261,140**	**408,678**	**564,002**
(23,498)	**(101,999)**	**(64,640)**	**Net Loss**	**(23,498)**	**(101,999)**	**(64,640)**	**(81,301)**

[1] The balance in Other Expense is related to the fair value valuation of the Energy Marketing - Hydro Power Purchase agreement derivative liability and associated gains and losses as a result of changes in forecasted energy prices as well as rate mitigation transfers under the Province's rate mitigation plan.

[2] Comparative figures for Operating Costs and Other Expense have been reclassified to conform to the current year's presentation. Restated balances are as follows:
Q1 2025 Operating Costs is restated from $11,977 to $15,420. Increase of $3,443.
Q1 2025 Other Expense is restated from $454,524 to $451,081. Decrease of $3,443.

Statement of Retained Earnings - Non-Regulated Activities
for the Three Months Ended March 31, 2026
($000)

Q1			YTD	
2026 Actual	**2025 Actual**		**2026 Actual**	**2025 Actual**
2,708,185	2,599,721	Balance, Beginning of Period	2,708,185	2,599,721
(23,498)	(64,640)	Net Loss	(23,498)	(64,640)
2,684,687	**2,535,081**	Balance, End of Period	**2,684,687**	**2,535,081**

Statement of Comprehensive Income - Non-Regulated Activities
for the Three Months Ended March 31, 2026
($000)

Q1 2026 Actual	Q1 2026 Budget	Q1 2025 Actual		YTD 2026 Actual	YTD 2026 Budget	YTD 2025 Actual	Annual 2026 Budget
(23,498)	(101,999)	(64,640)	Net Loss	(23,498)	(101,999)	(64,640)	(81,301)
			Other Comprehensive Income				
24		482	Share of other comprehensive income of joint arrangement [1]	24		482	
855	-	879	Share of other comprehensive income of subsidiaries [1]	855	-	879	-
(22,619)	**(101,999)**	**(63,279)**	**Total Comprehensive Loss**	**(22,619)**	**(101,999)**	**(63,279)**	**(81,301)**

[1] Comparative figures for Share of other comprehensive income of joint arrangement and Share of other comprehensive income of subsidiaries were previously combined.

Statement of Cash Flows - Non-Regulated Activities
for the Three Months Ended March 31, 2026
($000)

	YTD 2026	YTD 2025
Operating Activities		
Net Income	(23,498)	(64,640)
Adjusted for Items not Involving Cash Flow		
Depreciation and Amortization	9,805	9,912
Share of profit of Joint Arrangement	(18,382)	(19,146)
Share of profit of Subsidiaries	(334,678)	(387,665)
Amortization of Deferred Credits	(29,463)	(29,288)
Maritime Link Operating Costs	5,425	5,030
Net Changes in PPA[1] Fair Value	325	13,495
Employee Future Benefits	523	534
Accretion of Long-term Payables	532	561
Sinking Fund Earnings	(307)	(315)
Non-cash Distribution from Subsidiary[3]	29,463	29,288
Other	6	(3)
	(360,249)	**(442,237)**
Changes in Non-Cash Working Capital Balances		
Accounts Receivable	10,185	7,625
Accounts Payable and Accrued Liabilities[5]	(8,213)	1,062
Due to/from Related Parties[4]	(1,616)	(16,716)
Prepaid Expenses	204	612
Other Liabilities	3,491	3,443
	(356,198)	**(446,211)**
Financing Activities		
Increase in Promissory Notes[2,4]	21,912	24,015
Change in Deferred Credits[2]	(1,298)	1,892
	20,614	**25,907**
Investing Activities		
Additions to Property, Plant and Equipment	(2,281)	(1,283)
Dividends from Subsidiaries[3]	114,945	59,987
Distributions from Subsidiaries	49,604	50,082
Changes in Non-Cash Working Capital Balances[5]	(3,677)	(13,274)
	158,591	**95,512**
Net Change in Cash	(176,993)	(324,792)
Cash Position, Beginning of Period	654,636	771,669
Cash Position, End of Period	477,643	446,877

[1] Power Purchase Agreement ("PPA") between Newfoundland and Labrador Hydro and Nalcor Energy Marketing.

[2] Comparative figures for Change in Deferred Credits and Increase in Promissory Notes have been restated for transactions reclassified between Regulated and Non-Regulated Hydro.

[3] Comparative figures for Non-cash Distribution from Subsidiary and Dividends from Subsidiaries were previously combined. These have been broken out separately for presentation purposes.

[4] Comparative figures for Due to/from Related Parties and Increase in Promissory Notes have been restated due to a reclassification to the 2025 ending balance. Restated balances are as follows:
Q1 2025 Due to/from Related Parties is restated from ($14,544) to ($16,716). Change of ($2,172).
Q1 2025 Increase in Promissory Notes is restated from $21,833 to $24,015. Change of $2,182, of which $10 pertains to Note 2 above.

[5] Comparative figures for Accounts Payable and Accrued Liabilities and Changes in Non-Cash Working Capital Balances- Investing Activities have been restated to reflect an updated presentation change.

Attachment 1

Rate Stabilization Plan Report (Unaudited)

Quarter Ended March 31, 2026

Newfoundland and Labrador Hydro
Rate Stabilization Plan Report
March 31, 2026

Summary of Key Facts

The Rate Stabilization Plan ("RSP") of Newfoundland and Labrador Hydro ("Hydro") was established for Hydro's Utility customer, Newfoundland Power Inc. ("Newfoundland Power") and Island Industrial customers to smooth rate impacts for variations between actual results and Test Year Cost of Service estimates for:

● Hydraulic production;
● No. 6 Fuel cost at Hydro's Holyrood Thermal Generating Station;
● Customer Load (Utility and Island Industrial); and
● Rural rates.

In Board Order No. P.U. 33(2021), the Board of Commissioners of Public Utilities ("Board") approved the Supply Cost Variance Deferral Account ("SCVDA") to deal with future supply cost variances on the Island Interconnected System beginning in the month in which Hydro was required to begin payments under the Muskrat Falls Purchase Power Agreement (i.e., November 2021). The approval of the SCVDA discontinued transfers to the RSP, effective as of the implementation of the SCVDA, resulting from variations in future costs associated with the Test Year Cost of Service estimates for the items listed above. However, the Board directed that the RSP balances be maintained for the transparent and timely recovery of historical balances. The rules provide for the disposition of historical balances in accordance with the RSP Rules previously approved by the Board in Board Order No. P.U. 4(2022).

The Hydraulic Variation Account Balance as of October 31, 2021 was fully assigned to customers as of December 31, 2024 as per the Rate Stabilization Plan Rules for Balance Disposition approved by the Board in Board Order No. P.U. 4(2022).

Per Board Order No. P.U. 10(2025), finance charges are calculated on the balances using the approved weighted average cost of capital, which is currently 5.45% per annum effective January 1, 2025.

Rate Stabilization Plan
Summary of Utility Customer
March 31, 2026

	A	B	C	D	E	F	G	H
	Load Variation ($)	Allocation Fuel Variance ($)	Allocation Rural Rate Alteration ($)	Subtotal Monthly Variances ($) (A + B + C)	Financing Charges ($)	Adjustment[1] ($)	Transfers[2] ($)	Cumulative Net Balance ($) (to page 4)
Opening Balance								12,617,595
Adjustment								-
Adjusted Opening Balance								**12,617,595**
January	-	-	-	-	55,921	(2,968,148)	-	9,705,368
February	-	-	-	-	43,014	(2,579,117)	-	7,169,265
March	-	-	-	-	31,774	(2,784,379)	6,091,362	10,508,022
April								
May								
June								
July								
August								
September								
October								
November								
December								
Year-to-Date	-	-	-	-	130,709	(8,331,644)	6,091,362	(2,109,573)
Total	**-**	**-**	**-**	**-**	**130,709**	**(8,331,644)**	**6,091,362**	**10,508,022**

[1] Effective July 1, 2025, the Rate Stabilization Plan ("RSP") Adjustment rate is 0.413 cents per kWh as per Board Order No. P.U. 22(2025).

[2] Recovery of the 2025 Isolated Systems Supply Costs Deferral was approved in Board Order No. P.U. 9(2026).

Rate Stabilization Plan
Summary of Industrial Customers
March 31, 2026

	A	B	C	D	E	F	G
	Load Variation ($)	Allocation Fuel Variance ($)	Subtotal Monthly Variances ($) (A + B)	Financing Charges ($)	Adjustment ($)	Transfers[1] ($)	Cumulative Net Balance ($) (to page 4)
Opening Balance							(51,816)
Adjustment						51,816	51,816
Adjusted Opening Balance							-
January	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-
April							
May							
June							
July							
August							
September							
October							
November							
December							
Year-to-Date	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-

[1] As per Board Order No. P.U. 3(2026), the discontinuance of the Rate Stabilization Plan ("RSP") current plan adjustment for Island Industrial Customers ("IIC") effective January 1, 2026 was approved, and the RSP IIC balance as at December 31, 2025 of ($51,816) was transferred to the Supply Cost Variance Deferral Account- Industrial Customers Balance.

Rate Stabilization Plan
Overall Summary
March 31, 2026

	A	B	C
	Utility Balance ($)	**Industrial Balance[1] ($)**	**Total To Date ($)**
			(A + B)
	(from page 2)	**(from page 3)**	
Opening Balance	12,617,595	(51,816)	12,565,779
Adjustments	-	51,816	51,816
Adjusted Opening Balance	**12,617,595**	**-**	**12,617,595**
January	9,705,368	-	9,705,368
February	7,169,265	-	7,169,265
March	10,508,022	-	10,508,022
April			
May			
June			
July			
August			
September			
October			
November			
December			

[1] As per Board Order No. P.U. 3(2026), the discontinuance of the Rate Stabilization Plan ("RSP") current plan adjustment for Island Industrial Customers ("IIC") effective January 1, 2026 was approved and the RSP IIC balance as at December 31, 2025 of ($51,816) was transferred to the Supply Cost Variance Deferral Account- Industrial Customers Balance.

Attachment 2

Supply Cost Variance Deferral Account Report (Unaudited)

Quarter Ended March 31, 2026

Newfoundland and Labrador Hydro
Supply Cost Variance Deferral Account
March 31, 2026

Summary of Key Facts

In Board Order No. P.U. 33(2021), the Board of Commissioners of Public Utilities ("Board") approved Hydro's proposal to establish an account to defer payments under the Muskrat Falls Project agreements, rate mitigation funding, project cost recovery from customers and supply cost variances.

In Board Order No. P.U. 4(2022), the Board of Commissioners of Public Utilities ("Board") approved the Supply Cost Deferral Account definition with an effective date of November 1, 2021.

Financing charges accrued at the 2025 short-term cost of borrowing of 3.35% for the period of January to November, 2026. In December, financing costs will be trued-up to reflect the actual short-term cost of borrowing for 2026.

Supply Cost Variance Deferral Account[1,2]
Summary
March 31, 2026

	Supply Cost Variance Deferral Account Balance ($) (from page 3)	Utility Balance ($) (from page 4)	Industrial Balance [3] ($) (from page 5)	Total to Date ($)
Opening Balance	390,740,090	(40,366,584)	-	**350,373,506**
Adjustment	-	-	(51,816)	**(51,816)**
Adjusted Opening Balance	**390,740,090**	**(40,366,584)**	**(51,816)**	**350,321,690**
January [4]	422,656,688	(42,965,784)	(51,958)	**379,638,946**
February	457,801,440	(45,034,736)	(52,101)	**412,714,603**
March [5]	143,623,434	(47,364,302)	(25,322)	**96,233,810**
April				
May				
June				
July				
August				
September				
October				
November				
December				

[1] Numbers may not add throughout the report due to rounding.

[2] Financing charges accrued at the 2025 short-term cost of borrowing of 3.35%. In December, finance costs will be trued up to reflect the actual short-term cost of borrowing for 2026.

[3] The transfer of the December 2025 Rate Stabilization Plan ("RSP") Island Industrial Customers balance to the Supply Cost Variance Deferral Account was approved in Board Order No. P.U. 3(2026).

[4] January 2026 was updated to reflect the new terms under the Corner Brook Pulp and Paper Limited Power Purchase Agreement for purchases through June 2026.

[5] March activity includes transfers from the 2025 Return on Equity Rate Change Deferral Account balance for Newfoundland Power and Industrial customers as per Board Order No. P.U. 10 (2025). Please see Schedule B for additional details.

Supply Cost Variance Deferral Account
Section A: Summary
March 31, 2026

	Muskrat Falls Project Cost Variance ($)	Rate Mitigation Fund[2] ($)	Project Cost Recovery Rider: Utility[3] ($)	Project Cost Recovery Rider: Industrial[4] ($)	Holyrood TGS[5] Fuel Cost Variance ($)	Other IIS[6] Supply Cost Variance ($)	Net Revenue From Exports Variance ($)	Transmission Tariff Revenue Variance ($)	Load Variation: Utility[7] ($)	Load Variation: Industrial ($)	Greenhouse Gas Credit Revenue Variance ($)	Subtotal Monthly Variances ($)	Financing Charges[1]: Utility ($)	Financing Charges[1]: Industrial ($)	Financing Charges[1]: Other ($)	Transfers ($)	Cumulative Net Balance ($)
	(from page 6)	**(from page 15)**			**(from page 7)**	**(from page 8)**	**(from page 9)**	**(from page 10)**	**(from page 11)**	**(from page 12)**	**(from page 14)**						**(to page 2)**
Opening Balance	2,338,335,896	(1,279,833,434)	(193,562,699)	(11,578,905)	(224,201,524)	(100,346,437)	(184,174,921)	(62,735,864)	70,930,934	60,534,000	(71,725,266)	341,641,780	(11,886,862)	(315,161)	61,300,333	-	390,740,090
Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Adjusted Opening Balance	**2,338,335,896**	**(1,279,833,434)**	**(193,562,699)**	**(11,578,905)**	**(224,201,524)**	**(100,346,437)**	**(184,174,921)**	**(62,735,864)**	**70,930,934**	**60,534,000**	**(71,725,266)**	**341,641,780**	**(11,886,862)**	**(315,161)**	**61,300,333**	**-**	**390,740,090**
January	64,905,706	-	(10,895,187)	(873,993)	(27,432,786)	6,763,877	(391,142)	(1,498,023)	(318,080)	571,850	9,959	30,842,181	(532,239)	(31,838)	1,638,494	-	422,656,688
February	64,450,247	-	(9,467,169)	(897,630)	(17,022,931)	(3,758,973)	(447,275)	(1,498,023)	2,329,128	294,899	301	33,982,574	(562,198)	(34,242)	1,758,618	-	457,801,440
March	59,811,131	(350,300,000)	(10,220,627)	(1,090,712)	(3,835,182)	(5,336,924)	(237,635)	(1,498,023)	(2,733,269)	35,203	(30,784)	(315,436,822)	(588,229)	(36,710)	1,883,755	-	143,623,434
April																-	
May																-	
June																-	
July																-	
August																-	
September																-	
October																-	
November																-	
December																-	
Year-to-Date	**189,167,084**	**(350,300,000)**	**(30,582,983)**	**(2,862,335)**	**(48,290,899)**	**(2,332,020)**	**(1,076,052)**	**(4,494,069)**	**(722,221)**	**901,952**	**(20,524)**	**(250,612,067)**	**(1,682,666)**	**(102,790)**	**5,280,867**	**-**	**(247,116,656)**
Total	**2,527,502,980**	**(1,630,133,434)**	**(224,145,682)**	**(14,441,240)**	**(272,492,423)**	**(102,678,457)**	**(185,250,973)**	**(67,229,933)**	**70,208,713**	**61,435,952**	**(71,745,790)**	**91,029,713**	**(13,569,528)**	**(417,951)**	**66,581,200**	**-**	**143,623,434**

[1] Financing charges accrued at the 2025 short-term cost of borrowing of 3.35%. In December 2026, finance costs will be trued up to reflect the actual short-term cost of borrowing for 2026.

[2] As per Order in Council OC2024-062 dated May 7, 2024, Newfoundland and Labrador Hydro has been directed by the Government of Newfoundland and Labrador to use its own sources of rate mitigation and accordingly, in March 2026, transferred $350.3 million of funding to its Regulated operations. The $350.3 million includes $90.6 million of rate mitigation funding related to the retirement of the 2023 Supply Cost Variance Deferral Account of $271 million over the 2024 to 2026 period.

[3] As per Order No. P.U. 22(2025), the Board of Commissioners of Public Utilities ("Board") approved a Project Cost Recovery Rider of 1.516 cents per kWh effective July 1, 2025.

[4] As per Order No. P.U. 3(2026), the Board approved a Project Cost Recovery Rider of 1.745 cents per kWh effective January 1, 2026.

[5] Holyrood Thermal Generating Station ("Holyrood TGS").

[6] Island Interconnected System ("IIS").

[7] As per Board Order No. P.U. 1(2025), the Board approved a wholesale rate, effective as of January 1, 2025, to be charged to Utility of 9.698 cents per kWh for winter months of December to March and 3.354 cents per kWh for the non-winter months of April to November.

Supply Cost Variance Deferral Account
Section B: Utility Customer Balance
March 31, 2026

	Allocation Rural Rate Alteration[1] ($)	Financing Charges [2] ($)	Transfers[3] ($)	Cumulative Net Balance ($)
	(from page 13)			(to page 2)
Opening Balance	(37,866,434)	(2,500,150)	-	(40,366,584)
Adjustments	-	-	-	-
Adjusted Opening Balance	**(37,866,434)**	**(2,500,150)**	**-**	**(40,366,584)**
January	(2,488,204)	(110,996)	-	(42,965,784)
February	(1,950,809)	(118,143)	-	(45,034,736)
March	(2,614,154)	(123,832)	408,420	(47,364,302)
April			-	
May			-	
June			-	
July			-	
August			-	
September			-	
October				
November				
December				
Year-to-Date	**(7,053,167)**	**(352,971)**	**408,420**	**(6,997,718)**
Total	**(44,919,601)**	**(2,853,121)**	**408,420**	**(47,364,302)**

[1] The Rural Rate Alteration is allocated between Utility and Labrador Interconnected customers in the same proportion that the rural deficit was allocated in the approved 2019 Cost of Service Study, which is 96.1% and 3.9%, respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

The only transactions posted to the Utility's Customer Balance are Newfoundland Power's allocation of Rural Rate Alteration and associated interest until further approval is obtained from the Board.

[2] Financing charges accrued at the 2025 short-term cost of borrowing of 3.35%. In December, the interest expense will be trued up to reflect the short-term interest rate for 2026.

[3] The transfer of the December 2025 Return on Equity Rate Change Deferral Account balance attributable to Newfoundland Power to the Utility Customer Balance in the Supply Cost Variance Deferral Account for disposition, was approved in Board Order No. P.U. 10(2025).

Supply Cost Variance Deferral Account
Section B: Industrial Customers Balance
March 31, 2026

	Financing Charges ($)	Transfers ($)	Cumulative Net Balance ($) (to page 2)
Opening Balance	-	-	-
Adjustments[1]	-	(51,816)	(51,816)
Adjusted Opening Balance	-	(51,816)	(51,816)
January	(142)	-	(51,958)
February	(143)	-	(52,101)
March[2]	(143)	26,922	(25,322)
April		-	
May		-	
June		-	
July		-	
August		-	
September		-	
October		-	
November		-	
December		-	
Year-to-Date	**(428)**	**26,922**	**26,494**
Total	**(428)**	**26,922**	**(25,322)**

[1] The transfer of the December 2025 Rate Stabilization Plan ("RSP") Island Industrial Customers balance to the Supply Cost Variance Deferral Account was approved in Board Order No. P.U. 3(2026).

[2] The transfer of the December 2025 Return on Equity Rate Change Deferral Account balance attributable to Island Industrial Customers to the Industrial Customers Balance in the Supply Cost Variance Deferral Account for disposition, was approved in Board Order No. P.U. 10(2025).

Supply Cost Deferral Account
Muskrat Falls Project Cost Variances
March 31, 2026

	Muskrat Falls PPA[1] Charges Actual ($) (A)	Muskrat Falls PPA Charges Test Year ($) ($A_T$)	TFA[2] Charges Actual ($) (B)	TFA Charges Test Year ($) ($B_T$)	Total Variation ($) $(A - A_T) + (B - B_T)$ (to page 3)
January	25,404,942	-	39,500,763	-	**64,905,706**
February	25,287,679	-	39,162,568	-	**64,450,247**
March	25,681,137	-	34,129,994	-	**59,811,131**
April					
May					
June					
July					
August					
September					
October					
November					
December					
Total	**76,373,758**	**-**	**112,793,326**	**-**	**189,167,084**

[1] Power Purchase Agreement ("PPA").

[2] Transmission Funding Agreement ("TFA").

Supply Cost Deferral Account
Holyrood Thermal Generating Station Fuel Cost Variance
March 31, 2026

	Actual Quantity No. 6 Fuel (bbl.)	Actual Quantity No. 6 Fuel for Non-Firm Sales[1] (bbl.)	Net Quantity No. 6 Fuel (bbl.)	Actual Average No. 6 Fuel Cost ($Can./bbl)	Actual ($) C	Test Year Quantity No. 6 Fuel (bbl.)	Test Year No. 6 Fuel Cost ($Can./bbl)	Test Year ($) C_T	Total Variation ($) $(C - C_T)$ (to page 3)
January	181,309	676	180,633	95.03	17,165,093	421,132	105.90	44,597,879	**(27,432,786)**
February	219,733	586	219,148	97.78	21,427,983	363,087	105.90	38,450,913	**(17,022,931)**
March	153,714	125	153,589	98.22	15,085,124	178,662	105.90	18,920,306	**(3,835,182)**
April									
May									
June									
July									
August									
September									
October									
November									
December									
Total	**554,756**	**1,387**	**553,369**	**97.00**	**53,678,200**	**962,881**	**105.90**	**101,969,098**	**(48,290,899)**

[1] Includes non-firm sales to Island Industrial Customers and supply of emergency energy to Nova Scotia.

Supply Cost Deferral Account
Other Island Interconnected System Supply Cost Variance Summary
March 31, 2026

	Thermal Variation[1] ($)	Off-Island Power Purchase Variation[1] ($)	On-Island Power Purchase Variation[1] ($)	CBPP[2] Firm Energy Variation[1] ($)	Current Month Variation ($)	Year-to-Date Variation ($)	Cost Variance Threshold ($)	Other IIS Supply Cost Variance ($)
	(D)	(E)	(F)	(G)	(D + E + F + G)			
January	2,491,682	5,069,104	(296,909)	-	7,263,877	7,263,877	500,000	6,763,877
February	(869,686)	(2,610,641)	(278,646)	-	(3,758,973)	3,504,904	500,000	3,004,904
March	(668,026)	(5,801,330)	132,432	-	(6,336,924)	(2,832,020)	(500,000)	(2,332,020)
April								
May								
June								
July								
August								
September								
October								
November								
December								
Total	**953,970**	**(3,342,867)**	**(443,123)**	**-**	**(2,832,020)**			

[1] The calculation of the variation by source is provided in Appendix A.

[2] Corner Brook Pulp and Paper Ltd. ("CBPP").

Supply Cost Deferral Account
Net Revenue from Exports Variance
March 31, 2026

	Test Year ($) ($H_T$)	Net Revenue from Exports Excluding Non-Firm Sales Revenue	Non-Firm Sales Revenue[1]	Transfer	Actual[2] ($) (H)	Total Variation ($) ($H_T$ - H) (to page 3)
January	-	207,601	183,541		391,142	**(391,142)**
February	-	256,785	190,490		447,275	**(447,275)**
March[3]	-	132,937	104,698		237,635	**(237,635)**
April						
May						
June						
July						
August						
September						
October						
November						
December						
Total	**-**	**597,324**	**478,728**	**-**	**1,076,052**	**(1,076,052)**

[1] Hydro's application to implement a non-firm rate for the Labrador Interconnected System and for Island Industrial customers to be calculated based on export market prices was approved in Board Order No. P.U. 34(2023). The Board Order also approved a revision to the Supply Cost Variance Deferral Account so that revenues from non-firm sales on the Island Interconnected System, supplied by hydraulic generation and revenues from Rate No. 5.1L – Non-Firm Energy, will be credited to the Net Revenue from Exports Variance component.

[2] Muskrat Falls and Hydro entered into a Purchase Power Agreement for the purchase and sale of residual block energy. Under this Agreement, Labrador Rural and Industrial customer load, previously serviced with Recapture Energy from Churchill Falls, is now serviced with energy from the Muskrat Falls Hydroelectric Generating Facility. Entering into this Agreement has allowed additional Recapture Energy exports to external markets helping to ensure maximum value from the organization's hydrological resources.

[3] In March the actual settlement value for net export sales for 2025 was finalized. The settlement did not change the revenue that was accrued in December 2025, therefore no true-up was required.

Supply Cost Deferral Account
Tariff Revenue
March 31, 2026

	Test Year ($)	Actual ($)	Total Variation ($)
	(I_T)	(I)	(I_T - I)
			(to page 3)
January	-	1,498,023	**(1,498,023)**
February	-	1,498,023	**(1,498,023)**
March	-	1,498,023	**(1,498,023)**
April			
May			
June			
July			
August			
September			
October			
November			
December			
Total	**-**	**4,494,069**	**(4,494,069)**

Supply Cost Deferral Account
Load Variation - Utility
March 31, 2026

	Test Year Cost of Service Firm Sales (kWh)	Actual Firm Sales (kWh)	Sales Variance (kWh)	Firm Energy Rate (\$/kWh)[1]	Load Variation (\$)
	(J_T)	(J_A)	(J_T - J_A)	(K_R)	(J_T - J_A) x K_R (to page 3)
January	715,400,000	718,679,851	(3,279,851)	0.09698	(318,080)
February	648,500,000	624,483,417	24,016,583	0.09698	2,329,128
March	646,000,000	674,183,838	(28,183,838)	0.09698	(2,733,269)
April					
May					
June					
July					
August					
September					
October					
November					
December					
Total	**2,009,900,000**	**2,017,347,106**	**(7,447,106)**		**(722,221)**

[1] As per Order No. P.U. 1(2025), the Board approved a wholesale rate, effective as of January 1, 2025, to be charged to Utility of 9.698 cents per kWh for winter months of December to March and 3.354 cents per kWh for the non-winter months of April to November.

Supply Cost Deferral Account
Load Variation - Industrial
March 31, 2026

	Test Year Cost of Service Firm Sales (kWh) (J_T)	Actual Firm Sales (kWh) (J_A)	Sales Variance (kWh) (J_T - J_A)	Firm Energy Rate ($/kWh) ($K_R$)	Load Variation ($) ($J_T$ - J_A) x K_R (to page 3)
January	63,000,000	50,085,586	12,914,414	0.04428	571,850
February	58,100,000	51,440,128	6,659,872	0.04428	294,899
March	63,300,000	62,504,983	795,017	0.04428	35,203
April					
May					
June					
July					
August					
September					
October					
November					
December					
Total	**184,400,000**	**164,030,697**	**20,369,303**		**901,952**

Supply Cost Deferral Account
Rural Rate Alteration
March 31, 2026

	Price ($)	Volume ($)	Total[1] ($)	Utility Allocation[1] ($) (to page 4)	Labrador Interconnected Allocation[1] ($)	Balance ($)
January	(2,062,211)	(526,971)	(2,589,182)	(2,488,204)	(100,978)	-
February	(1,868,269)	(161,709)	(2,029,978)	(1,950,809)	(79,169)	-
March	(1,886,154)	(834,089)	(2,720,243)	(2,614,154)	(106,089)	-
April						
May						
June						
July						
August						
September						
October						
November						
December						
Total	**(5,816,634)**	**(1,522,769)**	**(7,339,403)**	**(7,053,167)**	**(286,236)**	**-**

[1] The Rural Rate Alteration is allocated between Utility and Labrador Interconnected customers in the same proportion that the Rural Deficit was allocated in the approved 2019 Cost of Service Study, which is 96.1% and 3.9%, respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

Supply Cost Deferral Account
Greenhouse Gas Credits
March 31, 2026

	Test Year ($)	Actual ($)	Total Variation ($)
	(T_T)	(T)	(T_T - T)
			(to page 3)
January	-	(9,959)	**9,959**
February	-	(301)	**301**
March	-	30,784	**(30,784)**
April		-	
May		-	
June		-	
July			
August			
September			
October			
November			
December			
Total	**-**	**20,524**	**(20,524)**

Supply Cost Deferral Account
Rate Mitigation Fund
March 31, 2026

	Test Year ($)	Actual ($)	Total Variation ($) (to page 3)
January	-	-	**-**
February[1]	-	-	**-**
March	-	350,300,000	**(350,300,000)**
April			
May			
June			
July			
August			
September			
October			
November			
December			
	-	**350,300,000**	**(350,300,000)**

[1] As per Order in Council OC2024-062 dated May 7, 2024, Hydro has been directed by the Government to use its own sources of rate mitigation and accordingly, in March 2026, transferred $350.3 million of funding to its Regulated operations. The $350.3 million includes $90.6 million of rate mitigation funding related to the retirement of the 2023 Supply Cost Variance Deferral Account of $271 million over the 2024 to 2026 period.

2025 Short-Term Interest Calculation[1]

	($000)
Promissory Note Interest	7,926
BA[2] Interest	-
CORRA[3] Interest	5,167
Operating Line Interest	0
Standby and Upfront Fee	709
Brokerage Fee	292
Debt Guarantee Fee – Recoverable Portion Only	375
Total Short-Term Borrowing Costs	**14,469**
Weighted Average Short-Term Debt Balance[4]	**431,293**
Short-Term Cost of Borrowing 2025	**3.35%**

[1] Financing charges accrued at the 2025 short-term cost of borrowing of 3.35% for the period of January to November, 2026. In December 2026, financing costs will be trued up to reflect the actual short-term cost of borrowing for 2026.

[2] Banker's Acceptance ("BA").

[3] Canadian Overnight Repo Rate Average ("CORRA").

[4] The weighted average of the short-term debt balance is calculated using the 365-day average of the credit facility debt and the promissory note debt balances.

Appendix A

Other Island Interconnected System

Supply Cost Variance Summary

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
March 31, 2026

Holyrood Combustion Turbine	Actual Cost ($) (A)	Fuel for Non-Firm Sales ($)[1,2] (B)	Net Cost ($) (C = A - B)	Test Year Cost ($) (D)	Thermal Variation ($) (C - D)
January	2,923,421	358,422	2,564,999	1,258,888	**1,306,111**
February	16,900	5,042	11,858	767,288	**(755,430)**
March	73,512	791	72,721	661,531	**(588,810)**
April					
May					
June					
July					
August					
September					
October					
November					
December					
Subtotal	**3,013,833**	**364,255**	**2,649,579**	**2,687,707**	**(38,129)**

[1] All non-firm sales are credited under Holyrood Combustion Turbines since the non-firm sales were not distinguished between Holyrood, Hardwoods or Stephenville.
[2] Includes Non-firm sales to Island Industrial Customers and supply of emergency energy to Nova Scotia.

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
March 31, 2026

Hardwoods Gas Turbine	Actual Cost ($) (A)	Fuel for Non-Firm Sales ($) (B)	Net Cost ($) (C = A - B)	Test Year Cost ($) (D)	Thermal Variation ($) (C - D)
January	654,410	-	654,410	122,478	**531,932**
February	36,296	-	36,296	123,884	**(87,588)**
March	17,895	-	17,895	117,271	**(99,376)**
April		-			
May		-			
June		-			
July		-			
August		-			
September		-			
October		-			
November		-			
December		-			
Subtotal	**708,601**	**-**	**708,601**	**363,633**	**344,968**

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
March 31, 2026

Stephenville Gas Turbine	Actual Cost ($) (A)	Fuel for Non-Firm Sales ($) (B)	Net Cost ($) (C = A - B)	Test Year Cost ($) (D)	Thermal Variation ($) (C - D)
January	661,875	-	661,875	68,116	**593,759**
February	25,122	-	25,122	46,923	**(21,801)**
March	63,153	-	63,153	40,867	**22,286**
April		-			
May		-			
June		-			
July		-			
August		-			
September		-			
October		-			
November		-			
December		-			
Subtotal	**750,150**	**-**	**750,150**	**155,906**	**594,244**

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
March 31, 2026

St. Anthony Diesel Generating Station	Actual Cost ($) (A)	Fuel for Non-Firm Sales ($) (B)	Net Cost ($) (C = A - B)	Test Year Cost ($) (D)	Thermal Variation ($) (C - D)
January	52,777	21,946	30,831	3,147	**27,684**
February	(96)	-	(96)	3,089	**(3,185)**
March	2,825	-	2,825	3,299	**(474)**
April		-			
May		-			
June		-			
July		-			
August		-			
September		-			
October		-			
November		-			
December		-			
Subtotal	**55,507**	**21,946**	**33,561**	**9,535**	**24,025**

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
March 31, 2026

Hawkes Bay Diesel Generating Station	Actual Cost ($) (A)	Fuel for Non-Firm Sales ($) (B)	Net Cost ($) (C = A - B)	Test Year Cost ($) (D)	Thermal Variation ($) (C - D)
January	33,771	-	33,771	1,575	**32,196**
February	(135)	-	(135)	1,547	**(1,682)**
March	-	-	-	1,652	**(1,652)**
April		-			
May		-			
June		-			
July		-			
August		-			
September		-			
October		-			
November		-			
December		-			
Subtotal	**33,636**	**-**	**33,636**	**4,774**	**28,862**
Total Thermal Generation Cost Variance					**953,970**

Supply Cost Variance Deferral Account
Off-Island Power Purchase
March 31, 2026

Maritime Link	**Actual Cost ($)** (A)	**Test Year Cost ($)** (B)	**Off-Island Power Purchase Variation ($)** (A - B)
January	5,526,816	325,148	5,201,668
February	(503)	2,548,040	(2,548,542)
March	98,470	5,799,459	(5,700,989)
April			
May			
June			
July			
August			
September			
October			
November			
December			
Subtotal	**5,624,783**	**8,672,647**	**(3,047,863)**

Supply Cost Variance Deferral Account
Off-Island Power Purchase
March 31, 2026

Labrador-Island Link	**Actual Cost ($)**	**Test Year Cost ($)**	**Off-Island Power Purchase Variation ($)**
	(A)	**(B)**	**(A - B)**
January	19,322	151,886	(132,564)
February	-	62,099	(62,099)
March	20,030	120,370	(100,341)
April			
May			
June			
July			
August			
September			
October			
November			
December			
Subtotal	**39,351**	**334,356**	**(295,004)**
Total Off-Island Power Purchase Variance			**(3,342,867)**

Supply Cost Deferral Account
On-Island Purchases Variation
March 31, 2026

Nalcor Exploits	Actual Production (kWh) (A)	Cost of Service Production (kWh) (B)	Monthly Production Variance (kWh) (C) = (A - B)	Cost of Service Cost (¢/kWh) (D)	Power Purchase Variation ($) (E) = (C x D)
January	45,292,370	54,196,680	(8,904,310)	0.0400	(356,172)
February	46,990,729	48,703,200	(1,712,471)	0.0400	(68,499)
March	51,507,814	53,794,920	(2,287,106)	0.0400	(91,484)
April					
May					
June					
July					
August					
September					
October					
November					
December					
Subtotal	**143,790,913**	**156,694,800**	**(12,903,887)**		**(516,155)**

Supply Cost Deferral Account
On-Island Purchases Variation
March 31, 2026

Star Lake	Actual Production (kWh)	Cost of Service Production (kWh)	Monthly Production Variance (kWh)	Cost of Service Cost (¢/kWh)	Power Purchase Variation ($)
	(A)	(B)	(C) = (A - B)	(D)	(E) = (C x D)
January	12,291,437	12,391,320	(99,883)	0.0400	(3,995)
February	10,478,789	11,245,920	(767,131)	0.0400	(30,685)
March	12,510,880	12,395,040	115,840	0.0400	4,634
April					
May					
June					
July					
August					
September					
October					
November					
December					
Subtotal	**35,281,106**	**36,032,280**	**(751,174)**		**(30,046)**

Supply Cost Deferral Account
On-Island Purchases Variation
March 31, 2026

Rattle Brook	Actual Production (kWh) (A)	Cost of Service Production (kWh) (B)	Monthly Production Variance (kWh) (C) = (A - B)	Cost of Service Cost (¢/kWh) (D)	Power Purchase Variation ($) (E) = (C x D)
January	1,178,434	680,000	498,434	0.0851	42,423
February	330,775	470,000	(139,225)	0.0851	(11,850)
March	1,228,163	630,000	598,163	0.0851	50,911
April					
May					
June					
July					
August					
September					
October					
November					
December					
Subtotal	**2,737,372**	**1,780,000**	**957,372**		**81,484**

Supply Cost Deferral Account
On-Island Purchases Variation
March 31, 2026

CBPP[1] Co-Generation	Actual Production (kWh)	Cost of Service Production (kWh)	Monthly Production Variance (kWh)	Cost of Service Cost (¢/kWh)	Power Purchase Variation ($)
	(A)	(B)	(C) = (A - B)	(D)	(E) = (C x D)
January	6,320,000	6,320,000	-	0.1884	-
February	4,980,000	4,980,000	-	0.1884	-
March	5,840,000	5,840,000	-	0.1884	-
April					
May					
June					
July					
August					
September					
October					
November					
December					
Subtotal	**17,140,000**	**17,140,000**	**-**		**-**

[1] Corner Brook Pulp and Paper Limited ("CBPP").

Supply Cost Deferral Account
On-Island Purchases Variation
March 31, 2026

St. Lawrence Wind	**Actual Production (kWh)**	**Cost of Service Production (kWh)**	**Monthly Production Variance (kWh)**	**Cost of Service Cost (¢/kWh)**	**Power Purchase Variation ($)**
	(A)	**(B)**	**(C) = (A - B)**	**(D)**	**(E) = (C x D)**
January	10,524,237	11,200,000	(675,763)	0.0722	(48,790)
February	10,040,200	11,200,000	(1,159,800)	0.0722	(83,738)
March	11,758,103	10,570,000	1,188,103	0.0722	85,781
April					
May					
June					
July					
August					
September					
October					
November					
December					
Subtotal	**32,322,540**	**32,970,000**	**(647,460)**		**(46,747)**

Supply Cost Deferral Account
On-Island Purchases Variation
March 31, 2026

Fermeuse Wind	Actual Production (kWh)	Cost of Service Production (kWh)	Monthly Production Variance (kWh)	Cost of Service Cost (¢/kWh)	Power Purchase Variation ($)
	(A)	(B)	(C) = (A - B)	(D)	(E) = (C x D)
January	9,922,226	9,020,000	902,226	0.0772	69,625
February	7,933,127	9,020,000	(1,086,873)	0.0772	(83,874)
March	9,580,238	8,510,000	1,070,238	0.0772	82,590
April					
May					
June					
July					
August					
September					
October					
November					
December					
Subtotal	**27,435,591**	**26,550,000**	**885,591**		**68,341**
Total On-Island Purchases Variance					**(443,123)**

TAB 2

Contribution in Aid of Construction

Quarter Ended March 31, 2026

Table 1 summarizes the CIAC[1] activity for the current quarter. It also provides an overview of the following:

- The type of service for which a CIAC has been calculated, either domestic or general service;
- The number of CIACs quoted during the quarter, as well as the number of CIAC quotes that remain outstanding as of the end of the quarter. This format facilitates a reconciliation of the total number of CIACs that were active during the quarter; and
- Information as to the disposition of the total CIACs quoted. A CIAC is considered accepted when a customer indicates that it wishes to proceed with the construction of the extension and has agreed to pay any charge that may be applicable. A CIAC is considered to expire after six months have elapsed and the customer has not indicated its intention to proceed with the extension. A quoted CIAC is outstanding if it is neither accepted nor expired.

Table 1: CIAC Report for the Current Quarter

Type of Service	CIACs Quoted	CIACs Outstanding from Last Quarter	Total CIACs Quoted	CIACs Accepted	CIACs Expired	CIACs Outstanding
Domestic						
Within Plan Boundary	1	4	5	2	3	0
Outside Plan Boundary	2	2	4	1	0	3
Subtotal	**3**	**6**	**9**	**3**	**3**	**3**
General Service	1	2	3	2	1	0
Total	**4**	**8**	**12**	**5**	**4**	**3**

[1] Includes residential, non-residential, and general service CIAC activities for Northern, Central, and Labrador regions.

The number of CIACs quoted during the current quarter by region is summarized in Table 2, which also identifies the following:

- The service location for the CIAC;
- The CIAC number related to the quote;
- The amount of the CIAC required to be paid by the customer;
- The estimated construction costs to provide the requested service; and
- Whether the CIAC has been accepted by the customer.

Table 2: CIAC Activity Report for the Current Quarter

Date Quoted	Service Location	CIAC Number	CIAC Amount ($)	Estimated Construction Costs ($)	Accepted
Domestic: Within Residential Planning Boundaries					
23-Mar-2026	South Brook; Green Bay	2117029	6,026	11,211	Yes
Domestic: Outside Residential Planning Boundaries					
16-Jan-2026	St. Anthony	2101734	4,045	1,160	Yes
09-Feb-2026	Roberts Arm	2096630	9,092	10,542	
General Service					
08-Jan-2026	Happy Valley-Goose Bay	2101815	2,610	7,540	Yes

TAB 3

Customer Damage Claims

Quarter Ended March 31, 2026

The Customer Damage Claims report contains a summary of all damage claims activity on a quarterly basis. The information contained in the report is broken down by cause as well as by the operating region where the claims originated.

The report provides an overview of the following:

- The number of claims received during the quarter, coupled with claims outstanding from the last quarter;
- The number of claims for which Newfoundland and Labrador Hydro ("Hydro") has accepted responsibility and the amount paid to claimants versus the amount originally claimed;
- The number of claims rejected and the dollar value associated with those claims; and
- Those claims that remain outstanding at the end of the quarter and the dollar value associated with such claims.

Definitions of Causes of Damage Claims:

- **System Operations:** Claims arising from system operations (e.g., normal reclosing or switching).
- **Power Interruptions:** Claims arising from the interruption of power supply (e.g., all scheduled or unscheduled interruptions).
- **Improper Workmanship:** Claims arising from the failure of electrical equipment caused by improper workmanship or methods (e.g., improper crimping of connections, insufficient sealing and taping of connections, improper maintenance, and inadequate clearance or improper operation of equipment).
- **Weather Related:** Claims arising from weather conditions (e.g., wind, rain, ice, lightning or corrosion caused by weather).
- **Equipment Failure:** Claims arising from failure of electrical equipment not caused by improper workmanship (e.g., broken neutrals, broken tie wires, transformer failure, insulator failure or broken service wire).
- **Third Party:** Claims arising from equipment failure caused by acts of third parties (e.g., motor vehicle accidents and vandalism).
- **Miscellaneous:** All claims that are not related to electrical service.
- **Waiting Investigation:** Cause to be determined.

Table 1: Customer Property Damage Claims Report by Region for the Current Quarter

				Claims Accepted			Claims Rejected		Claims Outstanding	
Region	**# Received**	**# Outstanding Since Last Quarter**	**Total**	**#**	**Amount Claimed ($)**	**Amount Paid ($)**	**#**	**Amount ($)**	**#**	**Amount ($)**
Central	15	10	**25**	0	0	0	14	18,772	11	15,219
Northern	8	9	**17**	0	0	0	7	11,297	10	19,992
Labrador	9	2	**11**	1	833	302	8	21,611	2	4,207
Total	**32**	**21**	**53**	**1**	**833**	**302**	**29**	**51,680**	**23**	**39,418**

Table 2: Customer Property Damage Claims Report by Region for the Same Quarter, Previous Year

				Claims Accepted			Claims Rejected		Claims Outstanding	
Region	**# Received**	**# Outstanding Since Last Quarter**	**Total**	**#**	**Amount Claimed ($)**	**Amount Paid ($)**	**#**	**Amount ($)**	**#**	**Amount ($)**
Central	7	7	**14**	2	1,788	702	2	227	10	14,873
Northern	12	6	**18**	1	551,049	10,537	5	1,518	12	36,551
Labrador	2	2	**4**	1	18,126	11,782	2	3,269	1	1,569
Total	**21**	**15**	**36**	**4**	**570,963**	**23,021**	**9**	**5,014**	**23**	**52,993**

Table 3: Customer Property Damage Claims Report by Cause for the Current Quarter[1]

Cause	# Received	# Outstanding Since Last Quarter	Total	Claims Accepted #	Claims Accepted Amount Claimed ($)	Claims Accepted Amount Paid ($)	Claims Rejected #	Claims Rejected Amount ($)	Claims Outstanding #	Claims Outstanding Amount ($)
System Operations	0	1	**1**	0	0	0	1	2,344	0	0
Power Interruptions	7	3	**10**	0	0	0	9	6,971	2	3,258
Improper Workmanship	2	3	**5**	0	0	0	0	0	5	14,854
Weather Related	12	2	**14**	0	0	0	13	30,373	2	5,130
Equipment Failure	9	7	**16**	1	833	302	4	8,041	11	11,170
Third Party	0	0	**0**	0	0	0	0	0	0	0
Miscellaneous	0	1	**1**	0	0	0	2	3,951	0	0
Awaiting Investigation	2	4	**6**	0	0	0	0	0	3	5,005
Total	**32**	**21**	**53**	**1**	**833**	**302**	**29**	**51,680**	**23**	**39,418**

Table 4: Customer Property Damage Claims Report by Cause for the Same Quarter, Previous Year[2]

Cause	# Received	# Outstanding Since Last Quarter	Total	Claims Accepted #	Claims Accepted Amount Claimed ($)	Claims Accepted Amount Paid ($)	Claims Rejected #	Claims Rejected Amount ($)	Claims Outstanding #	Claims Outstanding Amount ($)
System Operations	3	0	**3**	0	0	0	3	1,518	0	0
Power Interruptions	3	0	**3**	0	0	0	3	0	1	1,569
Improper Workmanship	1	3	**4**	1	551,049	10,537	0	0	3	16,844
Weather Related	5	5	**10**	1	1,688	602	2	696	7	8,095
Equipment Failure	8	1	**9**	1	18,126	11,782	0	0	8	23,004
Third Party	1	1	**2**	0	0	0	1	2,800	1	1,180
Miscellaneous	0	1	**1**	1	100	100	0	0	0	0
Awaiting Investigation	0	4	**4**	0	0	0	0	0	3	2,300
Total	**21**	**15**	**36**	**4**	**570,963**	**23,021**	**9**	**5,014**	**23**	**52,993**

[1] Claims classified as "Awaiting Investigation" are recategorized once investigations are complete. Accordingly, the total of accepted, rejected and outstanding claims for each cause in the current quarter may be greater than the number of claims received and carried into the quarter for that cause.
[2] Numbers may not add due to rounding.

TAB 4

Attachment 1

Short-Term Load Forecasting Accuracy
Island Interconnected System

January to March 2025

Short-Term Load Forecasting Accuracy Island Interconnected System

January to March 2025

May 29, 2026

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

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Appendix A: Supporting Tables

Appendix B: Supporting Charts

1.0 Load Forecasting

1.1 Load Forecasting Software

In 2023, Newfoundland and Labrador Hydro ("Hydro") adopted a new load forecasting software for its short-term load forecasting with a period of 14 days. This replaced the previous forecasting software, Nostradamus, on which reporting was based until 2023. This software uses a combination of regression and neural network models that are trained using a sequence of continuous historical periods of hourly weather and half-hourly demand data. The models then forecast system demand for a 14-day horizon using predictions of weather parameters.

Since December 2014, in accordance with direction from the Board of Commissioners of Public Utilities ("Board"), Hydro has submitted periodic reports on the accuracy of load forecasting.[1,2] As agreed upon by the Board, Hydro has condensed its annual report to focus on the winter period, in which the accuracy of the short-term load forecast is most consequential from a system planning perspective.[3] As such, this report will cover the winter months of 2025, which include January through March 2025.

1.2 Short-Term Load Forecasting

Hydro uses its short-term load forecast to manage the power system and ensure adequate generating resources are available to meet customer demand.

1.2.1 Utility Load[4]

Hydro has a contract with WSP Global Inc. ("WSP")[5] to provide the weather parameters in the form of half-hourly weather forecasts delivered twice a day for the following 14 days. At the same time this weather forecast data is provided, WSP also provides recent observed data at the locations used in the forecasts.[6] The actual and forecast data are automatically retrieved from WSP and input to the load forecast database.

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[1] Load forecasting accuracy reports were originally filed in relation to the *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System* proceeding.
[2] As per "Newfoundland and Labrador Hydro – Accuracy of Nostradamus Load Forecasting Reports – Filing Schedule," Board of Commissioners of Public Utilities, January 18, 2018, the Board indicated that the reporting frequency should change to annually commencing November 15, 2018.
[3] Newfoundland and Labrador Hydro – Short-Term Load Forecast Accuracy Report – Proposed Changes to Reporting, Board of Commissioners of Public Utilities, November 17, 2025.
[4] Utility load is the summation of Newfoundland Power Inc. ("Newfoundland Power") and Hydro Island Rural requirements.
[5] WSP acquired Wood PLC in 2022.
[6] The locations used for the weather forecast data are St. John's, Gander, and Deer Lake.

The load forecasting software uses a variety of weather parameters for forecasting, provided a sufficient historical record is available for training. Hydro currently uses air temperature, wind speed, and cloud cover. The load forecasting software can use each variable more than once; for example, both the current and forecast air temperatures are used in forecasting load. Wind chill is calculated in the load forecasting software using a set formula that requires wind speed and dry bulb input.

The load forecasting software uses weather data for St. John's, Gander, and Deer Lake, as well as a parameter that indicates daily daylight hours. Training and verification[7] periods are selected to provide sufficient time to ensure a range of weather parameters are included (e.g., high and low temperatures), but are still short enough that the historic load is representative of loads that can be expected in the near future. The load forecasting software is trained monthly[8] to further improve forecasting accuracy. The goal is to improve the forecasting accuracy by providing the software with updated data and trends of recent loads and weather patterns. This helps ensure variables such as load growth and extreme weather are properly accounted for when predicting future load requirements.

Demand data for the Island Interconnected System utility load is automatically imported to the load forecasting software every half hour. Newfoundland Power's and Hydro's total utility load (conforming)[9] is input in the model. Industrial load (non-conforming),[10] which is not a function of weather, is added to the forecasts within the software to derive the total load forecast.

The load forecasting software model creates separate sub-models for weekdays, weekends, and holidays during the training process to account for the variation in customer use of electricity. The load forecasting software has separate holiday groups for statutory holidays and for days that are known to have unusual loads, such as the days between Christmas Day and New Year's Day, as well as the closure of schools during the Easter break.

[7] The load forecasting software will automatically perform verification over a designated historical period upon completion of training. The verification period is used to evaluate the accuracy of the forecast using data on which the model has not been trained. This ensures that the model is not memorizing the correct answer.
[8] In the report "Short-Term Forecasting Accuracy – Island Interconnected System – 2023," Newfoundland and Labrador Hydro, January 31, 2024, Hydro reported it would conduct this training quarterly. With the increase of household electrification and efficiency measures, including the installation of mini-split systems, conversion from oil heating to electric, and higher prevalence of electric vehicles, Hydro has adjusted this process to occur monthly for a more accurate projected load measurement.
http://www.pub.nf.ca/indexreports/nostradamus/From%20NLH%20-%20Short-Term%20Load%20Forecasting%20Accuracy%20-%202023%20Annual%20Report%20-%202024-01-31.PDF
[9] Conforming load refers to load that changes consistently with the load pattern of an area.
[10] Non-conforming load refers to load that changes abnormally with respect to the load pattern of an area.

1.2.2 Industrial Load

Industrial loads tend to be almost constant, as industrial processes are independent of weather. Under the current procedure, the Power on Order[11] for each Industrial customer plus the expected owned generation from Corner Brook Pulp and Paper Limited are used as the industrial load forecasts. Industrial customer loads can be modified based on knowledge of customer loads; for instance, a temporary decrease in requirements at Vale Newfoundland and Labrador Limited is associated with planned maintenance. The expected load can be modified in any given hour of the 14-day forecast, or the default value can be modified to be used indefinitely.[12]

1.2.3 Supply and Demand Status Reporting

The forecast peak as of 7:20 a.m. is reported daily to the Board in Hydro's Supply and Demand Status reports.[13] The weather forecast for the following 14 days and the observed weather data for the previous day are input into the model at approximately 5:00 a.m. and 2:00 p.m.; the load forecasting software is then run every half hour of the day. Following completion of the software run, the generated forecast is made available for reference to assist in monitoring and managing both available and spinning reserves. The within-day forecast updates are primarily used to manage operating reserves, particularly in advance of the forecast system peaks.

1.3 Potential Sources of Variance

As with any forecasting analysis, there will be discrepancies between forecast and actual values. Typical sources of variance in the load forecasting are as follows:

- Differences in the export values in the forecast compared to actual exports throughout the day, which can be scheduled one hour in advance. These sources of variance are noted in the Supply and Demand Status reports to the Board.

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[11] Power on Order refers to the firm power Hydro agrees to deliver to a customer and the customer agrees to purchase from Hydro, as set out in a service agreement.
[12] In Hydro's Energy Management System, there is functionality to modify the industrial load value when the Newfoundland and Labrador System Operator is aware of circumstances where an Industrial customer will be reducing load; for example, if an Industrial customer is completing maintenance, the forecast load can be modified to provide a more accurate load forecast.
[13] Hydro's daily Supply and Demand Status reports can be accessed at http://www.pub.nf.ca/applications/IslandInterconnectedSystem/DemandStatusReports.php.

- Differences in the industrial load forecast due to unexpected changes in Industrial customer loads. For example, if an Industrial customer were to undertake maintenance that Hydro was unaware of, or increase production to meet customer demand, the actual load would deviate from the scheduled load.
- Inaccuracies in the weather forecast—particularly temperature, wind speed, or cloud cover.
- Non-uniform customer behaviour, resulting in unpredictability.

Delivery of the Nova Scotia Block and Supplemental Block continued in 2025.[14,15] These scheduled deliveries are included in the forecast peak, as reported by 7:20 a.m. daily. Decisions regarding additional exports over the Maritime Link during peak periods are carefully coordinated and include conservative consideration of Hydro's native load forecast and available supply. The forecast peak does not always account for exports, as exports can be contracted at any time throughout the day. As noted previously, this can result in an error when comparing a peak forecast prepared in the early morning against an actual peak that includes real-time exports. As of January 2024, Hydro began reporting the exports at peak on the daily Supply and Demand Status reports.

2.0 Forecast Accuracy Summary

2.1 Analysis

This report will examine the accuracy of the Hydro forecasting process for the winter months of 2025, January 1 through March 31, 2025[16]. Hydro's report includes details on the system peak day, as well as the three highest utility error days during these winter months.

[14] The first delivery of the Nova Scotia Block occurred in August 2021, and the first delivery of the Supplemental Block occurred in November 2021.
[15] Pursuant to the Energy and Capacity Agreement between Nalcor Energy and Emera Inc., the Nova Scotia Block is a firm annual commitment of 980 GWh, supplied from the Muskrat Falls Hydroelectric Generating Facility on peak. https://www.emeranl.com/docs/librariesprovider13/maritime-link-documents/commercial-agreements/amended-and-restated-energy-and-capacity-agreement.pdf?sfvrsn=dec21945_2.
[16] Winter months typically include December through March; however, December 2024 was previously included in the report "Short-Term Load Forecasting Accuracy – Island Interconnected System – 2024," Newfoundland and Labrador Hydro, January 31, 2025. Future reports will include the forecasting process for December through March. http://www.pub.nf.ca/indexreports/nostradamus/From%20NLH%20-%20Short-Term%20Load%20Forecasting%20Accuracy%20-%202024%20Annual%20Report%20-%202025-01-31.PDF

In Appendix A, Table A-1 to Table A-3 present the daily Island Interconnected System forecast total peak, actual total peak, available Island supply forecast reserve, as well as the error and percent error. The data is also presented in Appendix B, Chart B-1.

In Appendix B, Chart B-2 plots the total forecast and actual total peaks, as shown in Chart B-1, with the addition of a bar chart showing the difference between the two data series in megawatts. In both the tables and charts, a positive error is an overestimate and a negative error is an underestimate. Appendix B, Chart B-2 reveals that the forecasting process consistently overestimates the peak of the total load. This is typically the result of an overestimate in the industrial load forecast and/or export activity over the Maritime Link that was contracted after the forecast was published.

The total Island Interconnected System peak load, including exports during the period, varied between 965 MW (March 22, 2025) and 1,720 MW (January 23, 2025). The available Island supply varied from 1,623 MW to 2,284 MW. Island Interconnected System reserves were sufficient throughout the period.

In Appendix A, Table A-4 to Table A-6 present error statistics for the utility peak forecast (i.e., the portion of the forecast determined by the model). Neither the industrial forecast nor the Maritime Link export activity is included in the values presented in these tables. Appendix B, Chart B-3 plots the data and error for the utility peak. Examination of the utility forecast provides more insight into the accuracy of the load forecasting software, as changes or errors in the industrial forecast and the presence of export activity may increase the perceived error as compared to the total forecast as of 7:20 a.m., making the total forecast appear worse or, at times, better than it is.

2.2 Data Adjustments and Forecast Issues

In analysing the data, some instances require adjustments for a variety of reasons. In these instances, the data for the affected hours is either replaced using interpolation or is adjusted by a set value so that, in the future, when the data for this period is used in training, the load forecasting software will use a value not affected by the event.

On January 23, 2025, there was a short-term voltage reduction for Newfoundland Power and the actual Island utility load values in the load forecast software were adjusted upward by 20 MW for the reduction period.

2.3 Days of High Error[17]

The bolded dates in Appendix A, Table A-1 to Table A-6 indicate the days of high error[18] in the load forecast. Based on discussions with Board staff on December 19, 2022, Hydro will continue to select days of highest error based on the utility load (Appendix A, Table A-4 to Table A-6 data) in 2025. The days with the highest error (three per winter season), as well as Hydro's peak day, are selected for a more detailed analysis. The following are the days with the highest error and Hydro's peak day. Additional information on each is provided in Sections 2.3.1 to 2.3.3.

- January 23, 2025, Hydro's peak day in 2025;
- February 22, 2025; and
- March 7 and 23, 2025.

Each high error day includes a table with a peak data summary. The data reported to the Board ("Board Forecast" and "Board Actual") includes utility load, industrial load, and exports. The Island forecast data includes utility load as well as Industrial customer load.

2.3.1 January 2025

In January 2025, the forecast utility peak was 1,571 MW on January 23, 2025, which is consistent with the actual utility peak of 1,576 MW on that day. Absolute error was 31 MW on average, with an average percent error[19] of 0.0%, an average absolute error[20] of 2.6%, and an average actual/forecast of -0.1%.

January 2025 did not have any of the three highest error winter peak days; however, it had the peak day for 2025.

2.3.1.1 January 23, 2025 (Hydro's Peak Day)

Table 1 provides a summary of forecast peak data for January 23, 2025.

[17] All plots showing the hourly distribution of the load forecast in comparison to the actual total load do not include Maritime Link export activity to aid in determining other sources of differences between actual and forecast loads.
[18] Hydro considers an error below 4.95% to be within acceptable forecasting limits.
[19] Average of all daily errors.
[20] Average of all absolute value daily errors.

Table 1: Peak Data Summary for January 23, 2025

	Load (MW)	Time	Error (%)[21]	Temperature Delta (°C)[22]	Wind Speed Delta (km/h)[23]
Utility Forecast	1,571	8:00 a.m.	-0.3	2.00	20.00
Utility Actual	1,576	8:00 a.m.		2.00	20.00
Island Forecast	1,717	8:00 a.m.	0.1	2.00	20.00
Island Actual	1,716	8:00 a.m.		2.00	20.00
Board Forecast	1,720	N/A	N/A	N/A	N/A
Board Actual	1,720				

The forecast peak at 7:20 a.m., as reported to the Board, was 1,720 MW; the actual reported peak was 1,720 MW. Chart 1 to Chart 5 include hourly plots of forecast and actual values to illustrate Hydro's peak day.

Chart 1 shows the hourly distribution of the total load forecast compared to the actual load, exclusive of export activity. The hourly forecast predicted an 8:00 a.m. peak of 1,717 MW; the actual peak was 1,716 MW[24] and occurred at 8:00 a.m., resulting in an overestimate of 0.1%.

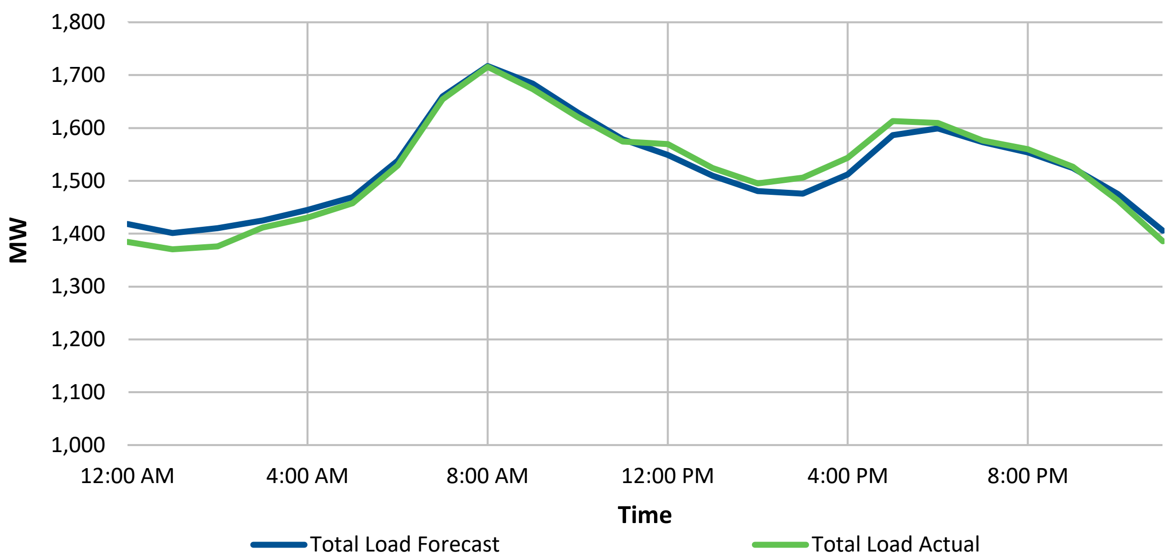

Chart 1: Forecast vs Actual Total Load for January 23, 2025

[21] Negative percentages indicate an under-forecasted peak. Positive percentages indicate an over-forecasted peak.
[22] Temperature difference at forecast peak and actual peak. Negative values indicate that the temperature was warmer than forecast. Positive values indicate the temperature was colder than forecast.
[23] Wind speed difference at the forecast peak and the actual peak. Negative values indicate wind speed was more than forecast. Positive values indicate the wind speed was less than forecast.
[24] The actual total peak reported in the daily Supply and Demand Status reports is based on a five-minute time step; however, the load forecasting software reports on an hourly time step, sometimes resulting in a different peak value.

Chart 2 shows the hourly distribution of the utility load forecast only. The hourly forecast predicted a utility peak at 8:00 a.m. of 1,571 MW; the actual peak was 1,576 MW, resulting in an underestimate of 0.3%.

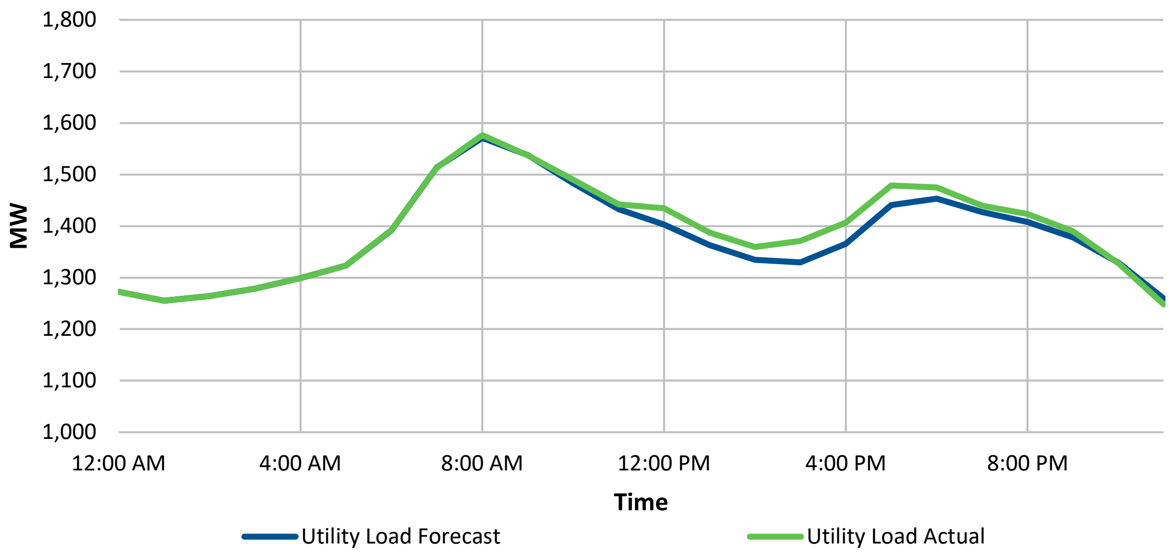

Chart 2: Forecast vs Actual Utility Load for January 23, 2025

Chart 3 shows the actual temperature in St. John's compared to the forecast. The temperature was approximately 2°C colder than forecast at the time of peak.

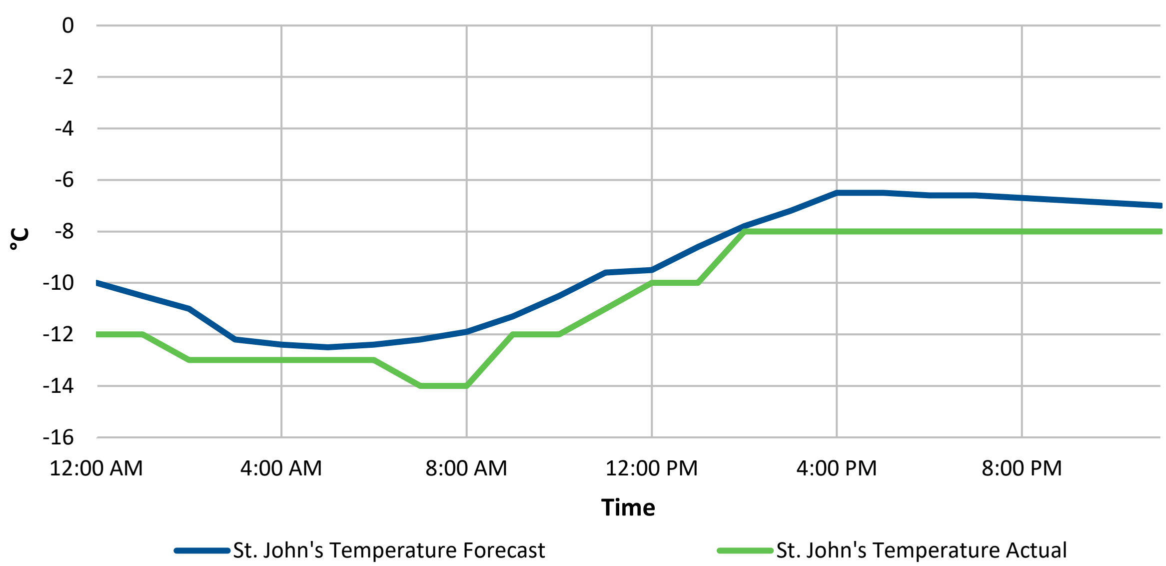

Chart 3: Forecast vs Actual Temperature for January 23, 2025

1 Chart 4 shows the actual wind speed in St. John's compared to the forecast. The actual wind speed was
2 mostly lower than forecast throughout the day.

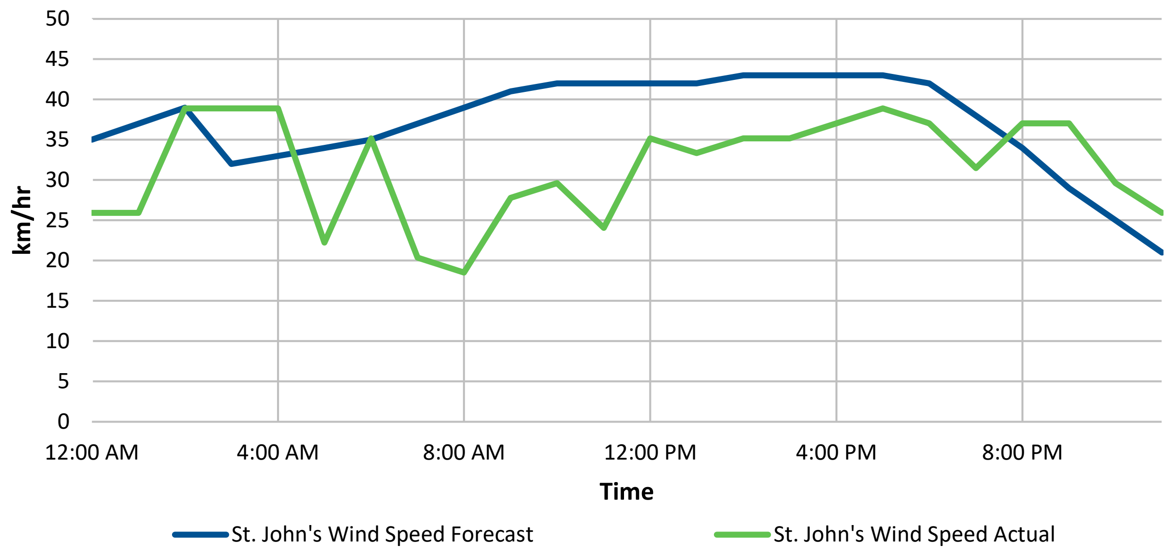

Chart 4: Forecast vs Actual Wind Speed for January 23, 2025

3 Chart 5 shows the actual cloud cover in St. John's compared to the forecast. It was cloudier than
4 forecast for the afternoon portion of the day.

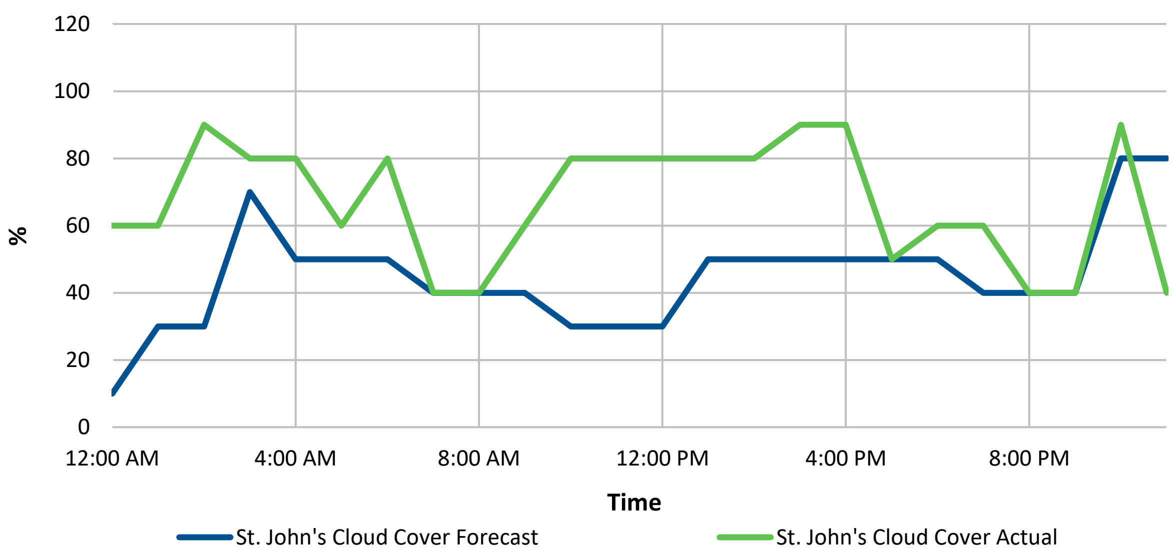

Chart 5: Forecast vs Actual Cloud Cover for January 23, 2025

5 The load forecast for Hydro's peak day was under 1% and well within acceptable forecast limits.

2.3.2 February 2025

In February 2025, the forecast utility peak was 1,558 MW on February 6, 2025, which is consistent with the actual utility peak of 1,561 MW on that day. Absolute error was 24 MW on average, with an average percent error[25] of -0.6%, an average absolute error[26] of 1.8%, and an average actual/forecast of -0.7%.

2.3.2.1 February 22, 2025

Table 1 provides a summary of forecast peak data for February 22, 2025.

Table 2: Peak Data Summary for February 22, 2025

	Load (MW)	Time	Error (%)[27]	Temperature Delta (°C)[28]	Wind Speed Delta (km/h)[29]
Utility Forecast	1,318	6:00 p.m.	6.5	0.00	10.00
Utility Actual	1,238	10:00 a.m.		0.00	9.00
Island Forecast	1,464	6:00 p.m.	6.3	0.00	10.00
Island Actual	1,378	10:00 a.m.		0.00	9.00
Board Forecast	1,465	N/A	N/A	N/A	N/A
Board Actual	1,384				

The forecast peak at 7:20 a.m., as reported to the Board, was 1,465 MW; the actual reported peak was 1,384 MW. Chart 6 to Chart 10 include hourly plots of forecast and actual values to assist in determining the sources of the differences between actual and forecast loads.

Chart 6 shows the hourly distribution of the total load forecast compared to the actual load, exclusive of export activity. The hourly forecast predicted a 6:00 p.m. peak of 1,464 MW; the actual peak was 1,378 MW[30] and occurred at 10:00 a.m., resulting in an overestimate of 6.3%. Forecast load at the time of peak was 1,402 MW.

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[25] Average of all daily errors.
[26] Average of all absolute value daily errors.
[27] Negative percentages indicate an under-forecasted peak. Positive percentages indicate an over-forecasted peak.
[28] Temperature difference at forecast peak and actual peak. Negative values indicate that the temperature was warmer than forecast. Positive values indicate the temperature was colder than forecast.
[29] Wind speed difference at the forecast peak and the actual peak. Negative values indicate wind speed was more than forecast. Positive values indicate the wind speed was less than forecast.
[30] The actual total peak reported in the daily Supply and Demand Status reports is based on a five-minute time step; however, the load forecasting software reports on an hourly time step, sometimes resulting in a different peak value.

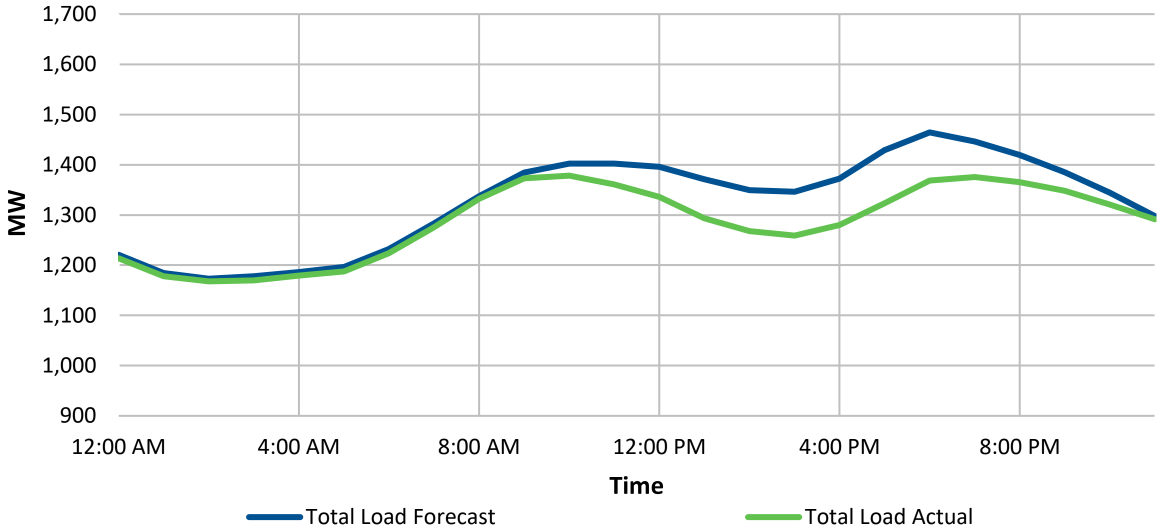

Chart 6: Forecast vs Actual Total Load for February 22, 2025

1 Chart 7 shows the hourly distribution of the utility load forecast only. The hourly forecast predicted a
2 utility peak at 6:00 p.m. of 1,318 MW; the actual peak was 1,238 MW and occurred at 10:00 a.m.,
3 resulting in an overestimate of 6.5%. The load forecast at the time of peak was 1,256 MW, resulting in
4 an overestimate of 1.4%, which was within forecast limits.

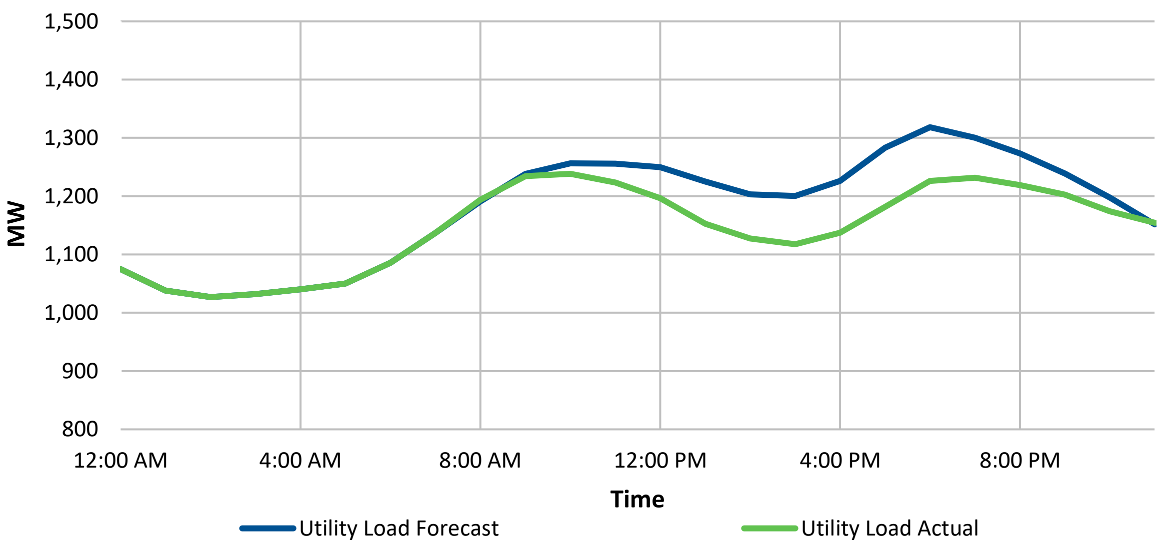

Chart 7: Forecast vs Actual Utility Load for February 22, 2025

1 Chart 8 shows the actual temperature in St. John's compared to the forecast. The temperature was
2 approximately 1°C colder leading up to the morning peak.

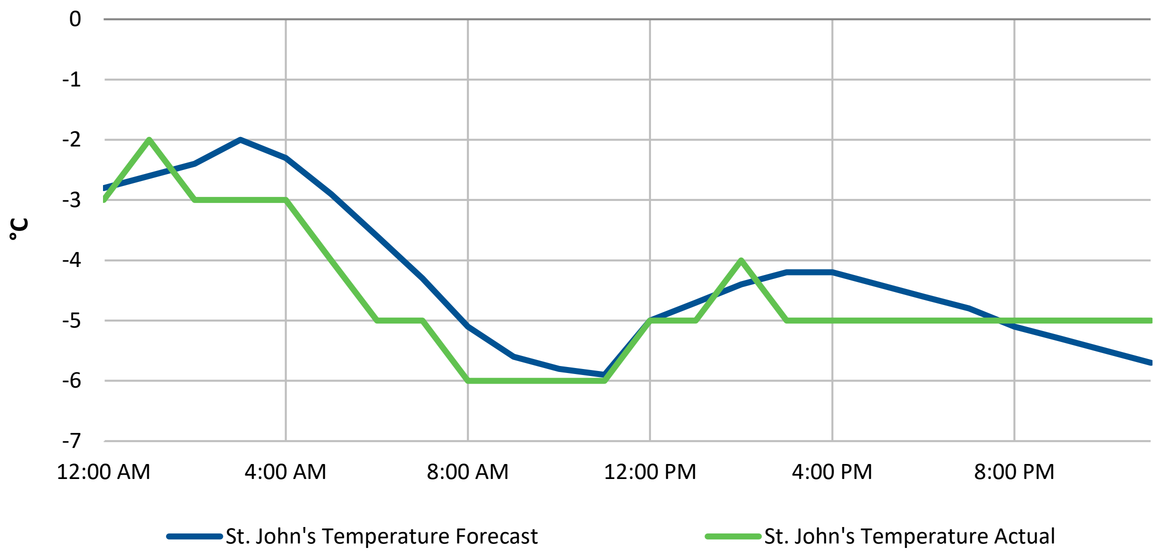

Chart 8: Forecast vs Actual Temperature for February 22, 2025

3 Chart 9 shows the actual wind speed in St. John's compared to the forecast. The actual wind speed was
4 lower than forecast throughout the day.

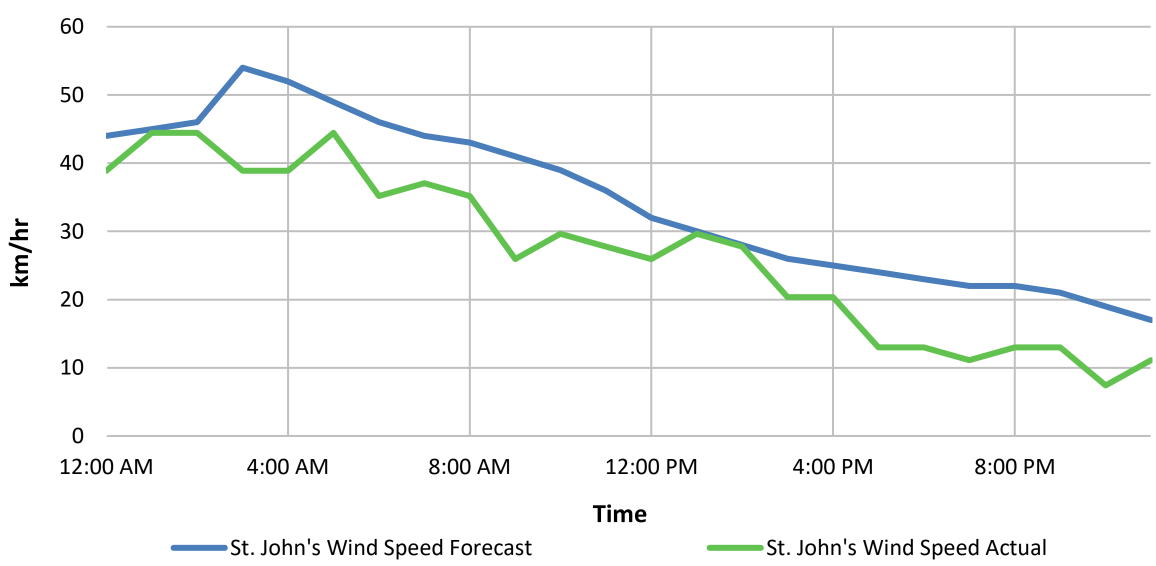

Chart 9: Forecast vs Actual Wind Speed for February 22, 2025

1 Chart 10 shows the actual cloud cover in St. John's compared to the forecast. It was cloudier than
2 forecast for the entire day.

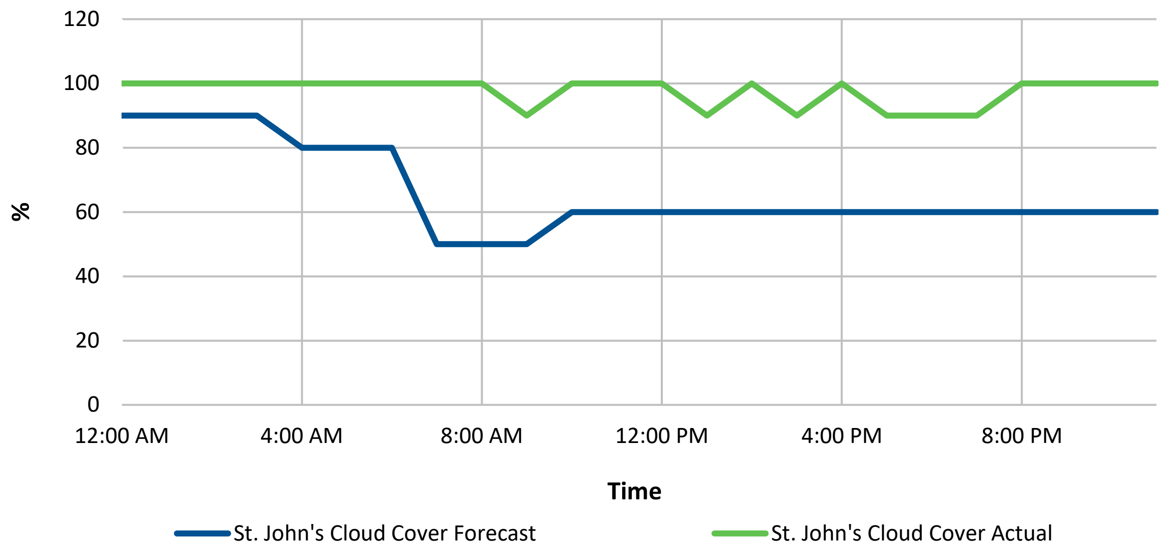

Chart 10: Forecast vs Actual Cloud Cover for February 22, 2025

3 The discrepancy between Utility Actual and Utility Forecast load was primarily attributed to the weather
4 forecast, which was colder than forecast leading up to peak. This shifted the peak to the morning,
5 instead of the forecasted evening peak. At the time of peak, the forecast was within acceptable forecast
6 limits.

7 2.3.3 March 2025

8 In March 2025, the forecast utility peak was 1,395 MW on March 4, 2025, which is consistent with the
9 actual utility peak for that day of 1,396 MW. Absolute error was 25 MW on average, with an average
10 percent error[31] of 0.1%, an average absolute error[32] of 2.3%, and an average actual/forecast of 0.0%.

[31] Average of all daily errors.
[32] Average of all absolute value daily errors.

1 **2.3.3.1 March 7, 2025**

2 Table 3 provides a summary of forecast peak data for March 7, 2025.

Table 3: Peak Data Summary for March 7, 2025

	Load (MW)	Time	Error (%)[33]	Temperature Delta (°C)[34]	Wind Speed Delta (km/h)[35]
Utility Forecast	1,055	6:00 p.m.	9.2	(1.00)	1.00
Utility Actual	966	8:00 a.m.		(1.00)	3.00
Island Forecast	1,206	6:00 p.m.	9.2	(1.00)	1.00
Island Actual	1,105	8:00 a.m.		(1.00)	3.00
Board Forecast	1,205	N/A	N/A	N/A	N/A
Board Actual	1,113				

3 The forecast peak at 7:20 a.m., as reported to the Board, was 1,205 MW; the actual reported peak was
4 1,113 MW. Chart 11 to Chart 15 include hourly plots of forecast and actual values to assist in
5 determining the sources of the differences between actual and forecast loads.

6 Chart 11 shows the hourly distribution of the total load forecast compared to the actual load, exclusive
7 of export activity. The hourly forecast predicted a 6:00 p.m. peak of 1,206 MW; the actual peak was
8 1,105 MW[36] and occurred at 8:00 a.m., resulting in an overestimate of 9.2%. The load forecast at the
9 time of peak was 1,131 MW.

[33] Negative percentages indicate an under-forecasted peak. Positive percentages indicate an over-forecasted peak.
[34] Temperature difference at forecast peak and actual peak. Negative values indicate that the temperature was warmer than forecast. Positive values indicate the temperature was colder than forecast.
[35] Wind speed difference at the forecast peak and the actual peak. Negative values indicate wind speed was more than forecast. Positive values indicate the wind speed was less than forecast.
[36] The actual total peak reported in the daily Supply and Demand Status reports is based on a five-minute time step; however, the load forecasting software reports on an hourly time step, sometimes resulting in a different peak value.

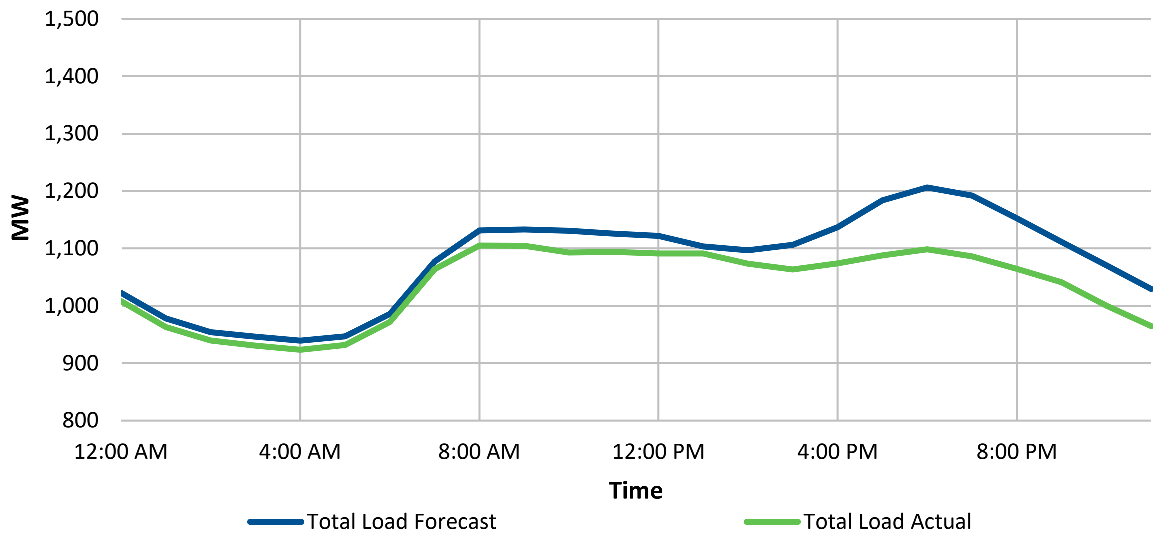

Chart 11: Forecast vs Actual Total Load for March 7, 2025

Chart 12 shows the hourly distribution of the utility load forecast only. The hourly forecast predicted a utility peak at 6:00 p.m. of 1,055 MW; the actual peak was 966 MW and occurred at 8:00 a.m., resulting in an overestimate of 9.2%. The load forecast at the time of peak was 980 MW, resulting in an overestimate of 1.4%, which was within forecast limits.

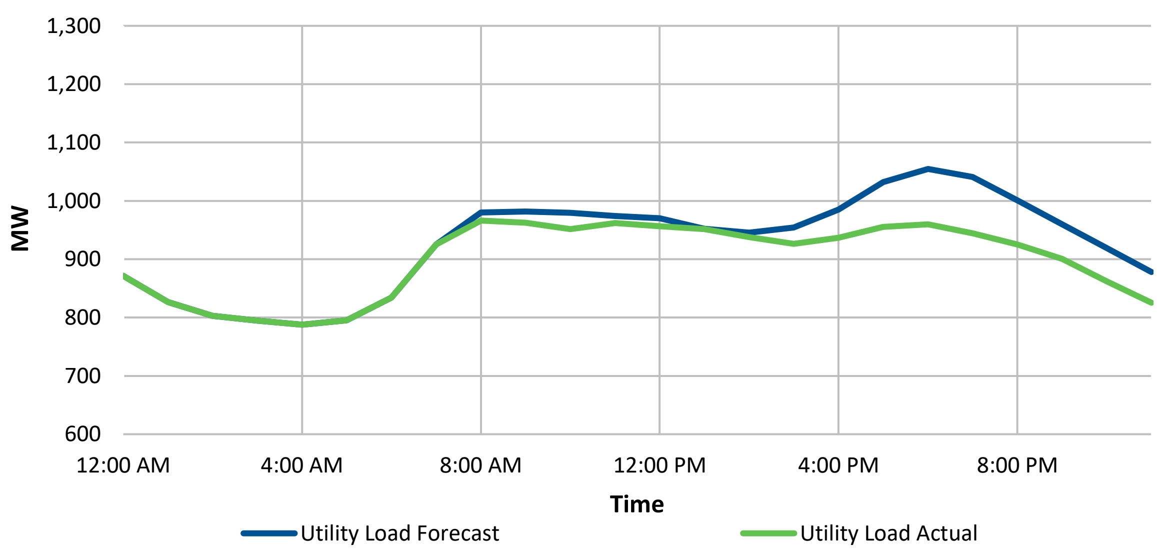

Chart 12: Forecast vs Actual Utility Load for March 7, 2025

1 Chart 13 shows the actual temperature in St. John's compared to the forecast. The actual temperature
2 was 1°C to 2°C above forecast for the entire day, which likely contributed to the over-forecasted peak.

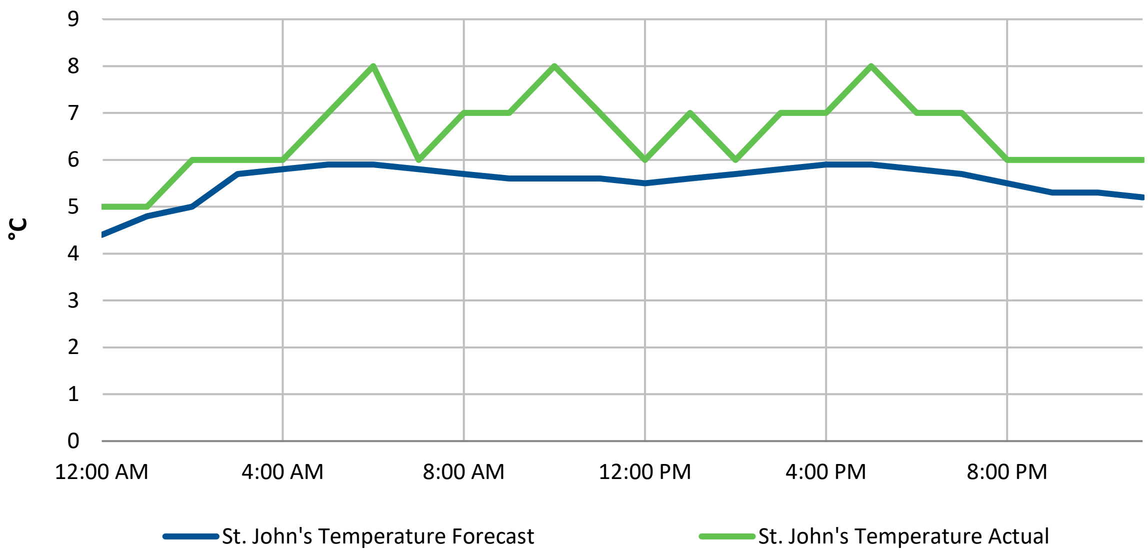

Chart 13: Forecast vs Actual Temperature for March 7, 2025

3 Chart 14 shows the actual wind speed in St. John's compared to the forecast. The actual wind speed was
4 close to forecast for most of the day.

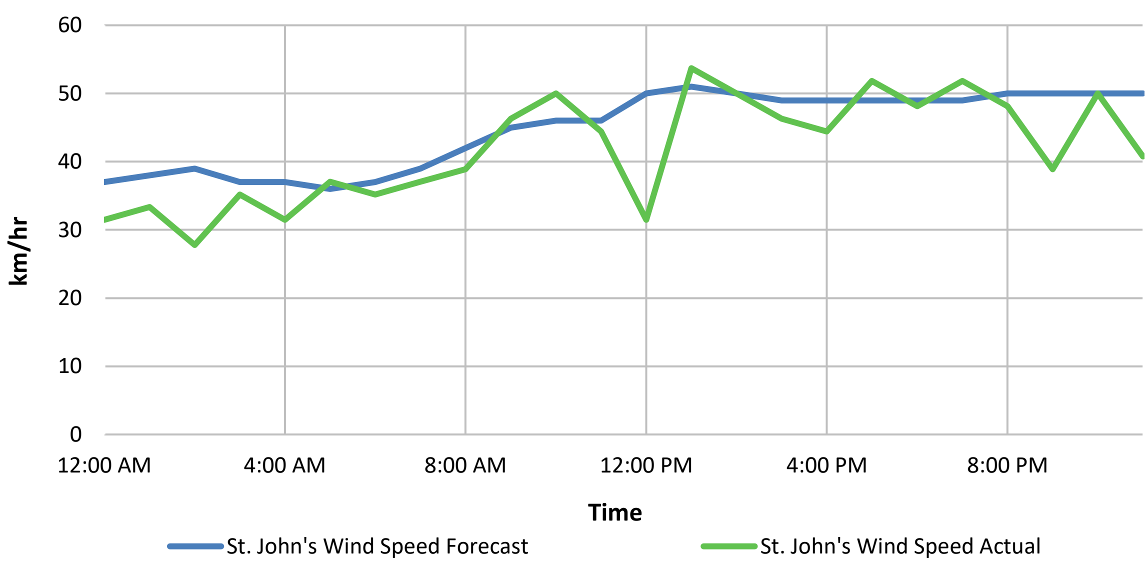

Chart 14: Forecast vs Actual Wind Speed for March 7, 2025

1 Chart 15 shows the actual cloud cover in St. John's compared to the forecast. It was slightly less cloudy
2 than forecast during the morning portion of the day.

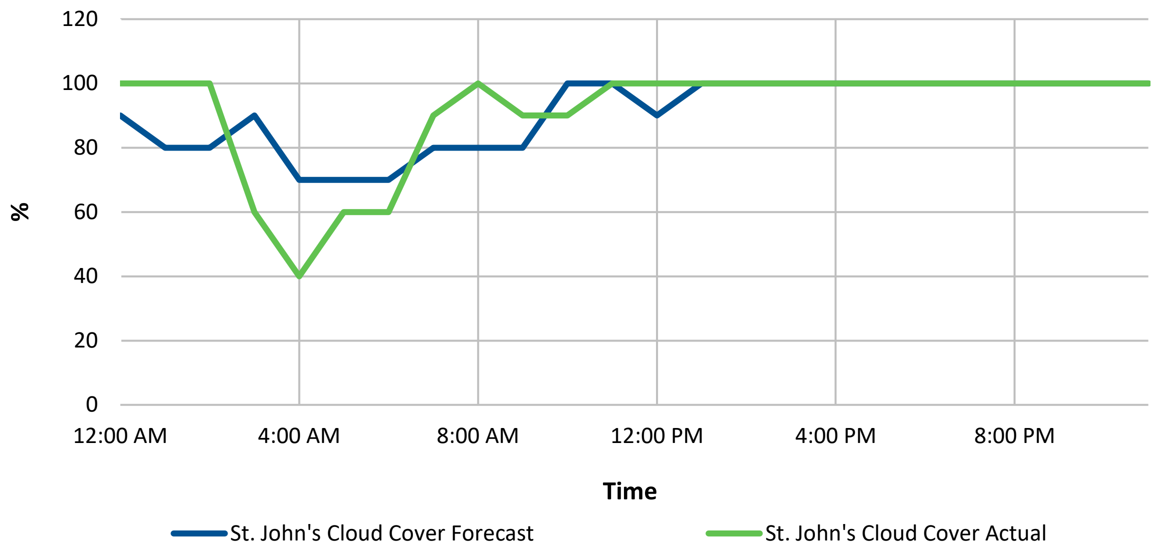

Chart 15: Forecast vs Actual Cloud Cover for March 7, 2025

3 The discrepancy between Utility Actual and Utility Forecast load was primarily attributed to the weather
4 forecast, which was warmer than forecast. Additionally, the peak shifted from a forecasted evening peak
5 to a morning peak. At the time of peak, the forecast was within acceptable forecast limits.

6 ### 2.3.3.2 March 23, 2025

7 Table 4 provides a summary of forecast peak data for March 23, 2025.

Table 4: Peak Data Summary for March 23, 2025

	Load (MW)	Time	Error (%)[37]	Temperature Delta (°C)[38]	Wind Speed Delta (km/h)[39]
Utility Forecast	972	10:00 a.m.	6.7	(1.00)	(9.00)
Utility Actual	911	10:00 a.m.		(1.00)	(9.00)
Total Forecast	1,128	10:00 a.m.	8.5	(1.00)	(9.00)
Total Actual	1,040	10:00 a.m.		(1.00)	(9.00)
Board Forecast	1,130	N/A	N/A	N/A	N/A
Board Actual	1,046				

[37] Negative percentages indicate an under-forecasted peak. Positive percentages indicate an over-forecasted peak.
[38] Temperature difference at forecast peak and actual peak. Negative values indicate that the temperature was warmer than forecast. Positive values indicate the temperature was colder than forecast.
[39] Wind speed difference at the forecast peak and the actual peak. Negative values indicate wind speed was more than forecast. Positive values indicate the wind speed was less than forecast.

1 The forecast peak at 7:20 a.m., as reported to the Board, was 1,130 MW; the actual reported peak was
2 1,046 MW. Chart 16 to Chart 20 include hourly plots of forecast and actual values to assist in
3 determining the sources of the differences between actual and forecast loads.

4 Chart 16 shows the hourly distribution of the total load forecast compared to the actual load, exclusive
5 of export activity. The hourly forecast predicted a 10:00 a.m. peak of 1,128 MW; the actual peak was
6 1,040 MW and occurred at 10:00 a.m., resulting in an overestimate of 8.5%.

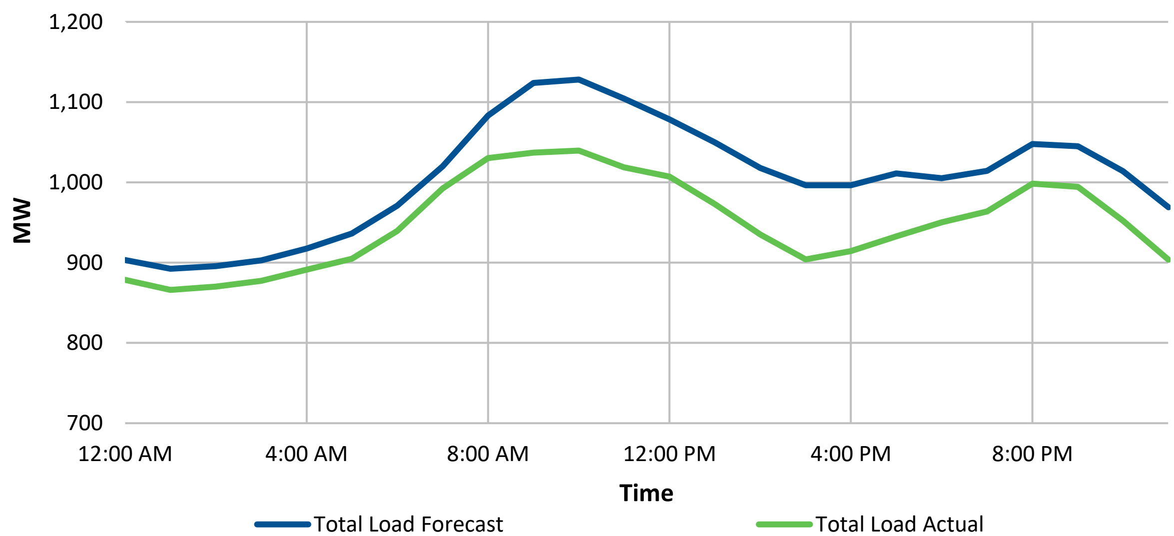

Chart 16: Forecast vs Actual Total Load for March 23, 2025

7 Chart 17 shows the hourly distribution of the utility load forecast only. The hourly forecast predicted a
8 utility peak at 10:00 a.m. of 972 MW; the actual peak was 911 MW and occurred at 10:00 a.m., resulting
9 in an overestimate of 6.7%.

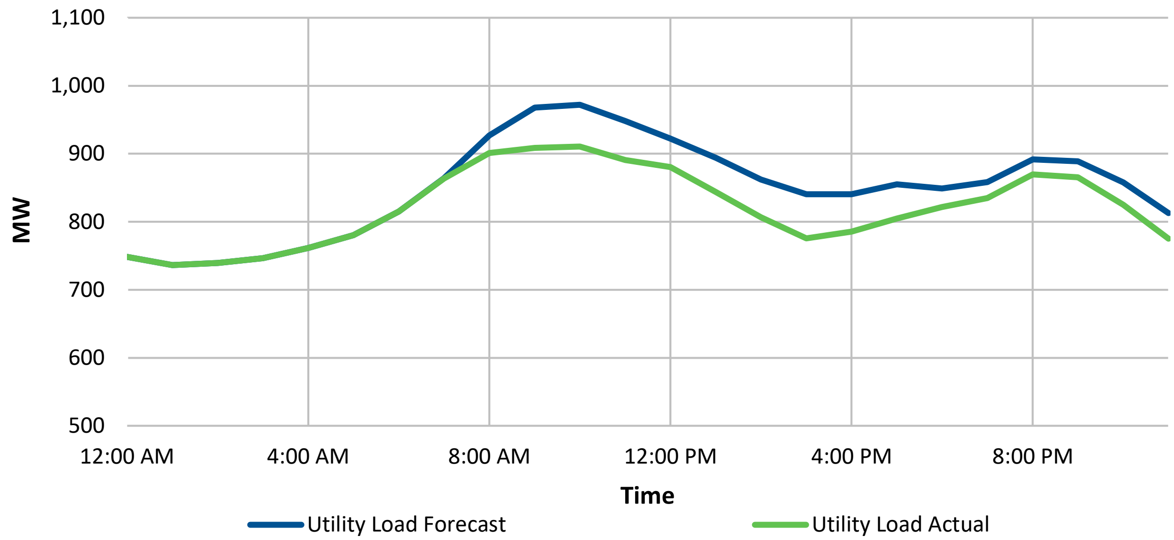

Chart 17: Forecast vs Actual Utility Load for March 23, 2025

1 Chart 18 shows the actual temperature in St. John's compared to the forecast. The temperature was
2 warmer than forecast for most of the day.

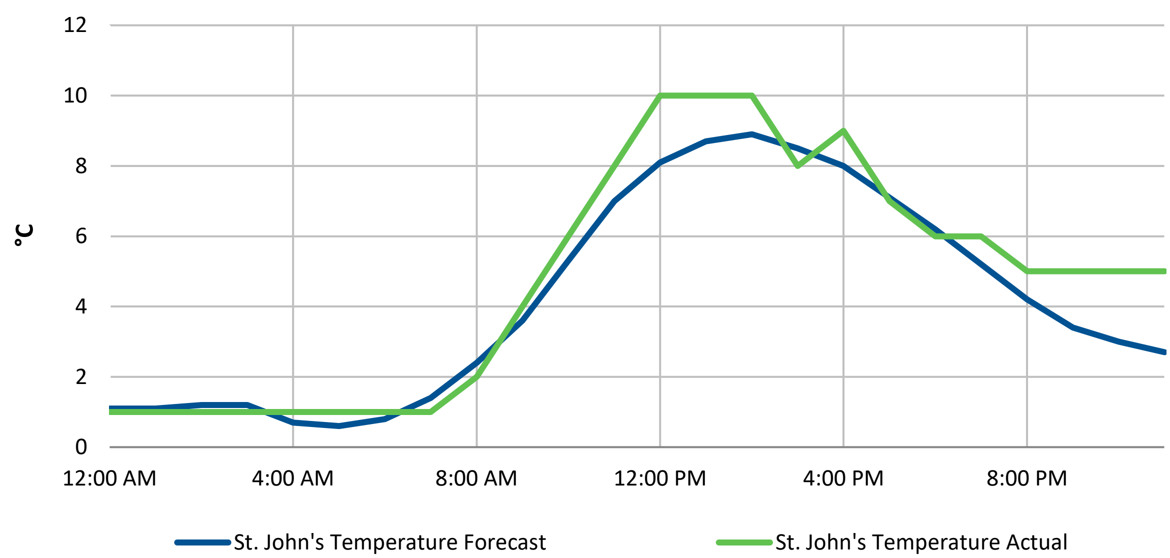

Chart 18: Forecast vs Actual Temperature for March 23, 2025

3 Chart 19 shows the actual wind speed in St. John's compared to the forecast. The wind speed on
4 average was higher during the day and lower during the evening period.

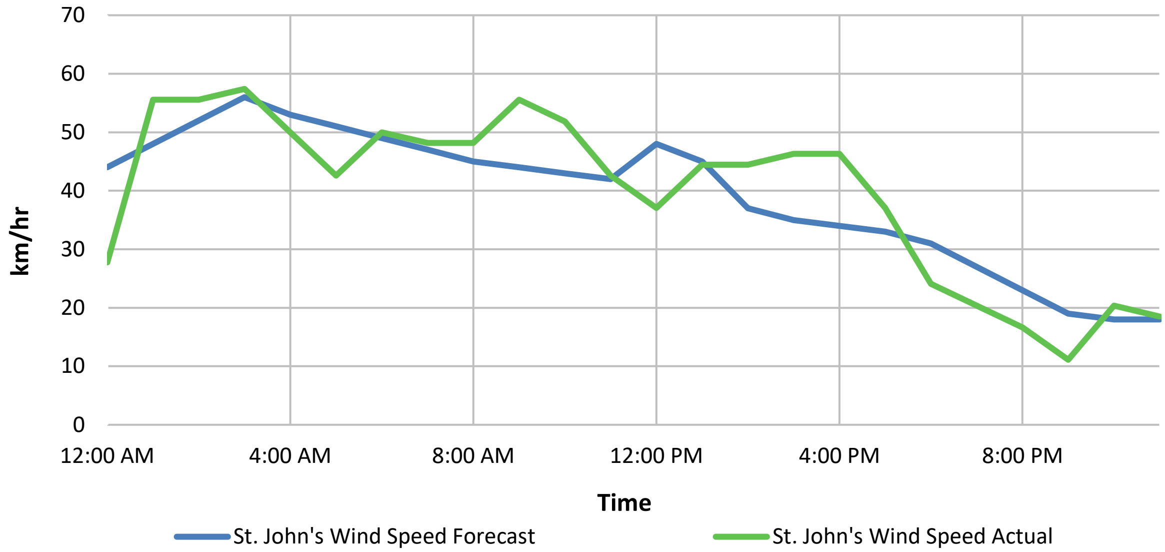

Chart 19: Forecast vs Actual Wind Speed for March 23, 2025

1 Chart 20 shows the actual cloud cover in St. John's compared to the forecast. It was cloudier than
2 forecast for the majority of the day.

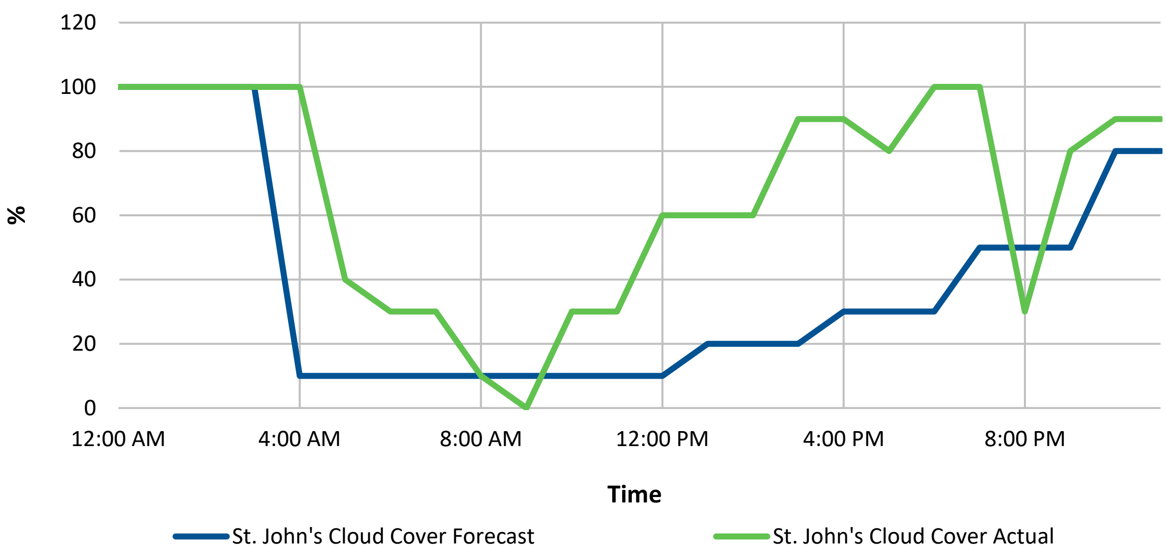

Chart 20: Forecast vs Actual Cloud Cover for March 23, 2025

3 The discrepancy between Utility Actual and Utility Forecast load was primarily attributed to non-
4 conforming load, as March 23, 2025, fell on a Sunday. Additionally, March 22, 2025 was fairly warm and
5 may have contributed to decreased heating requirements during the morning peak on March 23, 2025.

3.0 Forecast Accuracy Review

Table A-7 summarizes the error in the average monthly peak demand of the utility load forecast by winter month in 2025. The absolute percent error of the average demand for each month varied between 1.8% (February 2025) and 2.6% (January 2025), with an average of 2.2%. This is comparable to last year's observed absolute percent error for average monthly peak demand, which had an average error of 1.9%.[40] For reference, Hydro considers an error below 4.95% to be within acceptable forecasting limits. On average, the forecast typically underestimates the load, though the average understatement is -0.3% of actual peak. The average absolute error in Winter 2025 was 26 MW, which compares to the average absolute error in 2024[41] of 23 MW.

Table A-8 summarizes the maximum statistics for the utility load forecast by winter month in 2025. The maximum absolute error varied between 6.4% (January 2025) and 9.2% (March 2025). This is higher than last year's observed winter maximum error of 7.1%. For days that experienced the maximum errors, the forecast was typically underestimated, rather than overestimated. The largest absolute error at peak in Winter 2025 was 88 MW and occurred on March 7, 2025, which fell on a Friday.

The load forecast program uses historical data (weather and load) to predict the hourly load forecast. In the past two to three years, there has been an increase in oil-to-electric conversions. This impact on the load is still being "learned" by the program and may result in more underestimated loads during this period of transition.

Table A-9 summarizes the error at the ten highest utility loads during the reporting period. The highest loads in this reporting period occurred in January 2025 (three instances) and February 2025 (seven instances). Two of the ten highest loads were overestimated and eight were underestimated. The percent error varied from -5.7% to 0.6%; the overall average was -1.3%. The absolute percent error varied from 0.2% to 5.7%, with an average of 1.4%. With the exception of one day, these statistics confirm that there is no correlation between high load and high error in the load forecast, and that the short-term load forecasting software's forecasting of high loads is within the acceptable forecasting limit of less than 4.95% error.

[40] January through March 2024.
[41] January through March 2024.

Table A-10 summarizes the results of the investigations into instances of high forecast error selected based on high error in the utility load forecast against the actual utility load at peak. Common sources of error are variations in the weather forecast at or near the time of peak. Non-uniform customer behaviour is also a source of error, if a high error day occurred on the weekend or on a statutory holiday. Some errors remain unexplained; they result from unpredictable customer behaviour that was not modelled correctly by the load forecasting software. Of the three included instances of high forecast error, two occurred on a weekend and one occurred on a weekday.

Appendix A

Supporting Tables

Table A-1: Total Island Interconnected System Load Forecasting Data for January 2025[1]

Date	Forecast Total Peak (MW)	Actual Total Peak (MW)	Error (MW)	Error (%)	Available Island Supply[2] (MW)	Forecast Reserve[3] (MW)
1-Jan-2025	1,165	1,113	52	4.7%	1,919	754
2-Jan-2025	1,265	1,222	43	3.5%	1,969	704
3-Jan-2025	1,270	1,222	48	3.9%	2,100	830
4-Jan-2025	1,265	1,236	29	2.3%	1,860	595
5-Jan-2025	1,325	1,248	77	6.2%	2,012	687
6-Jan-2025	1,335	1,259	76	6.0%	2,164	829
7-Jan-2025	1,260	1,219	41	3.4%	2,163	903
8-Jan-2025	1,305	1,252	53	4.2%	1,902	597
9-Jan-2025	1,350	1,285	65	5.1%	2,002	652
10-Jan-2025	1,360	1,260	100	7.9%	1,945	585
11-Jan-2025	1,295	1,240	55	4.4%	1,830	535
12-Jan-2025	1,335	1,316	19	1.4%	1,847	512
13-Jan-2025	1,390	1,343	47	3.5%	2,015	625
14-Jan-2025	1,350	1,353	-3	-0.2%	1,873	523
15-Jan-2025	1,370	1,378	-8	-0.6%	1,845	475
16-Jan-2025	1,360	1,385	-25	-1.8%	1,865	505
17-Jan-2025	1,360	1,373	-13	-0.9%	1,750	390
18-Jan-2025	1,330	1,356	-26	-1.9%	1,840	510
19-Jan-2025	1,270	1,286	-16	-1.2%	1,855	585
20-Jan-2025	1,160	1,186	-26	-2.2%	1,991	831
21-Jan-2025	1,525	1,567	-42	-2.7%	2,146	621
22-Jan-2025	1,585	1,603	-18	-1.1%	1,832	247
23-Jan-2025	**1,720**	**1,720**	**0**	**0.0%**	**2,243**	**523**
24-Jan-2025	1,535	1,535	0	0.0%	2,197	662
25-Jan-2025	1,490	1,468	22	1.5%	2,160	670
26-Jan-2025	1,400	1,433	-33	-2.3%	2,150	750
27-Jan-2025	1,440	1,437	3	0.2%	2,131	691
28-Jan-2025	1,390	1,371	19	1.4%	2,167	777
29-Jan-2025	1,475	1,488	-13	-0.9%	2,230	755
30-Jan-2025	1,435	1,464	-29	-2.0%	2,214	779
31-Jan-2025	1,670	1,651	19	1.2%	2,276	606
Minimum	1,160	1,113	-42	-2.7%	1,750	247
Average	1,380	1,364	17	1.4%	2,016	636
Maximum	1,720	1,720	100	7.9%	2,276	903

[1] Forecast reserve does not include adjustments for interruptible load, the impact of voltage reduction, or scheduled off-Island imports.
[2] Includes total amount forecast to be delivered via the Labrador-Island Link (“LIL”), inclusive of exports.
[3] Includes exports via the Maritime Link.

Table A-2: Total Island Interconnected System Load Forecasting Data for February 2025[4]

Date	Forecast Total Peak (MW)	Actual Total Peak (MW)	Error (MW)	Error (%)	Available Island Supply[5] (MW)	Forecast Reserve[6] (MW)
1-Feb-2025	1,515	1,465	50	3.4%	2,126	611
2-Feb-2025	1,615	1,587	28	1.8%	2,222	607
3-Feb-2025	1,630	1,625	5	0.3%	2,240	610
4-Feb-2025	1,385	1,395	-10	-0.7%	2,202	817
5-Feb-2025	1,545	1,589	-44	-2.8%	2,220	675
6-Feb-2025	1,680	1,684	-4	-0.2%	2,214	534
7-Feb-2025	1,455	1,456	-1	-0.1%	2,231	776
8-Feb-2025	1,415	1,427	-12	-0.8%	1,882	467
9-Feb-2025	1,415	1,459	-44	-3.0%	1,811	396
10-Feb-2025	1,655	1,674	-19	-1.1%	2,210	555
11-Feb-2025	1,670	1,678	-8	-0.5%	2,259	589
12-Feb-2025	1,705	1,688	17	1.0%	2,252	547
13-Feb-2025	1,710	1,611	99	6.1%	1,749	39
14-Feb-2025	1,530	1,516	14	0.9%	2,138	608
15-Feb-2025	1,535	1,606	-71	-4.4%	2,099	564
16-Feb-2025	1,425	1,373	52	3.8%	2,116	691
17-Feb-2025	1,385	1,363	22	1.6%	2,194	809
18-Feb-2025	1,435	1,391	44	3.2%	2,274	839
19-Feb-2025	1,320	1,303	17	1.3%	2,195	875
20-Feb-2025	1,365	1,313	52	4.0%	2,211	846
21-Feb-2025	1,395	1,428	-33	-2.3%	2,193	798
22-Feb-2025	**1,465**	**1,384**	**81**	**5.9%**	**2,270**	**805**
23-Feb-2025	1,435	1,462	-27	-1.8%	2,210	775
24-Feb-2025	1,390	1,368	22	1.6%	2,242	852
25-Feb-2025	1,400	1,361	39	2.9%	2,272	872
26-Feb-2025	1,260	1,253	7	0.6%	1,930	670
27-Feb-2025	1,355	1,329	26	2.0%	1,997	642
28-Feb-2025	1,295	1,282	13	1.0%	2,137	842
Minimum	1,260	1,253	-71	-4.4%	1,749	39
Average	1,478	1,467	11	0.8%	2,146	668
Maximum	1,710	1,688	99	6.1%	2,274	875

[4] Forecast reserve does not include adjustments for interruptible load, the impact of voltage reduction, or scheduled off-Island imports.
[5] Includes total amount forecast to be delivered via the LIL, inclusive of exports.
[6] Includes exports via the Maritime Link.

Table A-3: Total Island Interconnected System Load Forecasting Data for March 2025[7]

Date	Forecast Total Peak (MW)	Actual Total Peak (MW)	Error (MW)	Error (%)	Available Island Supply[8] (MW)	Forecast Reserve[9] (MW)
1-Mar-2025	1,310	1,284	26	2.0%	2,129	819
2-Mar-2025	1,165	1,216	-51	-4.2%	2,021	856
3-Mar-2025	1,405	1,437	-32	-2.2%	2,178	773
4-Mar-2025	1,545	1,545	0	0.0%	1,962	417
5-Mar-2025	1,475	1,478	-3	-0.2%	1,976	501
6-Mar-2025	1,395	1,384	11	0.8%	2,204	809
7-Mar-2025	**1,205**	**1,113**	**92**	**8.3%**	**1,808**	**603**
8-Mar-2025	1,290	1,337	-47	-3.5%	2,053	763
9-Mar-2025	1,290	1,248	42	3.4%	2,031	741
10-Mar-2025	1,415	1,398	17	1.2%	2,284	869
11-Mar-2025	1,470	1,449	21	1.4%	2,134	664
12-Mar-2025	1,410	1,395	15	1.1%	2,067	657
13-Mar-2025	1,370	1,350	20	1.5%	2,011	641
14-Mar-2025	1,530	1,533	-3	-0.2%	2,061	531
15-Mar-2025	1,390	1,271	119	9.4%	2,033	643
16-Mar-2025	1,365	1,380	-15	-1.1%	2,002	637
17-Mar-2025	1,210	1,225	-15	-1.2%	2,039	829
18-Mar-2025	1,035	1,018	17	1.7%	1,936	901
19-Mar-2025	1,215	1,202	13	1.1%	1,876	661
20-Mar-2025	1,285	1,279	6	0.5%	1,939	654
21-Mar-2025	1,105	1,113	-8	-0.7%	1,840	735
22-Mar-2025	1,005	965	40	4.1%	1,623	618
23-Mar-2025	**1,130**	**1,046**	**84**	**8.0%**	**1,680**	**550**
24-Mar-2025	1,195	1,192	3	0.3%	1,789	594
25-Mar-2025	1,320	1,337	-17	-1.3%	2,034	714
26-Mar-2025	1,205	1,198	7	0.6%	1,879	674
27-Mar-2025	1,245	1,269	-24	-1.9%	2,000	755
28-Mar-2025	1,270	1,254	16	1.3%	1,965	695
29-Mar-2025	1,200	1,208	-8	-0.7%	1,747	547
30-Mar-2025	1,245	1,171	74	6.3%	1,749	504
31-Mar-2025	1,305	1,311	-6	-0.5%	2,117	812
Minimum	1,005	965	-51	-4.2%	1,623	417
Average	1,290	1,278	13	1.1%	1,973	683
Maximum	1,545	1,545	119	9.4%	2,284	901

[7] Forecast reserve does not include adjustments for interruptible load, the impact of voltage reduction, or scheduled off-Island imports.
[8] Includes total amount forecast to be delivered via the LIL, inclusive of exports.
[9] Includes exports via the Maritime Link.

Table A-4: Analysis of Utility Forecast Error for January 2025[10]

Date	Actual Utility Peak (MW)	Forecast Utility Peak (MW)	Error (MW)	Absolute Error (MW)	Error (%)	Absolute Error (%)	Actual/ Forecast (%)
1-Jan-2025	1,041	1,074	32	32	3.1%	3.1%	3.0%
2-Jan-2025	1,081	1,126	45	45	4.1%	4.1%	4.0%
3-Jan-2025	1,063	1,095	32	32	3.0%	3.0%	2.9%
4-Jan-2025	1,132	1,093	-40	40	-3.5%	3.5%	-3.6%
5-Jan-2025	1,106	1,164	58	58	5.2%	5.2%	5.0%
6-Jan-2025	1,122	1,172	50	50	4.5%	4.5%	4.3%
7-Jan-2025	1,066	1,097	31	31	2.9%	2.9%	2.8%
8-Jan-2025	1,099	1,142	43	43	3.9%	3.9%	3.8%
9-Jan-2025	1,148	1,186	38	38	3.3%	3.3%	3.2%
10-Jan-2025	1,123	1,195	72	72	6.4%	6.4%	6.0%
11-Jan-2025	1,117	1,141	24	24	2.2%	2.2%	2.1%
12-Jan-2025	1,188	1,185	-3	3	-0.2%	0.2%	-0.2%
13-Jan-2025	1,255	1,242	-13	13	-1.0%	1.0%	-1.0%
14-Jan-2025	1,215	1,198	-17	17	-1.4%	1.4%	-1.4%
15-Jan-2025	1,236	1,225	-11	11	-0.9%	0.9%	-0.9%
16-Jan-2025	1,248	1,212	-36	36	-2.9%	2.9%	-3.0%
17-Jan-2025	1,230	1,213	-17	17	-1.4%	1.4%	-1.4%
18-Jan-2025	1,212	1,170	-42	42	-3.5%	3.5%	-3.6%
19-Jan-2025	1,155	1,121	-34	34	-3.0%	3.0%	-3.0%
20-Jan-2025	1,046	998	-48	48	-4.6%	4.6%	-4.8%
21-Jan-2025	1,430	1,379	-51	51	-3.6%	3.6%	-3.7%
22-Jan-2025	1,495	1,438	-57	57	-3.8%	3.8%	-4.0%
23-Jan-2025	**1,576**	**1,571**	**-5**	**5**	**-0.3%**	**0.3%**	**-0.3%**
24-Jan-2025	1,386	1,387	0	0	0.0%	0.0%	0.0%
25-Jan-2025	1,325	1,345	20	20	1.5%	1.5%	1.5%
26-Jan-2025	1,290	1,255	-35	35	-2.7%	2.7%	-2.8%
27-Jan-2025	1,295	1,293	-2	2	-0.1%	0.1%	-0.1%
28-Jan-2025	1,251	1,241	-10	10	-0.8%	0.8%	-0.8%
29-Jan-2025	1,353	1,325	-28	28	-2.0%	2.0%	-2.1%
30-Jan-2025	1,339	1,288	-51	51	-3.8%	3.8%	-4.0%
31-Jan-2025	1,530	1,522	-8	8	-0.5%	0.5%	-0.5%
Minimum	1,041	998	-57	0	-4.6%	0.0%	-4.8%
Average	1,231	1,229	-2	31	0.0%	2.6%	-0.1%
Maximum	1,576	1,571	72	72	6.4%	6.4%	6.0%

[10] Lines that have been bolded indicate further examination of the hourly forecast provided in this report.

Table A-5: Analysis of Utility Forecast Error for February 2025[11]

Date	Actual Utility Peak (MW)	Forecast Utility Peak (MW)	Error (MW)	Absolute Error (MW)	Error (%)	Absolute Error (%)	Actual/ Forecast (%)
1-Feb-2025	1,355	1,365	9	9	0.7%	0.7%	0.7%
2-Feb-2025	1,467	1,467	0	0	0.0%	0.0%	0.0%
3-Feb-2025	1,489	1,465	-24	24	-1.6%	1.6%	-1.6%
4-Feb-2025	1,277	1,248	-29	29	-2.3%	2.3%	-2.4%
5-Feb-2025	1,472	1,396	-77	77	-5.2%	5.2%	-5.5%
6-Feb-2025	1,561	1,558	-3	3	-0.2%	0.2%	-0.2%
7-Feb-2025	1,326	1,330	4	4	0.3%	0.3%	0.3%
8-Feb-2025	1,298	1,288	-10	10	-0.8%	0.8%	-0.8%
9-Feb-2025	1,331	1,289	-42	42	-3.2%	3.2%	-3.3%
10-Feb-2025	1,539	1,527	-12	12	-0.8%	0.8%	-0.8%
11-Feb-2025	1,545	1,534	-10	10	-0.7%	0.7%	-0.7%
12-Feb-2025	1,553	1,555	3	3	0.2%	0.2%	0.2%
13-Feb-2025	1,537	1,546	9	9	0.6%	0.6%	0.6%
14-Feb-2025	1,383	1,342	-42	42	-3.0%	3.0%	-3.1%
15-Feb-2025	1,473	1,389	-84	84	-5.7%	5.7%	-6.0%
16-Feb-2025	1,237	1,280	42	42	3.4%	3.4%	3.3%
17-Feb-2025	1,243	1,236	-6	6	-0.5%	0.5%	-0.5%
18-Feb-2025	1,295	1,289	-7	7	-0.5%	0.5%	-0.5%
19-Feb-2025	1,157	1,172	15	15	1.3%	1.3%	1.3%
20-Feb-2025	1,189	1,221	31	31	2.6%	2.6%	2.6%
21-Feb-2025	1,289	1,249	-40	40	-3.1%	3.1%	-3.2%
22-Feb-2025	**1,238**	**1,318**	**80**	**80**	**6.5%**	**6.5%**	**6.1%**
23-Feb-2025	1,307	1,287	-20	20	-1.6%	1.6%	-1.6%
24-Feb-2025	1,242	1,220	-22	22	-1.8%	1.8%	-1.8%
25-Feb-2025	1,245	1,236	-9	9	-0.7%	0.7%	-0.7%
26-Feb-2025	1,130	1,111	-19	19	-1.7%	1.7%	-1.7%
27-Feb-2025	1,196	1,210	14	14	1.1%	1.1%	1.1%
28-Feb-2025	1,147	1,144	-2	2	-0.2%	0.2%	-0.2%
Minimum	1,130	1,111	-84	0	-5.7%	0.0%	-6.0%
Average	1,340	1,331	-9	24	-0.6%	1.8%	-0.7%
Maximum	1,561	1,558	80	84	6.5%	6.5%	6.1%

[11] Lines that have been bolded indicate further examination of the hourly forecast provided in this report.

Table A-6: Analysis of Utility Forecast Error for March 2025[12]

Date	Actual Utility Peak (MW)	Forecast Utility Peak (MW)	Error (MW)	Absolute Error (MW)	Error (%)	Absolute Error (%)	Actual/ Forecast (%)
1-Mar-2025	1,127	1,160	33	33	2.9%	2.9%	2.9%
2-Mar-2025	1,067	1,010	-57	57	-5.3%	5.3%	-5.6%
3-Mar-2025	1,289	1,247	-42	42	-3.3%	3.3%	-3.4%
4-Mar-2025	1,396	1,395	-1	1	-0.1%	0.1%	-0.1%
5-Mar-2025	1,332	1,315	-17	17	-1.3%	1.3%	-1.3%
6-Mar-2025	1,247	1,241	-6	6	-0.5%	0.5%	-0.5%
7-Mar-2025	**966**	**1,055**	**88**	**88**	**9.2%**	**9.2%**	**8.4%**
8-Mar-2025	1,192	1,134	-58	58	-4.9%	4.9%	-5.2%
9-Mar-2025	1,107	1,138	31	31	2.8%	2.8%	2.7%
10-Mar-2025	1,253	1,257	5	5	0.4%	0.4%	0.4%
11-Mar-2025	1,319	1,306	-12	12	-0.9%	0.9%	-0.9%
12-Mar-2025	1,256	1,252	-4	4	-0.3%	0.3%	-0.3%
13-Mar-2025	1,205	1,213	7	7	0.6%	0.6%	0.6%
14-Mar-2025	1,387	1,379	-8	8	-0.6%	0.6%	-0.6%
15-Mar-2025	1,167	1,230	63	63	5.4%	5.4%	5.1%
16-Mar-2025	1,237	1,203	-34	34	-2.7%	2.7%	-2.8%
17-Mar-2025	1,077	1,045	-31	31	-2.9%	2.9%	-3.0%
18-Mar-2025	873	879	7	7	0.8%	0.8%	0.8%
19-Mar-2025	1,064	1,057	-7	7	-0.7%	0.7%	-0.7%
20-Mar-2025	1,130	1,123	-8	8	-0.7%	0.7%	-0.7%
21-Mar-2025	961	949	-13	13	-1.3%	1.3%	-1.3%
22-Mar-2025	837	844	6	6	0.8%	0.8%	0.8%
23-Mar-2025	**911**	**972**	**61**	**61**	**6.7%**	**6.7%**	**6.3%**
24-Mar-2025	1,051	1,034	-17	17	-1.6%	1.6%	-1.7%
25-Mar-2025	1,182	1,166	-16	16	-1.3%	1.3%	-1.4%
26-Mar-2025	1,056	1,049	-7	7	-0.7%	0.7%	-0.7%
27-Mar-2025	1,124	1,089	-35	35	-3.1%	3.1%	-3.2%
28-Mar-2025	1,105	1,115	10	10	0.9%	0.9%	0.9%
29-Mar-2025	1,060	1,045	-15	15	-1.4%	1.4%	-1.5%
30-Mar-2025	1,022	1,087	66	66	6.4%	6.4%	6.0%
31-Mar-2025	1,157	1,151	-6	6	-0.5%	0.5%	-0.5%
Minimum	837	844	-58	1	-5.3%	0.1%	-5.6%
Average	1,134	1,134	-1	25	0.1%	2.3%	0.0%
Maximum	1,396	1,395	88	88	9.2%	9.2%	8.4%

[12] Lines that have been bolded indicate further examination of the hourly forecast provided in this report.

Table A-7: Monthly Peak Utility Load Error Summary – Average Error

Date	Actual Utility Peak (MW)	Forecast Utility Peak (MW)	Error (MW)	Absolute Error (MW)	Error (%)	Absolute Error (%)	Actual/ Forecast (%)
Jan 2025	1,231	1,229	-2	31	0.0%	2.6%	-0.1%
Feb 2025	1,340	1,331	-9	24	-0.6%	1.8%	-0.7%
Mar 2025	1,134	1,134	-1	25	0.1%	2.3%	0.0%
Total Average	1,235	1,231	-4	26	-0.2%	2.2%	-0.3%

Table A-8: Monthly Peak Utility Load Error Summary – Maximum Statistics[13]

Date	Actual Utility Peak (MW)	Forecast Utility Peak (MW)	Error (MW)	Absolute Error (MW)	Error (%)	Absolute Error (%)	Actual/ Forecast (%)
Jan 2025	1,576	1,571	72	72	6.4%	6.4%	6.0%
Feb 2025	1,561	1,558	80	84	6.5%	6.5%	6.1%
Mar 2025	1,396	1,395	88	88	9.2%	9.2%	8.4%
Winter	1,511	1,508	80	81	7.3%	7.3%	6.8%

Table A-9: Error in Ten Highest Utility Loads

Date	Actual Utility Peak (MW)	Forecast Utility Peak (MW)	Error (MW)	Absolute Error (MW)	Error (%)	Absolute Error (%)	Actual/ Forecast (%)
23-Jan-2025	1,576	1,571	-5	5	-0.3%	0.3%	-0.3%
6-Feb-2025	1,561	1,558	-3	3	-0.2%	0.2%	-0.2%
12-Feb-2025	1,553	1,555	3	3	0.2%	0.2%	0.2%
11-Feb-2025	1,545	1,534	-10	10	-0.7%	0.7%	-0.7%
10-Feb-2025	1,539	1,527	-12	12	-0.8%	0.8%	-0.8%
13-Feb-2025	1,537	1,546	9	9	0.6%	0.6%	0.6%
31-Jan-2025	1,530	1,522	-8	8	-0.5%	0.5%	-0.5%
22-Jan-2025	1,495	1,438	-57	57	-3.8%	3.8%	-4.0%
3-Feb-2025	1,489	1,465	-24	24	-1.6%	1.6%	-1.6%
15-Feb-2025	1,473	1,389	-84	84	-5.7%	5.7%	-6.0%
Average	1,530	1,511	-19	21	-1.3%	1.4%	-1.3%

[13] The maximum forecast, the maximum peak, and the maximum error do not necessarily occur on the same day.

Table A-10: Summary of Forecast Issues

Date	Actual Utility Peak (MW)	Forecast Utility Peak (MW)	Error (MW)	Absolute Error (MW)	Error (%)	Explanation
22-Feb-2025	1,238	1,318	80	80	6.5%	Error in Weather data/ Within Acceptable Limits at peak
7-Mar-2025	966	1,055	88	88	9.2%	Error in Weather data/ Within Acceptable Limits at peak
23-Mar-2025	911	972	61	61	6.7%	Non-Uniform Customer Behaviour

Appendix B

Supporting Charts

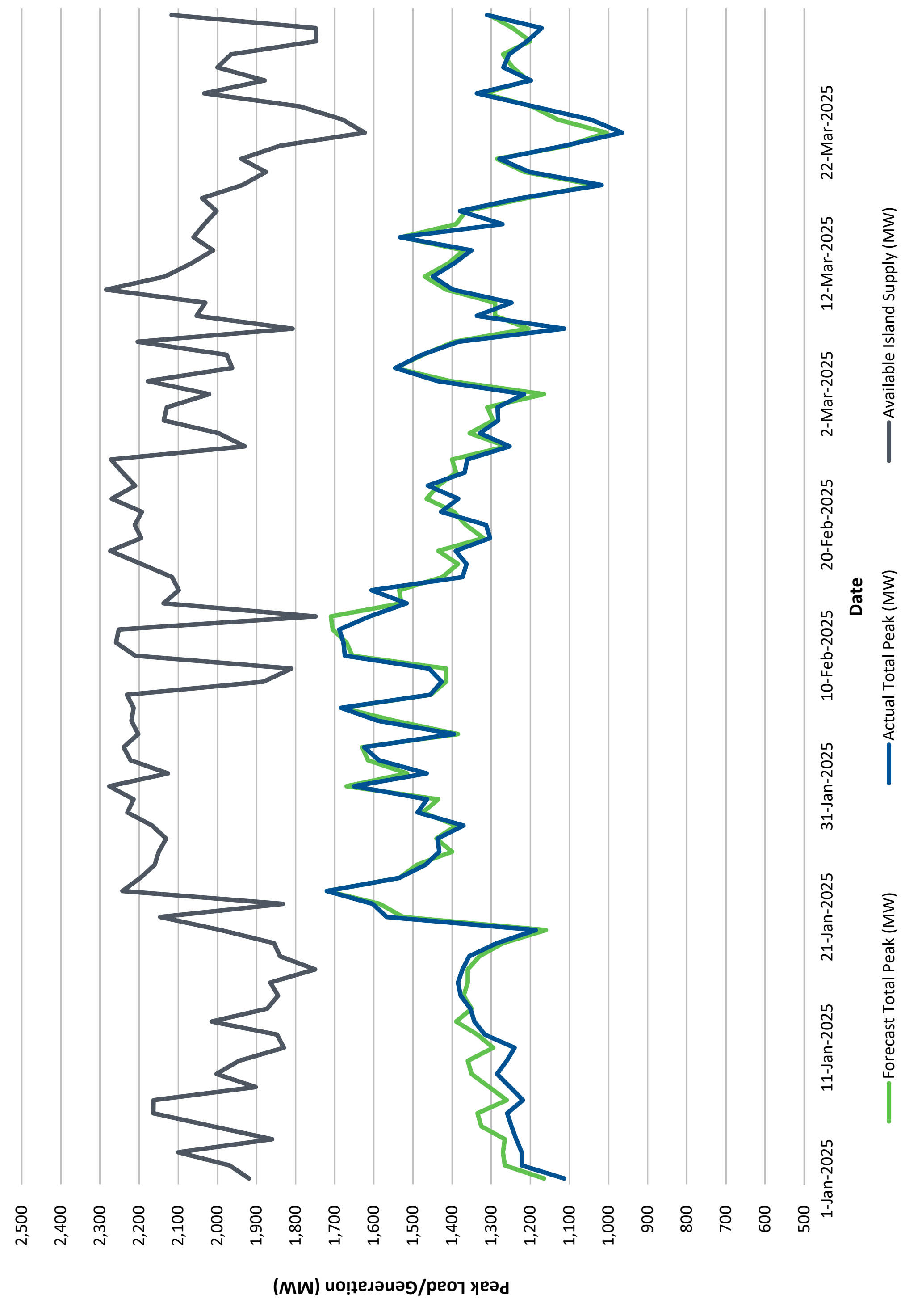

Chart B-1: Peak Forecast, Total Load, and Available Supply from January 2025 through March 2025

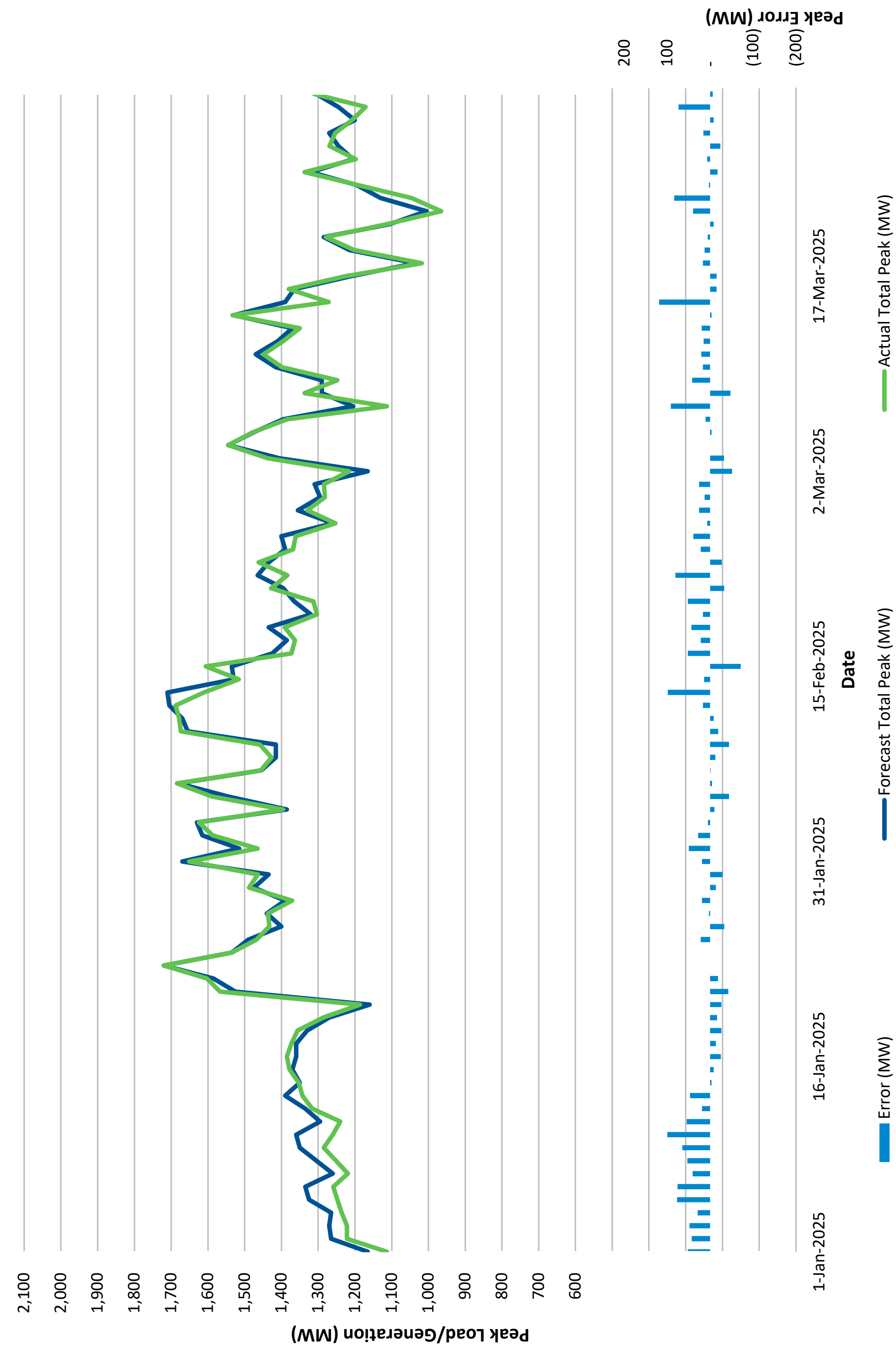

Chart B-2: Peak Forecast, Total Load, and Error from January 2025 through March 2025

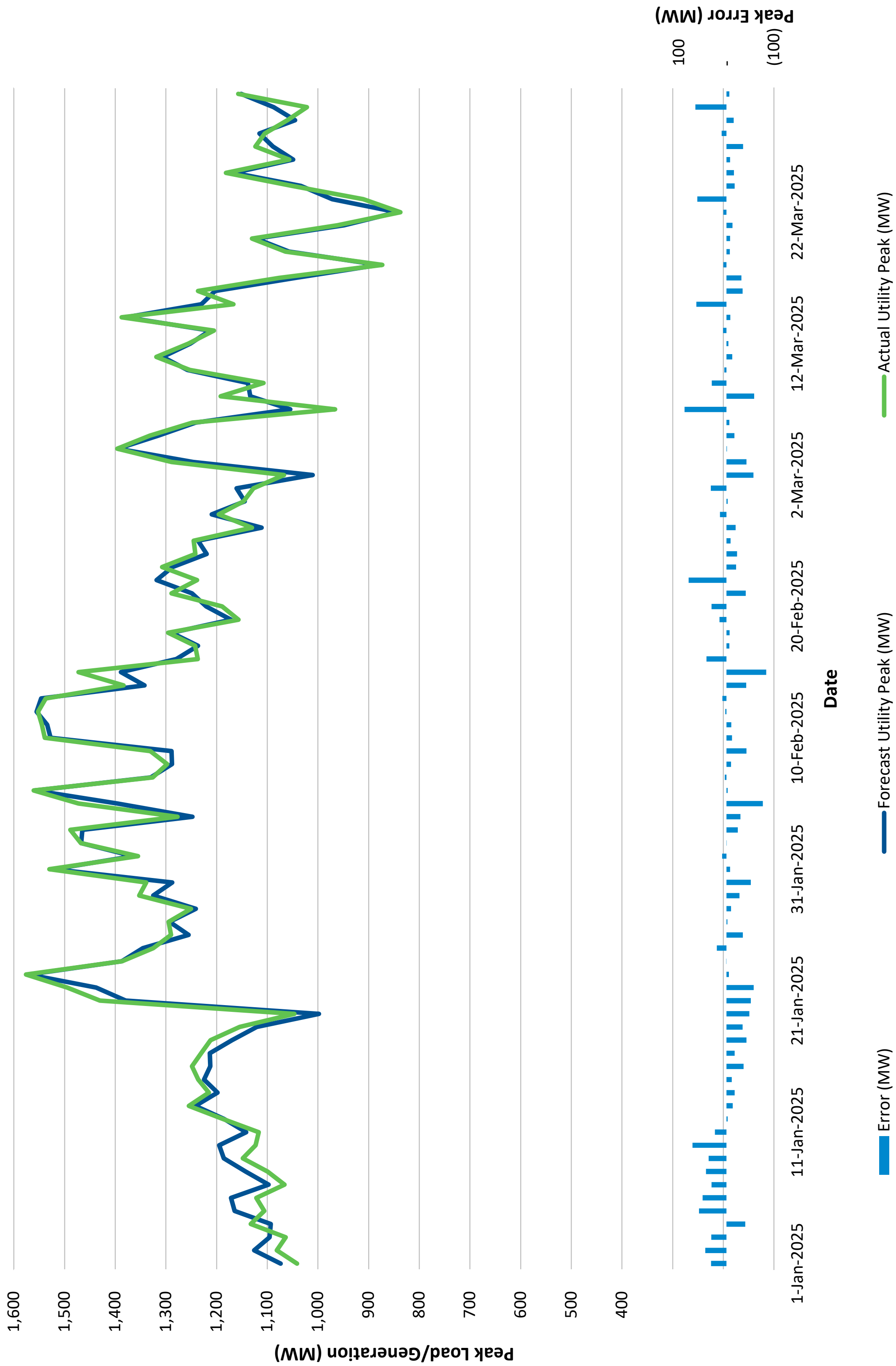

Chart B-3: Peak Forecast, Utility Load, and Error from January 2025 through March 2025

Attachment 2

Short-Term Load Forecasting Accuracy
Island Interconnected System

Winter 2025–2026

Short-Term Load Forecasting Accuracy Island Interconnected System

Winter 2025-2026

May 29, 2026

A report to the Board of Commissioners of Public Utilities

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Appendix A: Supporting Tables

Appendix B: Supporting Charts

1.0 Load Forecasting

1.1 Load Forecasting Software

In 2023, Newfoundland and Labrador Hydro ("Hydro") adopted a new load forecasting software for its short-term load forecasting with a period of 14 days. This replaced the previous forecasting software, Nostradamus, on which reporting was based until 2023. This software uses a combination of regression and neural network models that are trained using a sequence of continuous historic periods of hourly weather and half-hourly demand data. The models then forecast system demand for a 14-day horizon using predictions of weather parameters.

Since December 2014, in accordance with direction from the Board of Commissioners of Public Utilities ("Board"), Hydro has submitted periodic reports on the accuracy of load forecasting.[1,2] As agreed upon by the Board, Hydro has condensed its annual report to focus on the winter period, in which the accuracy of the short-term load forecast is most consequential from a system planning perspective.[3] As such, this report will cover the 2025–2026 winter period, which includes December 1, 2025 through March 31, 2026.

1.2 Short-Term Load Forecasting

Hydro uses its short-term load forecast to manage the power system and ensure adequate generating resources are available to meet customer demand.

1.2.1 Utility Load[4]

Hydro has a contract with WSP Global Inc. ("WSP")[5] to provide the weather parameters in the form of half-hourly weather forecasts delivered twice a day for the following 14 days. At the same time this weather forecast data is provided, WSP also provides recent observed data at the locations used in the

[1] Load forecasting accuracy reports were originally filed in relation to the *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System* proceeding.
[2] As per "Newfoundland and Labrador Hydro – Accuracy of Nostradamus Load Forecasting Reports – Filing Schedule," Board of Commissioners of Public Utilities, January 18, 2018, the Board indicated that the reporting frequency should change to annually commencing November 15, 2018.
[3] "Newfoundland and Labrador Hydro - Short-Term Load Forecast Accuracy Report – Proposed Changes to Reporting," Board of Commissioners of Public Utilities, November 17, 2025.
[4] Utility load is the summation of Newfoundland Power Inc. ("Newfoundland Power") and Hydro Island Rural requirements.
[5] WSP acquired Wood PLC in 2022.

forecasts.[6] The actual and forecast data are automatically retrieved from WSP and input to the load forecast database.

The load forecasting software uses a variety of weather parameters for forecasting, provided a sufficient historical record is available for training. Hydro currently uses air temperature, wind speed, and cloud cover. The load forecasting software can use each variable more than once; for example, both the current and forecast air temperatures are used in forecasting load. Wind chill is calculated in the load forecasting software using a set formula that requires wind speed and dry bulb input.

The load forecasting software uses weather data for St. John's, Gander, and Deer Lake as well as a parameter that indicates daily daylight hours. Training and verification[7] periods are selected to provide sufficient time to ensure a range of weather parameters are included (e.g., high and low temperatures), but are still short enough that the historic load is representative of loads that can be expected in the near future. The load forecasting software is trained monthly[8] to further improve forecasting accuracy. The goal is to improve the forecasting accuracy by providing the software with updated data and trends of recent loads and weather patterns. This helps ensure variables such as load growth and extreme weather are properly accounted for when predicting future load requirements.

Demand data for the Island Interconnected System utility load is automatically imported to the load forecasting software each half hour. Newfoundland Power's and Hydro's total utility load (conforming)[9] is input in the model. Industrial load (non-conforming),[10] which is not a function of weather, is added to the forecasts within the software to derive the total load forecast.

The load forecasting software model creates separate sub-models for weekdays, weekends, and holidays during the training process to account for the variation in customer use of electricity. The load

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[6] The locations used for the weather forecast data are St. John's, Gander, and Deer Lake.
[7] The load forecasting software will automatically perform verification over a designated historical period upon completion of training. The verification period is used to evaluate the accuracy of the forecast using data on which the model has not trained. This ensures that the model is not memorizing the correct answer.
[8] In the report "Short-Term Forecasting Accuracy – Island Interconnected System – 2023," Newfoundland and Labrador Hydro, January 31, 2024, Hydro reported it would conduct this training quarterly. With the increase of household electrification and efficiency measures, including the installation of mini-split systems, conversion from oil heating to electric, and higher prevalence of electric vehicles, Hydro has adjusted this process to occur monthly for a more accurate projected load measurement.
http://www.pub.nf.ca/indexreports/nostradamus/From%20NLH%20-%20Short-Term%20Load%20Forecasting%20Accuracy%20-%202023%20Annual%20Report%20-%202024-01-31.PDF
[9] Conforming load refers to load that changes consistently with the load pattern of an area.
[10] Non-conforming load refers to load that changes abnormally with respect to the load pattern of an area.

forecasting software has separate holiday groups for statutory holidays and for days that are known to have unusual loads, such as the days between Christmas Day and New Year's Day, as well as the closure of schools during the Easter break.

1.2.2 Industrial Load

Industrial loads tend to be almost constant, as industrial processes are independent of weather. Under the current procedure, the Power on Order[11] for each Industrial customer plus the expected owned generation from Corner Brook Pulp and Paper Limited are used as the industrial load forecasts. Industrial customer loads can be modified based on knowledge of customer loads; for instance, a temporary decrease in requirements at Vale Newfoundland and Labrador Limited is associated with planned maintenance. The expected load can be modified in any given hour of the 14-day forecast, or the default value can be modified to be used indefinitely.[12]

1.2.3 Supply and Demand Status Reporting

The forecast peak as of 7:20 a.m. is reported daily to the Board in Hydro's Supply and Demand Status reports.[13] The weather forecast for the following 14 days and the observed weather data for the previous day are input into the model at approximately 5:00 a.m. and 2:00 p.m.; the load forecasting software is then run every half hour of the day. Following completion of the software run, the generated forecast is made available for reference to assist in monitoring and managing both available and spinning reserves. The within-day forecast updates are primarily used to manage operating reserves, particularly in advance of the forecast system peaks.

[11] Power on Order refers to the firm power Hydro agrees to deliver to a customer and the customer agrees to purchase from Hydro, as set out in a service agreement.
[12] In Hydro's Energy Management System, there is functionality to modify the industrial load value when the Newfoundland and Labrador System Operator is aware of circumstances where an Industrial customer will be reducing load; for example, if an Industrial customer is completing maintenance, the forecast load can be modified to provide a more accurate load forecast.
[13] Hydro's daily Supply and Demand Status reports can be accessed at http://www.pub.nf.ca/applications/IslandInterconnectedSystem/DemandStatusReports.php.

1.3 Potential Sources of Variance

As with any forecasting analysis, there will be discrepancies between forecast and actual values. Typical sources of variance in the load forecasting are as follows:

- Differences in the export values in the forecast compared to actual exports throughout the day, which can be scheduled one hour in advance. These sources of variances are noted in the Supply and Demand Status reports to the Board.
- Differences in the industrial load forecast due to unexpected changes in Industrial customer loads. For example, if an Industrial customer were to undertake maintenance that Hydro was unaware of, or increase production to meet customer demand, the actual load would deviate from the scheduled load.
- Inaccuracies in the weather forecast—particularly temperature, wind speed, or cloud cover.
- Non-uniform customer behaviour, resulting in unpredictability.

Delivery of the Nova Scotia Block and Supplemental Block continued in Winter 2025–2026.[14,15] These scheduled deliveries are included in the forecast peak, as reported by 7:20 a.m. daily. Decisions regarding additional exports over the Maritime Link during peak periods are carefully coordinated and include conservative consideration of Hydro's native load forecast and available supply. The forecast peak does not always account for exports, as exports can be contracted at any time throughout the day. As noted previously, this can result in an error when comparing a peak forecast prepared in the early morning against an actual peak that includes real-time exports. As of January 25, 2024, Hydro began reporting the exports at peak on the daily Supply and Demand Status reports.

[14] The first delivery of the Nova Scotia Block occurred in August 2021, and the first delivery of the Supplemental Block occurred in November 2021.
[15] Pursuant to the Energy and Capacity Agreement between Nalcor Energy and Emera Inc., the Nova Scotia Block is a firm annual commitment of 980 GWh, supplied from the Muskrat Falls Hydroelectric Generating Facility on peak. https://www.emeranl.com/docs/librariesprovider13/maritime-link-documents/commercial-agreements/amended-and-restated-energy-and-capacity-agreement.pdf?sfvrsn=dec21945_2.

2.0 Forecast Accuracy Summary

2.1 Analysis

This report will examine the accuracy of the Hydro forecasting process for the winter months of 2025–2026, December 1, 2025 through March 31, 2026. Hydro's report includes details on the system peak day, as well as the three highest utility error days during these winter months.

In Appendix A, Table A-1 to Table A-4 present the daily Island Interconnected System forecast total peak, actual total peak, available Island supply forecast reserve, as well as the error and percent error. The data is also presented in Appendix B, Chart B-1.

In Appendix B, Chart B-2 plots the total forecast and actual total peaks, as shown in Chart B-1, with the addition of a bar chart showing the difference between the two data series in megawatts. In both the tables and charts, a positive error is an overestimate and a negative error is an underestimate. Appendix B, Chart B-2 reveals that the forecasting process consistently overestimates the peak of the total load. This is typically the result of an overestimate in the industrial load forecast and/or export activity over the Maritime Link that was contracted after the forecast was published.

The total Island Interconnected System peak load, including exports during the period, varied between 985 MW (January 16, 2026) and 1,646 MW (January 26, 2026). The available Island supply varied from 1,643 MW to 2,417 MW. Island Interconnected System reserves were sufficient throughout most of the period.[16]

In Appendix A, Table A-5 to Table A-8 present error statistics for the utility peak forecast (i.e., the portion of the forecast determined by the model). Neither the industrial forecast nor the Maritime Link export activity is included in the values presented in these tables. Appendix B, Chart B-3 plots the data and error for the utility peak. Examination of the utility forecast provides more insight into the accuracy of the load forecasting software, as changes or errors in the industrial forecast and the presence of

[16] On January 21, 2026, Hydro experienced a frazil ice event at the Bay d'Espoir Hydroelectric Generating Station ("Bay d'Espoir") that caused frazil ice to accumulate on the intakes, resulting in the unavailability of all seven generating units. While Bay d'Espoir was unavailable, the Holyrood Thermal Generating Station experienced issues, resulting in derations and/or unavailability of units. These conditions required Hydro to issue a Power Warning on January 24, 2026, asking customers on the Island to conserve electricity, as available system supply approached maximum capacity. Units 1–6 in Bay d'Espoir were returned to service on January 25, 2026, and the Power Warning was subsequently lifted. Additional details are provided in the report "Frazil Ice at Bay d'Espoir Hydroelectric Generating Station," Newfoundland and Labrador Hydro, April 30, 2026.

export activity may increase the perceived error as compared to the total forecast as of 7:20 a.m., making the total forecast appear worse or, at times, better than it is.

2.2 Data Adjustments and Forecast Issues

In analysing the data, some instances require adjustments for a variety of reasons. In these instances, the data for the affected hours is either replaced using interpolation or is adjusted by a set value so that, in the future, when the data for this period is used in training, the load forecasting software will use a value not affected by the event.

On January 26, 2026, there was a short-term voltage reduction for Newfoundland Power and the actual Island utility load values in the load forecast software were adjusted upward by 25 MW for the reduction period.

2.3 Days of High Error[17]

The bolded dates in Appendix A, Table A-1 to Table A-8 indicate the days of high error[18] in the load forecast. Based on discussions with Board staff on December 19, 2022, Hydro will continue to select days of highest error based on the utility load (Appendix A, Table A-5 to Table A-8 data) for the winter 2025–2026 period. The days with the highest error (three per winter season), as well as Hydro's peak day are selected for a more detailed analysis. The following are the days with the highest error and Hydro's peak day. Additional information on each is provided in Sections 2.3.1 to 2.3.4.

- December 31, 2025;
- January 26, 2026, Hydro's peak day in 2026; and
- March 13 and 24, 2026

Each high error day includes a table with a peak data summary. The data reported to the Board ("Board Forecast" and "Board Actual") includes utility load, industrial load, and exports. The Island forecast data includes utility load as well as Industrial customer load.

[17] All plots showing the hourly distribution of the load forecast in comparison to the actual total load do not include Maritime Link export activity to aid in determining other sources of differences between actual and forecast loads.
[18] Hydro considers an error below 4.95% to be within acceptable forecasting limits.

2.3.1 December 2025

In December 2025, the forecast utility peak was 1,431 MW on December 5, 2025, which is consistent with the actual utility peak of 1,443 MW on that day. Absolute error was 26 MW on average, with an average percent error[19] of -1.0%, an average absolute error[20] of 2.1%, and an average actual/forecast of -1.1%.

2.3.1.1 December 31, 2025

Table 1 provides a summary of forecast peak data for December 31, 2025.

Table 1: Peak Data Summary for December 31, 2025

	Load (MW)	Time	Error (%)[21]	Temperature Delta (°C)[22]	Wind Speed Delta (km/h)[23]
Utility Forecast	1,096	5:00 p.m.	-9.3	1.00	0.00
Utility Actual	1,207	5:00 p.m.		1.00	0.00
Island Forecast	1,187	5:00 p.m.	-7.9	1.00	0.00
Island Actual	1,288	5:00 p.m.		1.00	0.00
Board Forecast	1,195	N/A	N/A	N/A	N/A
Board Actual	1,289				

The forecast peak at 7:20 a.m., as reported to the Board, was 1,195 MW; the actual reported peak was 1,289 MW. Chart 1 to Chart 5 include hourly plots of forecast and actual values to illustrate Hydro's peak day.

Chart 1 shows the hourly distribution of the total load forecast compared to the actual load, exclusive of export activity. The hourly forecast predicted a 5:00 p.m. peak of 1,187 MW; the actual peak was 1,288 MW[24] and occurred at 5:00 p.m., resulting in an underestimate of 7.9%.

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[19] Average of all daily errors.
[20] Average of all absolute value daily errors.
[21] Negative percentages indicate an under-forecasted peak. Positive percentages indicate an over-forecasted peak.
[22] Temperature difference at forecast peak and actual peak. Negative values indicate that the temperature was warmer than forecast. Positive values indicate the temperature was colder than forecast.
[23] Wind speed difference at the forecast peak and the actual peak. Negative values indicate wind speed was more than forecast. Positive values indicate the wind speed was less than forecast.
[24] The actual total peak reported in the daily Supply and Demand Status reports is based on a five-minute time step; however, the load forecasting software reports on an hourly time step, sometimes resulting in a different peak value.

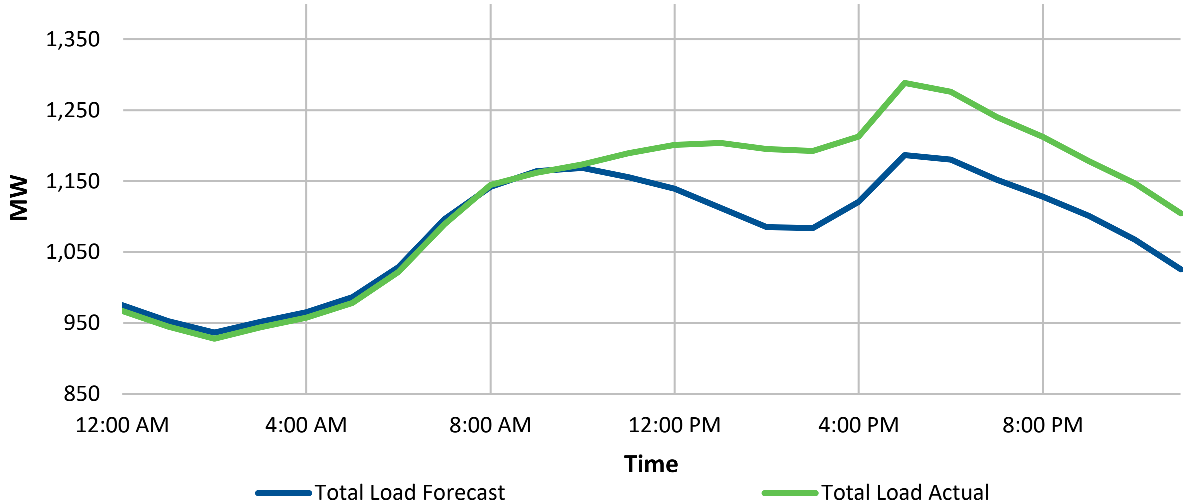

Chart 1: Forecast vs Actual Total Load for December 31, 2025

1 Chart 2 shows the hourly distribution of the utility load forecast only. The hourly forecast predicted a
2 utility peak at 5:00 p.m. of 1,096 MW; the actual peak was 1,207 MW and occurred at 5:00 p.m.,
3 resulting in an underestimate of 9.3%.

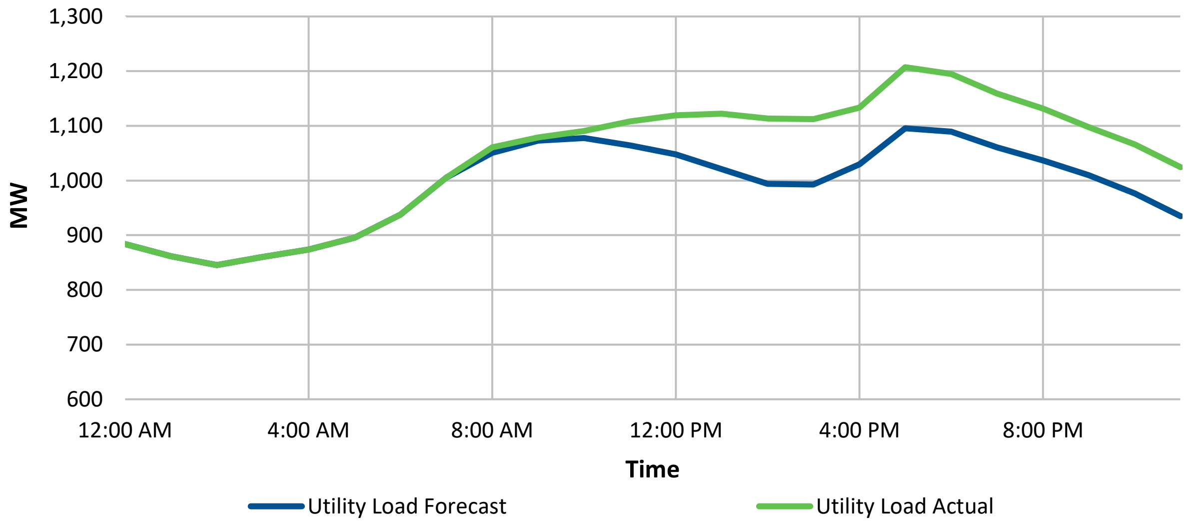

Chart 2: Forecast vs Actual Utility Load for December 31, 2025

Chart 3 shows the actual temperature in St. John's compared to the forecast. The temperature was approximately 1°C colder leading up to the peak.

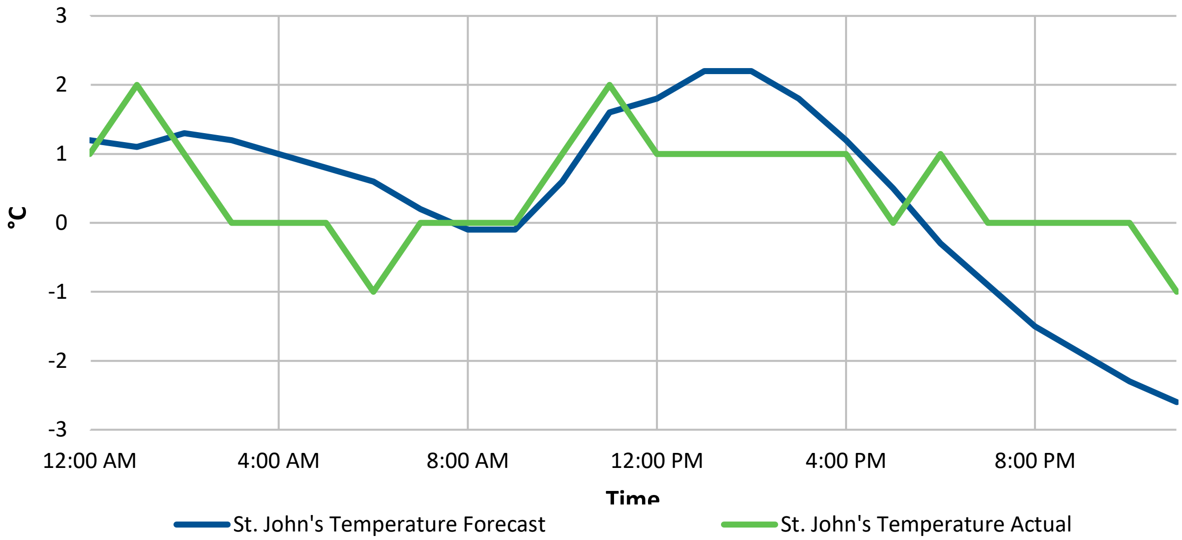

Chart 3: Forecast vs Actual Temperature for December 31, 2025

Chart 4 shows the actual wind speed in St. John's compared to the forecast. The actual wind speed was higher than forecast throughout the day.

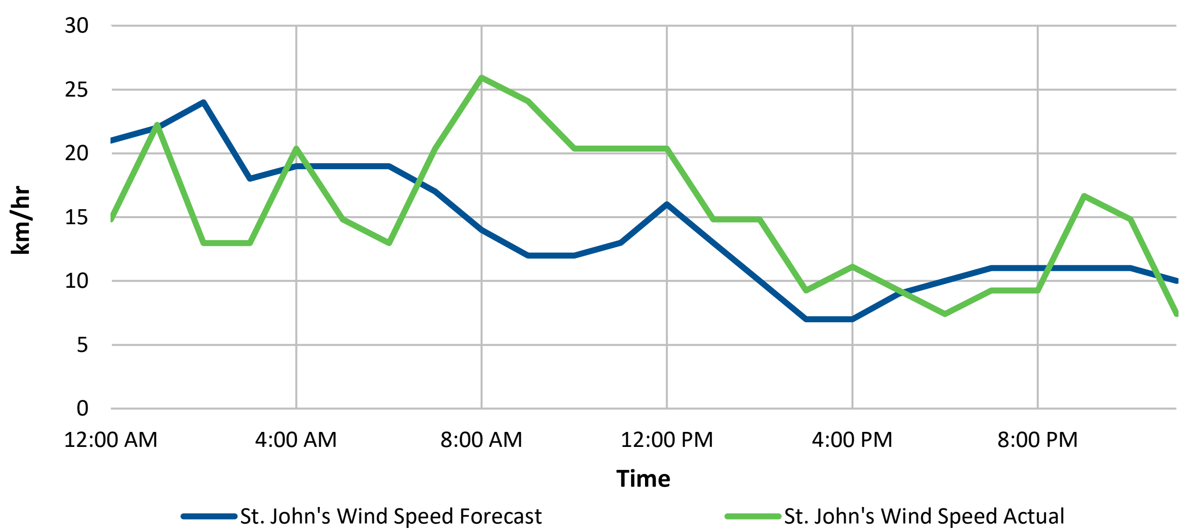

Chart 4: Forecast vs Actual Wind Speed for December 31, 2025

Chart 5 shows the actual cloud cover in St. John's compared to the forecast. Cloud cover was close to forecast during the daylight hours.

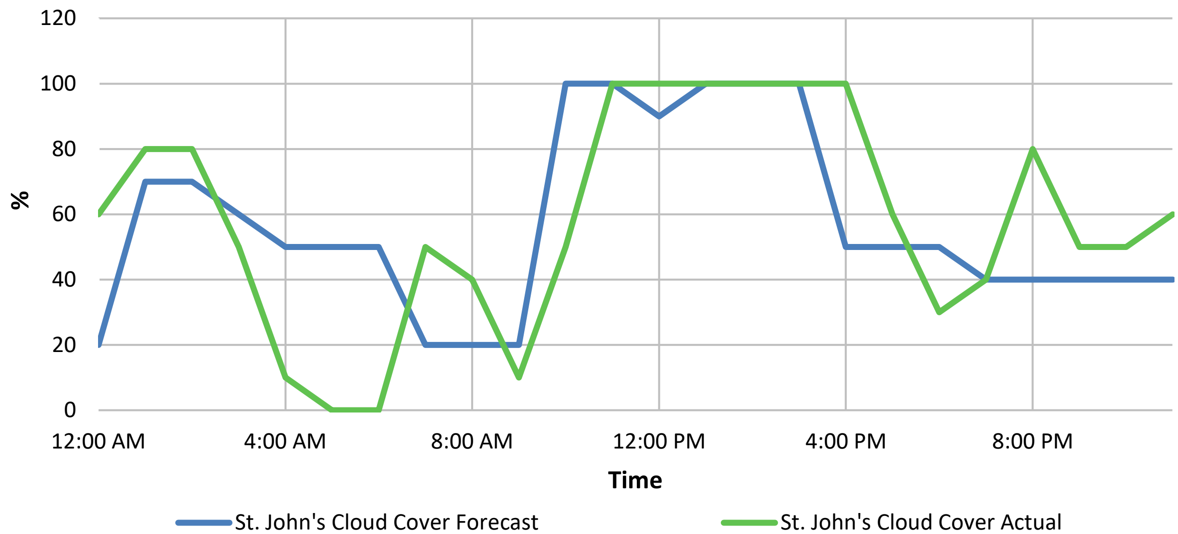

Chart 5: Forecast vs Actual Cloud Cover for December 31, 2025

The discrepancy between Utility Actual and Utility Forecast load was primarily attributed to non-conforming customer behaviour, as this was New Year's Eve. The slightly colder temperature and higher wind speed throughout the day may have also contributed to the forecast error.

2.3.2 January 2026

In January 2026, the forecast utility peak was 1,584 MW on January 26, 2026, which is consistent with the actual utility peak of 1,585 MW on that day. Absolute error was 20 MW on average, with an average percent error[25] of -0.6%, an average absolute error[26] of 1.7%, and an average actual/forecast of -0.7%.

January did not have any of the three highest error winter peak days but had the peak day for Winter 2025–2026.

[25] Average of all daily errors.
[26] Average of all absolute value daily errors.

2.3.2.1 January 26, 2026 (Hydro's Peak Day)

Table 2 provides a summary of forecast peak data for January 26, 2026.

Table 2: Peak Data Summary for January 26, 2026

	Load (MW)	Time	Error (%)[27]	Temperature Delta (°C)[28]	Wind Speed Delta (km/h)[29]
Utility Forecast	1,584	8:00 a.m.	-0.1	0.00	16.00
Utility Actual	1,585	9:00 a.m.		0.00	23.00
Island Forecast	1,680	8:00 a.m.	2.7	0.00	16.00
Island Actual	1,636	9:00 a.m.		0.00	23.00
Board Forecast	1,680	N/A	N/A	N/A	N/A
Board Actual	1,646				

The forecast peak at 7:20 a.m., as reported to the Board, was 1,680 MW; the actual reported peak was 1,646 MW. Chart 6 to Chart 10 include hourly plots of forecast and actual values to illustrate Hydro's peak day.

Chart 6 shows the hourly distribution of the total load forecast compared to the actual load, exclusive of export activity. The hourly forecast predicted an 8:00 a.m. peak of 1,680 MW; the actual peak was 1,636 MW[30] and occurred at 9:00 a.m., resulting in an overestimate of 2.7%. The load forecast at the time of peak was 1,669 MW.

[27] Negative percentages indicate an under-forecasted peak. Positive percentages indicate an over-forecasted peak.
[28] Temperature difference at forecast peak and actual peak. Negative values indicate that the temperature was warmer than forecast. Positive values indicate the temperature was colder than forecast.
[29] Wind speed difference at the forecast peak and the actual peak. Negative values indicate wind speed was more than forecast. Positive values indicate the wind speed was less than forecast.
[30] The actual total peak reported in the daily Supply and Demand Status reports is based on a five-minute time step; however, the load forecasting software reports on an hourly time step, sometimes resulting in a different peak value.

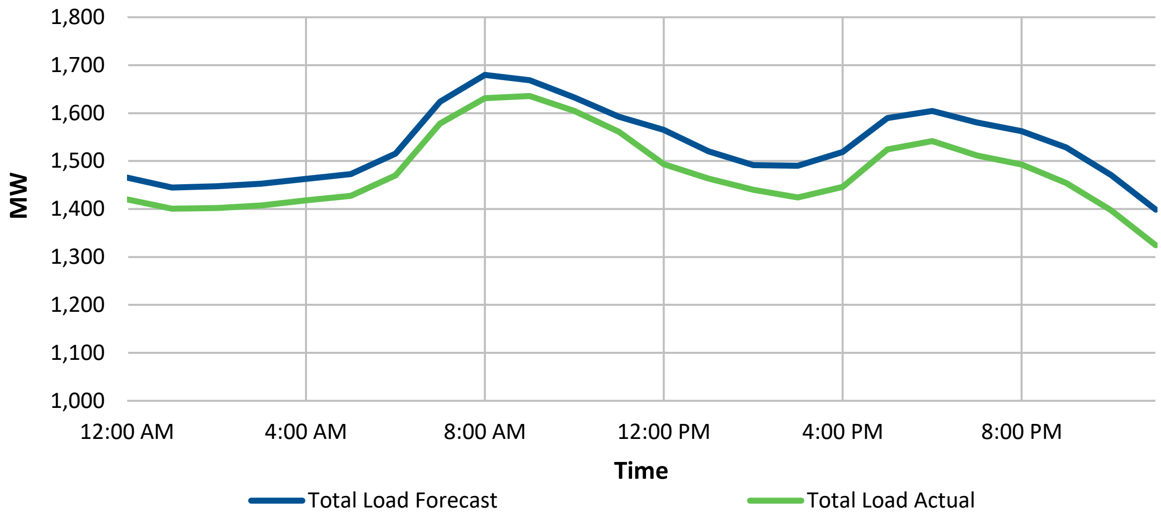

Chart 6: Forecast vs Actual Total Load for January 26, 2026

1 Chart 7 shows the hourly distribution of the utility load forecast only. The hourly forecast predicted a
2 utility peak at 8:00 a.m. of 1,584 MW; the actual peak was 1,585 MW, resulting in an underestimate of
3 0.1%. The load forecast at the time of peak was 1,573 MW.

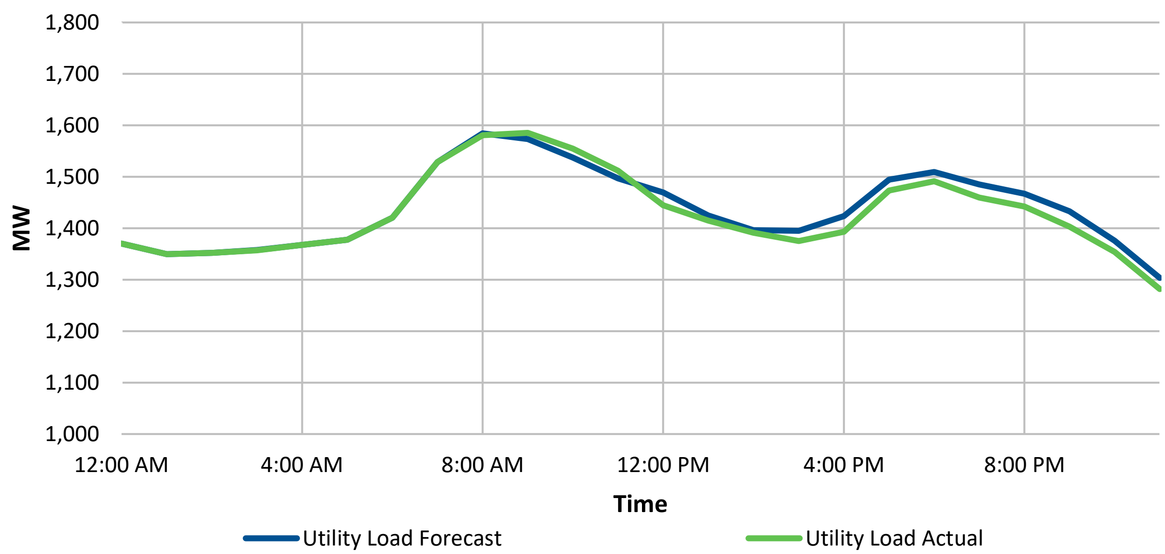

Chart 7: Forecast vs Actual Utility Load for January 26, 2026

1 Chart 8 shows the actual temperature in St. John's compared to the forecast. The temperature was close
2 to forecast at the time of peak and was slightly higher later in the day.

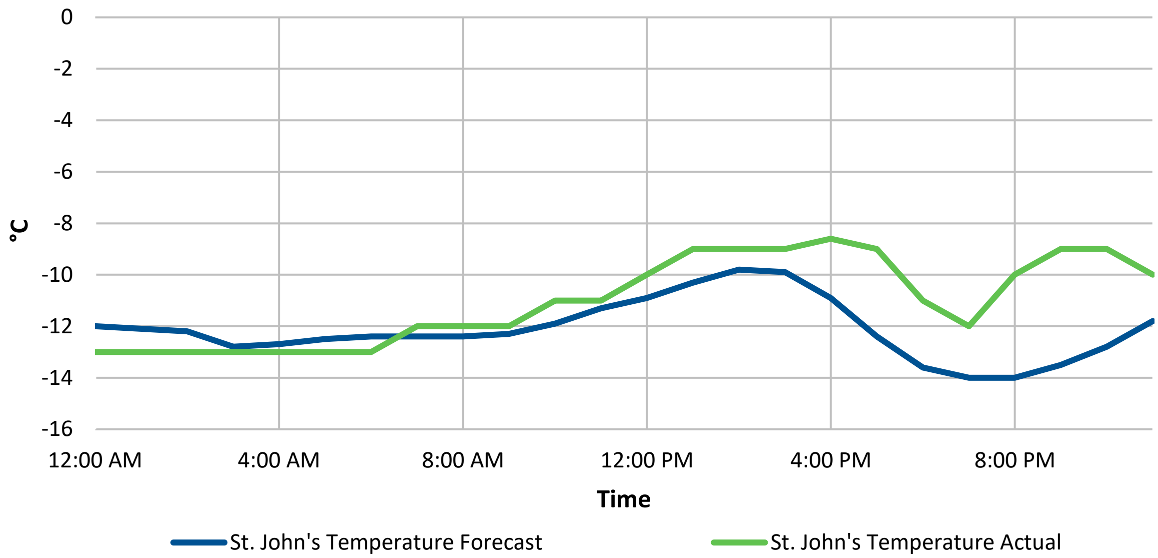

Chart 8: Forecast vs Actual Temperature for January 26, 2026

3 Chart 9 shows the actual wind speed in St. John's compared to the forecast. The actual wind speed was
4 lower than forecast at the time of peak.

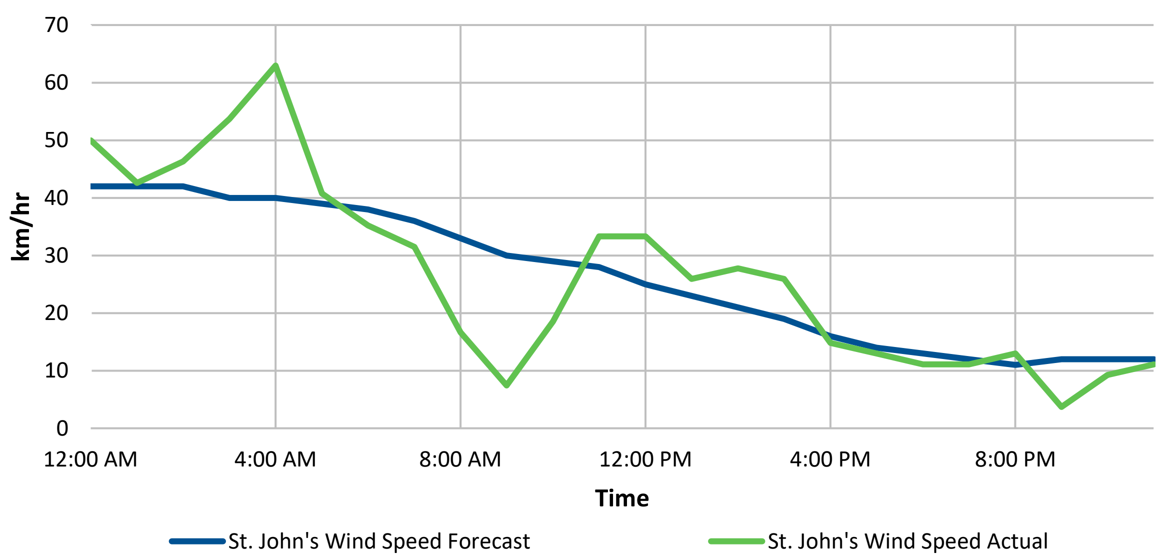

Chart 9: Forecast vs Actual Wind Speed for January 26, 2026

Chart 10 shows the actual cloud cover in St. John's compared to the forecast. It was cloudier than forecast for most of the day.

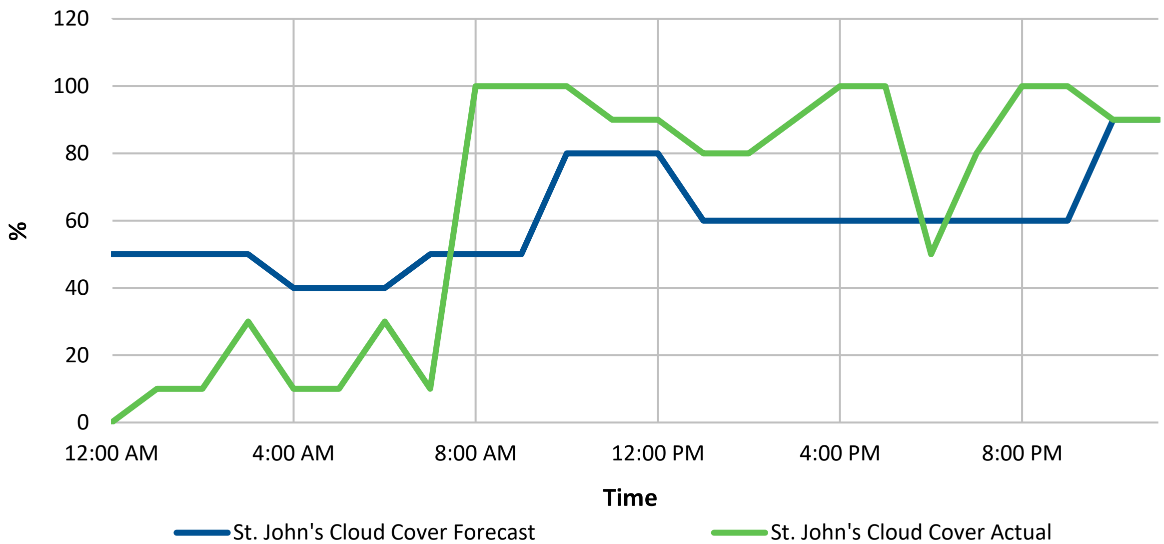

Chart 10: Forecast vs Actual Cloud Cover for January 26, 2026

The load forecast for Hydro's peak day was under 1% and well within acceptable forecast limits.

2.3.3 February 2026

In February 2026, the forecast utility peak was 1,362 MW on February 5, 2026, which is consistent with the actual utility peak of 1,367 MW on that day. Absolute error was 19 MW on average, with an average percent error[31] of -0.9%, an average absolute error[32] of 1.6%, and an average actual/forecast of -0.9%.

February 2026 did not have any of the three highest error winter peak days.

2.3.4 March 2026

In March 2026, the forecast utility peak was 1,511 MW on March 4, 2026, which is consistent with the actual utility peak for that day of 1,481 MW. Absolute error was 27 MW on average, with an average percent error[33] of -0.4%, an average absolute error[34] of 2.2%, and an average actual/forecast of -0.5%

[31] Average of all daily errors.
[32] Average of all absolute value daily errors.
[33] Average of all daily errors.
[34] Average of all absolute value daily errors.

2.3.4.1 March 13, 2026

Table 3 provides a summary of forecast peak data for March 13, 2026.

Table 3: Peak Data Summary for March 13, 2026

	Load (MW)	Time	Error (%)[35]	Temperature Delta (°C)[36]	Wind Speed Delta (km/h)[37]
Utility Forecast	1,045	9:00 p.m.	-7.4	(1.00)	(11.00)
Utility Actual	1,128	9:00 p.m.		(1.00)	(11.00)
Island Forecast	1,201	9:00 p.m.	-4.1	(1.00)	(11.00)
Island Actual	1,253	10:00 p.m.		0.00	(17.00)
Board Forecast	1,200	N/A	N/A	N/A	N/A
Board Actual	1,269				

The forecast peak at 7:20 a.m., as reported to the Board, was 1,200 MW; the actual reported peak was 1,269 MW. Chart 11 to Chart 15 include hourly plots of forecast and actual values to assist in determining the sources of the differences between actual and forecast loads.

Chart 11 shows the hourly distribution of the total load forecast compared to the actual load, exclusive of export activity. The hourly forecast predicted a 9:00 p.m. peak of 1,201 MW; the actual peak was 1,253 MW[38] and occurred at 10:00 p.m., resulting in an underestimate of 4.1%. The load forecast at the time of peak was 1,195 MW.

[35] Negative percentages indicate an under-forecasted peak. Positive percentages indicate an over-forecasted peak.
[36] Temperature difference at forecast peak and actual peak. Negative values indicate that the temperature was warmer than forecast. Positive values indicate the temperature was colder than forecast.
[37] Wind speed difference at the forecast peak and the actual peak. Negative values indicate wind speed was more than forecast. Positive values indicate the wind speed was less than forecast.
[38] The actual total peak reported in the daily Supply and Demand Status reports is based on a five-minute time step; however, the load forecasting software reports on an hourly time step, sometimes resulting in a different peak value.

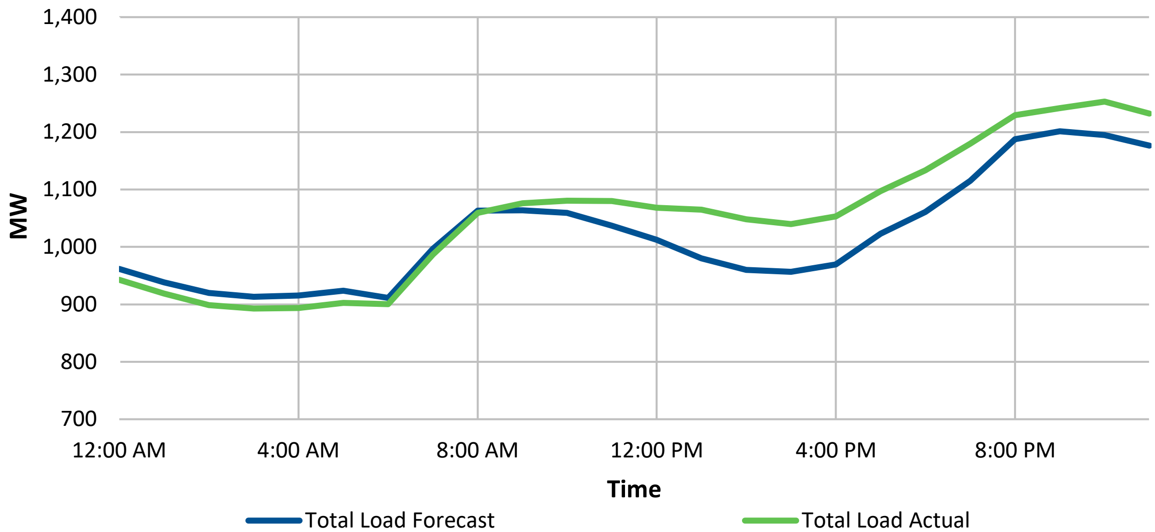

Chart 11: Forecast vs Actual Total Load for March 13, 2026

1 Chart 12 shows the hourly distribution of the utility load forecast only. The hourly forecast predicted a
2 utility peak at 9:00 p.m. of 1,045 MW; the actual peak was 1,128 MW and occurred at 9:00 p.m.,
3 resulting in an underestimate of 7.4%.

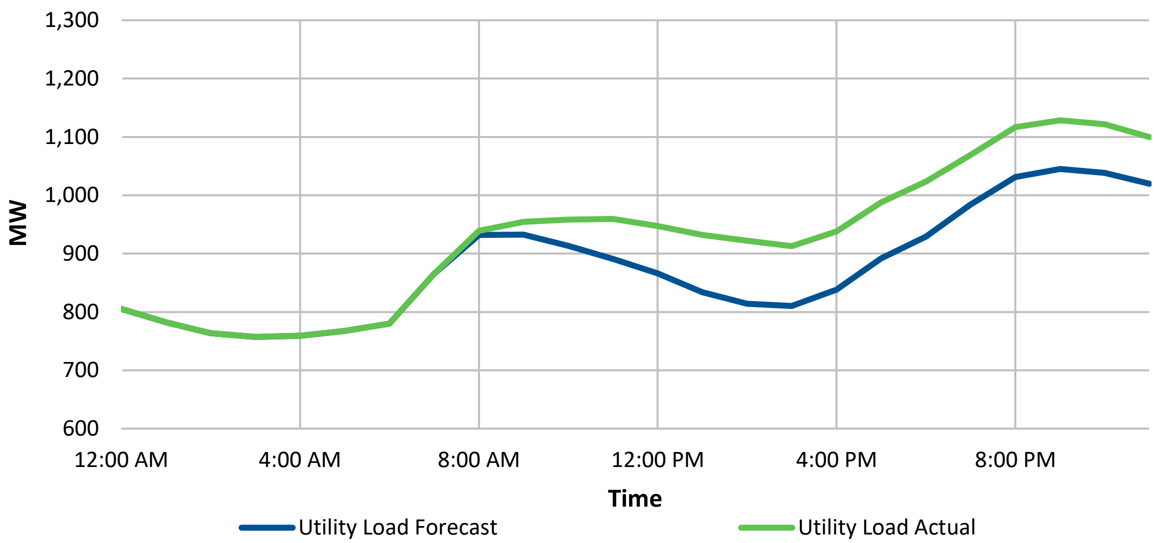

Chart 12: Forecast vs Actual Utility Load for March 13, 2026

1 Chart 13 shows the actual temperature in St. John's compared to the forecast. The actual temperature
2 was 1°C-2°C above forecast for the beginning part of the day, and then an average of 1°C lower in the 3
3 hours leading up to peak.

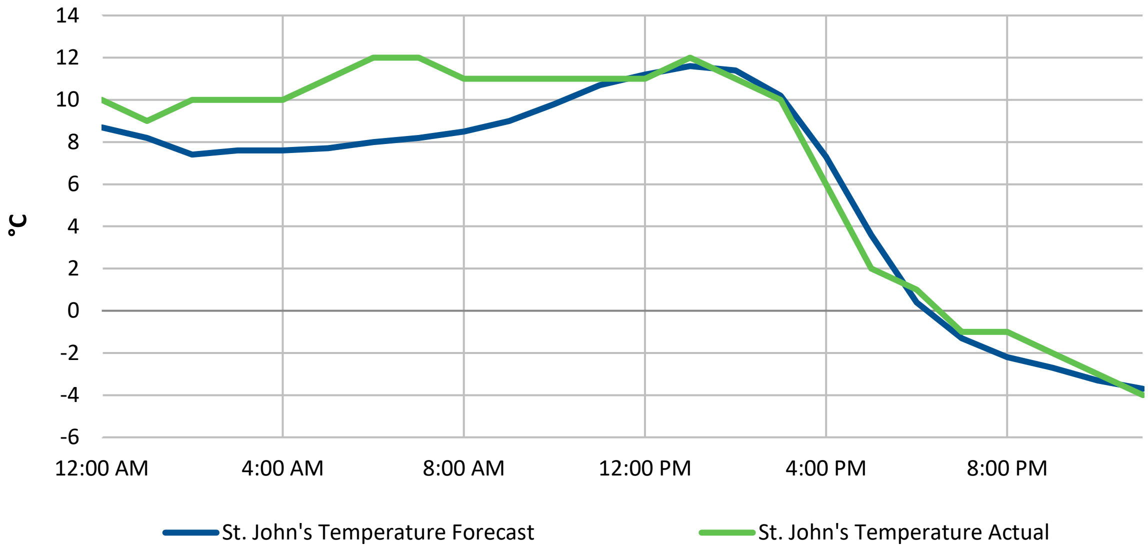

Chart 13: Forecast vs Actual Temperature for March 13, 2026

4 Chart 14 shows the actual wind speed in St. John's compared to the forecast. The actual wind speed was
5 higher than forecast for the majority of the day.

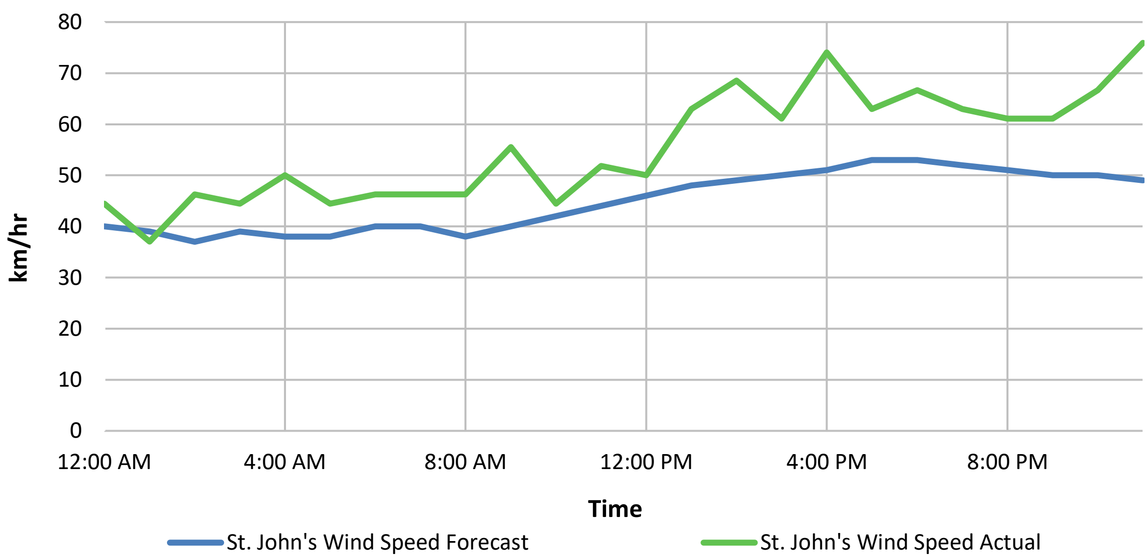

Chart 14: Forecast vs Actual Wind Speed for March 13, 2026

Chart 15 shows the actual cloud cover in St. John's compared to the forecast. It was cloudier than forecast during the daylight portion of the day.

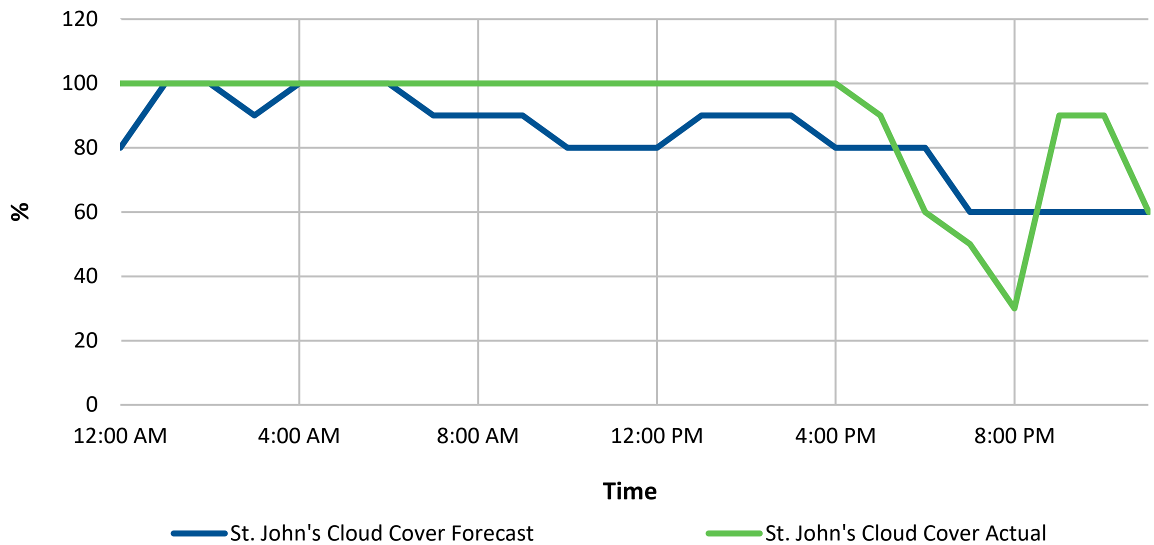

Chart 15: Forecast vs Actual Cloud Cover for March 13, 2026

The discrepancy between Utility Actual and Utility Forecast load was partially attributed to the weather forecast which was colder than forecast leading up to the peak. Other discrepancies may be attributed to forecast software error due to higher-than-average temperatures for the time of the year.

2.3.4.2 March 24, 2026

Table 4 provides a summary of forecast peak data for March 24, 2026.

Table 4: Peak Data Summary for March 24, 2026

	Load (MW)	Time	Error (%)[39]	Temperature Delta (°C)[40]	Wind Speed Delta (km/h)[41]
Utility Forecast	1,200	9:00 a.m.	-6.3	1.00	(5.00)
Utility Actual	1,281	12:00 p.m.		0.00	(2.00)
Island Forecast	1,346	9:00 a.m.	-4.5	1.00	(5.00)
Island Actual	1,411	12:00 p.m.		0.00	(2.00)
Board Forecast	1,365	N/A	N/A	N/A	N/A
Board Actual	1,434				

[39] Negative percentages indicate an under-forecasted peak. Positive percentages indicate an over-forecasted peak.
[40] Temperature difference at forecast peak and actual peak. Negative values indicate that the temperature was warmer than forecast. Positive values indicate the temperature was colder than forecast.
[41] Wind speed difference at the forecast peak and the actual peak. Negative values indicate wind speed was more than forecast. Positive values indicate the wind speed was less than forecast.

The forecast peak at 7:20 a.m., as reported to the Board, was 1,365 MW; the actual reported peak was 1,434 MW. Chart 16 to Chart 20 include hourly plots of forecast and actual values to assist in determining the sources of the differences between actual and forecast loads.

Chart 16 shows the hourly distribution of the total load forecast compared to the actual load, exclusive of export activity. The hourly forecast predicted a 9:00 a.m. peak of 1,346 MW; the actual peak was 1,411 MW[42] and occurred at 12:00 p.m., resulting in an underestimate of 4.5%. The load forecast at the time of peak was 1,259 MW.

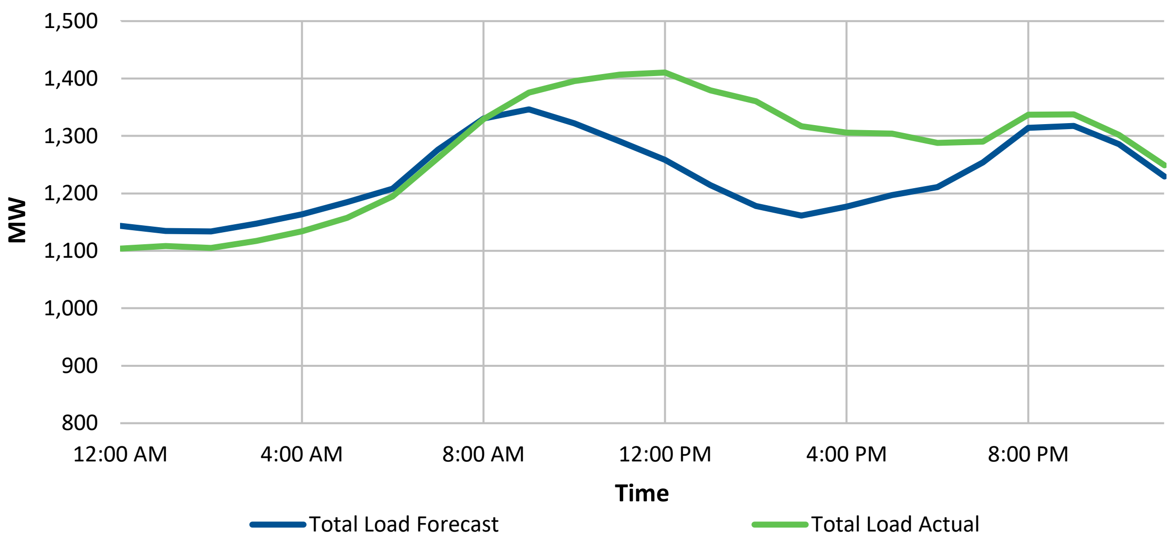

Chart 16: Forecast vs Actual Total Load for March 24, 2026

Chart 17 shows the hourly distribution of the utility load forecast only. The hourly forecast predicted a utility peak at 9:00 a.m. of 1,200 MW; the actual peak was 1,281 MW and occurred at 12:00 p.m., resulting in an underestimate of 6.3%. The load forecast at the time of peak was 1,112 MW.

[42] The actual total peak reported in the daily Supply and Demand Status reports is based on a five-minute time step; however, the load forecasting software reports on an hourly time step, sometimes resulting in a different peak value.

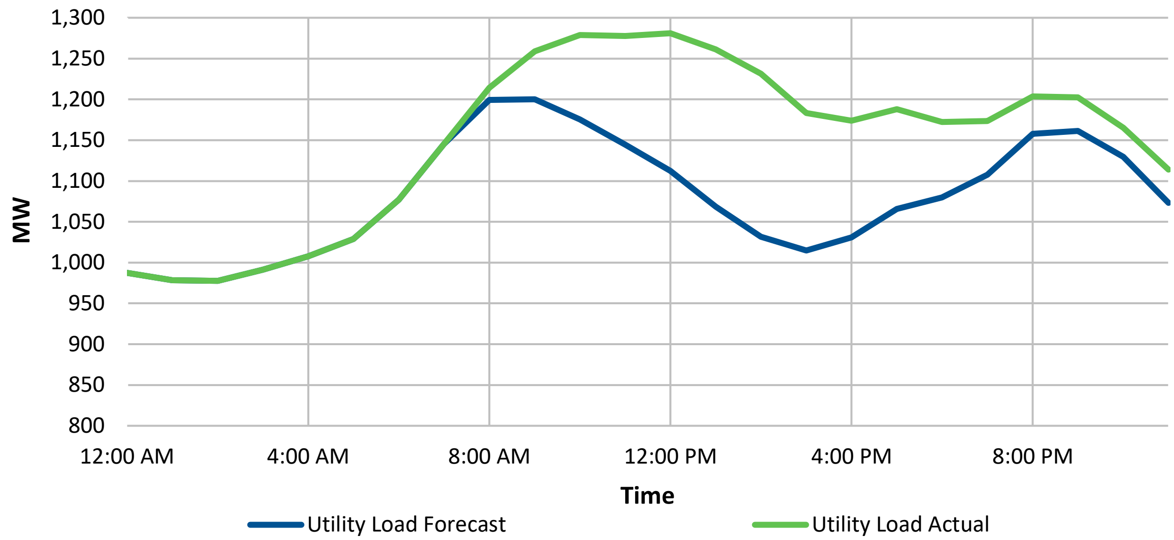

Chart 17: Forecast vs Actual Utility Load for March 24, 2026

1 Chart 18 shows the actual temperature in St. John's compared to the forecast. The actual temperature
2 was close to forecast leading up to peak and at peak.

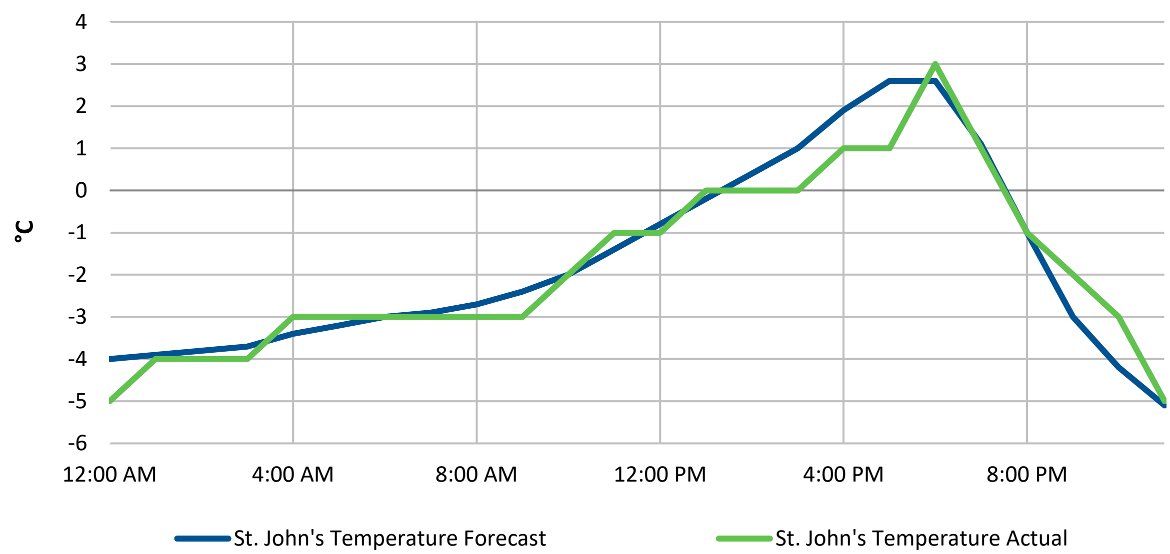

Chart 18: Forecast vs Actual Temperature for March 24, 2026

3 Chart 19 shows the actual wind speed in St. John's compared to the forecast. The actual wind speed was
4 close to forecast in the morning and lower than forecast in the afternoon.

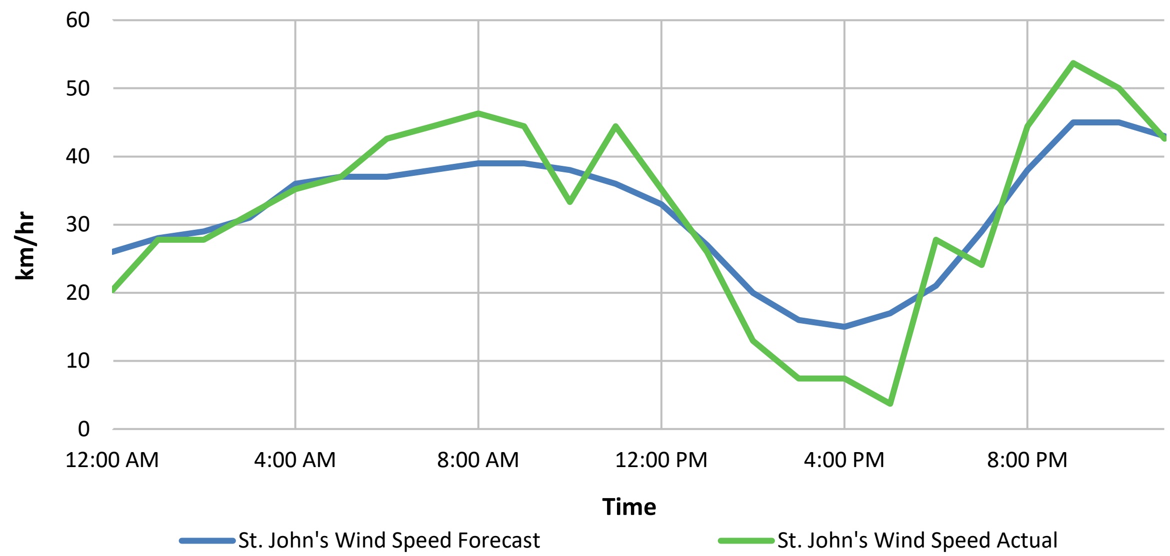

Chart 19: Forecast vs Actual Wind Speed for March 24, 2026

Chart 20 shows the actual cloud cover in St. John's compared to the forecast. It was less cloudy than forecast during the daylight portion of the day.

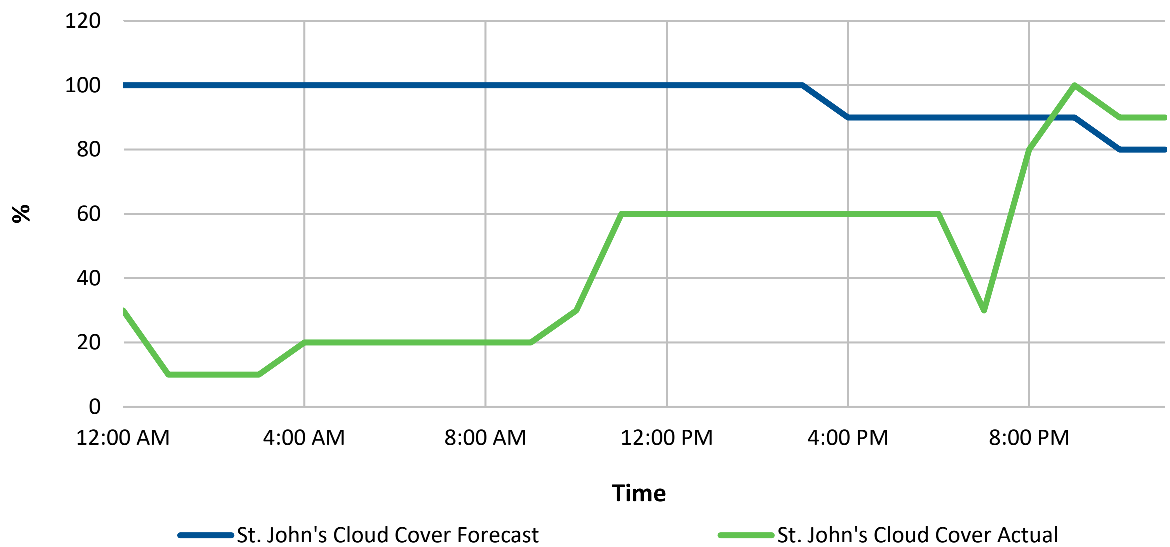

Chart 20: Forecast vs Actual Cloud Cover for March 24, 2026

The discrepancy between Utility Actual and Utility Forecast load was attributed to non-uniform customer behavior. A snowstorm on March 24, 2026, caused most schools and businesses to be closed for the day in the central and eastern parts of the Island. This resulted in a shift of peak from 9:00 a.m. to 12:00 p.m.

3.0 Forecast Accuracy Review

Table A-9 summarizes the error in the average monthly peak demand of the utility load forecast by winter month during the 2025–2026 season. The absolute percent error of the average demand for each month varied between 1.6% (February 2026) and 2.2% (March 2026), with an average of 1.9%. This is slightly lower compared to last year's observed absolute percent error for average monthly peak demand, which had an average error of 2.2%.[43] For reference, Hydro considers an error below 4.95% to be within acceptable forecasting limits. On average, the forecast typically underestimates the load, though the average understatement is -0.7% of actual peak. The average absolute error in Winter 2025–2026 was 23 MW, which compares to the average absolute error in Winter 2024–2025[44] of 26 MW.

Table A-10 summarizes the maximum statistics for the utility load forecast by winter month in 2025–2026. The maximum absolute error varied between 5.4% (February 2026) and 9.3% (December 2025). This is comparable to last year's observed winter maximum error of 9.2% (March 2025). For days that experienced the maximum errors, the forecast was typically underestimated, rather than overestimated. The largest absolute error at peak in Winter 2025–2026 was 112 MW and occurred on December 31, 2025, which fell on a Saturday.

The load forecast program uses historical data (weather and load) to predict the hourly load forecast. In the past two to three years, there has been an increase in oil to electric conversions. This impact on the load is still being "learned" by the program and may result in more underestimated loads during this period of transition.

Table A-11 summarizes the error at the ten highest utility loads during the reporting period. The highest loads in this reporting period occurred in December 2025 (one instance), January 2026 (five instances), and March 2026 (four instances). Four of the ten highest loads were overestimated and six were underestimated. The percent error varied from -2.0% to 2.3%; the overall average was 0.1%. The absolute percent error varied from 0.1% to 2.3%, with an average of 1.2%. These statistics confirm that there is no correlation between high load and high error in the load forecast, and that the short-term load forecasting software's forecasting of high loads are within the acceptable forecasting limit of less than 4.95% error.

[43] December 2024 through March 2025.
[44] December 2024 through March 2025.

Table A-12 summarizes the results of the investigations into instances of high forecast error selected based on high error in the utility load forecast against the actual utility load at peak. Common sources of error are variations in the weather forecast at or near the time of peak. Non-uniform customer behaviour is also a source of error, if a high error day occurred on the weekend or on a statutory holiday. Some errors remain unexplained; they result from unpredictable customer behavior that was not modelled correctly by the load forecasting software. Of the three included instances of high forecast error, all three occurred on a weekday.

Appendix A

Supporting Tables

newfoundland labrador hydro

Table A-1: Total Island Interconnected System Load Forecasting Data for December 2025[1]

Date	Forecast Total Peak (MW)	Actual Total Peak (MW)	Error (MW)	Error (%)	Available Island Supply[2] (MW)	Forecast Reserve[3] (MW)
1-Dec-2025	1,200	1,189	11	0.9%	1,940	740
2-Dec-2025	1,285	1,258	27	2.1%	1,950	665
3-Dec-2025	1,325	1,329	-4	-0.3%	1,896	571
4-Dec-2025	1,280	1,267	13	1.0%	2,017	737
5-Dec-2025	1,520	1,528	-8	-0.5%	2,010	490
6-Dec-2025	1,440	1,414	26	1.8%	1,961	521
7-Dec-2025	1,365	1,354	11	0.8%	2,068	703
8-Dec-2025	1,355	1,389	-34	-2.4%	2,086	731
9-Dec-2025	1,505	1,498	7	0.5%	1,961	456
10-Dec-2025	1,435	1,417	18	1.3%	2,088	653
11-Dec-2025	1,220	1,176	44	3.7%	1,754	534
12-Dec-2025	1,305	1,287	18	1.4%	1,771	466
13-Dec-2025	1,290	1,245	45	3.6%	1,818	528
14-Dec-2025	1,240	1,271	-31	-2.4%	1,960	720
15-Dec-2025	1,220	1,291	-71	-5.5%	2,095	875
16-Dec-2025	1,410	1,346	64	4.8%	1,968	558
17-Dec-2025	1,380	1,375	5	0.4%	1,847	467
18-Dec-2025	1,320	1,323	-3	-0.2%	1,901	581
19-Dec-2025	1,255	1,236	19	1.5%	2,011	756
20-Dec-2025	1,150	1,180	-30	-2.5%	2,016	866
21-Dec-2025	1,235	1,271	-36	-2.8%	1,961	726
22-Dec-2025	1,350	1,294	56	4.3%	1,934	584
23-Dec-2025	1,425	1,386	39	2.8%	2,110	685
24-Dec-2025	1,436	1,432	4	0.3%	2,086	650
25-Dec-2025	1,330	1,400	-70	-5.0%	2,055	725
26-Dec-2025	1,320	1,313	7	0.5%	2,001	681
27-Dec-2025	1,255	1,251	4	0.3%	2,013	758
28-Dec-2025	1,280	1,273	7	0.5%	2,032	752
29-Dec-2025	1,295	1,296	-1	-0.1%	2,033	738
30-Dec-2025	1,215	1,191	24	2.0%	1,871	656
31-Dec-2025	**1,195**	**1,289**	**-94**	**-7.3%**	**2,015**	**820**
Minimum	1,150	1,176	-94	-7.3%	1,754	456
Average	1,317	1,315	2	0.2%	1,975	658
Maximum	1,520	1,528	64	4.8%	2,110	875

[1] Forecast reserve does not include adjustments for interruptible load, the impact of voltage reduction, or scheduled off-Island imports.
[2] Includes total amount forecast to be delivered via the Labrador-Island Link (LIL), inclusive of exports.
[3] Includes exports via the Maritime Link.

Table A-2: Total Island Interconnected System Load Forecasting Data for January 2026[4]

Date	Forecast Total Peak (MW)	Actual Total Peak (MW)	Error (MW)	Error (%)	Available Island Supply[5] (MW)	Forecast Reserve[6] (MW)
1-Jan-2026	1,240	1,243	-3	-0.2%	1,915	675
2-Jan-2026	1,270	1,229	41	3.3%	1,985	715
3-Jan-2026	1,275	1,330	-55	-4.1%	1,961	686
4-Jan-2026	1,355	1,410	-55	-3.9%	2,057	702
5-Jan-2026	1,450	1,446	4	0.3%	1,989	539
6-Jan-2026	1,460	1,471	-11	-0.7%	2,185	725
7-Jan-2026	1,340	1,333	7	0.5%	2,173	833
8-Jan-2026	1,230	1,189	41	3.4%	1,863	633
9-Jan-2026	1,335	1,261	74	5.9%	2,127	792
10-Jan-2026	1,245	1,205	40	3.3%	1,973	728
11-Jan-2026	1,295	1,292	3	0.2%	2,000	705
12-Jan-2026	1,345	1,421	-76	-5.3%	2,114	769
13-Jan-2026	1,380	1,372	8	0.6%	1,825	445
14-Jan-2026	1,270	1,260	10	0.8%	1,844	574
15-Jan-2026	1,130	1,051	79	7.5%	1,907	777
16-Jan-2026	975	985	-10	-1.0%	1,911	936
17-Jan-2026	1,345	1,329	16	1.2%	2,005	660
18-Jan-2026	1,190	1,189	1	0.1%	1,977	787
19-Jan-2026	1,235	1,251	-16	-1.3%	1,965	730
20-Jan-2026	1,295	1,271	24	1.9%	2,068	773
21-Jan-2026	1,580	1,591	-11	-0.7%	2,262	682
22-Jan-2026	1,590	1,584	6	0.4%	1,827	237
23-Jan-2026	1,345	1,315	30	2.3%	1,647	302
24-Jan-2026	1,525	1,523	2	0.1%	1,643	118
25-Jan-2026	1,630	1,588	42	2.6%	1,750	120
26-Jan-2026	**1,680**	**1,646**	**34**	**2.1%**	**2,184**	**504**
27-Jan-2026	1,515	1,484	31	2.1%	2,091	576
28-Jan-2026	1,525	1,467	58	4.0%	2,030	505
29-Jan-2026	1,500	1,474	26	1.8%	2,050	550
30-Jan-2026	1,470	1,450	20	1.4%	2,043	573
31-Jan-2026	1,350	1,318	32	2.4%	1,925	575
Minimum	975	985	-76	-5.3%	1,643	118
Average	1,367	1,354	13	1.0%	1,977	611
Maximum	1,680	1,646	79	7.5%	2,262	936

[4] Forecast reserve does not include adjustments for interruptible load, the impact of voltage reduction, or scheduled off-Island imports.
[5] Includes total amount forecast to be delivered via the LIL, inclusive of exports.
[6] Includes exports via the Maritime Link.

Table A-3: Total Island Interconnected System Load Forecasting Data for February 2026[7]

Date	Forecast Total Peak (MW)	Actual Total Peak (MW)	Error (MW)	Error (%)	Available Island Supply[8] (MW)	Forecast Reserve[9] (MW)
1-Feb-2026	1,280	1,293	-13	-1.0%	2,017	737
2-Feb-2026	1,340	1,352	-12	-0.9%	1,995	655
3-Feb-2026	1,345	1,298	47	3.6%	2,010	665
4-Feb-2026	1,420	1,382	38	2.7%	2,016	596
5-Feb-2026	1,455	1,451	4	0.3%	1,933	478
6-Feb-2026	1,340	1,336	4	0.3%	1,953	613
7-Feb-2026	1,355	1,354	1	0.1%	2,021	666
8-Feb-2026	1,290	1,324	-34	-2.6%	1,866	576
9-Feb-2026	1,395	1,377	18	1.3%	2,158	763
10-Feb-2026	1,310	1,273	37	2.9%	1,937	627
11-Feb-2026	1,320	1,282	38	3.0%	1,990	670
12-Feb-2026	1,280	1,291	-11	-0.9%	1,879	599
13-Feb-2026	1,300	1,302	-2	-0.2%	2,011	711
14-Feb-2026	1,220	1,198	22	1.8%	1,687	467
15-Feb-2026	1,245	1,239	6	0.5%	1,759	514
16-Feb-2026	1,320	1,284	36	2.8%	2,058	738
17-Feb-2026	1,335	1,334	1	0.1%	2,248	913
18-Feb-2026	1,335	1,361	-26	-1.9%	2,087	752
19-Feb-2026	1,335	1,342	-7	-0.5%	2,060	725
20-Feb-2026	1,380	1,355	25	1.8%	2,023	643
21-Feb-2026	1,395	1,428	-33	-2.3%	1,946	551
22-Feb-2026	1,360	1,407	-47	-3.3%	2,022	662
23-Feb-2026	1,320	1,334	-14	-1.0%	2,016	696
24-Feb-2026	1,305	1,273	32	2.5%	2,002	697
25-Feb-2026	1,310	1,270	40	3.1%	2,015	705
26-Feb-2026	1,345	1,343	2	0.1%	2,025	680
27-Feb-2026	1,270	1,271	-1	-0.1%	1,939	669
28-Feb-2026	1,350	1,289	61	4.7%	2,111	761
Minimum	1,220	1,198	-47	-3.3%	1,687	467
Average	1,331	1,323	8	0.6%	1,992	662
Maximum	1,455	1,451	61	4.7%	2,248	913

[7] Forecast reserve does not include adjustments for interruptible load, the impact of voltage reduction, or scheduled off-Island imports.
[8] Includes total amount forecast to be delivered via the LIL, inclusive of exports.
[9] Includes exports via the Maritime Link.

Table A-4: Total Island Interconnected System Load Forecasting Data for March 2026[10]

Date	Forecast Total Peak (MW)	Actual Total Peak (MW)	Error (MW)	Error (%)	Available Island Supply[11] (MW)	Forecast Reserve[12] (MW)
1-Mar-2026	1,275	1,302	-27	-2.1%	1,971	696
2-Mar-2026	1,600	1,583	17	1.1%	2,341	741
3-Mar-2026	1,650	1,639	11	0.7%	2,276	626
4-Mar-2026	1,375	1,357	18	1.3%	2,244	869
5-Mar-2026	1,645	1,606	39	2.4%	2,340	695
6-Mar-2026	1,630	1,614	16	1.0%	2,417	787
7-Mar-2026	1,445	1,420	25	1.8%	2,077	632
8-Mar-2026	1,190	1,191	-1	-0.1%	1,917	727
9-Mar-2026	1,200	1,184	16	1.4%	1,883	683
10-Mar-2026	1,190	1,166	24	2.1%	2,027	837
11-Mar-2026	1,290	1,252	38	3.0%	1,994	704
12-Mar-2026	1,380	1,433	-53	-3.7%	2,149	769
13-Mar-2026	**1,200**	**1,269**	**-69**	**-5.4%**	**1,892**	**692**
14-Mar-2026	1,330	1,384	-54	-3.9%	2,011	681
15-Mar-2026	1,370	1,358	12	0.9%	1,929	559
16-Mar-2026	1,470	1,431	39	2.7%	1,940	470
17-Mar-2026	1,280	1,264	16	1.3%	1,939	659
18-Mar-2026	1,265	1,303	-38	-2.9%	1,748	483
19-Mar-2026	1,455	1,462	-7	-0.5%	2,047	592
20-Mar-2026	1,395	1,402	-7	-0.5%	1,984	589
21-Mar-2026	1,305	1,283	22	1.7%	2,064	759
22-Mar-2026	1,315	1,274	41	3.2%	1,923	608
23-Mar-2026	1,470	1,437	33	2.3%	1,867	397
24-Mar-2026	**1,365**	**1,434**	**-69**	**-4.8%**	**2,164**	**799**
25-Mar-2026	1,480	1,471	9	0.6%	2,093	613
26-Mar-2026	1,375	1,349	26	1.9%	2,008	633
27-Mar-2026	1,200	1,224	-24	-2.0%	1,971	771
28-Mar-2026	1,370	1,350	20	1.5%	2,089	719
29-Mar-2026	1,405	1,478	-73	-4.9%	2,070	665
30-Mar-2026	1,550	1,532	18	1.2%	2,149	599
31-Mar-2026	1,290	1,294	-4	-0.3%	2,190	900
Minimum	1,190	1,166	-73	-5.4%	1,748	397
Average	1,379	1,379	0	0.0%	2,055	676
Maximum	1,650	1,639	41	3.2%	2,417	900

[10] Forecast reserve does not include adjustments for interruptible load, the impact of voltage reduction, or scheduled off-Island imports.
[11] Includes total amount forecast to be delivered via the LIL, inclusive of exports.
[12] Includes exports via the Maritime Link.

Table A-5: Analysis of Utility Forecast Error for December 2025[13]

Date	Actual Utility Peak (MW)	Forecast Utility Peak (MW)	Error (MW)	Absolute Error (MW)	Error (%)	Absolute Error (%)	Actual/ Forecast (%)
1-Dec-2025	1,118	1,111	-8	8	-0.7%	0.7%	-0.7%
2-Dec-2025	1,179	1,191	12	12	1.0%	1.0%	1.0%
3-Dec-2025	1,259	1,232	-26	26	-2.1%	2.1%	-2.1%
4-Dec-2025	1,189	1,185	-4	4	-0.4%	0.4%	-0.4%
5-Dec-2025	1,443	1,431	-12	12	-0.8%	0.8%	-0.8%
6-Dec-2025	1,340	1,344	4	4	0.3%	0.3%	0.3%
7-Dec-2025	1,271	1,269	-2	2	-0.2%	0.2%	-0.2%
8-Dec-2025	1,312	1,263	-48	48	-3.7%	3.7%	-3.8%
9-Dec-2025	1,416	1,408	-8	8	-0.5%	0.5%	-0.5%
10-Dec-2025	1,344	1,346	2	2	0.1%	0.1%	0.1%
11-Dec-2025	1,104	1,128	23	23	2.1%	2.1%	2.1%
12-Dec-2025	1,218	1,208	-10	10	-0.9%	0.9%	-0.9%
13-Dec-2025	1,174	1,199	25	25	2.1%	2.1%	2.1%
14-Dec-2025	1,194	1,147	-47	47	-3.9%	3.9%	-4.1%
15-Dec-2025	1,206	1,131	-75	75	-6.2%	6.2%	-6.6%
16-Dec-2025	1,270	1,314	44	44	3.5%	3.5%	3.4%
17-Dec-2025	1,291	1,285	-7	7	-0.5%	0.5%	-0.5%
18-Dec-2025	1,249	1,222	-27	27	-2.1%	2.1%	-2.2%
19-Dec-2025	1,156	1,164	8	8	0.7%	0.7%	0.7%
20-Dec-2025	1,096	1,054	-42	42	-3.8%	3.8%	-4.0%
21-Dec-2025	1,196	1,136	-60	60	-5.0%	5.0%	-5.3%
22-Dec-2025	1,210	1,253	44	44	3.6%	3.6%	3.5%
23-Dec-2025	1,307	1,328	21	21	1.6%	1.6%	1.6%
24-Dec-2025	1,344	1,346	2	2	0.2%	0.2%	0.2%
25-Dec-2025	1,318	1,238	-80	80	-6.1%	6.1%	-6.5%
26-Dec-2025	1,246	1,222	-24	24	-1.9%	1.9%	-1.9%
27-Dec-2025	1,170	1,165	-5	5	-0.4%	0.4%	-0.4%
28-Dec-2025	1,194	1,189	-4	4	-0.4%	0.4%	-0.4%
29-Dec-2025	1,202	1,201	-1	1	-0.1%	0.1%	-0.1%
30-Dec-2025	1,105	1,125	20	20	1.8%	1.8%	1.8%
31-Dec-2025	**1,207**	**1,096**	**-112**	**112**	**-9.3%**	**9.3%**	**-10.2%**
Minimum	1,096	1,054	-112	1	-9.3%	0.1%	-10.2%
Average	1,236	1,224	-13	26	-1.0%	2.1%	-1.1%
Maximum	1,443	1,431	44	112	3.6%	9.3%	3.5%

[13] Lines that have been bolded indicate further examination of the hourly forecast provided in this report.

Table A-6: Analysis of Utility Forecast Error for January 2026[14]

Date	Actual Utility Peak (MW)	Forecast Utility Peak (MW)	Error (MW)	Absolute Error (MW)	Error (%)	Absolute Error (%)	Actual/ Forecast (%)
1-Jan-2026	1,159	1,148	-11	11	-0.9%	0.9%	-0.9%
2-Jan-2026	1,143	1,174	30	30	2.7%	2.7%	2.6%
3-Jan-2026	1,243	1,182	-61	61	-4.9%	4.9%	-5.2%
4-Jan-2026	1,324	1,263	-62	62	-4.7%	4.7%	-4.9%
5-Jan-2026	1,359	1,352	-7	7	-0.5%	0.5%	-0.5%
6-Jan-2026	1,386	1,363	-22	22	-1.6%	1.6%	-1.6%
7-Jan-2026	1,241	1,244	4	4	0.3%	0.3%	0.3%
8-Jan-2026	1,133	1,139	5	5	0.5%	0.5%	0.5%
9-Jan-2026	1,202	1,242	39	39	3.3%	3.3%	3.2%
10-Jan-2026	1,158	1,146	-12	12	-1.1%	1.1%	-1.1%
11-Jan-2026	1,210	1,199	-11	11	-0.9%	0.9%	-0.9%
12-Jan-2026	1,292	1,244	-47	47	-3.7%	3.7%	-3.8%
13-Jan-2026	1,286	1,287	1	1	0.1%	0.1%	0.1%
14-Jan-2026	1,176	1,175	0	0	0.0%	0.0%	0.0%
15-Jan-2026	976	1,038	62	62	6.3%	6.3%	6.0%
16-Jan-2026	916	885	-31	31	-3.4%	3.4%	-3.5%
17-Jan-2026	1,268	1,248	-20	20	-1.6%	1.6%	-1.6%
18-Jan-2026	1,111	1,095	-16	16	-1.5%	1.5%	-1.5%
19-Jan-2026	1,181	1,142	-39	39	-3.3%	3.3%	-3.4%
20-Jan-2026	1,191	1,192	1	1	0.1%	0.1%	0.1%
21-Jan-2026	1,508	1,480	-28	28	-1.9%	1.9%	-1.9%
22-Jan-2026	1,502	1,492	-9	9	-0.6%	0.6%	-0.6%
23-Jan-2026	1,231	1,243	12	12	1.0%	1.0%	1.0%
24-Jan-2026	1,460	1,431	-29	29	-2.0%	2.0%	-2.0%
25-Jan-2026	1,535	1,533	-1	1	-0.1%	0.1%	-0.1%
26-Jan-2026	**1,585**	**1,584**	**-1**	**1**	**-0.1%**	**0.1%**	**-0.1%**
27-Jan-2026	1,437	1,410	-27	27	-1.9%	1.9%	-1.9%
28-Jan-2026	1,400	1,424	24	24	1.7%	1.7%	1.7%
29-Jan-2026	1,404	1,399	-4	4	-0.3%	0.3%	-0.3%
30-Jan-2026	1,380	1,368	-12	12	-0.9%	0.9%	-0.9%
31-Jan-2026	1,251	1,254	3	3	0.2%	0.2%	0.2%
Minimum	916	885	-62	0	-4.9%	0.0%	-5.2%
Average	1,279	1,270	-9	20	-0.6%	1.7%	-0.7%
Maximum	1,585	1,584	62	62	6.3%	6.3%	6.0%

[14] Lines that have been bolded indicate further examination of the hourly forecast provided in this report.

Table A-7: Analysis of Utility Forecast Error for February 2026

Date	Actual Utility Peak (MW)	Forecast Utility Peak (MW)	Error (MW)	Absolute Error (MW)	Error (%)	Absolute Error (%)	Actual/ Forecast (%)
1-Feb-2026	1,218	1,187	-31	31	-2.6%	2.6%	-2.6%
2-Feb-2026	1,280	1,241	-39	39	-3.1%	3.1%	-3.2%
3-Feb-2026	1,246	1,247	2	2	0.1%	0.1%	0.1%
4-Feb-2026	1,315	1,325	10	10	0.8%	0.8%	0.8%
5-Feb-2026	1,367	1,362	-5	5	-0.4%	0.4%	-0.4%
6-Feb-2026	1,248	1,243	-5	5	-0.4%	0.4%	-0.4%
7-Feb-2026	1,267	1,258	-9	9	-0.7%	0.7%	-0.7%
8-Feb-2026	1,231	1,197	-34	34	-2.8%	2.8%	-2.9%
9-Feb-2026	1,276	1,262	-14	14	-1.1%	1.1%	-1.1%
10-Feb-2026	1,182	1,178	-4	4	-0.4%	0.4%	-0.4%
11-Feb-2026	1,190	1,190	0	0	0.0%	0.0%	0.0%
12-Feb-2026	1,162	1,152	-10	10	-0.9%	0.9%	-0.9%
13-Feb-2026	1,209	1,168	-41	41	-3.4%	3.4%	-3.5%
14-Feb-2026	1,078	1,086	8	8	0.7%	0.7%	0.7%
15-Feb-2026	1,134	1,090	-44	44	-3.9%	3.9%	-4.1%
16-Feb-2026	1,177	1,185	7	7	0.6%	0.6%	0.6%
17-Feb-2026	1,205	1,204	-1	1	-0.1%	0.1%	-0.1%
18-Feb-2026	1,236	1,202	-34	34	-2.8%	2.8%	-2.8%
19-Feb-2026	1,206	1,199	-7	7	-0.6%	0.6%	-0.6%
20-Feb-2026	1,221	1,247	27	27	2.2%	2.2%	2.1%
21-Feb-2026	1,296	1,259	-37	37	-2.8%	2.8%	-2.9%
22-Feb-2026	1,264	1,229	-35	35	-2.8%	2.8%	-2.9%
23-Feb-2026	1,197	1,181	-16	16	-1.4%	1.4%	-1.4%
24-Feb-2026	1,175	1,162	-12	12	-1.0%	1.0%	-1.0%
25-Feb-2026	1,190	1,180	-10	10	-0.9%	0.9%	-0.9%
26-Feb-2026	1,225	1,208	-18	18	-1.5%	1.5%	-1.5%
27-Feb-2026	1,135	1,123	-12	12	-1.1%	1.1%	-1.1%
28-Feb-2026	1,137	1,199	62	62	5.4%	5.4%	5.2%
Minimum	1,078	1,086	-44	0	-3.9%	0.0%	-4.1%
Average	1,217	1,206	-11	19	-0.9%	1.6%	-0.9%
Maximum	1,367	1,362	62	62	5.4%	5.4%	5.2%

Table A-8: Analysis of Utility Forecast Error for March 2026[15]

Date	Actual Utility Peak (MW)	Forecast Utility Peak (MW)	Error (MW)	Absolute Error (MW)	Error (%)	Absolute Error (%)	Actual/ Forecast (%)
1-Mar-2026	1,154	1,127	-27	27	-2.3%	2.3%	-2.4%
2-Mar-2026	1,440	1,443	3	3	0.2%	0.2%	0.2%
3-Mar-2026	1,481	1,511	30	30	2.0%	2.0%	2.0%
4-Mar-2026	1,252	1,246	-6	6	-0.5%	0.5%	-0.5%
5-Mar-2026	1,467	1,494	27	27	1.8%	1.8%	1.8%
6-Mar-2026	1,456	1,489	33	33	2.3%	2.3%	2.2%
7-Mar-2026	1,281	1,301	20	20	1.5%	1.5%	1.5%
8-Mar-2026	1,037	1,040	3	3	0.3%	0.3%	0.3%
9-Mar-2026	1,050	1,064	14	14	1.3%	1.3%	1.3%
10-Mar-2026	1,044	1,058	14	14	1.4%	1.4%	1.4%
11-Mar-2026	1,104	1,132	28	28	2.5%	2.5%	2.5%
12-Mar-2026	1,291	1,225	-65	65	-5.1%	5.1%	-5.3%
13-Mar-2026	**1,128**	**1,045**	**-83**	**83**	**-7.4%**	**7.4%**	**-8.0%**
14-Mar-2026	1,243	1,190	-52	52	-4.2%	4.2%	-4.4%
15-Mar-2026	1,208	1,212	3	3	0.3%	0.3%	0.3%
16-Mar-2026	1,323	1,323	0	0	0.0%	0.0%	0.0%
17-Mar-2026	1,125	1,114	-11	11	-1.0%	1.0%	-1.0%
18-Mar-2026	1,153	1,102	-51	51	-4.5%	4.5%	-4.7%
19-Mar-2026	1,322	1,308	-15	15	-1.1%	1.1%	-1.1%
20-Mar-2026	1,263	1,262	-1	1	-0.1%	0.1%	-0.1%
21-Mar-2026	1,148	1,173	25	25	2.2%	2.2%	2.2%
22-Mar-2026	1,142	1,156	14	14	1.2%	1.2%	1.2%
23-Mar-2026	1,307	1,328	22	22	1.6%	1.6%	1.6%
24-Mar-2026	**1,281**	**1,200**	**-81**	**81**	**-6.3%**	**6.3%**	**-6.7%**
25-Mar-2026	1,323	1,347	24	24	1.8%	1.8%	1.8%
26-Mar-2026	1,221	1,240	19	19	1.6%	1.6%	1.5%
27-Mar-2026	1,078	1,062	-16	16	-1.4%	1.4%	-1.5%
28-Mar-2026	1,195	1,224	29	29	2.4%	2.4%	2.4%
29-Mar-2026	1,320	1,257	-63	63	-4.7%	4.7%	-5.0%
30-Mar-2026	1,373	1,416	43	43	3.2%	3.2%	3.1%
31-Mar-2026	1,157	1,150	-8	8	-0.7%	0.7%	-0.7%
Minimum	1,037	1,040	-83	0	-7.4%	0.0%	-8.0%
Average	1,238	1,233	-4	27	-0.4%	2.2%	-0.5%
Maximum	1,481	1,511	43	83	3.2%	7.4%	3.1%

[15] Lines that have been bolded indicate further examination of the hourly forecast provided in this report.

Table A-9: Monthly Peak Utility Load Error Summary – Average Error

Date	Actual Utility Peak (MW)	Forecast Utility Peak (MW)	Error (MW)	Absolute Error (MW)	Error (%)	Absolute Error (%)	Actual/ Forecast (%)
Dec 2025	1,236	1,224	-13	26	-1.0%	2.1%	-1.1%
Jan 2026	1,279	1,270	-9	20	-0.6%	1.7%	-0.7%
Feb 2026	1,217	1,206	-11	19	-0.9%	1.6%	-0.9%
Mar 2026	1,238	1,233	-4	27	-0.4%	2.2%	-0.5%
Total Average	1,242	1,233	-9	23	-0.7%	1.9%	-0.8%

Table A-10: Monthly Peak Utility Load Error Summary – Maximum Statistics[16]

Date	Actual Utility Peak (MW)	Forecast Utility Peak (MW)	Error (MW)	Absolute Error (MW)	Error (%)	Absolute Error (%)	Actual/ Forecast (%)
Dec 2025	1,443	1,431	44	112	3.6%	9.3%	3.5%
Jan 2026	1,585	1,584	62	62	6.3%	6.3%	6.0%
Feb 2026	1,367	1,362	62	62	5.4%	5.4%	5.2%
Mar 2026	1,481	1,511	43	83	3.2%	7.4%	3.1%
Winter	1,469	1,472	53	80	4.6%	7.1%	4.4%

Table A-11: Error in Ten Highest Utility Loads

Date	Actual Utility Peak (MW)	Forecast Utility Peak (MW)	Error (MW)	Absolute Error (MW)	Error (%)	Absolute Error (%)	Actual/ Forecast (%)
26-Jan-2026	1,585	1,584	-1	1	-0.1%	0.1%	-0.1%
25-Jan-2026	1,535	1,533	-1	1	-0.1%	0.1%	-0.1%
21-Jan-2026	1,508	1,480	-28	28	-1.9%	1.9%	-1.9%
22-Jan-2026	1,502	1,492	-9	9	-0.6%	0.6%	-0.6%
3-Mar-2026	1,481	1,511	30	30	2.0%	2.0%	2.0%
5-Mar-2026	1,467	1,494	27	27	1.8%	1.8%	1.8%
24-Jan-2026	1,460	1,431	-29	29	-2.0%	2.0%	-2.0%
6-Mar-2026	1,456	1,489	33	33	2.3%	2.3%	2.2%
5-Dec-2025	1,443	1,431	-12	12	-0.8%	0.8%	-0.8%
2-Mar-2026	1,440	1,443	3	3	0.2%	0.2%	0.2%
Average	1,488	1,489	1	17	0.1%	1.2%	0.1%

[16] The maximum forecast, the maximum peak, and the maximum error do not necessarily occur on the same day.

Table A-12: Summary of Forecast Issues

Date	Actual Utility Peak (MW)	Forecast Utility Peak (MW)	Error (MW)	Absolute Error (MW)	Error (%)	Explanation
31-Dec-2025	1,207	1,096	-112	112	-9.3%	Non-Uniform Customer Behaviour/Error in Weather Data
13-Mar-2026	1,128	1,045	-83	83	-7.4%	Error in Weather Data/Under estimate by load forecasting software
24-Mar-2026	1,252	1,246	-6	6	-0.5%	Non-Uniform Customer Behaviour

Appendix B

Supporting Charts

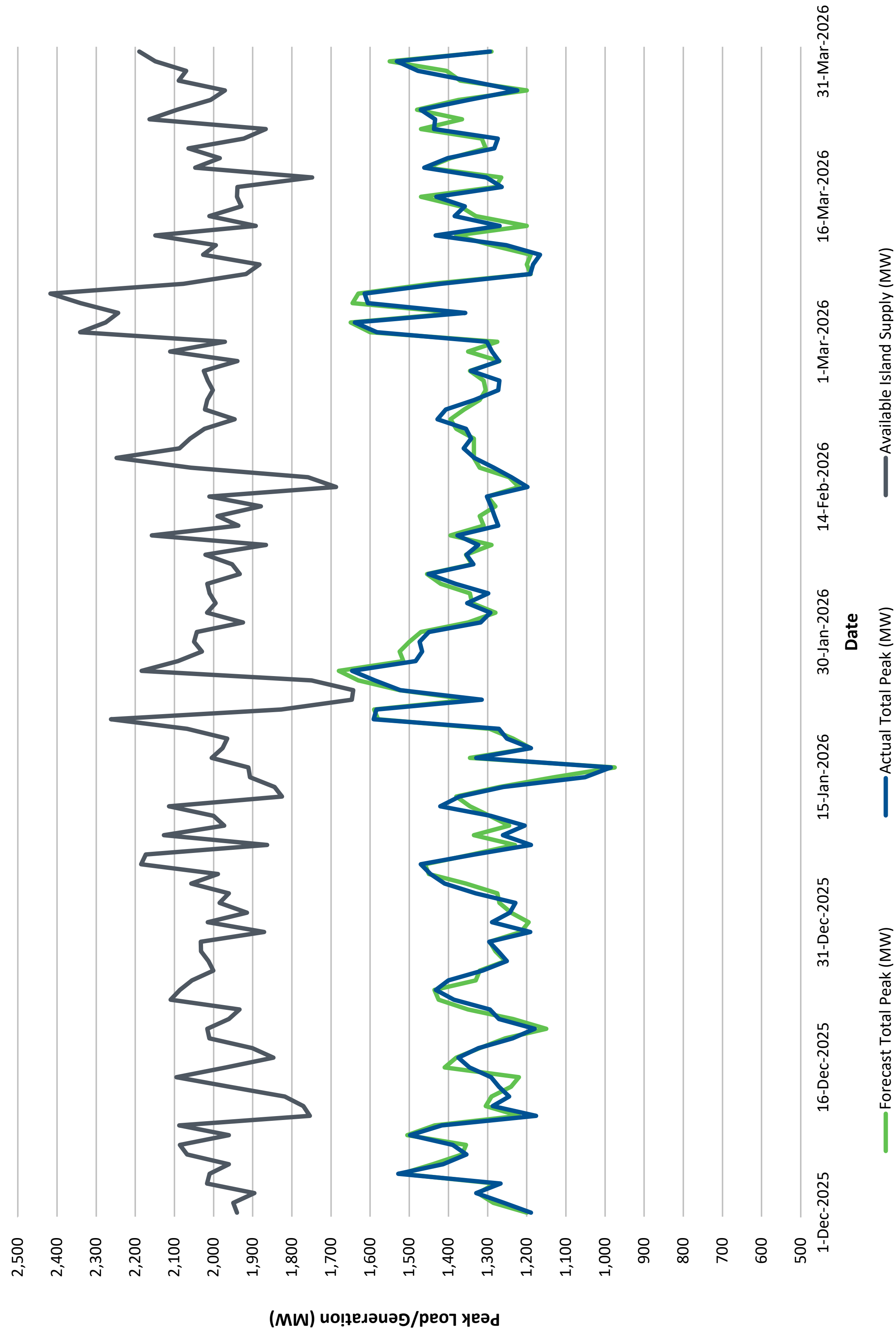

Chart B-1: Peak Forecast, Total Load, and Available Supply from December 2025 through March 2026

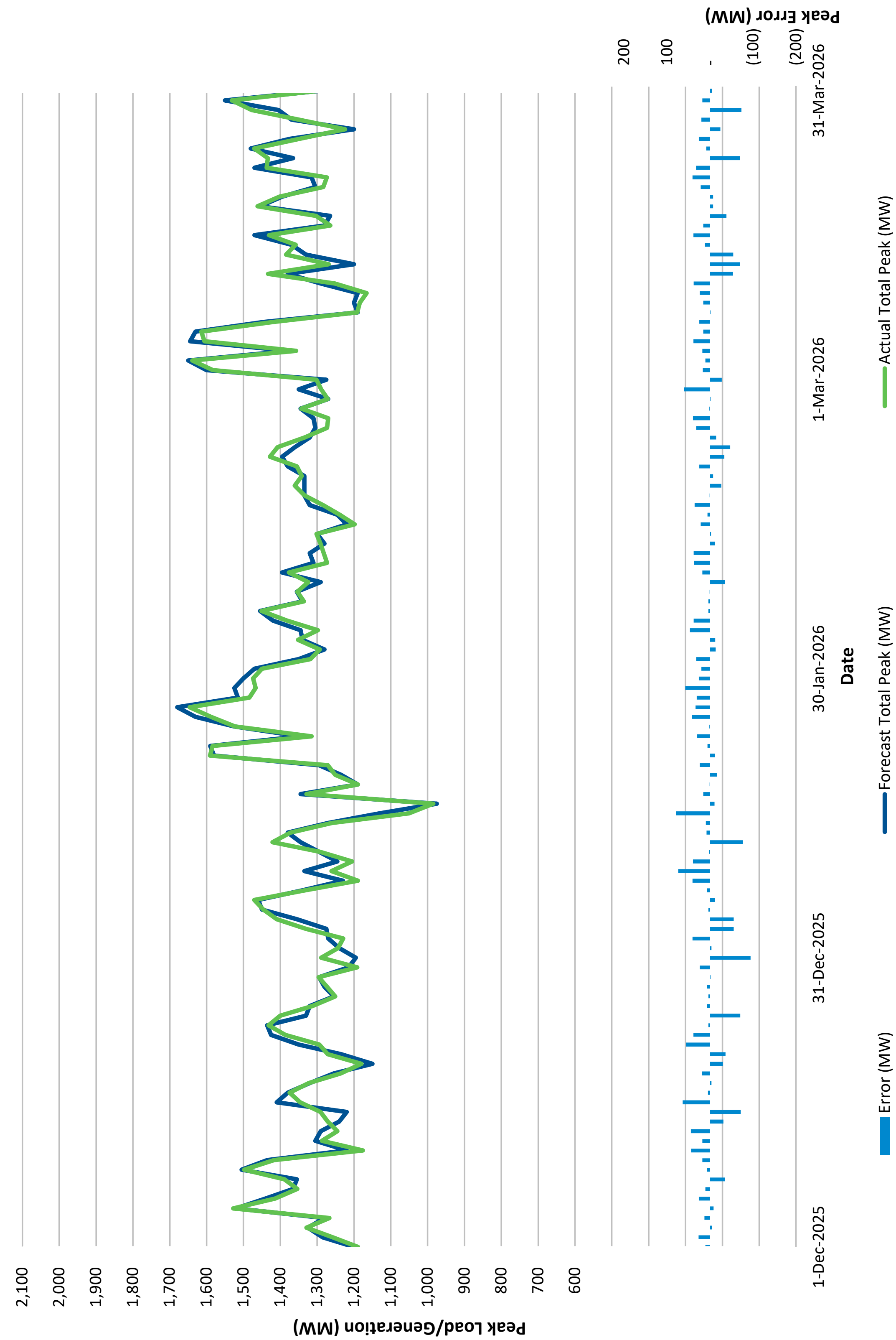

Chart B-2: Peak Forecast, Total Load, and Error from December 2025 through March 2026

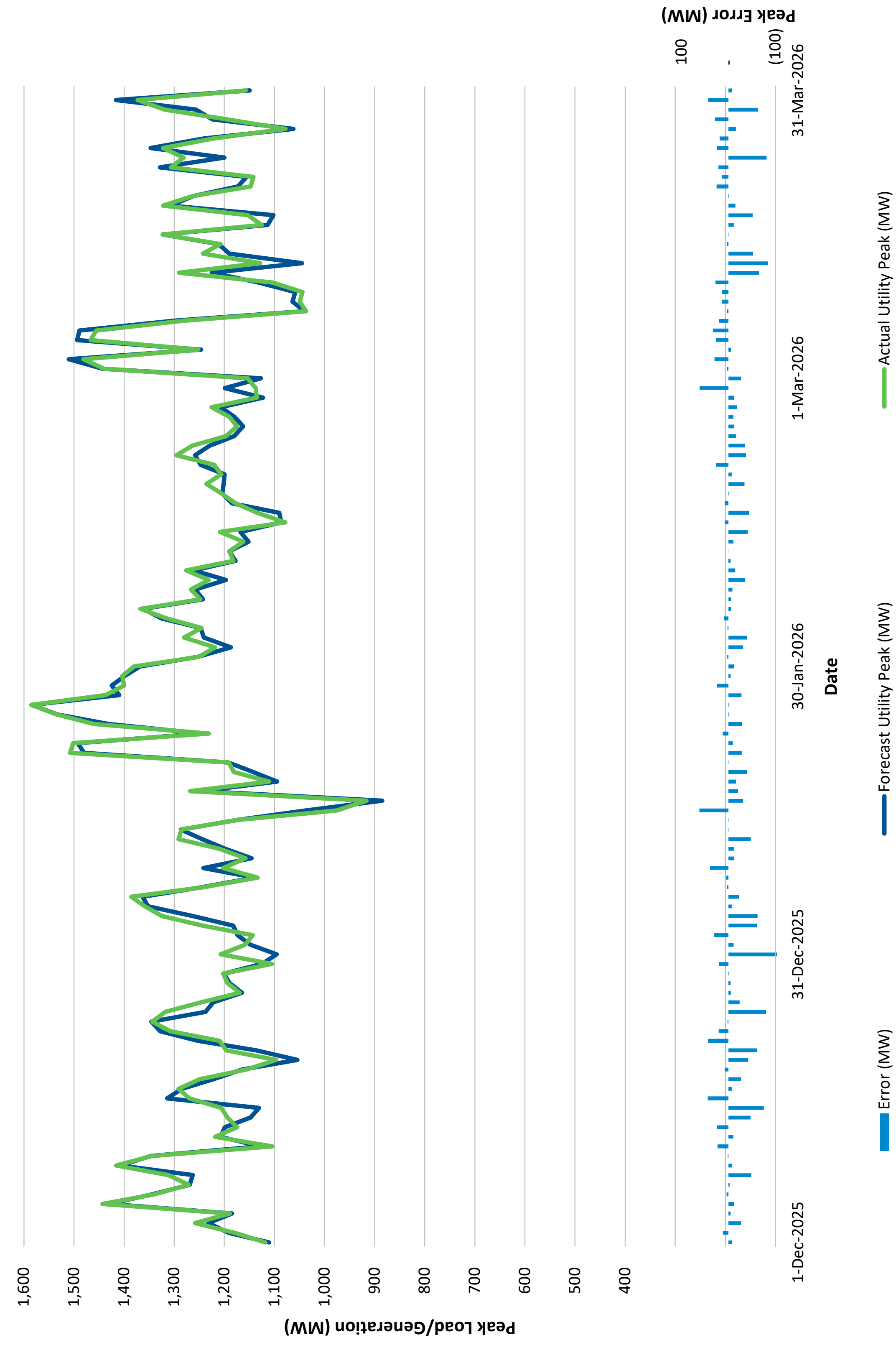

Chart B-3: Peak Forecast, Utility Load, and Error from December 2025 through March 2026