newfoundland labrador hydro

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June 30, 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: *Reliability and Resource Adequacy Study Review* – Semi-Annual Update for the Second Quarter of 2026

In 2025, as part of the Settlement Agreement[1] entered into between the parties to the *Reliability and Resource Adequacy Study Review* proceeding ("*RRA Study Review*"), Newfoundland and Labrador Hydro ("Hydro") committed to providing a semi-annual status update regarding the work ongoing in planning for reliability and resource adequacy for the Island Interconnected System, including information to address specific requests by the Board of Commissioners of Public Utilities ("Board").[2]

This update is made in compliance with that provision of the Settlement Agreement. Throughout the *RRA Study Review*, Hydro has committed to providing other updates to the Board,[3,4] which are also included herein.

1.0 Background

Through Hydro's ongoing *RRA Study Review*, Hydro identified the need for additional generation to meet load growth and system reliability requirements. In the 2024 Resource Adequacy Plan,[5] Hydro focused on the production of an Island Interconnected System Expansion Plan that satisfied both capacity and energy requirements. The 2024 Resource Adequacy Plan assessed the integration of new assets, retirement of existing aging assets, system reliability, and the effects of electrification and decarbonization across various scenarios. The analysis highlights that, in all modeled scenarios, urgent investment in increased electrical supply is essential and justified to maintain a reliable power supply for customers on the Island. The 2024 Resource Adequacy Plan also demonstrated that retirement of the Holyrood Thermal Generating Station ("Holyrood TGS") cannot be fully enabled until both the Avalon Combustion Turbine ("CT") and Bay d'Espoir ("BDE") Unit 8 are in service. The extension of the Holyrood TGS operations will result in combined fuel, capital, and operating costs exceeding $100 million per year.[6]

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[1] "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 2.
[2] Please refer to Section 10 of the Settlement Agreement.
[3] Please refer to Hydro's response to PUB-NLH-334 of the *RRA Study Review*.
[4] Please refer to Hydro's response to Question 11 of "2025 Build Application – Request to Hydro to Provide Additional Information – Hydro's Reply," Newfoundland and Labrador Hydro, September 11, 2025.
[5] "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024).
[6] "Newfoundland and Labrador Hydro - Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine, and Bay d'Espoir Unit 8 Project and Avalon Combustion Turbine Project Early Execution Updates for October 2025 – Request for Further Information – Hydro's Reply," Newfoundland and Labrador Hydro, December 19, 2025, p. 3.

In the 2024 Resource Adequacy Plan, Hydro recommended the Minimum Investment Required Expansion Plan that meets reliability while balancing cost and environmental considerations, as a first and significant step to meeting the expected case (also known as the "Reference Case"). The 2024 Resource Adequacy Plan's Reference Case results indicate that approximately 525 megawatts ("MW") of capacity is required by 2034. The Minimum Investment Required Expansion Plan, based on the Slow Decarbonization load forecast results, indicate a minimum of 385 MW of new capacity is required by 2034. The preferred, least-cost, environmentally responsible resource options under this recommendation are BDE Unit 8 and the Avalon CT for an approximate total of 296 MW.

On March 21, 2025, Hydro filed its application for capital expenditures for the purchase and installation of BDE Unit 8 and the Avalon CT ("2025 Build Application").

2.0 Energy and Capacity Expression of Interest Update

The 2024 Resource Adequacy Plan analysis also identified a requirement for approximately 400 MW of wind to meet its firm energy requirements. While Hydro is pursuing further studies[7] in support of reliability and supply adequacy to maximize energy delivery to the Island over the LIL, potentially reducing this requirement, Hydro launched a call for power process in 2025. This process was conducted in parallel to the 2025 Build Application process to help determine resource options and costs to meet the Island Interconnected System energy requirements; however, these potential solutions do not reduce the capacity requirements for the Island Interconnected System recommended in the 2025 Build Application.

As a first step in the call for power process, Hydro issued a Request for Expression of Interest ("EOI") on July 9, 2025, for the supply of energy and capacity that, in combination, can provide for up to 150 MW of firm capacity and up to 500 gigawatt hours ("GWh") of firm energy. The Request for EOI closed on September 2, 2025, and Hydro received 17 responses. The next step was to evaluate the responses; however, since that time, the call for power process has been and remains paused. Engagement with the Government of Newfoundland and Labrador continues, and Hydro will provide an update to the Board on progress toward such procurement in its next semi-annual report in the fourth quarter of 2026.

3.0 Fuel Supply Update

There are currently no identified issues with fuel supply for the existing Holyrood CT facility and the proposed 150 MW facility;[8] however, Hydro is continuing to study storage options to mitigate risks with long-term fuel supply.[9]

Without confirmed expansion of fuel supply investments on the Island, Hydro would not have a reliable supply of fuel that additional CTs, beyond the 150 MW Avalon CT proposed in the 2025 Build Application, would require to run reliably. This is a primary consideration for the Reference Case Expansion Plan and future resource planning.

Hydro has formed a committee to develop and implement strategic procurement plans to derisk the sourcing of certain commodities and services that have elevated risks as a result of market conditions

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[7] The Final Under Frequency Load Shedding ("UFLS") Study was filed with the Board on August 11, 2025. In addition, Hydro is studying the use of Battery Energy Storage Systems ("BESS") as frequency support, which may allow for additional energy to be brought to the Island via the Labrador-Island Link ("LIL").

[8] "Newfoundland and Labrador Hydro Conception Design Report – Final Report," Hatch Ltd., September 28, 2023.

[9] Hydro provided an update on fuel management and logistics to the Board in March 2026. Please refer to "Bates White Economic Consulting, LLC Expert Report – Phase Two – Newfoundland and Labrador Hydro's Response to Identified Issues for Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 12, 2026.

(the "Strategic Procurement Committee"). One of the initial commodities being assessed by the Strategic Procurement Committee is the supply of fuel for Hydro's fleet of current and future diesel generators. This analysis is being informed by previous research and studies, including a study prepared by Hatch Ltd. on the segregation of fuel storage for third-party access to identify potential options at the Holyrood site and to inform the strategic procurement analysis.

Hydro will continue to update the Board on any developments regarding fuel risks or mitigation in its semi-annual reports.

4.0 Progress Since Last Semi-Annual Update

4.1 2025 Build Application

On March 12, 2025, Hydro filed an application for approval of capital expenditures to ensure that the schedule and costs that would be proposed in the 2025 Build Application, that was to be filed shortly after, would not be impacted by a delay resulting from an inability to proceed with capital expenditures prior to approval.[10] Hydro proposed to defer the determination of whether the expenditures can be recovered from customers to the subsequent application for approval of the full projects. The Board issued Order No. P.U. 17(2025) approving Hydro's Early Execution Application on April 25, 2025, accepting that the approval of the proposed early execution work would reduce risks to the schedule and costs of the proposed projects.

Since the filing of the 2025 Build Application in March 2025, Hydro has assisted with the review of the application by the Board's consultant, Bates White Economic Consulting, LLC ("Bates White"). As noted in the Board's correspondence on May 7, 2025, the Board asked Bates White to review the application. Bates White subsequently provided a preliminary report in June 2025, which was shared with the parties and placed on the record, with an addendum issued in November 2025.[11,12] Bates White provided their Phase 2 Expert Report addressing outstanding items and their conclusions concerning Hydro's 2025 Build Application on February 3, 2026, with an Addendum Report provided on June 6, 2026.

In December 2025, Hydro executed a contract for the procurement of the CT package for the Avalon CT project at a cost materially higher than originally estimated. Hydro filed the updated actual costs for the Avalon CT project with the Board on December 19, 2025,[13] and, on March 9, 2026,[14] Hydro filed revised cost estimates for the project, including updated contingency and management reserve informed by a refreshed Monte Carlo analysis. On April 16, 2026, Hydro provided an evidentiary update, which included a revised expansion plan analysis, a revised basis of estimate for the project, and a briefing note summarizing the cost revision and Monte Carlo Simulation analysis performed.[15]

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10 "Early Execution Capital Work – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 12, 2025 ("Early Execution Application").
11 "Expert Report of Vincent Musco and Collin Cain," Bates White Economic Consulting, LLC, June 26, 2025.
12 "Expert Addendum Report of Vincent Musco and Collin Cain," Bates White Economic Consulting, LLC, November 6, 2025.
13 Please refer to "Newfoundland and Labrador Hydro – Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine, and Bay d'Espoir Unit 8 Project and Avalon Combustion Turbine Project Early Execution Updates for October 2025 – Request for Further Information – Hydro's Reply," Newfoundland and Labrador Hydro, December 19, 2025.
14 "Newfoundland and Labrador Hydro – 2025 Capital Budget Supplemental Application – Application for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine – Avalon Combustion Turbine Estimate Refresh," Newfoundland Hydro, March 9, 2026.
15 "Newfoundland and Labrador Hydro – 2025 Capital Budget Supplemental Application – Application for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine – Revision 1 and Evidentiary Update," Newfoundland and Labrador Hydro, April 16, 2026.

On May 13, 2026, the Board initiated a review schedule for the Avalon CT project within the 2025 Build Application, with the process through late July 2026.[16] A review schedule for BDE Unit 8 with the 2025 Build Application has not yet been received.

As the review process for the 2025 Build Application continues, Hydro has filed additional early execution applications to continue the expenditures necessary to maintain the project schedule. Hydro filed its first additional early execution application on December 12, 2025.[17] A Settlement Agreement was reached between the parties to this application in February 2026, wherein the parties agreed that the expenditures for the Avalon CT should be approved.

The Board approved the Settlement Agreement in Order No. P.U. 7(2026) on March 13, 2026. The proceeding related to the additional early execution expenditures for BDE Unit 8 is ongoing. To avoid interruption in the expenditures and adequately funding activities, and to mitigate against schedule delays, the approval of the Additional Early Execution Application would be needed in August 2026 to allow the approvals to be processed and commitments for payments to be confirmed.[18]

Based on the review schedule set by the Board for the Avalon CT within the 2025 Build Application, Hydro anticipates that approval for the Avalon CT project will not be received prior to the completion of the currently approved expenditures and budget.[19] Therefore, Hydro has filed a second additional early execution application for expenditures related to the Avalon CT, which is currently before the Board.[20] Hydro is also examining the possibility of a third early execution application submittal, depending on the process set for review of the BDE Unit 8 project.

4.2 Update on Analysis for the Reference Case

To continue to update the Reference Case scenario load forecast, Hydro has provided its 2025 Load Forecast Report[21] to the Board and continues to closely monitor demand and energy requirements for the next Resource Adequacy Plan.

Hydro completed a Transmission Expansion Feasibility Study in March 2026 to develop cost estimates for a new 230 kilovolt ("kV") transmission line from Western Avalon to Soldiers Pond; the results of this study were filed with the Board.

Table 1 outlines the applications and studies filed to date in support of the Reference Case Expansion Plan and provides a brief summary of each study.

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[16] The Board issued a review schedule that includes a process for requests for information to end on July 3, 2026, and Hydro's reply to party comments on the proposed project due on July 22, 2026.

[17] "Additional Early Execution Capital Work – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, December 12, 2025 ("Additional Early Execution Application").

[18] Approval of the additional expenditures with an estimated budget of $5.63 million submitted as part of the Additional Early Execution Application would provide funding to October 2026.

[19] As discussed in the May 2026 Avalon CT Early Execution Report, a reforecast of the latest approved additional early execution budget has been completed to better reflect the anticipated rate of expenditure. It is expected that the current budget of approximately $60 million will be expended by mid-August 2026.

[20] "Phase II Additional Early Execution Capital Work – Avalon Combustion Turbine," Newfoundland and Labrador Hydro, June 19, 2026 ("Phase II Additional Early Execution Application").

[21] "2025 Island Interconnected System Load Forecast Report," Newfoundland and Labrador Hydro, November 5, 2025.

Table 1: Applications and Studies Filed in Support of the Next Resource Adequacy Plan

Study	Date Filed	Summary
2024 Resource Adequacy Plan	July 9, 2024	Update to the *RRA Study Review,* which proposed Hydro's Minimum Investment Required Expansion Plan.
Holyrood TGS Capital Refresh	March 7, 2025	Summary of capital, operating and fuel costs to continue operation of the Holyrood TGS up to 2035.
2025 Build Application	March 21, 2025	Application for capital expenditures for Avalon CT and BDE Unit 8, related to the Minimum Investment Required Expansion Plan, and included the 2024 Long-Term Load Forecast report.
The Final Lower Churchill Project Operational Study	August 10, 2025	Final UFLS scheme, which will reduce the firm energy deficit that was presented in the 2025 Build Application by approximately 450–500 GWh.
Evaluation of a Remedial Action Scheme ("RAS") for the Avalon 230 kV Corridor	October 14, 2025	Recommended Avalon RAS as the least-cost alternative to the construction of a new transmission line, which can support an island demand up to 2,000 MW during a LIL shortfall scenario.[22]
CDM[23] Potential Study	November 5, 2025	No impact on the projects proposed within the 2025 Build Application, as Hydro has already reflected an appropriate level of savings from CDM programming and energy efficiency in its 2024 Slow Decarbonization Load Forecast.
2025 Load Forecast Update: Island Interconnected System	November 5, 2025	Load Forecast Update for 2025, which demonstrates that there is an immaterial difference between the compound annual growth rate between the 2024 and 2025 Load Forecasts.
ELCC[24] Study	December 9, 2025	ELCC Study to determine the capacity contribution for wind, solar, and battery storage, as it applies to the Island Interconnected System.
Transmission Feasibility Study	April 17, 2026	The study evaluates the technical feasibility, preliminary design considerations, risks, schedule, and a high-level capital cost estimate associated with a potential additional 230 kV transmission line between the Western Avalon and Soldiers Pond terminal stations.
Condition Assessment and Retirement Optimization Study	June 15, 2026	Assessment of the remaining useful life for the Hardwoods and Stephenville Gas Turbines, and estimated Class 5 capital and operating costs up to 2040.
Conservation, Demand Management and Electrification Plan 2026–2030	June 30, 2026	Joint Utility Conservation, Demand Management and Electrification Plan provided as Attachment 1.

[22] Assuming the proposed Avalon CT is online.
[23] Conservation and Demand Management ("CDM").
[24] Effective Load Carrying Capability ("ELCC").

4.3 Upcoming Studies

To assess the need and timing for further supply expansion to meet the Reference Case, Hydro is advancing work on the next potential options in its supply stack by undertaking multiple feasibility studies through 2026 to advance analysis of resource options, driven by the outcome of the 2024 Resource Adequacy Plan. Hydro will use the outputs of these feasibility studies and incorporate them into its next Resource Adequacy Plan analysis.

This feasibility work consists of feasibility and supporting studies on Cat Arm Unit 3 and BESS options, as shown in Table 2.

Table 2: Estimated Filing Dates – Upcoming Studies and Reports

Study	Estimated Completion Date[25]	Status Update	Estimated Filing Date[26]
Avalon Reactive Power Study – Phase 1	Q2 2026	Study complete. Hydro will file final report in the third quarter of 2026.	July 2026
Cat Arm Unit 3 Feasibility Study	Q3 2026	Study and report are nearly complete, and final report is now anticipated in the third quarter of 2026.	August 2026
BESS Feasibility Study	Q3 2026	Study and report are nearly complete, and final report is now anticipated in the third quarter of 2026.	August 2026
Evaluation of BESS for Frequency Support	Q4 2026	Study is anticipated to be completed in the fourth quarter of 2026.	December 2026

In line with its legislated mandate, Hydro is currently prioritizing activities and focusing its efforts based on the resource options that its analysis indicates are the next least-cost options for environmentally responsible, reliable service. Hydro's approach is data-driven and, as a result, the activities and studies are subject to change in scope or prioritization should the outcome of the analysis indicate that the applicable resource option(s) are not a feasible or a least-cost option to meet Hydro's needs for the Reference Case.

4.4 New Studies

At this time, Hydro has determined that one additional study is necessary to inform the Reference Case resource selection options, as outlined in Table 3.

Table 3: Additional Study Necessary to Inform the Reference Case

Study	Estimated Completion Date[27]	Purpose
Avalon Reactive Power Study – Phase 2	Q4 2026	Avalon Reactive Power Study – Phase 1 focuses on the transmission impacts and upgrades required resulting from the addition of the Avalon CT and BDE Unit 8. Additional analysis is required beyond the scope of Phase 1 as a result of ongoing developments related to additional off-Avalon generation expansion.

[25] As outlined within the Settlement Agreement, Hydro will file the study after internal review is completed within 45 days of receipt of the final report.
[26] Hydro's internal review, as referenced herein, will be completed within 45 days of the completion of the report. Should additional time be required to complete the internal review, Hydro will advise the Board and the parties of the amount of additional time needed and the reasons for the additional time.
[27] *Supra,* f.n. 25.

5.0 Next Resource Adequacy Plan

Hydro believes it is prudent to have an approved plan in place to meet the Minimum Investment Required Expansion Plan prior to determining next steps to meet the Reference Case. The need for additional resources, even in the Minimum Investment Required scenario, is substantial and Hydro considers this the first step. With the ongoing review of the Minimum Investment Required Expansion Plan through the 2025 Build Application proceeding, Hydro is planning to submit its next Resource Adequacy Plan in 2027 with an Expansion Plan to meet the Reference Case.

Hydro will identify any new resource requirement or new projects that may be required to meet the Reference Case within its next Resource Adequacy Plan prior to submission of an application for any required capital expenditures.

If you have any questions or comments, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

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

Encl.

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Attachment 1

Conservation, Demand Management and Electrification Plan 2026–2030

Conservation, Demand Management and Electrification Plan

2026-2030

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1.0 EXECUTIVE SUMMARY

The Conservation, Demand Management and Electrification Plan: 2026-2030 (the “2026 Plan”) is the fifth plan implemented by Newfoundland Power Inc. (“Newfoundland Power”) and Newfoundland and Labrador Hydro (“Hydro” and, collectively, the “Utilities”) under the TakeCharge partnership which has existed since 2009. The 2026 Plan continues long-standing conservation and demand management (“CDM”) programs, expands programming for income-qualified customers, and provides for the assessment of potential load shifting and demand response opportunities. The 2026 Plan uses CDM programs to help reduce electricity consumption, help create space on the grid to meet electrification needs, and provide benefits to customers. The 2026 Plan continues TakeCharge’s education and awareness initiatives about energy efficiency and electrification. While the Plan does not contain any programs to promote electrification, it does contain initiatives designed to better position the Utilities to mitigate the effect of increasing demand throughout the Plan period and into the 2030s.

CDM programs directly help customers save on their energy bills and are an essential part of managing peak demand and energy supply requirements in North America. In Canada, energy efficiency programs have prevented roughly 40% growth in residential energy demand since 2000.[1] Similarly, efficiency improvements in the United States have avoided roughly 60% in additional energy consumption since 1980.[2] CDM programming is viewed as a critical aspect of both countries’ energy goals and, as such, CDM programs continue to be offered across Canada and the United States.[3] In Newfoundland and Labrador, CDM programming has resulted in estimated total customer energy savings of 2,386 GWh over the 2009 to 2025 timeframe. Over the same period, CDM programs have reduced system peak by 79 MW. Participating customers have saved an estimated $322 million on their electricity bills and over $288 million in system costs have been avoided because of CDM programs. CDM programming will be of continued importance moving forward to continue to lower customer energy bills and system costs.[4]

CDM programs included in the 2026 Plan are designed to be cost-effective and aligned with best practice across the industry. In addition, the CDM programs are designed to be responsive to customer expectations, market trends, electricity sector impacts and government funding opportunities. All programs are based on local market research, stakeholder consultation and estimates of long-term energy and demand impacts as determined by past program offerings and the completion of the most recent Energy Solutions Potential Study (the “Potential Study”).

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1 https://energy-information.canada.ca/en/energy-facts/energy-efficiency.

2 https://www.energy.gov/eere/2024-eere-funding-impacts-snapshot.

3 See, for example, Efficiency Canada’s 2024 Canadian Energy Efficiency Scorecard. In addition, the American Council for an Energy-Efficient Economy evaluated the 53 largest U.S. electric utilities across 31 different state and regulatory environments in its 2023 Utility Energy Efficiency Scorecard.

4 See, for example, Bates White Economic Consulting, *Assessment of Newfoundland and Labrador Hydro’s 2024 Resource Adequacy Plan*, dated August 30, 2024, page 24.

The Potential Study, completed by Posterity Group, evaluated the potential for demand and energy reduction on the Island Interconnected System ("IIS"). The results of the study indicated that energy efficiency programs continue to have significant potential to reduce costs for customers and reduce peak demand on the electricity system. However, the Potential Study showed that there is little opportunity for incremental demand response on the IIS outside of curtailment contracts, electrical thermal storage and future opportunities related to electric vehicle ("EV") load management.

CDM programs remain essential for customers and play a key role in supporting the operations of the IIS. With the rising cost of living, affordability is a growing concern for many households. The Utilities understand the concerns customers have about their electricity bills, especially during colder months when energy use is at its highest. Through the TakeCharge partnership, the Utilities are committed to helping customers lower their energy use and reduce their electricity bills through practical programs and meaningful education. These tools are essential in empowering customers to take control of their energy costs.

The 2026 Plan supports customer affordability. It includes the development of enhanced programming for income-qualified customers, alongside continued access to valuable rebate offerings for all customers. All programs—regardless of customer income level—are designed to meet the same cost-effectiveness standards approved by the Public Utilities Board. To support the broader reach of these initiatives, the Utilities are also exploring complementary funding opportunities where they exist.

Energy savings forecast to be achieved in the 2026 Plan are estimated to be 1,556 GWh. This figure includes savings carried forward from existing program participation, but also additional participants who are forecast to participate from 2026-2030. Additionally, peak demand reduction resulting CDM programs is forecast to reach approximately 96 MW by 2030. These energy and demand savings result in avoided system costs of an estimated $164 million from 2026 to 2030.[5] Customers who participate in CDM programs are anticipated to collectively save an estimated $242 million on their electricity bills over the same period.[6]

The cost of implementing the 2026 Plan is forecast to total $69.8 million over the period 2026 to 2030.[7]

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5 System savings are calculated by multiply the cumulative energy and capacity savings each year by the marginal cost of energy and capacity for that year.

6 Bill savings are calculated using the cumulative energy savings in a given year multiplied by the retail electricity rate in that year.

7 See Table 11 for details.

2.0 BACKGROUND

2.1 Customer Program Delivery

Newfoundland Power and Hydro have offered customer programming under the TakeCharge brand since 2009. The Utilities have successfully implemented four multi-year plans as part of the TakeCharge partnership.

Programs implemented since 2009 have been responsive to customers' expectations and consistent with the provision of least-cost, reliable service. Between 2009 and 2025, over 84,000 customers have participated in TakeCharge programs. Additionally, over 124,000 customers have received home energy reports through Newfoundland Power's Benchmarking Program and over 4.2 million products were rebated through the Instant Rebate Program. Participating customers have saved an estimated $322 million on their electricity bills and $288 million in system costs have been avoided because of these programs.[8]

The Electrification, Conservation and Demand Management Plan: 2021-2025 (the "2021 Plan") Plan introduced air sealing and duct insulation rebates and the Energy Savers Kit Program for income-qualified customers. During the 2021 Plan, the Instant Rebate Program and the Thermostat Program were discontinued.[9] Customers who participated in TakeCharge programs between 2009 and 2025 are saving over 306 GWh per year and have reduced system peak by 79 MW.[10] These results were achieved by strategically removing barriers to energy efficiency. Financial incentives have addressed customer cost barriers and education initiatives have addressed gaps in customer awareness and knowledge. By addressing barriers, the Utilities have enabled market transformation to higher efficiency standards.

The 2026 Plan is consistent with the Utilities' long-term history of delivering customer programs and education to reduce system costs, save customers money on their bills and meet customer

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8 Electricity bill savings are calculated using the cumulative gross energy savings in each year multiplied by the appropriate rate in each year. Avoided system costs are calculated using the cumulative gross energy and capacity savings by the marginal cost of energy and capacity in each year.

9 LED lighting was the primary product purchased through the Instant Rebate Program. Customer reported socket saturation of LED bulbs increased from 34% in 2017 to 67% in 2022. Over the course of the Instant Rebate Program, LED adoption increased, while the price of LED bulbs decreased making the program no longer necessary to promote increased adoption of LED bulbs. The Thermostat Program ended due to technology saturation, decreasing annual participation, reduction of energy savings attributed per thermostat, and the average price of thermostats rising. The combination of these factors made it challenging for the program to pass the required cost-effectiveness screening. Between 2009 and 2023, over 149,000 thermostats were rebated through the TakeCharge program.

10 Schedule A provides a summary of the results and customer benefits delivered from the 2021 Plan.

expectations to help them with energy efficiency.[11] The 2026 Plan will continue efforts to help customers understand what impacts their electricity usage and how to reduce it.

2.2 Current Utility Practice

To ensure alignment with utility practice, TakeCharge contracted Econoler Inc. to complete a jurisdictional scan of demand-side management ("DSM") and electrification initiatives across Canada and winter-peaking jurisdictions in the United States.[12] Fifteen jurisdictions were selected, with 13 of those participants providing information that was applicable to all areas of the scan (details on both program offerings and cost-effectiveness testing).[13] The scan was completed in September 2024.

Schedule B provides the results of the jurisdictional scan. Key findings of the jurisdictional scan are that the CDM offerings in the 2026 Plan are consistent with those offered in other jurisdictions and the cost-effectiveness tests used to screen the CDM programs in the 2026 Plan remain consistent with industry best practice.

Effectively all the participants in the jurisdictional scan offer weatherization programs that make homes more energy efficient and protect them from external weather elements.[14] This can include upgrades to insulation and air sealing, which help maintain comfortable indoor air temperatures while reducing energy consumption. In addition, the majority of the participants also offer home energy report and Heating, Ventilation, and Air Conditioning ("HVAC") programs.[15] The offering of low-income programs are also common practice.[16]

Consistent with the jurisdictional scan findings, the 2026 Plan includes weatherization programs (insulation and air sealing programs), home energy report and HVAC programs (HRV and business efficiency programs) and low-income programs (energy savers kit, income-qualified insulation and heat pump programs).

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11 In a 2024 survey conducted by MQO Research, an Atlantic Canadian firm specializing in market research, opinion polling, and program evaluation services, 61% of respondents felt the responsibility for providing information on energy efficiency lay with the utility company.

12 Econoler is an international consulting firm with 40 years of experience in the design, implementation, evaluation and financing of energy efficiency and renewable energy programs and projects. Over the years, Econoler has contributed to developing and implementing about 5,000 projects in over 160 countries. Econoler staff is comprised of about 100 experts, including engineers, economists, financial specialists, marketing specialists and professional statisticians.

13 Of those 13 participants, nine were utilities.

14 Of the 13 participants where full information was available, 12 provided weatherization programs.

15 Of the 13 participants where full information was available, seven provided home energy report programs and 11 provided HVAC programs.

16 Of the 13 participants where full information was available, nine provided enhanced programming for income-qualified customers to support customer affordability.

The Total Resource Cost ("TRC") test, or a modified variation of the TRC test, is the most common primary cost-effectiveness test used to screen energy efficiency and demand response programs, followed by the Program Administrator Cost ("PAC") test.[17]

Consistent with the jurisdictional findings, the cost effectiveness of CDM programs in the 2026 Plan continue to be evaluated using both the TRC and PAC tests as approved by the Board in Order No. P.U. 18 (2016).

Research completed for the 2026 Plan also found that higher levels of CDM program spending are anticipated in other Canadian jurisdictions over the next five years, including an increased focus on programs for customers with low income.[18]

2.3 Government Programs

The Utilities have an established history of working with the federal and provincial governments on customer programs. The Utilities have the knowledge, infrastructure and customer connections required to effectively deliver programs that are either fully or partially funded by government. For example, the Utilities have offered programs relating to low-interest financing for energy efficiency projects, rebates for oil customers installing insulation or digital thermostats, heat pump rebates, EV rebates, EV charger rebates and fuel switching programs.

In the 2026 Plan period, the Utilities will continue to administer the Oil to Electric Program on behalf of the Government of Newfoundland and Labrador. The Utilities plan to continue this coordinated approach, where possible, with both the provincial and federal governments to ensure utility programming is complementary to government funded programs. This includes seeking opportunities to leverage government funding for programs and education as they arise.

The Utilities have applied to the federal government for funding towards CDM program offerings and is receiving funding from the provincial government for a demand response pilot.[19]

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17 The mTRC, which is used by three of the participants, is consistent with the TRC test but also includes non-energy benefits such as greenhouse gas reductions. The SCT, which is used by two of the participants, builds on the mTRC and also considers reduced arrearages, water savings and health and productivity improvements. The remaining six participants use the PAC test as their primary cost-effectiveness test. One of these six participant used a variation of the PAC test to also include non-energy benefits. The "Minnesota Test," is used by Xcel Energy based in Minnesota. The non-energy benefits include the impact on air emissions, other environmental impacts, job impacts and energy security and equity related considerations.

18 Six utilities responded to a survey administered through Electricity Canada in 2025 on CDM cost trends. Of the six utilities, five forecasted increases in their CDM program costs and four of the utilities expected an increase in their low-income CDM program costs.

19 For further details on these programs see section 4.0.

3.0 Potential Study and Pilot Results

Posterity Group completed an electrification, conservation and demand management potential study for the IIS in 2025.[20] The study identified energy and demand savings potential from energy efficiency, energy impacts from electrification of space heating, water heating and EVs, and potential impacts of demand response initiatives. The Potential Study period examined was 2025 to 2040.

Inputs into the Potential Study include residential and commercial customer surveys, historical TakeCharge program achievements, utility sales forecasts, scans of other jurisdictions and engagement with local industry stakeholders such as trade allies, industry associations and government.

The Potential Study provides a framework within which the Utilities can assess program and education potential. The findings enable the Utilities to focus on cost-effective technologies and begin assessment of market characteristics to guide program development. It also allows the Utilities to understand baseline trends of electricity usage in the absence of any utility programs. The results of the Potential Study are one of many inputs into the development of programs and education initiatives for the Utilities. The Utilities also rely on historical results from ongoing programs, market research and consultations with local trade allies and stakeholders to finalize the offerings in each plan.

The following sections provide key results from the Potential Study to demonstrate the range of impacts shown in the study. The 2026 Plan forecast for energy and demand savings is most closely aligned with the medium achievable potential scenario, as outlined in section 3.2. The full Potential Study findings are in Schedule C.

3.1 Potential Study Reference Case

The Utilities' 2023 consumption data and forecasts were used by Posterity Group to create a reference case, or baseline year. The Potential Study then forecast baseline consumption across the study period using this baseline year and the short and long-term utility load forecasts. The reference case represents energy consumption in the absence of programs to which the results of electrification and CDM efforts can be compared. Further details of how the reference case is developed are outlined below:

- To ensure reasonableness of results, the reference case is calibrated to Hydro's long-term forecast and reflects current consumption patterns and known future changes,

20 Posterity Group is a Canadian consulting firm specializing in energy planning, climate change and technology innovation.

including expected customer growth and current and known future changes to codes and standards.

- It considers the expected natural turnover and increased efficiency of equipment and appliances, and natural conversions in space heating and water heating fuel types from non-electric to electric.

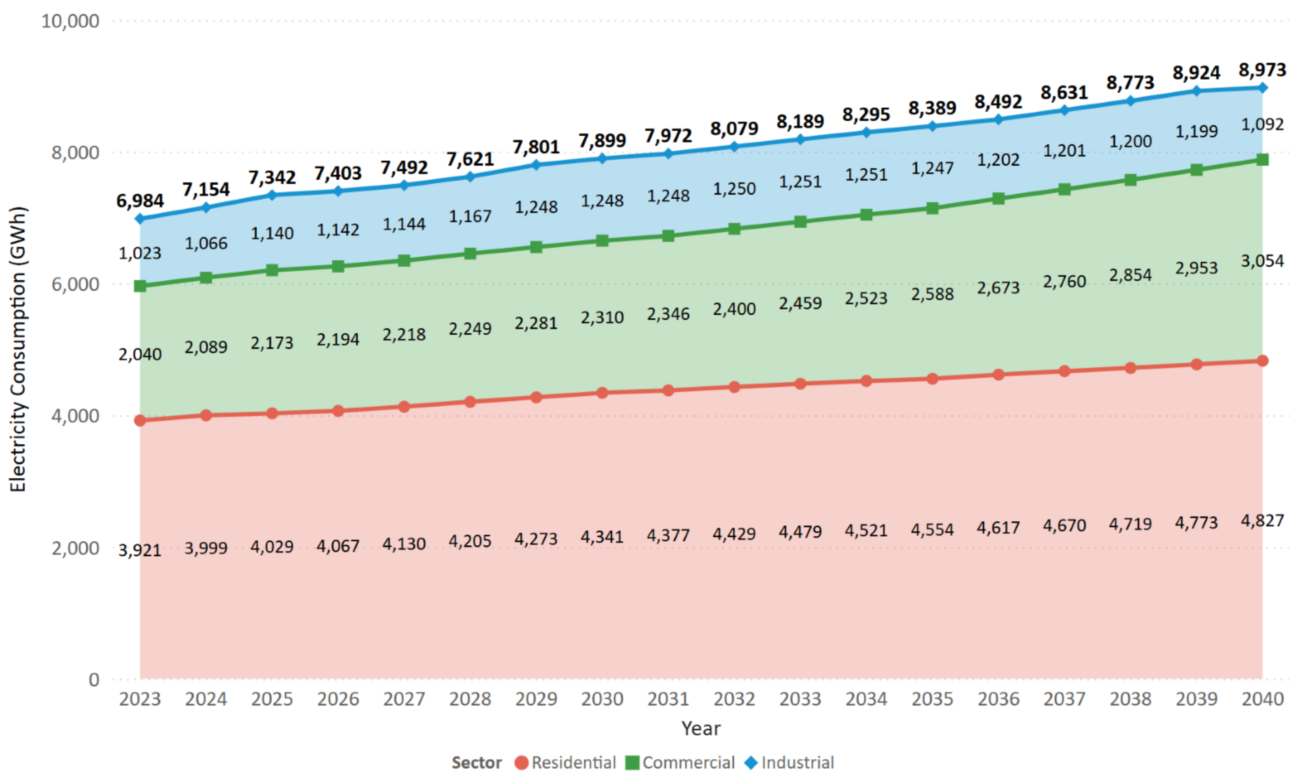
- It excludes conservation from conservation, demand management and electrification ("CDME") activities carried out after 2023.

- The reference case includes EV adoption from the "intermediate" scenario, as this was forecast to be the most likely scenario to be realized.[21]

Figure 1 outlines the baseline energy consumption for the Potential Study period by sector and Figure 2 outlines the baseline peak demand. Both figures include the impacts of forecast electrification, showing steady growth over the forecast period.

[21] The intermediate scenario represents an EV adoption scenario that falls between the baseline scenario and the scenario that represented EV adoption under Government of Canada EV mandates in place at the time the study was completed. The intermediate scenario is influenced by the existence of EV purchase incentives and investments in EV charging infrastructure.

Figure 1
Reference Case Consumption (GWh) – Island Interconnected System



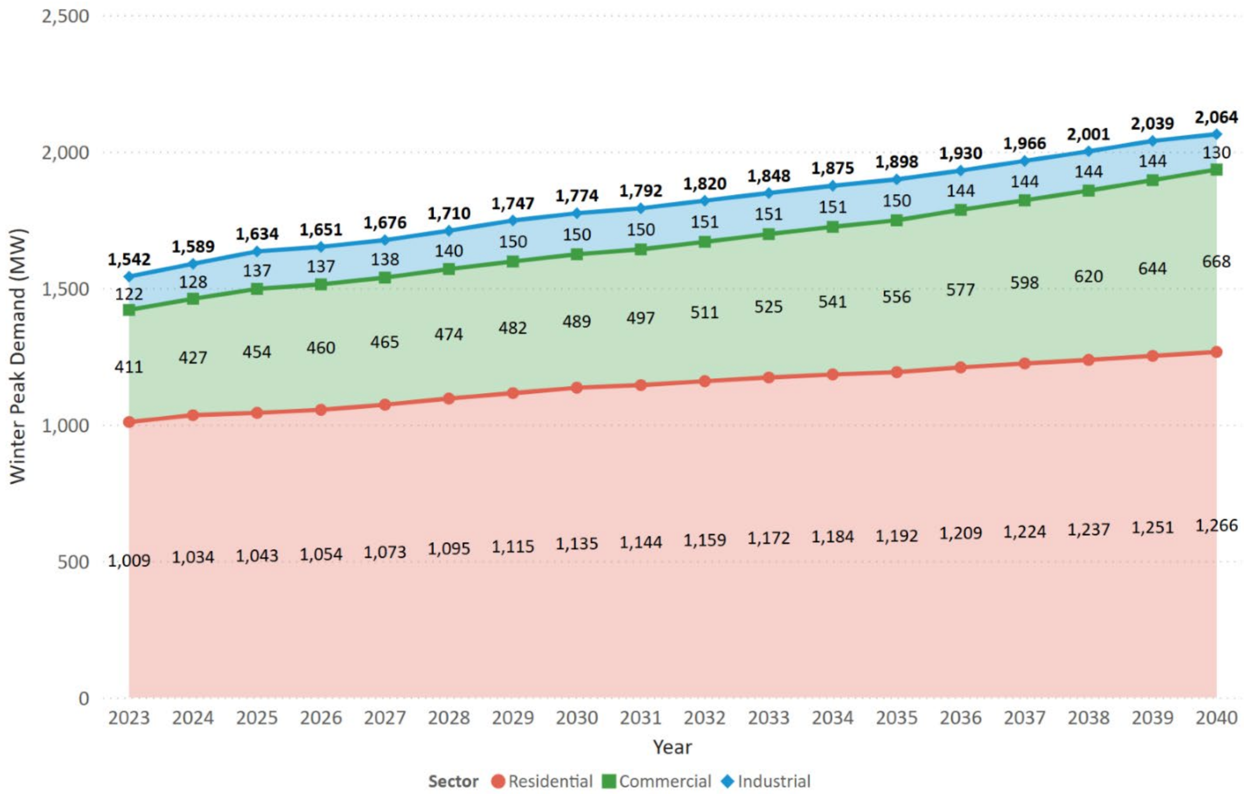
The following conclusions can be made from Figure 1:

- Total base year (2023) electricity consumption is 6,984 GWh. The residential sector represents 56% of this total (3,921 GWh). The commercial and industrial sectors represent 29% (2,040 GWh) and 15% (1,023 GWh) of the total, respectively. In 2040, these contributions are 54% residential, 34% commercial and 12% industrial.

- Electricity consumption is forecast to increase by 1,989 GWh (28%) between 2023 and 2040, ranging between an increase of 1% to 3% per year. The adoption of 160,699 EVs in the intermediate scenario accounts for 1,000 GWh (50%) of this increase. Of the 1,000 GWh of EV load, 39% (386 GWh) is expected in the residential sector and 61% (614 GWh) is expected in the commercial sector. This is due to the relatively high energy consumption of medium and heavy-duty vehicles compared to light duty vehicles.

- The remainder of the increase is driven by space heating electrification and an increase in customer accounts over the period. The adoption of heat pumps in homes that currently heat with electric resistance heat offsets some of the expected growth from space heating electrification. Overall, residential space heating impacts are expected to be 2,379 GWh in 2040, compared to 2,088 GWh in 2023. Commercial space heating impacts are expected to be 751 GWh in 2040, compared to 465 GWh in 2023.

Figure 2
Reference Case Peak Demand (MW) – Island Interconnected System



The following conclusions can be made from Figure 2:

- Peak demand in the base year (2023) is 1,542 MW. The residential sector represents 65% (1,009 MW) of this total, while the commercial and industrial sectors represent 27% (411 MW) and 8% (122 MW) of the total, respectively. By 2040, these contributions will shift to 61% residential, 33% commercial and 6% industrial.

- Peak demand is forecast to increase by 522 MW (34%) between 2023 and 2040. The increase to 2,064 MW by 2040 is primarily driven by the adoption of 160,699 EVs in the intermediate scenario, which is forecast to increase peak by 273 MW.[22] The adoption of heat pumps in homes that currently heat with electric resistance heat offsets some of the expected growth from space heating electrification.

[22] The intermediate scenario represents an EV adoption scenario that falls between the baseline scenario and the scenario that represented EV adoption under Government of Canada EV mandates in place at the time the study was completed. The intermediate scenario is influenced by the existence of EV purchase incentives and investments in EV charging infrastructure. Figure 2 does not assume any level of managed EV charging.

3.2 Potential Study Energy Efficiency Results

The study assessed three levels of energy efficiency potential: technical, economic and achievable. These levels of potential are in comparison to the reference case.

Technical potential is an estimate of the technically feasible energy and demand savings potential, ignoring measure cost effectiveness or market acceptance. In essence, it is a theoretical maximum amount of potential ignoring all market constraints and consumer behaviour.

Economic potential is an estimate of the energy and demand savings potential for measures that pass the cost effectiveness screening criteria in the study. For this study, that includes any measures that received a 0.8 or higher on the TRC test. This potential also ignores consumer and market behaviour.

Achievable potential is an estimate of the energy and demand savings potential considering feasible adoption rates of cost-effective measures over the study period. Achievable potential considers market barriers, customer payback acceptance, and awareness of energy efficiency measures among other factors, making it the most relevant of the three levels of potential. The study analyzed three different achievable potential scenarios. The “lower” scenario models an incentive rate of 25% of the incremental cost of the efficiency measure, the “medium” scenario models an incentive rate of 50% of the incremental cost of the efficiency measure, and the “higher” scenario models an incentive rate of 100% of the incremental cost of the efficiency measure.

The results presented in this report focus primarily on the medium achievable potential, which best aligns with the historical results the Utilities have been able to achieve and are most aligned with the 2026 Plan. The results for the other levels of potential, as well as the complete medium achievable potential results, are provided in Schedule C.

Figure 3 shows the expected annual energy usage under each scenario, including the reference case. The distance of a line from the reference case indicates its potential for energy savings.

Figure 3
Annual Consumption by Scenario
GWh

The following conclusions can be made from Figure 3:

- By 2040, the technical potential shows 3,127 GWh of energy savings, and the economic potential shows 2,445 GWh of energy savings. This indicates that there is approximately 682 GWh of available energy savings that is not economic using the TRC. As discussed above, neither the technical nor economic potentials represent a realistic achievement of energy savings.

- The difference between the medium achievable and the higher achievable potential in 2040 is estimated to be 733 GWh. The higher achievable potential is notably larger due to the modelling impact of increasing the customer incentive from 50% of the incremental measure cost in the medium achievable scenario to 100% of the incremental measure cost in the higher achievable scenario. The largest driver of the variance in energy savings between the medium and higher potential scenarios is customers adopting ductless mini-split heat pumps.[23] The Utilities do not currently offer a rebate for this technology due to the high levels of natural adoption rates occurring in the market, leading to high free ridership levels.[24]

- The difference between the medium achievable and the lower achievable potential in 2040 is estimated to be approximately 100 GWh. The Utilities typically use the medium scenario for analysis when completing CDM plans as it most often aligns with historically achieved results from CDM programs, helps ensure a balance between cost and program benefits, and is generally reflective of utility CDM programs, including those offered by TakeCharge.[25]

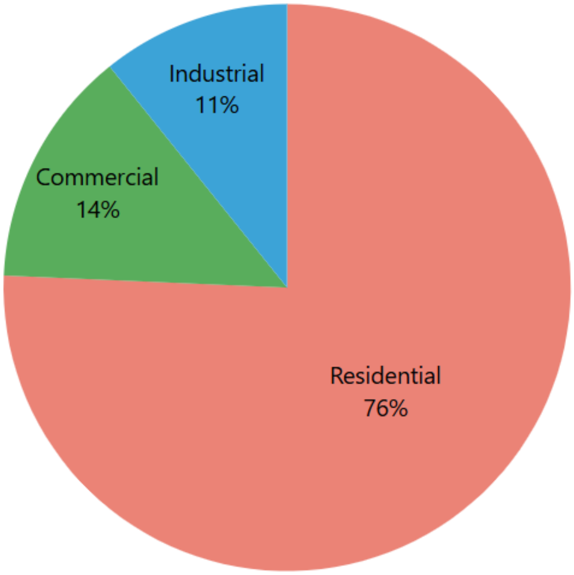
Figure 4 provides the energy efficiency potential by sector for the medium achievable potential scenario for 2025 (top) and 2040 (bottom).

[23] The higher potential scenario assumes that the customer receives an incentive that is equal to 100% of their incremental purchase cost, including ductless mini split heat pumps. In the higher scenario, ductless mini split heat pumps are estimated to save 2,968 GWh of energy by 2040.

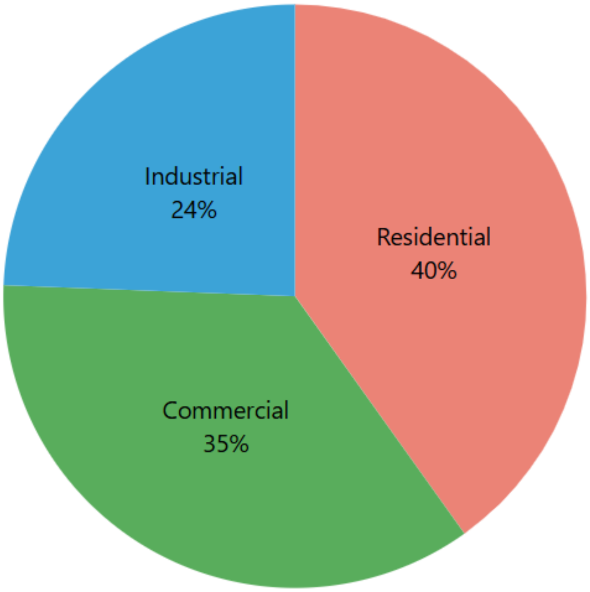
[24] A survey conducted by "Thinkwell Research + Strategy" in 2025 estimates that 33% of customers now have a mini-split heat pump.

[25] According to various sources including E Source, the California Public Utilities Commission and the U.S. Energy Information Administration, typical DSM program incentives for residential customers range from 30-50% of the incremental cost of participating while incentives for commercial and industrial customers typically range from 50-70%. Incentives for low-income programs and program related to emerging technology or hard-to-reach customers typically range from 75-100% of the incremental cost to participate.

Figure 4
Medium Achievable Potential by Sector[26]
GWh



2025 Energy Savings Potential: 32 GWh



2040 Energy Savings Potential: 344 GWh

26 The industrial sector includes, but is not limited to, Hydro's transmission-level customers. The industrial sector also accounts for customer accounts in the follow segments: fishing and fish processing, manufacturing, other industrial, water and wastewater, mining and processing and pulp and paper.

The residential sector has the highest potential for savings across the study period. The savings of 32 GWh in 2025 represents the first year of the study period, whereas the savings of 344 GWh in 2040 would represent the cumulative savings achieved between 2025 and 2040.

Residential energy savings typically dominate the Utilities CDM portfolio. The Potential Study, however, expects that the opportunities for energy efficiency potential will begin to more closely align with the reference case consumptions of each sector throughout the study period.

Table 1 provides the average annual peak demand reduction resulting from energy efficiency measures included in the medium achievable potential scenario relative to the reference case.[27]

Table 1
Cumulative Demand Reduction from Energy Efficiency[28]
Medium Achievable Potential Scenario

Year	Morning Peak (MW)	Morning Peak Reduction Available (MW)	Morning Reduction (%)	Evening Peak (MW)	Evening Peak Reduction Available (MW)	Evening Reduction (%)
2025	1,592	8	0.5%	1,556	7	0.4%
2026	1,606	11	0.7%	1,581	11	0.7%
2027	1,627	16	1.0%	1,605	15	0.9%
2028	1,656	22	1.3%	1,637	21	1.3%
2029	1,689	29	1.7%	1,673	28	1.7%
2030	1,709	37	2.2%	1,698	36	2.1%
2031	1,720	43	2.5%	1,715	43	2.5%
2032	1,739	49	2.8%	1,742	48	2.8%
2033	1,757	54	3.1%	1,769	53	3.0%
2034	1,772	57	3.2%	1,794	56	3.1%
2035	1,782	60	3.4%	1,817	59	3.2%
2036	1,798	62	3.4%	1,848	61	3.3%
2037	1,816	64	3.5%	1,881	63	3.3%
2038	1,833	67	3.7%	1,915	65	3.4%
2039	1,851	69	3.7%	1,952	67	3.4%
2040	1,855	72	3.8%	1,975	69	3.5%

27 Table 1 does not represent the impacts of demand response measures, rather the demand reduction benefits of energy efficiency initiatives.

28 These figures exclude the impacts of EVs on baseline peak load.

Efficiency measures reduce the winter morning peak more than the evening peak in each year of the forecast period, though the difference is less than three megawatts annually. The morning impacts are slightly higher as efficiency measures that impact water heating usage tend to be more effective during the morning peak than the evening peak since the load curve for water heating shows more usage in the morning than the evening.

By 2040, it is estimated there could be incremental peak reductions of up to 72 MW available through energy efficiency.

3.3 Potential Study Demand Response Results

Demand response refers to programs and strategies that enable electricity consumers to adjust or reduce their power usage during peak demand periods on the electricity grid. Demand response programs can often include time-of-use pricing, smart grid technologies or direct load control, such as when a utility sends a signal to a thermostat to reduce the temperature setting. Typically, customers respond to either a price signal or receive an incentive to shift their energy usage.

The Potential Study explored three primary methods for enabling demand response on the IIS. These methods include rate design, direct load control and customer curtailment. It is important to note that demand response activities are best used to address short-term requirements to help defer or reduce investment in supply side resources, such as helping manage system reserve margins due to increasing peaks associated with load growth.[29]

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[29] Other use cases for demand response can include reducing curtailment of renewable energy resources or reducing carbon emissions or managing power purchase costs on interconnect grids such as those with independent system operators.

Table 2 shows the peak demand reduction from the Potential Study by sector and resource type that may be achieved by 2040.[30]

Table 2
Demand Response by Sector and Resource Type (2040)
Peak Demand Reduction (MW)

Sector	Time-of-Use	Critical Peak Pricing	Utility-Driven DR	Thermal Storage w/TOU	Commercial Curtailment	Large Industrial Curtailment
Residential	4.8	7.9	7.6	1.6	-	-
Commercial	1.1	1.5	11.1	3.5	36.9	-
Industrial	0.3	0.3	0.7	-		98.1
EV	4.7	-[31]	41.0	-	-	-
Total	**10.9**	**9.7**	**60.4**	**5.1**	**36.9**	**98.1**

The greatest demand response potential on the IIS is large industrial curtailment and commercial customer curtailment, much of which is already being achieved by the Utilities.[32]

After commercial and large industrial curtailment, utility driven direct load control provides the most potential for demand response. The Potential Study indicates that most of this potential comes from managing EV load after 2033 when Posterity's forecasts expects the IIS peak to shift from a morning peaking system to an evening peaking system. It is forecast that increased use of EVs, which typically consume more energy in the evening than in the morning, will lead to a consistent evening peak on the IIS when adoption levels are sufficiently high.[33]

Until EV adoption grows, there are limited opportunities to reduce peak demand beyond existing measures already implemented by the Utilities such as CDM and curtailment. While upwards of 41 MW of load reduction potential exists for EVs, this only represents an estimated 15% of the total baseline EV peak load in 2040.[34]

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30 Unlike energy efficiency modelling, the Potential Study only modelled one achievable scenario for demand response potential.

31 The Potential Study modelled the impact of TOU rates on EV load shifting but did not model the impact of CPP rates on EV load shifting as there was no industry precedent of using CPP to influence EV charging that could be modelled.

32 Curtailment programs or power purchase agreements are currently in place at Newfoundland Power and Hydro and are generally reserved for times of system constraint. The potential shown in Table 3 includes existing contracted potential under these programs and agreements and is not all incremental.

33 Depending on the adoption scenario, this is expected to either occur in 2030, 2033 or 2037.

34 Unmanaged EV load in the intermediate scenario is forecast to be 275 MW by 2040. 41 MW / 275 MW = 14.9%.

Table 3 shows the Program Administrator Cost ("PAC") test results of the electricity rate design measures in the Potential Study. A PAC result of 1.0 or higher shows that the investment is cost-effective.

Table 3
PAC Test Results for Rate Design Demand Response Measures[35]

Rate	Residential (Without EV)	Residential (With EV, Opt-In)	Residential (With EV, Opt-Out)	Commercial	Industrial
TOU	0.12	0.20	0.95	0.29	0.39

The Potential Study shows that none of the evaluated rate design measures are cost-effective due to the capital and operating costs associated with Advanced Metering Infrastructure ("AMI") which would be required to implement rate design measures, and the relatively low time-varying rate participation and load reduction seen in other jurisdictions.[36] The cost-effectiveness ratios range from 0.12 for residential time-of-use ("TOU") rates excluding EV load, to 0.95 for residential TOU rates that include EV load and are opt-out driven versus opt-in driven. The forecast benefits used in the cost-effectiveness testing are highly dependent on the forecast number of EVs adopted and how many customers would participate in the TOU rate.

The "Residential (With EV, Opt-Out)" scenario with a PAC result of 0.95, shown in Table 3, is based on the intermediate scenario of EV adoption (see section 3.4 for more information) and assumes that 100% of EV owners are on a TOU rate.[37] This analysis was completed on a theoretical basis for completeness and does not consider utility practice or practical limitations to achieving a 100% participation rate. While it is possible to employ an "opt-out" strategy for time-of-use rates, it is not common utility practice.[38] Further, it is not be reasonable to expect no customers would not opt out of TOU rates.[39]

35 The Potential Study modeled AMI rates being implemented in 2029, assuming a 4-year project to install AMI. For further details on opt-in rates and costs associated with AMI metering see Potential Study, Section 4.1.1 in Schedule C.

36 Time-varying rates are electricity rates that differ based on the time of day and/or year. Examples of time-varying rates would include time-of-use rates and critical peak pricing. The Potential Study assumed a 15% adoption rate, based on a 5-year ramp up using an S-Curve. This is consistent with TOU rate participation projected in Nova Scotia and British Columbia, and higher than actual participation in dynamic rate offerings in Quebec. Hydro Quebec implemented dynamic pricing in 2019. At the end of the 2024-2025 winter season, participation in its dynamic pricing rate offerings was an estimated 9%.

37 High time-of-use rate adoption for EVs can also lead to more localized distribution problems when the EVs on the same distribution infrastructure start charging at the same time.

38 In Canada, only Ontario has an opt-out time of use rate which was government mandated.

39 Per E Source, a utility consulting firm, utilities in Colorado and California with opt-out TOU rates have participation rates ranging from 61.1% to 99.8%.

3.4 Potential Study Electrification Results

Electric Vehicles

While the 2026 Plan does not contain electrification programming, understanding the drivers and impacts of electrification will be a key focus of the Utilities to ensure adequate preparation for managing EV load on the system, where possible.

The Potential Study identified three potential scenarios for EV adoption on the IIS. A natural adoption scenario, an intermediate scenario and a scenario in line with government mandates at the time of the study.[40] These scenarios were accompanied by an analysis of the estimated investments required to support these levels of adoption. This information will help the utilities track which scenario is the most likely outcome based on information such as available vehicle incentives and charging infrastructure installed in the province.

A key takeaway from the Potential Study is that EV load is not expected to materially impact the IIS system load until 2033. This is largely due to EV adoption remaining low until this point, keeping the IIS as a morning peaking system. EV load has little effect on the morning peak because most vehicles finish charging before morning. When EV adoption is anticipated to grow in the 2030s, the load is anticipated to shift the system to a consistent evening peak, at which point managing EV load will have benefits for the system. The Utilities will monitor EV adoption throughout the 2026 Plan to assess which scenario is most likely to occur and if a demand management program is warranted. If the baseline scenario occurs, the projected impact of EVs on system peak would be delayed until 2037. In contrast, if the government target scenario is realized, the expected impact on peak would occur earlier, in 2030. While EV adoption in Newfoundland and Labrador is continuously showing year over year growth, actual EV adoption is currently below the "natural adoption" scenario outlined in the Potential Study.[41]

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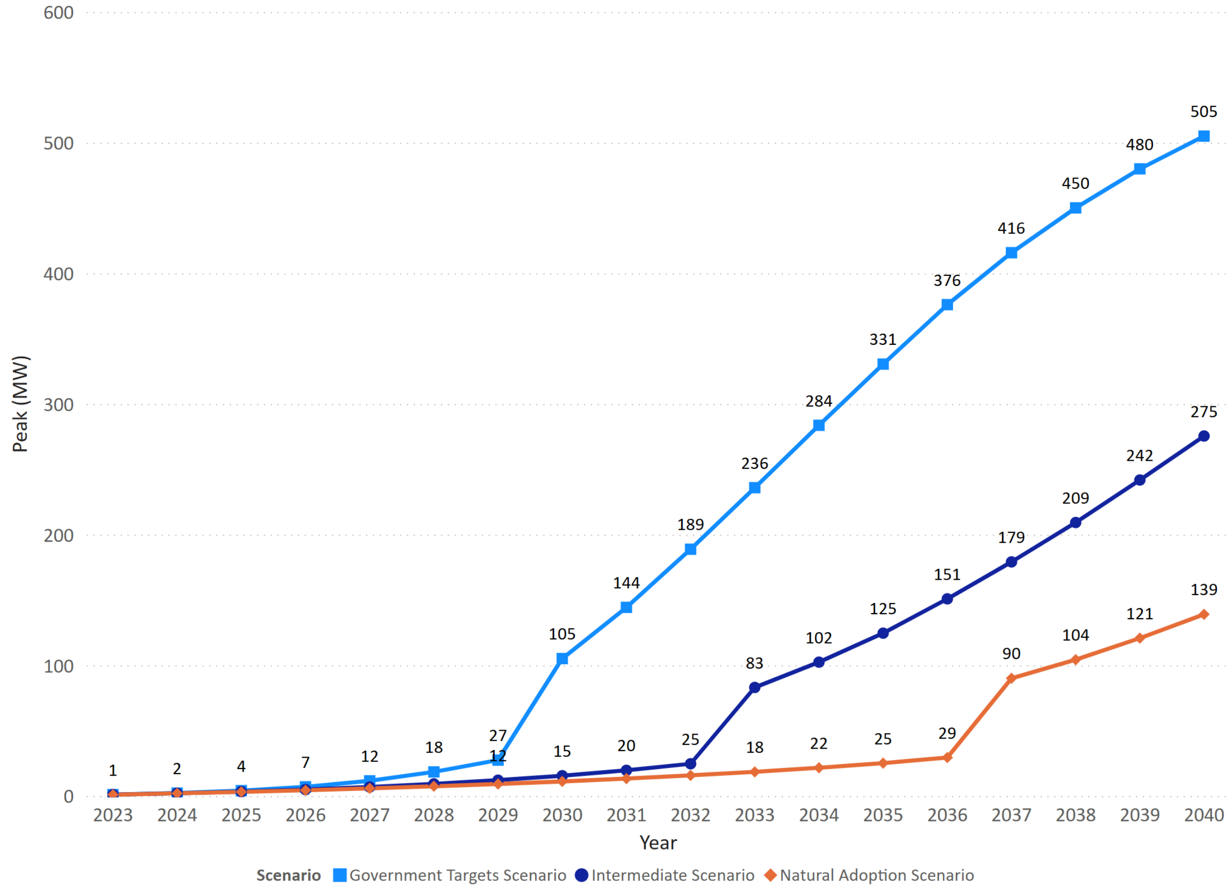
40 The natural adoption scenario estimates EV adoption based on current incentives and market conditions. The intermediate scenario includes EV uptake beyond the natural adoption scenario, consistent with additional market interventions such as vehicle rebates and accelerated build-out of charging infrastructure for light duty vehicles, and/or more favourable EV capital cost declines for medium and heavy-duty vehicles. The government targets scenario uses the Government of Canada targets as of the completion of the Potential Study for sales shares of light duty vehicles and medium duty vehicles by 2030, 2035 and 2040. These mandates are no longer in effect.

41 The Potential Study predicted that at the end of 2024 there would be 2,376 fully electric vehicles in Newfoundland and Labrador. According to NL Q2 2023 – Q2 2025 Registered Active Passenger Vehicles by Selected Fuel Type Report, the number of fully electric vehicles registered in the province was 1,690.

Figure 5 shows the estimated unmanaged peak impacts by year for each EV adoption scenario in the Potential Study.

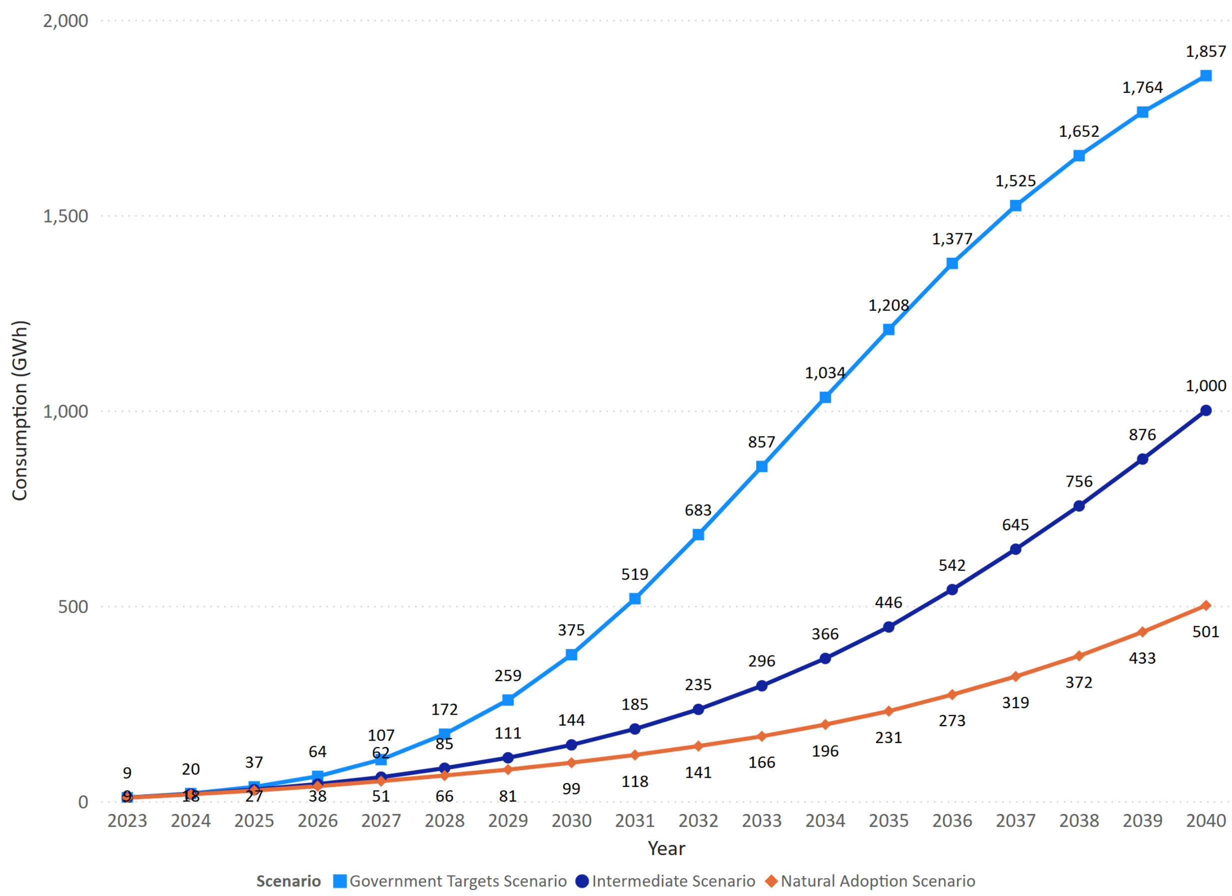
Figure 5
Forecast EV Peak Demand by Scenario (MW)



The first large increase in peak demand in each scenario is due to that year being the year that EV load is expected to transition the IIS from morning peaking to evening peaking. Unmanaged peak impacts range from 139 MW in the natural adoption scenario to 505 MW in the government target scenario by 2040.

Figure 6 shows the estimated energy sales from EV adoption in each presented scenario.

Figure 6
Forecast EV Consumption by Scenario (GWh)



Market interventions such as vehicle incentives and charging infrastructure are key factors in which scenario is most likely to be realized.

By 2030, market interventions are projected to impact electricity use. These interventions include increased vehicle rebates and faster expansion of charging infrastructure for light-duty vehicles ("LDVs"). Under the intermediate scenario, electricity use is expected to increase by an additional 45 GWh compared to the natural adoption scenario. This means electricity use will reach 144 GWh instead of 99 GWh.

By 2040, these market interventions are responsible for 499 GWh of additional consumption (1,000 GWh vs. 501 GWh). By 2040, the government targets scenario predicts nearly twice the electricity consumption from EV charging compared to the intermediate scenario (1,857 GWh vs. 1,000 GWh) and nearly four times the electricity consumption compared to the natural adoption scenario (1,857 GWh vs. 501 GWh).

Table 4 shows the estimated rebate amounts required to move adoption from the natural adoption scenario to the intermediate or government target scenario. For the government target scenario this is meant to demonstrate the market intervention required if legislation were not used.

Table 4
Personal Vehicle Adoption Incentives to Move Between Potential Scenarios

Starting Scenario	Ending Scenario	Median Incentive
Natural Adoption	Government Target	$23,833
Natural Adoption	Intermediate	$4,691

Annual vehicle incremental incentives of $23,833 would be required to achieve EV adoption levels in the government targets scenario. To reach the EV adoption levels associated with the intermediate scenario, a $4,691 incremental incentive would be required.[42]

The data in Table 4 refers to incentives required to support personal vehicle adoption. According to Posterity Group, there is no literature to support sales market share uplift of fleet vehicles due to purchase incentives. The Potential Study offers some insights into the fleet market:

- Fleet LDV and lighter-duty medium duty vehicles may behave like personal LDVs based on their incremental capital costs, vehicle kilometers travelled ("VKT"), and reliance on Level 2 chargers.

- Heavy duty vehicles ("HDVs") likely behave differently than personal LDVs based on their incremental capital costs, VKT and reliance on direct current fast chargers ("DCFCs") in many cases. Directionally, the absolute per-vehicle incentive values and total annual incentive budgets may need to be much higher for HDV than personal LDV.

[42] At the time of the completion of the study, a $5,000 Government of Canada rebate was offered along with a $2,500 Government of Newfoundland and Labrador rebate, indicating a rebate of $12,191 per vehicle would be required to move from the natural adoption to intermediate scenarios ($5,000 + $2,500 + $4,691 = $12,191). As of June 2026, the Government of Canada still offers a rebate of up to $5,000 for qualifying EVs but the $2,500 Government of Newfoundland and Labrador rebate has ended.

Table 5 outlines the cumulative number of charging ports required to support each scenario of EV adoption by 2040. These figures include at-home charging.

Table 5
Charging Infrastructure Port Count by Scenario

Scenario	2030	2035	2040
Natural Adoption	18,345	44,375	92,618
Intermediate	23,360	69,820	157,179
Government Targets	60,966	179,286	284,264

It is estimated that, by 2040, at home charging will make up approximately 82% of the charging requirements in the intermediate scenario.[43] Level 2 at-home charging is estimated to account for approximately 52% of all charging requirements and Level 1 at-home charging is estimated to account for approximately 27%.[44] Transport Canada estimates that there are currently 149 public EV chargers in Newfoundland and Labrador.[45] While there is no available tracking of at-home chargers, there are currently 2,080 fully EVs and 948 plug-in hybrid EVs in the province.[46] Assuming each vehicle has a charger would bring the charger count to 3,177.[47] This most closely aligns, but still falls below, the 4,748 charging ports estimated to be needed by 2025 to support adoption in the "natural adoption" scenario of the Potential Study.

By 2040, is it estimated that required investments in charging infrastructure will be $370 million in the natural adoption scenario, $840 million in the intermediate scenario and $1.57 billion in the government targets scenario.[48]

Based on existing levels of EV adoption and infrastructure, the Potential Study scenario that seems most reasonably aligned to where EV adoption may go in the coming years is the

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43 In the intermediate scenario, by 2040, at home charging ports will make up 82.4% of the 157,179 charging ports required to support that level of EV adoption. This means there are 129,515 at home charging ports (157,179 x 0.824 = 129,515). Costs for installing home or workplace charging and any electrical upgrades required are borne by the customer and not the utility.

44 Of the estimated 157,159 charging ports required to support the intermediate level of adoption, 51.9% of those are expected to be at-home Level 2 chargers and 27.2% are expected to be at-home Level 1 chargers. This results in a total number of at-home Level 2 chargers of 81,566 (157,159 x 0.519 = 81,566) and a total number of at home Level 1 chargers of 42,747 (157,159 x 0.272 = 42,747).

45 Data obtained on June 16, 2026 from Transport Canada website ZEV Council Dashboard.

46 Data obtained on June 16, 2026 from Government of Newfoundland and Labrador Department of Finance website Hybrid_Electric_Quarterly_NL.pdf.

47 149 public chargers + 2,080 fully electric vehicles + 948 plug-in hybrid electric vehicles = 3,177.

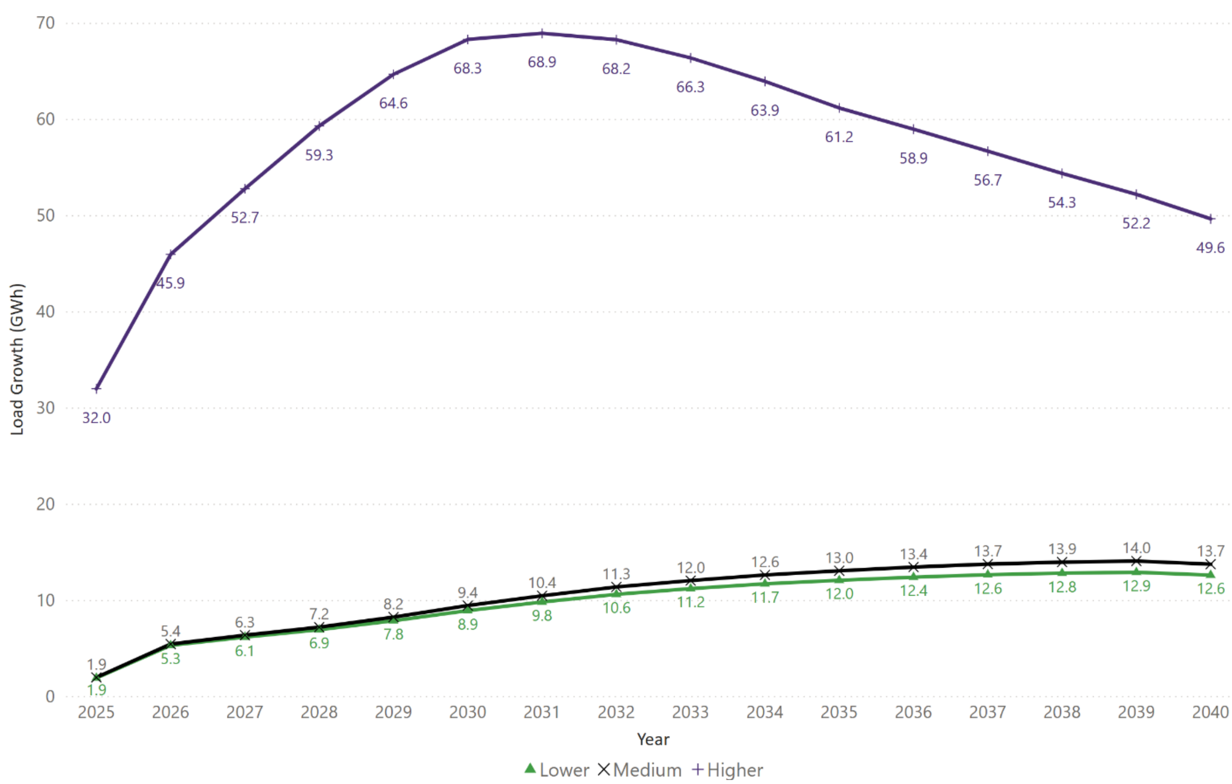
48 This investment includes at-home charging (20%), depot charging for fleet vehicles (58%) and public charging infrastructure (22%). While at-home charging makes up 80% of the charging required, it only contributes to 20% of the total cost due to the higher cost of public and fleet charging infrastructure required.

"natural adoption" scenario. Currently, vehicle and infrastructure adoption rates are below the forecast for that scenario to the end of 2025. With government mandated EV sales targets recently being revoked, the intermediate adoption scenario most likely represents the upper limit of adoption over the Plan period.[49] These assumptions are subject to change depending on incentive programs, government mandates and changes in consumer behaviour and purchasing patterns.

Fuel Switching

The impacts of fuel switching and off-road electrification in the lower, medium and higher achievable potential scenarios are shown in Figure 7. The data in Figure 7 shows incremental adoption against the baseline, not the total impacts of fuel switching. Any impacts from fuel switching expected to occur without intervention are accounted for in the reference case.

Figure 7
Fuel Switching and Off-Road Electrification Impacts



49 The Government of Canada has reinstated a purchase rebate for EVs of up to $5,000 on qualifying models in 2026, scaling down to $2,000 by 2030. The EV sales mandate that was in effect has been removed, but the Government of Canada has announced an EV sales target of 75% of vehicles by 2035. The Government of Newfoundland and Labrador EV purchase rebate expired on March 15, 2026.

Most of the electrification potential on the IIS comes from space and water heating. The Potential Study assessed the electrification impacts of two non-road vehicle types, forklifts and Zambonis, and dockside electrification for cruise ships. The Potential Study determined that the impact of forklift electrification is approximately 200 MWh in 2040. The impact of Zamboni electrification is approximately 65 MWh over the same period. Cruise ship electrification potential is approximately 1,300 MWh per year by 2040.

Measures that would impact fuel switching and off-road electrification above the already high reference case would be expected to increase system peak by 14.8 MW in 2040.

Measures in the higher achievable potential scenario cause 49.6 GWh of load growth, compared to 13.7 GWh and 12.6 GWh in the medium and lower scenarios, respectively.

Fuel switching potential is limited in all scenarios because of the high relative share of electric space heating in the base year and natural fuel switching expected in the reference case.

Load growth from fuel switching increases year over year in all scenarios between 2025 and 2031 but decreases after 2031 in the higher achievable potential scenario. In the higher scenario, the Oil to Electric Program accelerates the timeline for oil to electric conversions, pushing more conversions to the short-term instead of the long-term. However, since these conversions would have otherwise occurred at a later stage without the influence of the program, they are removed from the results of the higher scenario in the year it is estimated the conversion would have naturally happened.[50]

3.5 Electric Vehicle Load Management Pilot Results

From 2023-2025 Newfoundland Power implemented the EV Load Management Pilot to gain insight into the challenges and opportunities for managing EV Load on the IIS. The results of the study were evaluated by Guidehouse in May 2025.[51]

The primary conclusions from Newfoundland Power's EV Load Management Pilot are:

- **Both active and passive load management strategies show evidence of successful load curtailment.** The passive treatment group curtailed their load in the evening peak

50 For example, if it was estimated that 100 oil to electric conversions would have naturally happened in 2033, but they happened in 2026 because of the oil to electric program, then those conversions would appear in Figure 7 until 2033 when they would have naturally occurred and are no longer attributable to the program associated with the higher scenario. A reduction in the higher scenario in Figure 7 does not indicate a reduction in customers using electric space heating, nor does it reflect customers switching from electricity to oil.

51 Guidehouse is a global advisory, technology, and managed services firm which completes program evaluations for utility companies.

period, with an average reduction of charging demand between 4 PM and 11 PM of 0.37 kW/device. Active events resulted in an average reduction of charging demand of up to 0.46 kW/device (events called between 7 PM and 11 PM).

- **Load was generally shifted from the evening period to overnight.** This result aligns with the prediction that both treatments delay charging when participants return home and plug in their vehicles. The morning peak period (6 AM to 10 AM) shows less potential for load reduction, as participants do not typically charge their vehicles in the morning.
- **EV managed charging provides system benefits in the form of avoided cost of capacity**. The exact potential benefits will vary depending on how treatments are ultimately used to target system peak, and how the system peak coincides with the treatment period. Guidehouse estimated the potential range of benefits based on average curtailment during peak periods. For example, in the morning peak period (6 AM to 10 AM) Guidehouse estimated the benefit to be $27.03 per device for active management participants. For the evening peak period (4 PM to 11 PM), benefits were estimated to be $131.76 per device for the passive management group, and $114.81 per device for the active management group.
- **The passive management group demonstrated persistent load shifting behaviour after the Winter 2023/2024 season.** The data from September 2024 to November 2024 showed persistence of savings during the shoulder season months, which suggests the treatment is still effective in the off-season, absent a direct monthly incentive.
- **Technical and operational challenges reduced program impacts and may be a barrier to future scaling of the program.** For example, there were challenges with customer enrollment and successfully dispatching events with the Uplight platform in year two.[52] These types of challenges appeared to have less effect on passive treatment, which relies more on participants' behavioural changes rather than a technology platform.
- **Participants were generally satisfied with the Pilot charging platform and program communication.** The frequency and method of communication were effective for respondents. Dissatisfaction related to the charging platform was due to Hyundai's BlueLink App issues and Optiwatt App incompatibility.
- **Most participants are interested in participating in future EV load management programs, but at a cost.**

[52] AutoGrid was the vendor selected to implement the EV Load Management Pilot through a competitive request for proposal process. AutoGrid was acquired by Uplight during the Pilot period. Uplight then partnered with Optiwatt for the second winter of the Pilot for enrollment and dispatch of demand response events to try to enhance customer experience.

Table 6 outlines what survey respondents indicated was the minimum ongoing annual reward that would make them participate in a future EV load management program.

Table 6
Minimum Ongoing Annual Reward to Participate in EV Load Management

Annual Reward	Percentage Interested
$20	5%
$40	2%
$60	14%
$80	15%
$100	41%
None of these are high enough	22%

Sixty-three percent of respondents would require an incentive of $100 or higher to participate in an EV Load Management Program. [53] If instituted, this incentive level would erode most of the value these customers contribute to the program in avoided costs which was estimated to be between $115 and $132 per participant.

The full results of the EV Load Management Pilot can be found in Schedule I.

The Potential Study provided that managing EV load has more impact on the evening peak than the morning peak. The Potential Study has predicted that the IIS in Newfoundland and Labrador will likely continue to be a morning peaking system into the early 2030s. This coincides with forecast adoption of EVs in the intermediate scenario of the Potential Study, driving more evening load than morning load. Since the absolute peak will likely remain in the morning, it is not forecast that managing EV load will be required during the 2026 Plan. However, the timeframe of the 2026 Plan allows the Utilities the opportunity to follow the technology to determine whether there is standardization and improvement, follow EV adoption rates, better understand from other utilities the benefits on the distribution network of managed charging, and continue to understand trends and best practices.

While the timing and pace of EV adoption remain uncertain, EV load is expected to eventually have a significant impact on the IIS. Newfoundland Power's EV Load Management Pilot demonstrated that EV load can be successfully shifted to off-peak periods, and at a larger scale could represent a cost-effective way to manage peak load impacts from EVs.[54] Should EV

[53] The maximum incentive a customer could receive during year one of the Pilot was $115. The maximum incentive a customer could receive during year two of the Pilot was $230.

[54] This assumes adoption aligns with the Potential Study EV intermediate adoption scenario and that information obtained from the EV Load Management Pilot on costs and load shifting potential per vehicle are also consistent into the future. Lower vehicle adoption rates, increased costs, or reduced impacts from load management will alter the cost-effectiveness.

adoption show continued growth and EV load shifting technology continue to advance, it may be beneficial for the Utilities to consider another pilot study in the later years of the 2026 Plan. The Utilities will continue to monitor EV adoption and load management technologies to make this determination.

The timing of potential utility investment in AMI technology may also influence the scope and necessity of the program, as time-varying rates can also be used to shift load associated with EVs.[55] Though if time-varying rates were implemented, it may also lead to EV peaks at a different hour on the system, potentially leading to distribution capacity issues that may then need to be addressed.

4.0 The 2026 Plan

The 2026 Plan continues long-standing CDM programs and education for customers and includes pilot studies to assess the impacts and effectiveness of demand response programs on the IIS. The 2026 Plan uses findings from the Potential Study and incorporates the Utilities' past program experience, as well as feedback from stakeholders and customers.

The nature of customer load requirements on the IIS presents several challenges in implementing demand response programs, making pilot projects necessary to evaluate effectiveness. These challenges include the flatness and persistence of the load curve observed on peak days. The flatness of the curve limits the ability to shift load without potentially creating a new peak due to equipment rebound effects. Additionally, the prolonged morning and evening peak periods present difficulties for customers to participate, as they may experience event fatigue leading to reduced benefits over the duration of a long demand response event. Pilot studies are appropriate to assess both the impacts and customer acceptance of demand response initiatives on the IIS.

During the 2026 Plan, TakeCharge will maintain its focus on working with customers to help them better understand their energy usage and the actions they can take to help achieve energy savings. This will include working with customers to understand the opportunities and impacts of electrification.

Schedule F provides a fulsome description of the programs included in the 2026 Plan.

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[55] As provided in Table 3, AMI is not currently a cost-effective demand response measure. However, in its AMI Update filed with the Board as part of its 2026 Capital Budget Application, Newfoundland Power provided that the Company's AMR technology will require mass replacement in the mid-2030s. Based on current Canadian utility practice, Newfoundland Power anticipates that transitioning to AMI at that time will be a reasonable alternative to re-investing in AMR technology.

4.1 Program Screening

All programs in the 2026 Plan are screened to ensure they are cost effective from the total resource and program administrator perspective.[56]

Cost-effectiveness includes considerations of marginal energy and capacity costs.[57] Schedule E provides the forecast marginal cost of energy and capacity used in the 2026 Plan.[58]

Cost-effectiveness of CDM programs in the 2026 Plan continues to be evaluated using both the TRC and PAC test as approved by the Board in Order No. P.U. 18 (2016). These tests continue to be the most common for evaluating DSM initiatives in other jurisdictions.[59] Table 7 outlines the benefits and costs that are considered in both the TRC and PAC tests.

Table 7
Cost Effectiveness Test Benefits and Costs

Cost or Benefit	TRC	PAC
Avoided Capacity Cost	Benefit	Benefit
Avoided Energy Cost	Benefit	Benefit
Program Administration Costs	Cost	Cost
Program Incentive Costs		Cost
Incremental Customer Costs	Cost	

4.2 CDM Programs

CDM programs continue to provide opportunities for customers in all three sectors: residential, commercial and industrial. CDM program estimates are developed using past program performance, potential study results and results from other primary and secondary research with customers, trade allies and stakeholders. The resulting energy saving targets for energy efficiency programs align closest with the "Medium Achievable Potential" results from the Potential Study.[60]

56 The TRC is a metric to evaluate the cost-effectiveness of a measure, or a program based on both the participants' and utility's costs and the utility's benefits. The PAC is a metric to evaluate the cost-effectiveness of a measure, or a program based only on the utility's costs and benefits.

57 Marginal cost is the cost to supply electricity to meet an incremental kW of demand and kWh of energy. The marginal cost of energy is based on the forecast export price of electricity during on and off-peak hours, and the marginal cost of capacity is based on the forecast avoided cost of additional supply to meet customer demand at times of system peak.

58 The marginal costs were provided by Hydro in their 2025 Marginal Cost Update, February 20, 2025.

59 See Section 2.2 Current Utility Practice.

60 See 3.2 Potential Study Energy Efficiency Results.

4.2.1 Energy Efficiency

Table 8 shows the portfolio of energy efficiency programs to be offered in the 2026 Plan.

Table 8
Energy Efficiency Programs
By Sector

Residential	Commercial	Industrial
Benchmarking[61]	Business Efficiency Program	Industrial Energy Efficiency Program
Energy Savers Kit	Isolated Systems Business Efficiency Program[62]	
HRV	Isolated Community Energy Efficiency Program[63]	
Insulation and Air Sealing		
Income-Qualified Heat Pump and Insulation		
Isolated Community Energy Efficiency Program[64]		

All energy efficiency programs currently offered will continue in the 2026 Plan. As explained in each section below, there will be one new program offering for income-qualified customers, the "Income-Qualified Heat Pump and Insulation Program". Modifications have also been made to existing programs, mostly focusing on increased incentive levels to address rising costs for customers to participate in the programs.[65]

Insulation and Air Sealing Program

Changes to the Insulation and Air Sealing program have increased the maximum incentive level for attic and basement insulation projects from $1,000 to $1,500 per project. The rebate will now incorporate labour costs associated with customers having projects completed by qualified installers. These changes address the rising costs of insulation materials and the barrier of the additional cost of hiring an installer.

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61 The Benchmarking Program is only offered to Newfoundland Power customers.

62 Isolated System and Industrial Programs are only offered to Hydro customers.

63 This is a program offering for both residential and commercial customers.

64 This is a program offering for both residential and commercial customers.

65 For example, the average cost for approved projects for basement ceiling rebates increased from $1,034 in 2020 to $1,718 in 2024. Similarly, the average cost for approved projects for attic insulation rebates increased from $1,069 in 2020 to $1,439 in 2024.

HRV Program

To reflect the increase in costs of qualifying units, the rebate amount for the HRV program has increased from $175 per qualifying unit to $225 per qualifying unit. The current rebate amount has not changed since 2013. A scan of pricing from installers indicates the cost of eligible HRVs has increased.

Benchmarking Program

Newfoundland Power has added an additional 50,000 households to the Benchmarking program to expand the reach of the program and to increase energy and peak demand savings. The Benchmarking Program also provides seasonal usage alerts which provide a mid-billing cycle alert to customers if temperature is expected to significantly impact their next bill. The alert will also direct customers to energy efficiency tips they can use to help reduce their usage. The expansion of the program will provide Newfoundland Power with a frequent touch point with customers and opportunities to provide them with energy saving advice and promote other TakeCharge programs.

Business Efficiency Program

The Business Efficiency Program will add new rebate options under the prescriptive program path. Based on the Potential Study findings and feedback from customers and contractors, these will include rebates for variable speed drives and motors.

The Program will also expand to include energy savers kits for small businesses. These kits will include lighting and water saving measures free of charge to qualifying small businesses to help get them started on their energy efficiency journey. The contents of the kit will be evaluated when the program is implemented to ensure the right mix of products is included.

The program will also see an increase in the incentive amount for demand reduction projects from $100/kW to $250/kW. This change better reflects the marginal costs of capacity on the system and aims at making the program more attractive to customers to pursue. To date, there have been no demand reduction projects through TakeCharge.

To better increase the viability of demand reduction projects, the Utilities will work with manufacturers of electric thermal storage systems ("ETS").[66] The Potential Study identified ETS as both a viable and potentially cost-effective means of lowering peak demand. The Utilities are targeting a pilot program by 2030 and will work with manufacturers to train local installers on ETS to help make it more readily available to customers in the province. Currently, there is limited to no market in Newfoundland and Labrador for ETS units.

[66] More information on ETS can be found in section 4.2.2.

Income-Qualified Heat Pump and Insulation Program

The Utilities will offer a heat pump and insulation program for income-qualified customers. This program will be a continuation and extension of the "All-In Attic Insulation" pilot that was offered by Newfoundland Power in 2024 and 2025. The program allows the Utilities to cost-effectively provide benefits to customers who face significant barriers to participating in the Utilities' existing programs. These customers will potentially see energy savings and lower bills, while also reducing peak demand on the electricity system.

Data from customer surveys indicate that customers with a household income of less than $80,000 per year are significantly less likely to have a heat pump installed in their home and are less likely to upgrade the insulation in their home. The Income-Qualified Heat Pump and Insulation program will provide customers with no-cost attic insulation upgrades, and an incentive to install a ductless mini-split heat pump. The estimated heat pump rebate amount will be $4,000 per home, and in most cases will be paid directly to the installer to remove the upfront cost barrier for the customer. To cover any remaining cost of the heat pump project, customers can choose to participate in each utility's on-bill financing program. The estimated savings from the project will likely offset the increase in the customer's bill from the financing plan.[67]

The Utilities have applied to Natural Resources Canada under the "Canada Greener Homes Affordability Program" for funding to help offset the costs of the Utilities CDM programs and to expand the reach and eligibility of the "Income-Qualified Heat Pump and Insulation Program".[68] Should the Utilities be successful, this will likely result in modifications to this program in terms of timing, income eligibility levels and measures considered for rebates. If successful, the Utilities are expected to receive approximately $10.5 million to supplement CDM program costs.[69]

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[67] For example, if a customer's heat pump cost $5,000, they could finance the remaining $1,000 over a 60-month term (or shorter) with their utility. At an interest rate of 8.7% that would represent a payment of $20.61 per month on their utility bill. It is estimated that an electric heat customer may save 4,500 kWh per year by installing a heat pump. At a cost of 15.213 cents per kWh, which equates to annual savings of $685, or $57 per month.

[68] Information on the Canada Greener Homes Affordability Program can be found at https://natural-resources.canada.ca/energy-efficiency/home-energy-efficiency/canada-greener-homes-initiative/canada-greener-homes-affordability-program.

[69] It is anticipated that 80% of the funding will be used for programs on the IIS and 20% will be used for programs on Hydro's isolated systems.

Energy and Demand Reduction Estimates

Table 9 shows the forecast annual customer energy and demand reduction estimates from energy efficiency programs by sector from 2026 to 2030.[70] Cost effectiveness testing results for these programs can be found in section 4.4.1 and full program descriptions in Schedule F.

Table 9
2026 Plan Annual Energy and Demand Reduction Estimates
2026 through 2030

	2026	2027	2028	2029	2030
Energy (GWh)					
Residential	23.0	24.4	25.5	26.9	28.2
Commercial	4.8	4.7	4.7	4.9	5.0
Industrial	0.0	0.0	0.0	0.0	0.0
Total	**27.8**	**29.1**	**30.2**	**31.8**	**33.2**
Demand (MW)					
Residential	10.5	11.0	11.4	11.9	12.3
Commercial	0.6	0.7	0.7	0.7	0.7
Industrial	0.0	0.0	0.0	0.0	0.0
Total	**11.1**	**11.7**	**12.1**	**12.6**	**13.0**

When accounting for savings achieved prior to the 2026 Plan, and new savings achieved during the 2026 Plan, CDM programs are expected to contribute to cumulative customer energy savings of approximately 1,556 GWh and achieve peak demand reductions of 96 MW.[71] These energy and demand savings result in avoided system costs estimated to be $164 million from 2026 to 2030.[72] Customers participating in CDM programs are anticipated to save an estimated $242 million on their electricity bills over the same period.

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70 Incremental savings represent new savings in that year. They do not incorporate savings from participation in prior years which persist over time. Since each program has a different effective useful life, not all energy or peak savings will persist from year to year. For example, savings from the Benchmarking Program only have a one year effective life. Therefore, if 5.0 MW of demand reduction is achieved in 2026, and 6.0 MW of demand reduction is achieved in 2027, then the total demand reduction in 2027 is not 11.0 MW (5.0 MW + 6.0 MW), it is only 6.0 MW, because the 5.0 MW achieved in 2026 have expired. For other programs, with longer effective useful lives, like the insulation program, the impacts would be cumulative across years.

71 A further breakdown of cumulative savings estimates by program can be found in Schedule G. Figures in Schedule G include savings achieved prior to the 2026 Plan, new incremental savings from the 2026 Plan, and reductions in savings from technologies that have reached the end of their useful life and can no longer be claimed by the Utilities. For example, if a customer purchased an LED bulb 8 years ago and have since replaced that bulb with another LED bulb that was not purchased through a utility program, the utility can no longer claim the savings, but the overall energy usage remains the same, as the LED bulb was replaced with another LED bulb.

72 Avoided system costs from new participation occurring only in the 2026 Plan are estimated to be $129 million. This is based on estimated program participation and the persistence of those energy savings over time (i.e., an insulation project will provide energy savings and avoided system costs for 25 years).

4.2.2 Demand Response

Demand Response Pilots

The Utilities will complete pilot studies on demand response technologies during the 2026 Plan. This will include pilots of smart thermostats and, potentially, ETS systems.[73]

While demand response programs are common in many jurisdictions, the IIS peak is unique, with the possibility of two peaks (one in the morning and one in the evening) on a given day, with each peak persisting for 4 hours or longer. The peak is primarily driven by electric space heating which requires many devices to shift the load due to the number of baseboards in the home, which can lead to high costs to administer a program.

System peak on the IIS typically occurs from 7:00 a.m. to 10:00 a.m. in the morning and 4:00 p.m. and 9:00 p.m. in the evening. Effective management of peak load requires a strategy for both the morning and evening peak; however, the effectiveness of results may be constrained by the flatness of the load curve. The flatness makes it difficult to shift load to other periods of the day without creating a new peak. The long duration of the peak (4 to 5 hours) can make sustaining customer participation in demand response events difficult.

[73] While not currently planned, the Utilities will monitor EV adoption to determine is implement measures to manage EV demand are warranted during the 2026 Plan.

Figure 8 shows the reference load shape from the Potential Study and the associated morning and evening peak windows.[74]

Figure 8
Reference Load Shape (2023)

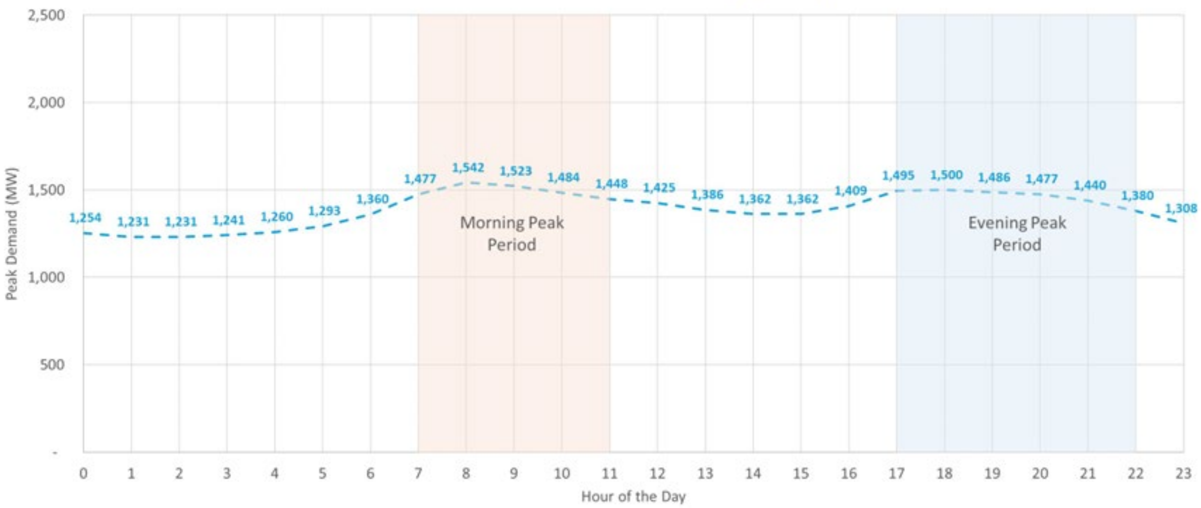

Figure 8 highlights the relative flatness of the peak day load curve, meaning that even in periods outside the morning and evening peak, there is still high demand on the electricity system, making it difficult to shift load without creating a new peak.

Despite limited new demand response potential, the Utilities already have high levels of existing resources for managing demand compared to other utilities. These resources include CDM programs and curtailment contracts or power purchase agreements.

74 The load shape from the Potential Study was creating by scaling the reference load shape to match the forecast 2023 peak hourly demand value of 1,542 MW. The reference load shape does not reflect an actual historical peak day. Instead the Posterity generated a calibrated reference load shape using a method grounded in statistics. For further details, see the Potential Study in Schedule C. Page 133.

Table 10 outlines several Canadian utilities and their estimated average demand reduction capacity from energy efficiency and demand response as a percentage of their estimated system peak.[75]

Table 10
Demand Reduction Capacity as a Percentage of System Peak
Energy Efficiency and Demand Response Resources

Utility	Reduction as a % of Peak
Newfoundland Power/NL Hydro	13.1%[76]
Nova Scotia Power	10.0%
IESO (Ontario)	8.5%
Hydro Quebec	8.4%
NB Power	7.6%
Fortis BC	5.9%
BC Hydro	5.8%

Table 10 shows that of the data obtained, Newfoundland Power and Hydro have the highest demand reduction amount as a percentage of their system peak from its energy efficiency and demand response initiatives.

During the 2026 Plan, the Utilities will use pilots to help determine a long-term strategy for demand response and validate results from the Potential Study.

Space Heating Pilots

Mysa Smart Thermostat Pilot

In the 2025-26 winter season, Newfoundland Power, under the TakeCharge brand (with support from Hydro) implemented an electric space heating load management pilot using Mysa thermostats for baseboard heaters. The pilot project has several goals. It will assess how smart thermostats impact peak load reduction and rebound effects on the IIS. The project will also gauge customer acceptance of load management. Finally, it will evaluate the potential overall cost-effectiveness of scaling the pilot to a program.

The results of the pilot will be used to determine whether investment in load management of electric baseboard heat is a cost-effective approach to managing load on the IIS. Newfoundland

[75] Utilities included are those that either responded to an Electricity Canada survey, or information was obtained by E Source.

[76] Newfoundland Power also completes conservation voltage reduction at times of peak; however, these impacts are not included in Table 10.

Power has received funding from the Government of Newfoundland and Labrador in the amount of $258,400 through the "Green Transition Fund" to support this pilot.[77]

A pilot program is appropriate to assess heating load management to help inform the scalability and reliability of load reduction from this type of program and to confirm assumptions from the Potential Study. The information gathered through this pilot program will be vital in understanding whether thermostats can become part of a reliable virtual power plant to help reduce investment in electricity system capacity.[78]

Thermostat demand response programs are common in other jurisdictions; however, most programs target customers with central space heating or cooling. The nature of baseboard heating presents complications to demand response programs that do not exist for central heating and cooling programs. Baseboards heaters interact with each other to provide heating load to the entire home and have a higher number of control points/thermostats in a home. Another consideration, unique to the IIS, is how the load curve rises in the morning and stays relatively flat until later in the evening. It will be imperative to consider how management of thermostats will impact the load curve to ensure a different peak is not created.

Results of the Pilot will be available after the 2026-27 winter season. The full scope of the Pilot can be found in Schedule H.

Electric Thermal Storage

ETS has been identified in the Potential Study as a possible source of cost-effective demand response for space heating, especially in the commercial sector. These systems work by heating ceramic bricks during off-peak hours and using a fan and the pre-heated bricks for space heating during peak hours. Shifting space heating load to off-peak hours can have system benefits through a reduction of peak heating loads, forecast to exceed 5 MW by 2040.

While other jurisdictions in Canada have successfully deployed ETS as a demand response measure, the technology is new to Newfoundland and Labrador and the Utilities are not aware of any existing ETS units installed in the province. In the 2026 Plan, the Utilities will execute foundational work to try to build a potential market for ETS units. This foundational work will include working with an ETS partner to provide training to local installers on ETS. The installer

[77] The Green Transition Fund provides financial support to businesses, organization, post-secondary institutions, and industry associations to assist with the province's transition to a green economy. Details of the fund can be found at https://www.gov.nl.ca/iet/funding/green-transition-fund-program/.

[78] A combination of dispatchable distributed energy resources is commonly referred to as a Virtual Power Plant ("VPP"). VPPs can be a combination of energy efficiency, demand response or distributed energy resources that a utility can rely on to provide firm capacity. The U.S. Department of Energy defines a VPP as "aggregations of clean distributed energy resources that act like a power plant…large enough to be utility scale, and connected, controllable and reliable enough to be utility grade."

market is crucial to increase ETS adoption, as customers often rely on their installer when choosing a heating system.

If traction can be gained with installers - and ultimately with customers - in the ETS market, the Utilities will launch an ETS pilot in the second half of the plan period. The completion of this foundational work is necessary to confidently assess whether a pilot will be able to achieve the scale of adoption necessary to draw conclusions. A pilot would consider residential and commercial customers, varying ETS technologies and required incentives, customer interest, and installer capacity.

Additionally, in support of ETS installation in commercial facilities, the Utilities are increasing the incentive level in the demand component of the Business Efficiency Program from $100 per kW to $250 per kW. The increased incentive, combined with the foundational work with installers, may lead to ETS uptake with commercial customers.

4.3 Customer Education and Outreach

During the 2026 Plan, TakeCharge will maintain its focus on working with customers to help them better understand their energy usage and the actions they can take to achieve energy savings. This will include working with customers to understand the opportunities and impacts of electrification.

Through TakeCharge initiatives, the Utilities will continue to work directly with customers and stakeholders who represent the interests of customers who face challenges paying their electricity bills. Efforts include providing clear and effective tips and resources that can be readily implemented to reduce energy use. While education and outreach efforts apply to all customers, TakeCharge puts emphasis on groups who may be less likely to participate in, or directly benefit from, rebate programs. This may include customers with low or fixed incomes, customers with disabilities, renters, new Canadians and small businesses. As outlined above, TakeCharge will also implement a new program to provide better reach to income-qualified customers beyond the existing Energy Savers Kit program.

TakeCharge will continue its outreach efforts, having a presence at a variety of trade shows, industry events and retail locations throughout the year, to allow customers to interact with energy experts in person and learn about TakeCharge programs. TakeCharge will also continue to deliver presentations to a variety of audiences including residential customers, businesses and industry stakeholders. This includes use of online tools and delivering webinars. The TakeCharge school program will continue throughout the 2026 Plan, with presentations available for children from Kindergarten to Grade 6 and contests and resources available for children in all grades.

Electrification education will help homeowners and businesses make informed decisions when considering EVs and other fuel switching opportunities. Online resources such as calculators and training modules will supplement utility outreach and education activities. During the 2026 Plan, the utilities will put more focus on commercial fleet electrification, including demand management education. According to utility consulting firm E Source, “fleet electrification remains both one of the single largest opportunities and one of the largest challenges utilities face in preparing for an electrified future. When these markets do take off, they’ll represent larger concentrated power demand – both per vehicle and per customer – than anything that’s come before”.[79]

The Utilities will continue to seek funding opportunities to help offset costs of CDM and electrification efforts as those opportunities become available.

[79] E Source, “Finding the right customers for fleet electrification programs.” May 17, 2024.

4.4 CDME Costs

Table 11 provides a summary of the Utilities' total forecast Conservation, Demand Management and Electrification ("CDME") costs from 2026 to 2030.[80]

Table 11
CDME Costs
2026 through 2030
($000s)

	2026	2027	2028	2029	2030	Total
CDM Programs[81]	7,693	10,262	12,344	14,711	16,559	**61,569**
Customer Education, Support and Research	1,562	1,429	1,424	1,992[82]	1,225	**7,632**
Electrification Programs[83]	109	112	114	133	136	**604**
Total	**9,747**	**11,480**	**13,823**	**16,835**	**17,920**	**69,805**

The Utilities' costs related to CDM programs in the 2026 Plan are forecast to be approximately $61.6 million over the 5-year planning period. This represents an increased investment of $29.4 million compared to the 2021 Plan CDM program costs, which were $32.2 million over five years.[84] The increase in spending is largely driven by new programming with higher incentive levels for customers with low income, which represents approximately $21 million.

80 This cost summary does not include costs related to Newfoundland Power's Curtailable Rate Service Option and facilities management or costs related to Hydro's interruptible load arrangements. The Utilities' curtailment costs and results will continue to be reported separately to the Board.

81 Differences in year-to-year program costs typically reflect forecast changes in customer program participation, program evaluation cycles, timing of new program implementation, program marketing cycles and program planning cycles.

82 Increased spending in Customer Education, Support and Research in 2029 reflects the next Potential Study along with other planning activities, such as residential and commercial end use surveys.

83 Electrification Program costs reflect costs associated with the operation and maintenance of the TakeCharge EV Charging Network. This represents 10 charging sites owned and operated by Newfoundland Power and 9 charging sites owned and operated by Hydro. The revenue generated from these charging stations are credited to the same Electrification Deferral Account that costs are expensed to. Annual revenue and costs are reported in the Utilities' annual CDME reports.

84 During the 2021 Plan, CDM costs were forecast to be $40.9 million but were lower than planned, primarily due to decreases in customer participation and customer outreach events following the COVID-19 pandemic. Incremental program spending from the 2026 Plan compared to the original 2021 Plan is $20.6 million ($61.5 million – $40.9 million).

The remainder of the forecast increase in CDM programs in the 2026 Plan when compared to the 2021 Plan is driven by higher customer program incentives, reflecting an anticipated increase in customer participation and increased incentive levels compared to the 2021 Plan.

During the 2021 Plan period, customer participation was lower than originally forecast following the COVID-19 pandemic and as outlined in section 4.2.1, the 2026 Plan includes increased incentive levels to address rising costs for customers to participate in the programs. The 2026 Plan, when compared to the 2021 Plan, also reflects inflationary pressures on program delivery, evaluation, planning and research costs.

As shown in Table 12 in the following section, all CDM programs continue to be cost-effective using both the TRC and PAC, meaning that CDM continues to be lower cost than supply side alternatives. Further, as outlined in section 4.2.1, CDM program participants will continue to receive direct benefits on their electricity bills from the energy savings they achieve, and all customers will benefit from avoided system costs.[85]

Schedule G provides a more detailed forecast of energy savings and costs for the 2026 Plan.

Customer education, support and planning costs are forecast to be approximately $7.6 million over the 2026 Plan period. This is relatively consistent with the $6.8 million in forecast customer education, support and planning costs during the 2021 Plan.[86] These costs include forecast cost for planning projects such as the next Energy Solutions Potential Study and demand response pilots.

The Utilities will continue to recover costs associated with CDM Program and Electrification Program costs over a ten year period, consistent with current practice approved by the Board, and will expense annually recurring general education, support and planning costs as they are incurred.[87] The Utilities will continue to seek funding opportunities to help offset costs of CDM and electrification efforts as those opportunities become available, including applications

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85 See the subsection *Energy and Demand Reduction Estimates* of section 4.2.1 Energy Efficiency.

86 Customer outreach events were lower than expected during the 2021 Plan period due to the COVID-19 pandemic. In addition, the increased forecast would also reflect inflationary cost increases.

87 In Order No. P.U. 13 (2013), the Board approved the deferral of annual customer energy conservation program costs and the amortization of annual costs over seven years, with recovery through the Rate Stabilization Account ("RSA"). In Order No. P.U. 3 (2022), the Board approved the amortization of annual costs over 10 years, commencing January 1, 2021 for historical balances and annual charges.
In Order No. P.U. 3 (2022), the Board approved the establishment of the Electrification Cost Deferral Account but did not approve the amendments to the RSA to allow for recovery over a 10-year period through the RSA. In Order No. P.U. 33 (2022), the Board agreed with Newfoundland Power that the 10-year recovery period for deferred electrification costs was appropriate, consistent with sound utility practice, current practices for CDM initiatives and regulatory fairness principles. In Order No. P.U. 3 (2025), the Board approved the amendments to the RSA to allow for the recovery of deferred costs over the 10-year period.

already filed with Natural Resources Canada and approved funding from the Government of Newfoundland and Labrador.

4.4.1 Program Cost-Effectiveness

Table 12 provides the provincial TRC and PAC forecast results for CDM programs offered in the 2026 Plan. Results greater than 1.0 indicate the benefits are greater than the costs over the lifetime of the program. The jurisdictional scan completed in 2024 confirmed that the TRC and PAC remain the most common tests used by other jurisdictions for program screening.[88]

Table 12
Program Cost-Effectiveness Testing Results
2026-2030

Program	TRC	PAC
Benchmarking	2.7	2.7
Energy Savers Kit	3.1	3.1
HRV Program	1.7	2.1
Insulation and Air Sealing	4.3	4.8
Business Efficiency	1.4	2.0
Income-Qualified Heat Pump and Insulation	1.5	1.8
Isolated Systems Business Efficiency	1.1	1.1
Isolated Community Energy Efficiency	1.2	1.3

5.0 OUTLOOK

The Utilities have successfully implemented cost-effective CDM programs under the TakeCharge brand since 2009 and will continue to do so throughout the 2026 Plan. CDM Programs included in the 2026 Plan are designed to be cost-effective, responsive to customer expectations and aligned with best practice from other jurisdictions. All programs are based on local market research, stakeholder consultation and estimates of long-term energy and demand impacts as determined by past program offerings and the completion of the most recent Potential Study. The 2026 Plan for the Utilities reflects the broader trends in the Canadian utility landscape. Newfoundland Power and Hydro will continue to lead in the areas of customer engagement and supporting customers, for which the Utilities have received several awards since TakeCharge was launched.

88 See section 2.2 Current Utility Practice.

The Utilities recognize customers' concerns about their electricity bills, especially during colder months when energy usage is the highest. In the 2026 Plan, the Utilities are expanding their focus on programs for customers with low income, which is consistent with other jurisdictions. The Utilities first engaged with a program for this group of customers in the 2021 Plan, with the launch of the Energy Savers Kit Program. The Utilities will now include a cost-effective program to allow customers with low income to improve their attic insulation and adopt a ductless heat pump. These measures will potentially provide energy savings to customers who may not be able to participate otherwise and will provide the benefit of reducing system costs for all other customers.

While programs for customers with low income are expanding, the Utilities remain committed to their existing suite of rebate program offerings and education that is available to all customers beyond the low-income segment. The Utilities have applied for government funding through the Canada Greener Homes Affordability Program to help offset the costs of CDM programs.

The Utilities will assess the role played by demand response on the IIS. The nature of the IIS load curve (specifically the duration of the peak driven by high levels of electric space heating) may limit the potential for broad demand response programs in the near-term. The Utilities plan to undertake demand response pilot programs in the 2026 Plan to help inform future demand response programs. This includes a pilot using Mysa Smart Thermostats to control electric baseboard heat that was approved for $258,400 in funding from the Government of Newfoundland and Labrador through the Green Transition Fund, and a potential ETS pilot.

Despite anticipated limitations from demand response programs that may impact their effectiveness, the Utilities' CDM programs provide meaningful reductions in peak demand. Cumulative impacts from the Utilities CDM efforts since 2009 will avoid approximately 96 MW of system peak by 2030. The Utilities curtailment programs and power purchase agreements also significantly contribute to managing peak on the system. As outlined in Table 10, The Utilities already reduce a high percentage of their system peak from energy efficiency and demand response initiatives compared to other utilities in Canada.

The Utilities will utilize demand-side management to offset system impacts from the energy transition. This includes closely monitoring EV adoption and improvements in EV load management technologies. While EV load is not expected to materially impact the IIS load curve until the 2030s, when it does, it will be important that the Utilities are positioned to capture EV load that can be managed.

The Utilities will continue their relationships with key stakeholders throughout the 2026 Plan. Although all programs are currently cost-effective, the Utilities will seek funding opportunities to offset costs where possible. In keeping with past practice, the Utilities will report progress on the 2026 Plan to the Board through annual report filings.

Schedule A
Five-Year Electrification, Conservation and Demand Management Plan: 2021-2025 Summary

Five-Year Electrification, Conservation and Demand Management Plan: 2021-2025 Summary

Electrification, Conservation and Demand Management Programs

Through the delivery of the 2021 Plan, the Utilities jointly offered customer energy efficiency programs providing both education and financial incentives to encourage customer installation of energy efficient technologies and adoption of energy efficiency behaviours.[1] Additionally, the Utilities engaged in education and awareness efforts around electric vehicles, utilizing funding provided by Natural Resources Canada to help offset the costs of these efforts.[2]

Table A-1 shows, by sector, the portfolio of energy efficiency programs that have been offered during the 2021 Plan.[3]

Table A-1
Energy Efficiency Programs by Sector
2021 Plan

Residential	Commercial	Industrial
Insulation and Air Sealing Thermostat[4] Heat Recovery Ventilator Small Technologies[5] Benchmarking Isolated Community Energy Efficiency Program	Business Efficiency Program Isolated Systems Business Efficiency Program Isolated Community Energy Efficiency Program	Industrial Energy Efficiency

[1] Once installed, these energy efficient technologies provide energy savings for the customer throughout the life of the product. For example, insulation has an estimated life of 25 years and will result in energy saving benefits throughout that period.

[2] To date, the Utilities have received $492,500 from Natural Resources Canada Zero Emission Vehicle Awareness Initiatives to support customer education on electric vehicles. This funding has been used to create webpages, web tools and enable community events such as “ride and drives” to allow customers to meet with EV owners and test drive an EV. The Utilities expanded their education efforts in 2024 to included medium and heavy-duty electric vehicles.

[3] Detailed program descriptions found in Schedule F.

[4] The Thermostat Program ended in 2023.

[5] The Small Technologies Program ended in 2023.

Table A-2 provides a summary of energy and demand savings forecast to be achieved through the Utilities' energy efficiency programs from 2021 to 2025. The energy and demand savings are cumulative, building upon the achievements of the energy efficiency programs since 2009.

Table A-2
Summary of 2021 Plan Results[6]
2021 through 2025

	2021	2022	2023	2024	2025	Total
Annual Energy Savings (GWh)						
Residential	187.9	199.4	205.0	208.4	209.2	1,009.9
Commercial	50.6	54.3	58.9	62.8	65.4	292.0
Industrial	31.2	31.5	31.5	31.5	31.5	157.2
Total Energy Savings	**269.7**	**285.2**	**295.4**	**302.7**	**306.1**	**1,458.9**
Annual Demand Savings (MW)						
Residential	52.3	56.7	61.1	64.8	66.3	66.3
Commercial	9.8	10.4	10.8	11.5	12.0	12.0
Industrial	0.7	0.7	0.7	0.7	0.7	0.7
Total Demand Savings	**62.8**	**67.8**	**72.6**	**77.0**	**79.0**	**79.0**

Delivery of the 2021 Plan resulted in 1,458.9 GWh of cumulative energy savings and 79.0 MW of cumulative peak demand reduction. The residential programs are the largest contributor to energy and demand savings.

The Utilities continuously review customer programs to ensure they provide relevant energy efficient initiatives for customers and are responsive to evolving customer needs. This is accomplished through potential studies, customer surveys, stakeholder and partner engagement, and formal program evaluations.

[6] Energy efficiency program savings indicated for the 2021 Plan are cumulative. The savings reflect all technologies installed since program implementation which have not reach the end of their useful life. For example, Heat Recovery Ventilators ("HRV") are expected to last for 15 years. Therefore, an HRV installed in 2015 will provide savings until 2029. Program savings shown are gross savings achieved by customers. Net savings reflect adjustments for: (i) installation rates; (ii) the timing of customer installations giving rise to the energy savings; and (iii) program free ridership (an estimate of participants who would have installed the energy efficiency product without the program but participated anyway).

Delivery of Government Programs

Table A-3 **TakeCharge Government Program Delivery**	
Energy Efficiency in Oil Heated Homes Program	The Government of Canada's Low Carbon Economy Leadership Fund ("LCELF") aimed to reduce greenhouse gas emissions from customers who heated their home with oil. The TakeCharge Insulation and Thermostat Programs were extended to customers with oil heat through the LCELF and Provincial Government funding. The program officially ended in March 2024.
Electric Vehicle (EV) Rebate Program	The EV Rebate Program aimed to make electric vehicles more affordable for Newfoundlanders and Labradorians to help reduce carbon emissions and help slow the pace of climate change in the province. The program, funded by the Government of Newfoundland and Labrador, provided a rebate of up to $2,500 for each BEV and $1,500 for each PHEV purchased within the province. This program was administered by Hydro and ended in March 2026.
Commercial Electric Vehicle Charger Rebate Program	The Commercial Electric Vehicle Charger Rebate Program provided a 50% rebate, up to $5,000 for a Level 2 charger and $50,000 for a Level 3 charger. The program was funded by Natural Resources Canada, administered by Hydro, and was fully subscribed and ended in August 2024.
Oil to Electric Program	The Oil to Electric program provides rebates of up to $22,000 for customers with oil heating to convert to electric heating systems such heat pumps and electric furnaces. The program is funded by the Government of Newfoundland and Labrador and has two streams, with higher rebate amounts for customers with low to moderate income. By working with the provincial government, the Utilities are able to track conversions and their impact on the electrical system and promote least-cost conversion alternatives such as heat pumps over resistance heat.

Education and Support

The Utilities continued to focus on customer education and community outreach in the delivery of the 2021 Plan. While COVID-19 restrictions slowed the normal pace of community outreach activities from 2020 into 2022, energy efficiency education and support was provided through a variety of channels, including a joint website and social media accounts, outreach activities, school presentations and partnerships with stakeholders and organizations. Table A-4 shows the number of customer-initiated contacts and outreach events from 2021 to 2025.

Table A-4
Customer Contacts and Outreach Events
2021 through 2025

	2021	2022	2023	2024	2025	Total
Customer Inquiries[7]	3,743	4,379	3,351	4,109	4,092	**19,674**
Website Visits	292,405	661,744	643,417	567,839	621,468	**2,786,873**
Outreach Events	132	156	203	97	108	**696**

The Utilities had 19,674 customer contacts and over 2.7 million visits to TakeCharge website from 2021 to 2025. The majority of customers choose electronic means to obtain information on electrification and energy efficiency. This is consistent with promotion of the TakeCharge website as the primary resource for customer inquiries and information.

The TakeCharge website received a number of updates to help customers with their energy solutions needs in the 2021 to 2025 period. Some examples of website enhancements are:

- Insulation savings calculator
- Resources for municipalities
- Electric vehicle resources

The Utilities participated in an average of 139 community events each year between 2021 and 2025.[8] Through these events, TakeCharge assisted customers with their energy efficiency and electrification questions, while helping them take advantage of the TakeCharge rebate programs. Energy conservation presentations were delivered to students, community groups and industry associations, as well as the general public through webinars. The Utilities participated at trade fairs and industry conferences, and also set up at retail locations across the province to reach a wide audience. Specialized outreach events were also offered throughout the 2021 Plan, such as the TakeCharge of Your Town Challenge, Make the Switch, Energy Efficiency Week, Customer Energy Forums and the Luminary Awards.

Trade allies, retailers and a variety of partners play an integral role in helping customers make knowledgeable decisions about their energy use. Trade allies and retail partners share and display information about TakeCharge programs and promote energy efficiency during special events. The Utilities continued to develop partnerships and strengthen relationships throughout the 2021 Plan. Some of these organizations include Seniors NL, the Association of Newfoundland and Labrador Realtors, the Association for New Canadians, the Automobile Dealers Association of Newfoundland and Labrador, Empower NL, the Canadian Home Builders Association, Municipalities Newfoundland and Labrador, econext, Newfoundland and Labrador Housing Corporation, the Government of Newfoundland and Labrador and the Government of Canada.

7 Customer inquiries include calls and emails received by the Utilities regarding energy efficiency and electrification. Inquiries are not categorized individually by energy efficiency or electrification, nor do they include other inquiry types such as direct contacts to specific utility employees.

8 A significant number of annual outreach events were related to the Small Technologies Program which ended in 2023. As a result, there is a decrease in outreach events in 2024.

Costs

Table A-5 provides a summary of the research and customer education, conservation and demand management (CDM) program costs incurred by the Utilities from 2021 through 2025.[9]

Table A-5
CDM and Electrification Costs
2021 through 2025
($000s)

	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Research and Customer Education	1,000	1,088	1,679	1,523	1,496	**6,786**
CDM Programs	6,312	6,021	6,817	6,410	6,687	**32,247**
Electrification Programs	-	28	373	487	294	**1,182**
Total	**7,312**	**7,137**	**8,869**	**8,420**	**8,477**	**40,215**

The Utilities' costs related to customer energy conservation programs were lower during 2021 and 2022, mostly related to COVID-19 related impacts. Fluctuations in year over year spending are typically related to variable expenditures associated with customer rebate program participation and other cyclical expenses such as third-party evaluations.

The Utilities each bear the costs related to the provision of customer programming in their own service territory. General conversation and program costs, such as customer rebates and costs related to responding to customer inquiries are incurred directly by each utility. Costs which are incurred jointly, such as provincial mass media advertising are typically split on an 85%/15% basis between Newfoundland Power and Hydro respectively.

[9] In Order No. P.U. 13 (2013), the Board approved the deferral of annual customer energy conservation program costs and the amortization of annual costs over seven years, with recovery through the Rate Stabilization Account ("RSA"). In Order No. P.U. 3 (2022), the Board approved the amortization of annual costs over 10 years, commencing January 1, 2021 for historical balances and annual charges.
In Order No. P.U. 3 (2022), the Board approved the establishment of the Electrification Cost Deferral Account but did not approve the amendments to the RSA to allow for recovery over a 10-year period through the RSA. In Order No. P.U. 33 (2022), the Board agreed with Newfoundland Power that the 10-year recovery period for deferred electrification costs was appropriate, consistent with sound utility practice, current practices for CDM initiatives and regulatory fairness principles. In Order No. P.U. 3 (2025), the Board approved the amendments to the RSA to allow for the recovery of deferred costs over the 10-year period. Newfoundland Power expenses its annually recurring general conservation costs – including those not directly related to programs for customer information, community outreach, and planning – in the same year they are incurred.

Tables A-6, A-7 and A-8 outline energy savings, demand savings and costs for each energy conservation program by sector from 2021 to 2025.

Table A-6 Conservation Programs Energy Savings: 2021-2025 By Sector (GWh)						
	2021	**2022**	**2023**	**2024**	**2025F**	**Total**
Residential						
Insulation & Air Sealing	51.2	54.4	57.5	61.1	63.5	287.7
Thermostat	24.8	25.2	25.3	25.3	25.3	125.9
ENERGY STAR Window	10.1	10.1	10.1	10.1	10.1	50.5
HRV	1.8	2.2	2.5	2.9	3.2	12.6
Small Technologies	77.1	83.3	84.4	83.0	76.7	404.5
Benchmarking	16.9	17.3	15.9	15.6	15.8	80.9
Energy Savers Kit	0.0	1.9	4.5	6.4	11.2	24.0
Isolated Community Energy Efficiency	6.0	5.0	4.8	4.0	3.4	23.2
Total Residential	**187.9**	**199.4**	**205.0**	**208.4**	**209.2**	**1,009.9**
Commercial						
Business Efficiency	48.9	52.3	56.4	59.9	62.1	279.6
Isolated Systems Business Efficiency	0.9	0.9	0.9	0.9	0.9	4.5
Isolated Community Energy Efficiency	0.8	1.1	1.6	2.0	2.4	7.7
Total Commercial	**50.6**	**54.3**	**58.9**	**62.8**	**65.4**	**291.8**
Industrial						
Industrial Energy Efficiency	31.2	31.5	31.5	31.5	31.5	157.2
Total Portfolio	**269.7**	**285.2**	**295.4**	**302.7**	**306.1**	**1,458.9**

Table A-7
Conservation Programs
Peak Demand Savings: 2021-2025
By Sector
(MW)

	2021	2022	2023	2024	2025
Residential					
Insulation & Air Sealing	18.1	20.4	22.5	25.0	26.7
Thermostat	3.3	3.4	3.5	3.5	3.4
ENERGY STAR® Window	3.1	3.1	3.1	3.1	3.1
HRV	0.6	0.7	0.8	0.9	1.0
Small Technologies	17.8	18.8	19.4	19.0	18.8
Benchmarking	7.5	8.1	9.0	10.9	10.1
Energy Savers Kit	0.0	0.5	1.3	1.2	2.4
Isolated Community Energy Efficiency	2.0	1.7	1.6	1.2	0.9
Total Residential	**52.4**	**56.7**	**61.2**	**64.8**	**66.3**
Commercial					
Business Efficiency	9.2	9.7	10.1	10.8	11.2
Isolated Systems Business Efficiency	0.4	0.4	0.4	0.4	0.4
Isolated Community Energy Efficiency	0.1	0.2	0.3	0.3	0.4
Total Commercial	**9.7**	**10.3**	**10.8**	**11.5**	**12.0**
Industrial					
Industrial Energy Efficiency	0.7	0.7	0.7	0.7	0.7
Total Portfolio	**62.8**	**67.7**	**72.7**	**77.0**	**79.0**

Table A-8 Conservation Programs Program Costs: 2021-2025 By Sector ($000s)						
	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Residential						
Insulation & Air Sealing	1,259	1,420	1,645	2,437	2,453	9,214
Thermostat	352	165	61	7	-	585
ENERGY STAR Window	-	-	-	-	-	-
HRV	209	231	221	288	264	1,213
Small Technologies	1,122	995	995	(2)	-	3,110
Benchmarking	974	986	1,122	798	850	4,730
Energy Savers Kit	103	305	429	374	387	1,598
Isolated Community Energy Efficiency	775	556	372	516	297	2,516
Total Residential	**4,794**	**4,658**	**4,845**	**4,418**	**4,251**	**22,966**
Commercial						
Business Efficiency	1,112	1,021	1,371	1,471	1,526	6,501
Isolated Systems Business Efficiency	43	18	29	11	71	172
Isolated Community Energy Efficiency	349	310	554	466	694	2,373
Total Commercial	**1,504**	**1,349**	**1,954**	**1,948**	**2,291**	**9,046**
Industrial						
Industrial	14	14	18	44	145	235
Total Portfolio	**6,312**	**6,021**	**6,817**	**6,410**	**6,687**	**32,247**

Schedule B
Jurisdictional Scan Results

Jurisdictional Scan Results

To ensure alignment with utility practice, TakeCharge contracted Econoler Inc. to complete a jurisdictional scan of demand-side management and electrification initiatives across Canada and in selected winter-peaking jurisdictions in the United States of America.[1] In total 15 program administrators were selected and participated in the scan. The scan was completed in September of 2024.

Findings on cost-effectiveness testing and non-energy benefits

- Cost-effectiveness approaches are generally driven by legislative policy or regulatory requirements.
- The Total Resource Cost ("TRC") test is the most common primary cost-effectiveness test used to screen energy efficiency and demand response programs, followed closely by the Program Administrator Cost ("PAC") test.
- The majority of utilities use the same primary test for both energy efficiency and demand response.
- Seven jurisdictions account for non-energy benefits ("NEBs") in their primary cost-effectiveness tests for energy efficiency programs. In these cases, NEBs are added as part of a modified TRC ("mTRC").
    - In all cases, NEBs applied in cost-effectiveness testing are based on secondary data or assumptions rate than on quantitative studies by the jurisdictions applying them.
- The most common method of deriving discount rates for cost-effectiveness testing is the weighted average cost of capital ("WACC").
- Of the eight jurisdictions with electrification programs, five jurisdictions test programs for cost-effectiveness, using a variety of tests including the Ratepayer Impact Measure ("RIM"), the Societal Cost Test ("SCT"), the TRC, or a jurisdictional specific test (Xcel Energy Minnesota uses the Minnesota Test).

[1] Econoler is an international consulting firm with 40 years of experience in the design, implementation, evaluation and financing of energy efficiency and renewable energy programs and project. Over the years, Econoler has contributed to developing and implementing about 5,000 projects in over 160 countries. Econoler staff is comprised of about 100 experts, including engineers, economists, financial specialists, marketing specialists and professional statisticians.

Table B-1 outlines the cost-effectiveness levels and tests for energy efficiency, demand response and electrification programs across the jurisdictions surveyed.

Table B-1
Cost-Effectiveness (CE) Levels and Tests
Energy Efficiency (EE), Demand Response (DR) and Electrification Programs

Jurisdiction/Program Administrator	Primary CE Analysis Level	Primary CE Test for EE	Primary CE Test for DR	Electrification CE Test
BC Hydro	Portfolio	PAC	PAC	Modified RIM
Central Hudson	Program	SCT	SCT	SCT
DTE Energy	Portfolio	PAC	PAC	N/A
EfficiencyOne	Portfolio	TRC	TRC	N/A
FortisBC	Portfolio	PAC	PAC	N/A
Green Mountain Power/Efficiency VT	Program	SCT	SCT	SCT
Hydro-Quebec	Program	TRC	TRC	N/A
IESO	Portfolio	PAC	N/A	N/A
National Grid (MA)	Sector	mTRC	mTRC	N/A
New Brunswick Power	Program	PAC	PAC	N/A
Puget Sound Energy	Portfolio	mTRC	SCT	SCT
SaskPower	Program	TRC	See footnote[2]	N/A
Seattle City Light	Measure	mTRC	N/A	N/A
Xcel Energy (MN)	Sector	Minnesota Test	Minnesota Test	Minnesota Test
Yukon Energy	Program	TRC	N/A	N/A
Newfoundland Power	Program	TRC/PAC	N/A	N/A

[2] The value of demand response is the sum of:
- Avoided net cost of a peaking plant: The cost avoided if DR temporarily delays the need to build additional infrastructure;
- Avoided spinning reserve cost: This is the avoided cost for fuel to maintain generating capacity in a ready state;
- The opportunity cost of energy: The potential revenue that could be made from selling capacity abroad while paying the cost of curtailing customers in Saskatchewan.

Table B-2 outlines the jurisdictions that include non-energy benefits in their cost-effectiveness testing and how those benefits are derived if applicable.

Table B-2
Non-Energy Benefits (NEBs) Included in Cost-Effectiveness Testing

Jurisdiction/Program Administrator	Primary Test	Are NEBS Used?	How NEB Values Are Derived	Source of GHG Benefit Value
BC Hydro	PAC	No	N/A	N/A
Central Hudson	SCT	Yes	N/A	N/A
DTE Energy	PAC	No	N/A	N/A
EfficiencyOne	TRC	No	N/A	N/A
FortisBC	PAC	Yes	15% Adder	N/A
Green Mountain Power/Efficiency VT	SCT	Yes	15% Adder	N/A
Hydro-Quebec	TRC	No	N/A	N/A
IESO	PAC	No	See footnote[3]	See footnote[4]
National Grid (MA)	mTRC	Yes	N/A	See footnote[5]
New Brunswick Power	PAC	No	N/A	N/A
Puget Sound Energy	mTRC	Yes	See footnote[6]	N/A
SaskPower	TRC	No	No	N/A
Seattle City Light	mTRC	Yes	N/A	See footnote[7]
Xcel Energy (MN)	Minnesota Test	Yes	See footnote[8]	See footnote[9]
Yukon Energy	TRC	No	N/A	N/A
Newfoundland Power	TRC/PAC	No	N/A	N/A

3 In 2021, the IESO conducted a study to quantify NEBs ($/kWh) specific to different sectors (agricultural, residential, low-income, First Nations, commercial, institutional, and industrial) for their TRC test.

4 Environment and Climate Change Canada (2019). Canada's Air Pollutant Emissions Inventory (2020). Canada's Energy Future 2020 Data Appendices.

5 Massachusetts Department of Environmental Protection. Represents the emissions that natural gas-fired power plants would not emit for each MWh not needed to be generated because energy efficiency reduced the load.

6 All non-energy impacts that are quantifiable are included in the TRC.

7 Interagency Working Group on Social Cost of Greenhouse Gases, United States Government (2016).

8 NEBs include criteria on air emissions, other environmental impacts as well as energy security and equity.

9 "In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3", Docket No. E-999/CI-14-643, January 3, 2018, p. 6.

Table B-3 outlines the discount rates and method or source of the discount rate for each jurisdiction.

Table B-3
Discount Rates and Method or Source

Jurisdiction/Program Administrator	Primary Test	Discount Rate	Real or Nominal	Method or Source
BC Hydro	PAC	6.0%	Nominal	WACC
Central Hudson	SCT	6.4%	Nominal	WACC
DTE Energy	PAC	7.6%	Nominal	WACC
EfficiencyOne	TRC	N/A	N/A	WACC
FortisBC	PAC	7.9%	Nominal	N/A
Green Mountain Power/Efficiency VT	SCT	3.0%	Nominal	N/A
Hydro-Quebec	TRC	5.9%	Nominal	WACC
IESO	PAC	4.0%	Real	N/A
National Grid (MA)	mTRC	2.3%	Nominal	U.S. Treasury Notes
New Brunswick Power	PAC	5.9%	Nominal	WACC
Puget Sound Energy	mTRC	6.8%	Nominal	Return-on-rate base
SaskPower	TRC	N/A	N/A	N/A
Seattle City Light	mTRC	N/A	N/A	WACC
Xcel Energy (MN)	Minnesota Test	3.3%	Nominal	U.S. Treasury Notes
Yukon Energy	TRC	N/A	N/A	N/A
Newfoundland Power	TRC/PAC	6.0%	Nominal	WACC

Findings on Energy Efficiency Programs

- The most common residential program types in the scanned jurisdictions are residential weatherization programs.
- Seven scanned jurisdictions have a home energy report program.
- Thirteen scanned jurisdictions have a prescriptive program for non-residential customers and twelve have a custom program.
- Strategic energy management, small business and new construction are common types of non-residential programs.

Findings on Demand Response Programs

- Thirteen jurisdictions have a residential DR program offering and eleven have commercial DR programs.
- Ten jurisdictions have heating, ventilation and air conditioning DR programs. Six jurisdictions have residential programs based on direct load control for electric central heating, two offer

direct load control for electric baseboard heating, and eight offer direct load control for central cooling DR programs.
- Most commercial and industrial DR programs are measure agnostic and rely on day-ahead communication and participant control.

Finding on Electrification Programs
- Eight jurisdictions offer some kind of electrification program that are largely ratepayer funded.
- Jurisdictions have offered electrification programs from one to six years.
- Seven jurisdictions offer residential programs, six have non-residential programs.
- Five jurisdictions have programs involving electric vehicle charging equipment.
- Four jurisdictions have prescriptive building electrification/fuel-switching offerings and four have custom building electrification/fuel-switching options.
- Policy and business drivers for electrification programs vary:
  - BC Hydro first introduced electrification programs because they had surplus electricity and to comply with BC's Greenhouse Gas Reduction Regulation.
  - Central Hudson's main drivers are state government policy and regulation.
  - New Brunswick Power's main business driver is increasing utility revenue.
  - Puget Sound Energy introduced electrification programs as a result of a settlement agreement in their 2022 general rate case.
  - Xcel's main driver is to respond to business customer demand for electrification offerings.
- Central Hudson and Xcel Energy Minnesota are allowed by their regulators to count fuel-switching savings toward energy efficiency program savings.

Schedule C
Newfoundland Power and Newfoundland and Labrador Hydro Energy Solutions Potential Study Final Report

Newfoundland Power and Newfoundland and Labrador Hydro

Energy Solutions Potential study

Final Report

Date: May 5, 2025

Western Brook Pond, Gros Morne National Park
Photo by Dave Shipley

Newfoundland Power and
Newfoundland and Labrador Hydro

Posterity Group
135 Laurier Ave W, Suite 408
Ottawa, ON K1P 5J2

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Definitions

Customer Accounts: Number of Newfoundland Power and Newfoundland and Labrador Hydro customer accounts. This report refers to 'customer accounts' rather than customers because there may be multiple customer accounts associated with one customer.

Advanced Metering Infrastructure: An integrated system of sensors and equipment for enhanced energy metering.[1]

Addressable Peak: The peak hour consumption in the demand response windows that can be shifted outside the window without creating a new peak hour.

Base Year: The first year of a forecast period and is based on historical data provided by the Utilities.

Battery Electric Vehicle (BEV): Vehicle powered solely by a rechargeable battery pack that produces zero tailpipe emissions.[2]

Behind-the-Meter: Energy that originates from a source other than the publicly owned and operated power grid.[3]

Bounce-Back Effect: The phenomenon that can occur when energy consumption and peak demand increase after a demand response resource is called.

Cost of Conserved Energy (CCE): Annualized incremental capital and operations and maintenance cost of the upgrade measure divided by the annual energy savings achieved, excluding any administrative program costs. The CCE represents the cost of conserving one kilowatt hour of electricity and can be directly compared to the cost of supplying one new kilowatt hour of electricity.

Critical Peak Pricing (CPP): An electricity rate structure that encourages customers to shift electricity use from periods of unusually high demand. During CPP events, customers pay critical peak pricing rates.

Customer or End-User Payback Acceptance: Customer or end-user willingness to invest in an energy or demand savings measure based on how long it will take to recoup their initial investment.

Direct Current Fast Charging (DCFC): DCFC chargers convert utility-supplied alternating current power to direct current power and charge electric vehicles directly with the direct current power.

Electricity Conservation and Demand Management (ECDM): A strategy used by utilities to reduce electricity consumption and peak demand.

End Use: The final purpose for which energy is used. For example, space heating, water heating, or industrial process heating.

Electrically Heated Dwelling/Building, Non-Electrically Heated Dwelling/Building: In the residential and commercial sectors, a dwelling or general service building that primarily uses electricity for space heating heat (>50% of the fuel share for space heating) is considered an electrically heated dwelling/building. A dwelling/building that has an electricity space heating fuel share <50% is considered

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[1] "Advanced Metering Infrastructure," Manitoba Hydro, Available: https://www.hydro.mb.ca/articles/2022/04/advanced_metering_infrastructure/ (Accessed Jan. 21, 2025).
[2] "Light and medium-duty vehicle registrations: Interactive dashboard," Statistics Canada, Available: https://www150.statcan.gc.ca/n1/pub/71-607-x/71-607-x2022023-eng.htm (Accessed Feb. 29, 2024).
[3] "Behind the Meter," Electricity Canada, Available: https://tinyurl.com/324mkhpd (Accessed Jan. 21, 2025).

a non-electrically heated dwelling/building. Electrically heated dwellings/buildings may have other fuels serving the space heating end use, but electricity comprises at least 50% of the fuel share.

Electric Vehicle Supply Equipment (EVSE): Electric vehicle supply equipment supplies electricity to an electric vehicle. Other terms for EVSE include charging station or charging dock. EVSE include the electrical conductors, related equipment, software and communications protocols that deliver electricity efficiently and safely to the vehicle.[4]

Energy Curtailment Program: Program offered by Newfoundland Power that incentivizes commercial rate 2.3 or 2.4 customers to reduce their demand on the IIS on request during the winter peak period.[5]

Exogenous: Relating to external factors.

External Advisory Committee (EAC): External stakeholder Study participants. External stakeholders included including retailers, property managers, representatives from industry associations and the provincial government, and others. External stakeholders were consulted in May 2024 during the achievable potential workshops.

Fuel Share: Ratio of a specific end use load that is met by a particular fuel. For example, if 90% of the space heating load in large offices is met by electric equipment, the electricity fuel share for space heating in large offices is 90%.

Heavy-Duty Vehicle (HDV): On-road vehicle with a gross vehicle weight of more than 11,793 kilograms.[2]

Internal Combustion Engine (ICE) Vehicle: Vehicle powered by an internal combustion engine that burns fuel (e.g., gasoline or diesel) to generate the power required to propel the vehicle.

Light-Duty Vehicle (LDV): Vehicle with a gross vehicle weight less than 4,536 kilograms.[2]

Level 1 (L1): Level 1 equipment provides charging through a 120-Volt alternating current outlet.[6]

Level 2 (L2): Level 2 equipment provides charging through a 208-Volt or 240-Volt alternating current outlet.[6]

Medium-Duty Vehicle (MDV): Vehicle with a gross vehicle weight between 4,536 kilograms and 11,793 kilograms.[2]

Multi-Unit Residential Building (MURB): A residential building that contains two or more units.

Other Industrial: The segment that includes all industrial facilities not categorized as large industrial, manufacturing, fishing and fish processing, water and wastewater, mining and processing, or pulp and paper.

Participant Cost Test (PCT): A metric to evaluate the cost-effectiveness of a measure based on the participant's costs and benefits.

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[4] "Electric Vehicle Supply Equipment System," NEMA, Available: https://www.nema.org/membership/products/view/electric-vehicle-supply-equipment-system (Accessed Aug. 9, 2024).
[5] "Energy Curtailment Program" Newfoundland Power, Available: https://www.newfoundlandpower.com/Business-Services/Rates-and-Services/Curtailment-Program (Accessed Jan. 22, 2025).
[6] "Charger Types and Speeds," U.S. Department of Transportation, Available: https://www.transportation.gov/rural/ev/toolkit/ev-basics/charging-speeds (Accessed Aug. 9, 2024).

Peak Demand: The single highest hour of system demand, typically occurring on the coldest day of the winter.

Plug-In Hybrid Electric Vehicle (PHEV): Vehicle with an internal combustion engine and a high-capacity battery that can be recharged using a wall outlet or charging equipment, by the ICE, or through regenerative braking.

Program Administrator Cost (PAC): A metric to evaluate the cost-effectiveness of a measure based on the program administrator's costs and benefits.

Reference Adoption: The adoption level for a measure if there is no program activity in the marketplace.

Reference Case: Represents the baseline forecast period against which new potential can be calculated.

Replace on Burnout (ROB): Measure that is replaced at the end of its useful life.

Retrofit (RET): Measure that is implemented immediately.

Saturation: For most end uses, saturation is the extent to which an end use is present in a segment. For some specific end uses that are associated with appliances, saturation is defined as the average number of appliances per unit.

Sector: Grouping or category of customers, buildings, or vehicles by type: residential, commercial, industrial and transportation.

Segment: Grouping or category of buildings (e.g., single-family detached in residential, large offices in commercial). Segments reflect the main purpose of the building and helps to differentiate between energy use intensity or patterns across building types within a sector.

Simple Payback: The duration of time to recover the cost of a project based on cumulative savings, without accounting for the time value of money. Calculated from the perspective of an end use and presented in units of years. For example, a measure that costs $600 and results in energy savings valued at $200 annually has a simple payback of 3 years (i.e., $600 ÷ $200/yr = 3 years).

Single-Family Detached: A dwelling unit with walls and roofs independent of any other building.[7]

Size Factor: The change in average number of units per customer account. Size factor is primarily used to reflect the forecast change in production volumes in industry.

Stock Average Efficiency: Average efficiency of equipment serving the tertiary load for that end use.

Tertiary Load: The useful energy delivered to an end use. In the context of the Study, tertiary load is the amount of energy required to be delivered as an end use service, for example, heat delivered by a heat pump to a residential dwelling.

Time-of-Use (TOU) Rates: An electricity rate that reflects the cost of producing electricity at different times of day based on demand. TOU pricing has two or more periods. These periods may include on-

[7] "Eligible Property Types," Natural Resources Canada, Available: https://natural-resources.canada.ca/energy-efficiency/home-energy-efficiency/canada-greener-homes-initiative/eligible-property-types (Accessed Feb. 27, 2025).

peak, when energy demand and cost is high, mid-peak, when energy demand and cost is moderate, and off-peak, when energy demand and cost is low.[8]

Time-Variable Rate (TVR): An electricity rate that varies depending on time of day.

Total Resource Cost (TRC): A metric to evaluate the cost-effectiveness of a measure based on both the participants' and utility's costs and benefits.

Unit Energy Consumption (UEC): The amount of energy used by each end use per unit.

Units: The sector-specific unit of analysis: dwellings in the residential sector, square feet in the commercial sector, and production capacity in the industrial sector.

Vehicle Telematics: Method of monitoring cars, trucks, equipment and other assets using global positioning system (GPS) technology and on-board diagnostics to plot the asset movements on a computerized map.[9]

Vehicle to Load (V2L): Applications use vehicle battery power as a backup source for localized loads within a site.

Vehicle to Building (V2B): Applications enable feeding battery power from the vehicle to serve end uses in the building and are expected to primarily serve for building resilience but may also reduce building peak power demand.

Vehicle to Grid (V2G): Applications enable feeding battery power from the vehicle back to the grid during peak periods.

Vintage: A grouping of facilities based on their age.

[8] "Electricity Prices and Costs," Hydro One Networks Inc, Available: https://bit.ly/4jvPEom (Accessed Aug. 9, 2024).
[9] "What is Telematics," Geotab, Available: https://www.geotab.com/blog/what-is-telematics/ (Accessed Aug. 9, 2024).

Acronyms

a.m.	Before noon
AMI	Advanced Metering Infrastructure
ASD	Adjustable Speed Drive
BEV	Battery Electric Vehicle
BTM	Behind-the-Meter
CDME	Conservation, Demand Management and Electrification
CED	Customer, Energy and Demand
CEUS	Commercial End Use Survey
CPP	Critical Peak Pricing
DC	Direct Current
DCFC	Direct Current Fast Charging
DHW	Domestic Hot Water
DLC	Direct Load Control
DR	Demand Response
EAC	External Advisory Committee
EC	Electronically Commutated
ECDM	Electricity Conservation and Demand Management
ECP	Energy Curtailment Program
EMIS	Energy Management Information System
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
GEB	Grid Interactive Efficient Buildings
GWh	Gigawatt hour
HDV	Heavy-Duty Vehicle
HVAC	Heating, Ventilation, and Air Conditioning
ICE	Internal Combustion Engine
ICEV	Internal Combustion Engine Vehicle
IIS	Island Interconnected System
kW	Kilowatt
kWh	Kilowatt hour
kVA	Kilo-Volt-Ampere
LD	Light-Duty
LDV	Light-Duty Vehicle
L1	Level 1
L2	Level 2
MDV	Medium-Duty Vehicle
MHDV	Medium-and Heavy-Duty Vehicle
MUN	Memorial University of Newfoundland
MURB	Multi-Unit Residential Building
MW	Megawatt
MWh	Megawatt hour
NAICS	North American Industry Classification System
NEW	New Construction
NLH	Newfoundland and Labrador Hydro
NP	Newfoundland Power

PAC	Program Administrator Cost Test
PCT	Participant Cost Test
PHEV	Plug-In Hybrid Electric Vehicle
p.m.	After noon
RET	Retrofit
REUS	Residential End Use Survey
ROB	Replace on Burnout
SFD	Single-family detached home
TCO	Total cost of ownership
TOU	Time-of-Use
TRC	Total Resource Cost
TRM	Technical Reference Manual
TVR	Time-Variable Rate
UEC	Unit Energy Consumption
VFD	Variable Frequency Drive
VKT	Vehicle Kilometre Travelled
VT	Vehicle Telematics
V2L	Vehicle to Load
V2B	Vehicle to Building
V2G	Vehicle to Grid
ZEV	Zero-Emissions Vehicle

Executive Summary

The Energy Solutions Potential Study (the Study) evaluates the potential for energy efficiency, electrification, and peak demand management activities led by Newfoundland Power and Newfoundland and Labrador Hydro (the Utilities) from 2025-2040.

Posterity Group Consulting (PG, the Study Team) completed the analysis and reporting for the Study, in collaboration with the Utilities and their stakeholders. This collaboration included the provision of customer data, inputs to the measure analysis, and participation in achievable potential workshops.

The Study relied on the Utilities' knowledge of their customer base; the best available research and data available to the Utilities; internal and external stakeholder feedback; extensive original research; and the Study Team's professional judgement. The results in this report reflect rigorous analysis and estimate the opportunities available to the Utilities.

Study Scope

The Utilities' energy conservation activities under the takeCHARGE brand have historically focused on energy savings but are increasingly considering demand management technologies and their potential to reduce or shift peak demand. Accordingly, the Study scope examines opportunities for energy efficiency, fuel switching and to deploy demand response (DR) resources including managed electric vehicle (EV) charging to manage peak demand on the Island Interconnected system (IIS). The Study scope is summarized in in Exhibit 1.

Exhibit 1: Study Scope

Study Period

- **Base Year**: 2023 base year
- **Forecast Period**: 2024-2040
- **Measure Application**: 2025-2040

Geographical Coverage

- **Includes:** The IIS, both Utilities' customers
- **Excludes:** Labrador Interconnected & Isolated Diesel Generation Systems

Sectors

- **Four Sectors:** Residential, commercial, industrial, & transportation
- **Transportation sector**: Personal & fleet EVs

Measures

- **Types**: Efficiency, fuel switching, & DR
- **DR:** Time-variable rates, EV managed charging, thermal storage, and others.

Given the emphasis on demand management, the Study Team was asked to examine the impact of all measure types for three peak periods:

1. **Peak Hour:** The single highest hour of IIS demand, typically occurring on the coldest day in the winter. Depending on the Study year, the single hour peak can occur in the morning or the evening.
2. **Morning Peak Period:** The four-hour period in the morning with the highest average IIS demand, defined as 7 a.m. to 10:59 a.m.
3. **Evening Peak Period:** The five-hour period in the evening with the highest average IIS demand, defined as 5 p.m. to 9:59 p.m.

EV Forecast Scenarios

EV adoption represents both a large potential load and an important opportunity for load management. Because future EV adoption is uncertain and Newfoundland-specific data on recent EV registration trends is limited, the Study Team modelled three EV adoption scenarios:

1. The **Natural Adoption Scenario**, the lowest adoption scenario, which estimates EV adoption based on current incentives, with fleet vehicle and bus adoption in this scenario aligned with global forecasts for all countries.
2. The **Intermediate Scenario**, which includes EV uptake beyond the Natural Adoption scenario consistent with additional market interventions such as Provincial vehicle rebates and accelerated build-out of charging infrastructure.
3. The **Government Targets Scenario**, the highest adoption scenario, in which aggressive Federal Government targets for sales of Zero Emissions Vehicles by 2030, 2035, and 2040 are met.

Efficiency Savings Potential

The Study Team assessed technical, economic, and achievable efficiency potential for a range of efficiency measures in the residential, commercial, and industrial sectors. Measures are included in the economic and achievable potential if their total resource cost (TRC) test benefit/cost ratio is 0.8 or higher.

The achievable potential includes three levels of savings, as shown in Exhibit 2.

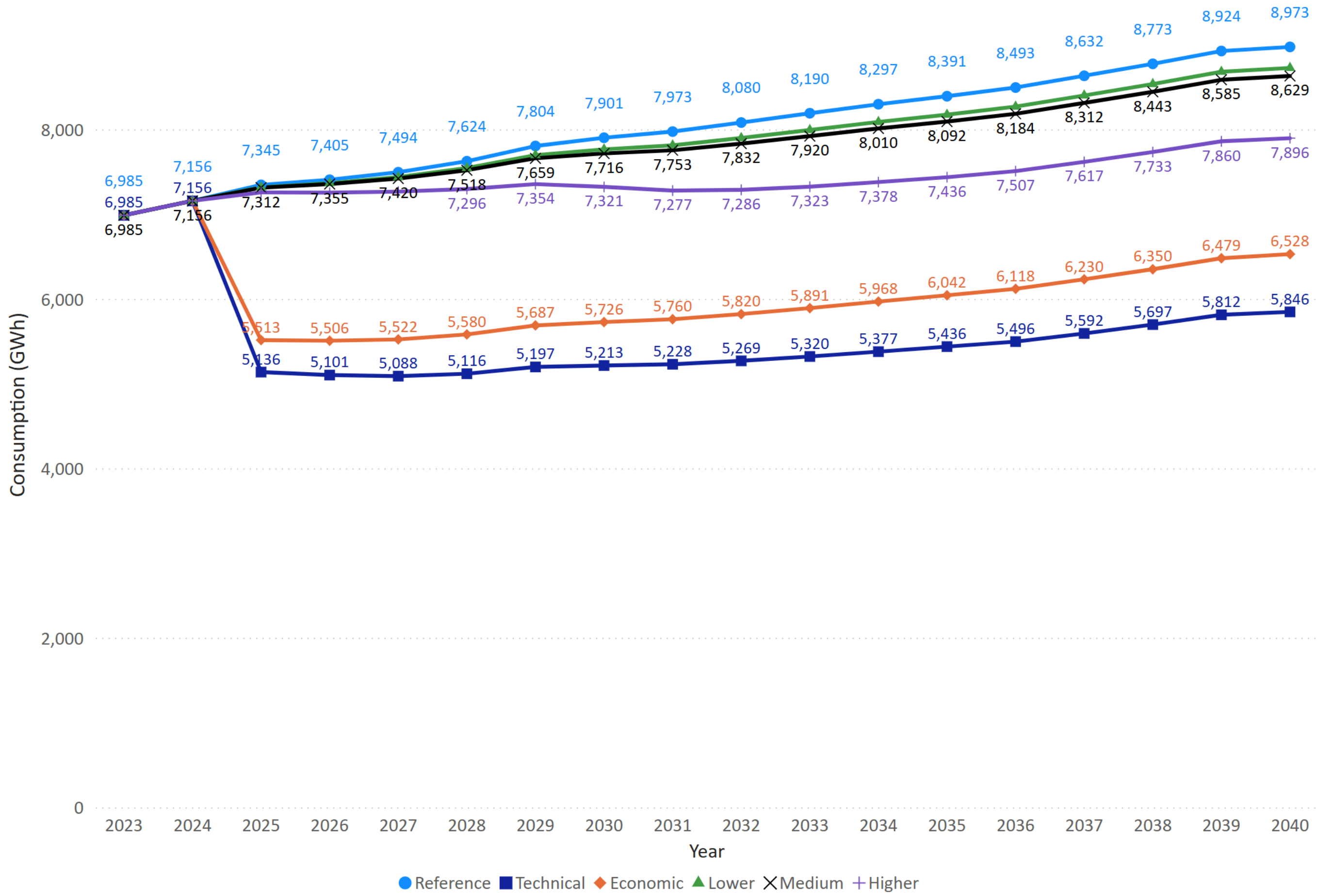
Exhibit 2: Achievable Potential Scenarios Summary

Scenario	Incentive Level	Non-Incentive Costs[10]
Lower	25% of incremental cost	25% of measure-level incentive costs
Medium	50% of incremental cost	
Higher	100% of incremental cost	

[10] While 25% is a standard estimate used for the purposes of this Study, non-incentive costs would vary from program to program.

Exhibit 3 shows annual consumption in the reference case and by potential scenario.[11] The difference between the reference case consumption and the consumption in each potential scenario represents cumulative potential savings. For example, savings in 2025 represent potential for measures adopted that year, whereas savings in 2040 represent savings for measures adopted that year, plus the savings for all measures adopted between 2025 and 2039, provided they did not reach end of life in that period.

Exhibit 3: Annual Consumption by Scenario - Efficiency

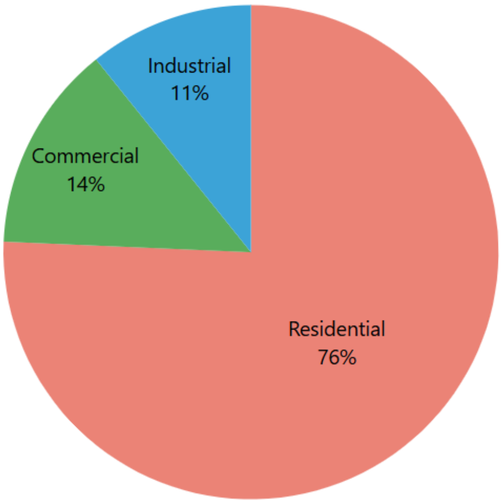


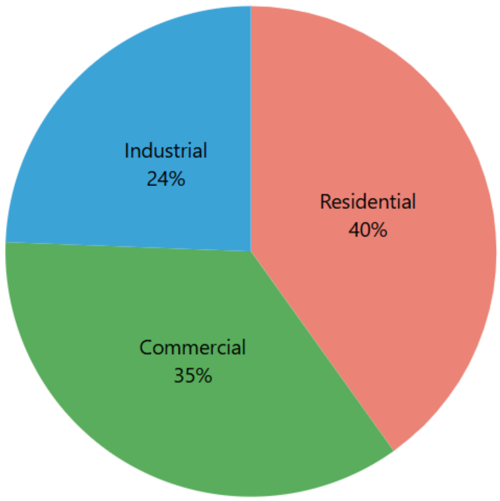
The difference in consumption between the lower and medium achievable potential scenarios is approximately 100 GWh by 2040, while the difference in consumption between the medium and higher achievable potential scenarios is approximately 700 GWh by 2040. This suggests that doubling the incentive between the lower and medium achievable scenarios has a smaller impact on measure adoption than doubling the incentive between the medium and higher achievable scenarios.

[11] The reference case in Exhibit 3 includes intermediate scenario EV consumption.

Exhibit 4 shows medium achievable potential energy savings by sector in 2025 (32 GWh) and 2040 (344 GWh). In both milestone years, the highest potential exists in the residential sector. The 2025 potential savings allocation by sector is directionally consistent with recent electricity conservation and demand management (ECDM) program results, in which residential sector programs contributed 88% of total energy savings in 2023.

Exhibit 4: Medium Achievable Potential Energy Savings by Sector, 2025 (left) and 2040 (right)

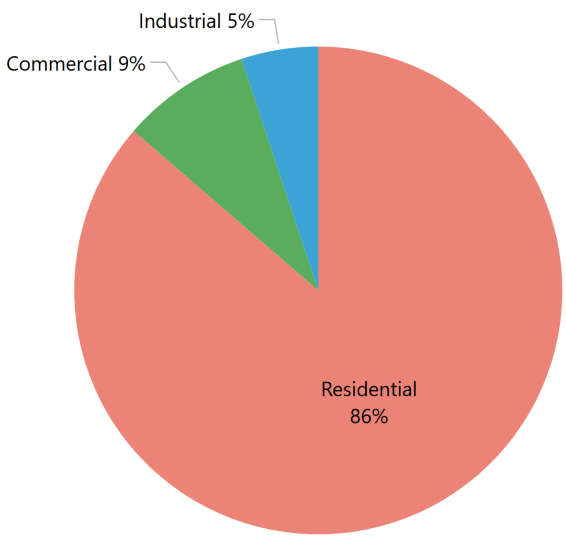


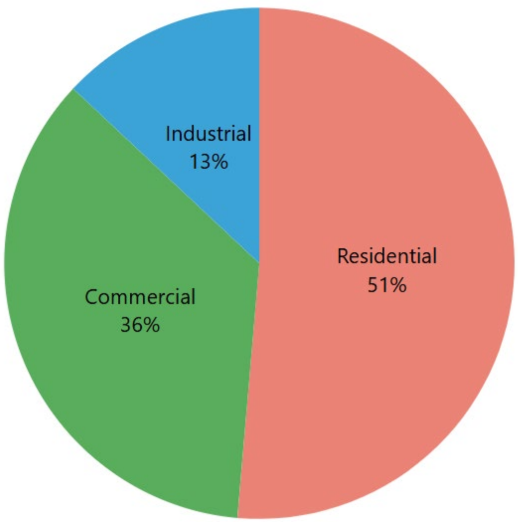


By 2040, potential savings by sector are more consistent with the reference case electricity consumption forecast by sector: the residential sector is forecast to contribute 54% of reference consumption and 40% of medium achievable savings; commercial 34% of consumption, 35% of savings; and the industrial sector contributing higher relative savings levels with 12% of reference consumption and 24% of savings.

Exhibit 5 shows medium achievable potential savings for the peak hour by sector in 2025 (7.7 MW) and 2040 (71.7 MW). Peak savings by sector are directionally consistent with energy savings by sector.

Exhibit 5: Medium Achievable Peak Demand Reduction Potential by Sector, 2025 (left) and 2040 (right)





Conclusions from the efficiency potential analysis include:

- In the residential sector, **home energy reports** offer the most energy savings potential and peak demand savings in 2025 because they are broadly applicable. By 2040, home energy reports remain among the top ten measures by annual and peak hour demand savings, but by 2040, **equipment measures that affect space heating** (e.g., central air source heat pumps, ductless mini-split heat pumps, and heat recovery ventilators) also offer substantial savings.
- Commercial sector savings in 2025 are dominated by **indoor lighting** measures, but their contribution to potential savings for the sector drops from 52% in 2025 to 26% in 2040. The decrease is attributable to high (60%) reference adoption of interior LED lighting, and the introduction of Natural Resources Canada's Amendment 18 that mandates LED lighting starting in 2028.[12] By 2040, **equipment measures that affect space heating** (e.g., electric furnace to air source heat pump, baseboard heating to ductless mini-split heat pump) offer substantial savings, as do **whole-building new construction** measures.
- In the industrial sector, annual and peak demand savings by end use remains relatively consistent between 2025 and 2040, which suggests a broad-based opportunity for cost-effective conservation. Measures targeting the **other motors** and **pumps** end use represent four of the top ten efficiency measures in both 2025 and 2040. **Energy management information system** is among the top ten measures in 2025 and 2040 because it is broadly applicable and targets all industrial sector end uses.

[12] "Amendment 18," Natural Resources Canada, Available: https://natural-resources.canada.ca/energy-efficiency/energy-efficiency-regulations/amendment-18 (Accessed: Dec. 3, 2024).

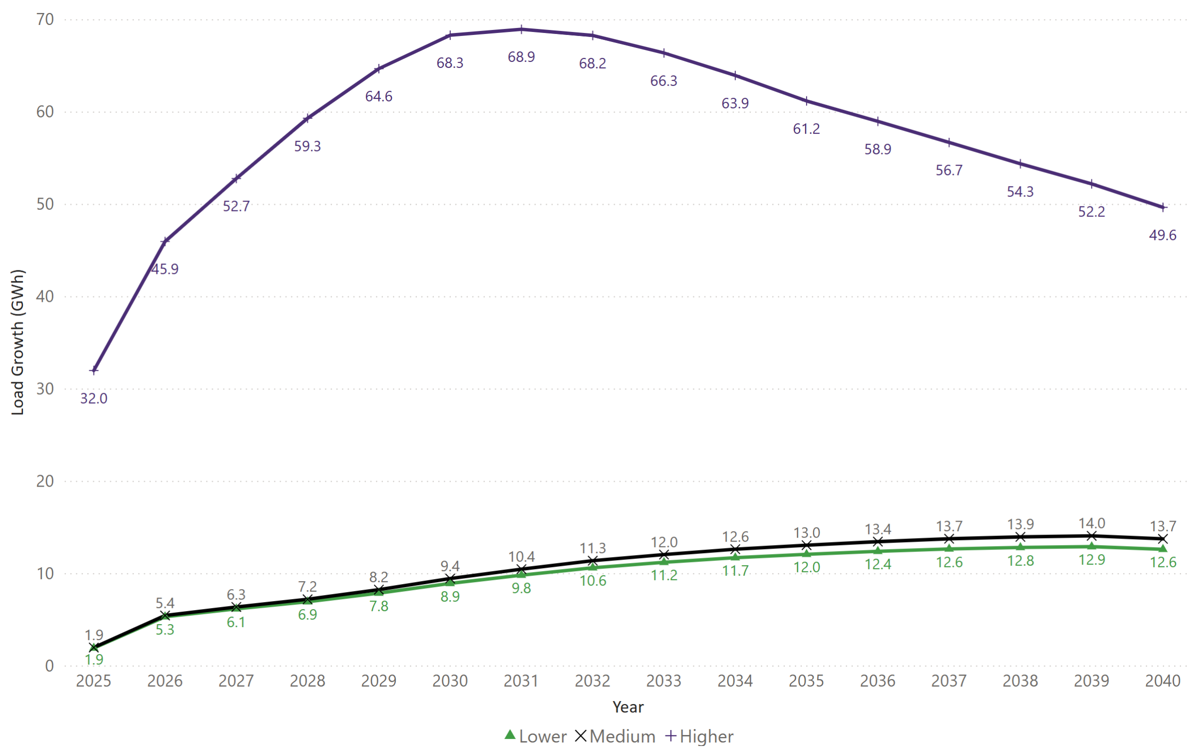
Fuel Switching and Off-Road Electrification Potential

The fuel switching analysis examines the potential for IIS customers to switch from fossil to electric space heating, water heating, and cooking. It also explores the electrification potential for select off-road vehicles. The fuel switching and off-road electrification potential assessment mirrors the efficiency potential assessment in structure and economic screening criteria:

- Three levels of fuel switching and off-road electrification savings potential are assessed: technical, economic, and achievable.
- The total resource cost (TRC) test is used to screen fuel switching and off-road electrification measures, and measures are included in the economic potential if their benefit-cost ratio is 0.8 or higher. In addition, three residential sector fuel switching measures (oil furnace to cold climate air source heat pump, oil furnace to air source heat pump (partial switch), and oil furnace to electric furnace.) These measures are being adopted in the Oil to Electric program administered by the Utilities even though they may not be cost-effective.
- The achievable potential includes lower, medium and higher scenarios, with incentive levels of 25%, 50% and 100% of incremental cost, respectively.

The cumulative impacts of fuel switching and off-road electrification in the lower, medium and higher achievable potential scenarios are shown in Exhibit 6.[13]

Exhibit 6: Fuel Switching and Off-Road Electrification Impacts by Achievable Scenario



[13] The decrease in load growth from fuel switching from 2031 to 2032 in the higher achievable potential scenario is driven by forecast space heating conversions in the Oil to Electric program, and natural fuel switching from oil to electricity included in the reference case which erodes the impact of these space heating conversions.

Conclusions from the fuel switching and off-road electrification potential analysis include:

- By 2040, measures in the higher achievable potential scenario cause 49.6 GWh of load growth, compared to 13.7 GWh and 12.6 GWh in the medium and lower scenarios, respectively. Reference case consumption is forecast to be roughly 9,000 GWh in 2040, so this growth represents an **increase of less than one percent of annual consumption for all scenarios**. Fuel switching potential is limited in all three sectors **because of the high relative fuel share of electric space heating in the base year and natural electrification that occurs in the reference case**.
- By 2040, approximately **5,600** incremental **residential sector dwellings** are forecast to be heated electrically or have electric water heating compared to 2025. This forecast includes the 3,000 space heating fuel switching projects expected to be completed under the Oil to Electric program in 2025. An incremental **1.1 million** additional **square feet** of commercial sector floor area are forecast to be heated electrically in 2040 compared to 2025 in the medium achievable scenario.
- The electrification of **forklifts** and **Zambonis** is expected to have a very small effect, adding approximately 0.3 GWh of electricity consumption to the IIS by 2040.
- By 2040, the peak impacts of the fuel switching and off-road electrification measures in the higher achievable potential scenario for the residential sector and in the medium achievable potential scenario for the commercial and industrial sectors are forecast to be 14.8 MW during the morning peak and 14.3 MW in the evening peak.

Demand Response Potential

Exhibit 7 shows the demand response resources examined in the Study: electricity rate design, equipment demand response, and customer curtailment.

Exhibit 7: Summary of Demand Response Resources

Demand Response Resources

- **Electricity Rate Design**
  Customers opt into one of two time-variable rates at their discretion: time of use or critical peak pricing.
- **Equipment Demand Response**
  Utility has direct load control of customer end use equipment including thermostats, water heaters, EV chargers, and thermal storage systems during on-peak times.
- **Customer Curtailment**
  Select customers curtail their energy use when one of the Utilities issues a request for curtailment.

Like for efficiency and electrification, the Study Team assessed three levels of demand response savings potential for each resource shown in: technical, economic, and achievable. However, the demand response potential assessment differs in the following ways:

- Measure-level incentives and non-incentive program costs are not varied, so there is only one achievable potential scenario. Throughout this section, this scenario is referred to as the medium achievable potential scenario.
- Participation rates are based on research and consultation with the Utilities. The only demand resource response currently in market in Newfoundland is customer curtailment, so there are no historical savings to benchmark against for the electricity rate design and equipment DR measures.
- The Program Administrator Cost (PAC) test is used to assess cost-effectiveness of the DR measures because utilities typically pay all incremental equipment costs in a DR program, and because incentives to participants are typically an expense to the utility over and above the incremental equipment costs. This differs from efficiency programs where the incentives usually cover a portion of the participant's incremental costs for the efficiency upgrade.[14]

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[14] Conservation Potential Study, Final Report (Volume 2 – Appendices)," Dunsky Energy Consulting (2019).

Electricity Rate Design

The Study includes two opt-in electricity rate design measures: time-of-use (TOU) and critical peak pricing (CPP). Exhibit 8 shows the rate structures for these measures in the Study. These rate structures are representative, and neither is currently offered or under specific consideration by the Utilities.

Exhibit 8: TOU and CPP Rates

Season	Peak	Time	Residential ($/kWh)[15]	Commercial ($/kWh)	Industrial ($/kWh)
December to March	On-peak	Morning Peak Evening Peak	$0.24	$0.17	$0.18
	Off-peak	Hours Outside of Peak Periods	$0.06	$0.04	$0.04
December to March	Critical Peak	Critical Peak Events	$0.55	$0.83	$0.85
	Off-Peak	Hours Outside of Critical Peak Periods	$0.06	$0.07	$0.07

Substantial investment in Advanced Metering Infrastructure (AMI) would be required to implement time-variable rates for NP and NLH customers, estimated at approximately $80 Million over four years

The frequency and duration of the TOU and CPP peak events are as follows:

- **TOU:** The TOU on-peak rate is modelled as being in effect during the morning (4 hours) and evening (5 hours) peak periods on weekdays from December to March (i.e. a total of 89 days per year).
- **CPP:** The critical peak rate is modelled as being in effect during critical peak events, as determined by the Utilities. The Study Team assumes events are called 12 times per year during the morning and evening peak periods for the purposes of the analysis.

[15] The residential rate applies to "at home" personal EV charging.

Exhibit 9 shows the medium achievable potential peak demand reduction potential for the electricity rate design measures by sector, excluding savings from EV TOU.

Exhibit 9: Medium Achievable Peak Demand Reduction– Electricity Rate Design (2040)

Measure	2029 Winter Peak Hour Reduction (MW)	2029 Winter Morning Average Peak Reduction (MW)	2029 Winter Evening Peak Average Reduction (MW)	2040 Winter Peak Hour Reduction (MW)	2040 Winter Morning Average Peak Reduction (MW)	2040 Winter Evening Average Peak Reduction (MW)
CPP	0.34	0.34	0.33	9.77	9.40	9.35
TOU	0.22	0.22	0.21	6.23	6.09	5.98

The following observations can be made on Exhibit 9:

- **CPP** shows **higher savings potential than TOU** because peak events are less frequent, and the on-peak retail rate is higher.
- The 2040 peak hour demand reduction potential for the rate design measures (6.23 MW for TOU, 9.77 MW for CPP) is **less than** for the efficiency measures (71.7 MW) in 2040.

Exhibit 10 shows the medium achievable PAC results by sector for the electricity rate design measures, none of which pass the PAC due to high costs associated with AMI installation and operation.[16]

Exhibit 10: Medium PAC Cost-Effectiveness Test Results – Electricity Rate Design

Measure	Residential	Commercial	Industrial
CPP	0.19	0.39	0.43
TOU	0.12	0.29	0.39

A TOU rate can have a larger effect on EV charging compared to any other end use in the residential, commercial and industrial sectors because EV charging is flexible.[17] The Study Team modelled two EV TOU participation scenarios, defined as follows:

- **Opt-in participation scenario**: Reflects a 15% participation rate, which matches the one used for the residential sector TOU measure.
- **Opt-out participation scenario**: 100% of EVs are on a time-of-use rate.

[16] The PAC results reflect costs and benefits incurred during the four-year AMI meter installation period and the 20-year smart meter lifetime. These measures assume an opt-in rate structure where participation ramps up to a maximum of 15% in the later years of the study.

[17] The impact of a TOU rate on EV charging depends on the number of EVs participating in the TOU rate.

Exhibit 11 shows demand reduction potential for the opt-in and out-out EV TOU scenarios during the morning and evening peak periods, and for the peak hour. The 51.60 MW peak hour reduction from EVs based on an opt-out TOU rate in 2040 is more than eight times higher than the TOU rate reduction potential from the residential, commercial, and industrial sectors combined (6.23 MW), which highlights the flexibility of EV charging loads and the value to the IIS of managing the load.

Exhibit 11: Medium Achievable Peak Demand Reduction - EV TOU[18]

Measure	2029 Winter Peak Hour Reduction (MW)	2029 Winter Morning Peak Reduction (MW)	2029 Winter Evening Peak Reduction (MW)	2040 Winter Peak Hour Reduction (MW)	2040 Winter Morning Peak Reduction (MW)	2040 Winter Evening Peak Reduction (MW)
Opt-In EV TOU	0.10	0.12	0.72	4.69	0.77	4.36
Opt-Out EV TOU	1.12	1.38	7.24	51.60	9.62	48.39

Exhibit 12 shows the medium achievable PAC results by sector for the TOU measure. Three results are shown for the residential sector: excluding EVs, including EVs with opt-in participation, and including EVs with opt-out participation.[19] The PAC is less than 1 for all sectors, though the **residential sector** result **including EVs with opt-out participation** exceeds the **PAC screening threshold of 0.8**.

Exhibit 12: Medium PAC Cost-Effectiveness Test Results – Electricity Rate Design with EV TOU

Measure	Residential (Excl. EVs)	Residential (Incl. EVs, Opt-In)	Residential (Incl. EVs, Opt-Out)	Commercial	Industrial
TOU	0.12	0.20	0.95	0.29	0.39

[18] Reductions in load can be higher for the morning or evening periods when compared to the peak hour because the system peak hour doesn't coincide with the highest EV load. The value for the peak hour is the value that the overall system peak is reduced by.

[19] The results reflect costs and benefits incurred during the four-year AMI meter installation period, and the 20-year smart meter lifetime.

Equipment Demand Response

The Study's equipment DR measures are split into three categories: utility-driven, EV managed charging, and thermal storage with TOU. Each thermal storage measure has a utility-driven version and a thermal storage with TOU version. The measures are modelled at the following frequency and peak event durations:

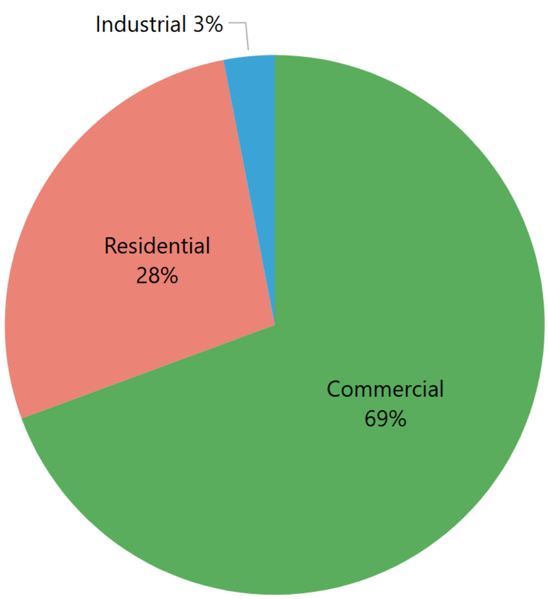
- **Equipment DR Measures (Utility-Driven):** The utility shifts customer load 12 times annually, for four hours during the morning peak period and five hours during the evening peak period.
- **EV Managed Charging:** The utility shifts customer EV charging for five hours during the evening peak period. Managed charging programs are not modelled at a system wide scale until 2029 (coinciding with the introduction of TOU rates).[20,21]
- **Equipment DR Measures (Thermal Storage with TOU):** Customers shift load off the peak periods on weekdays from December to March, for a total of 89 events per year.

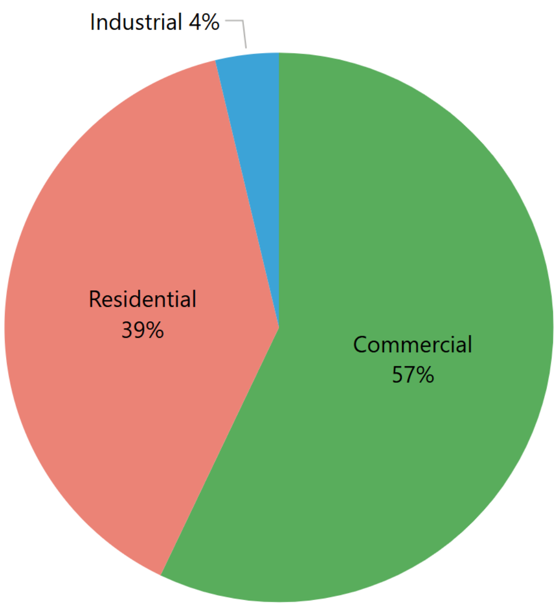
[20] EV managed charging measures are modelled without TOU rates. Studies show that with sufficient equipment and enrolment incentives, participation in managed charging programs does not depend on TOU rates.
[21] "PG&E Electric Vehicle Automated Demand Response Study Report," Opinion Dynamics, Available: https://opiniondynamics.com/wp-content/uploads/2022/03/PGE-EV-ADR-Study-Report-3-16.pdf (Accessed Feb. 24, 2025).

Utility-Driven Equipment DR

Exhibit 13 shows the medium achievable potential peak reduction for the utility-driven measures by sector in 2031 (12.2 MW) and 2040 (19.4 MW), excluding the impacts of EV managed charging. The commercial sector shows the most peak demand reduction in both milestone years. The proportion of peak demand reduction attributed to the residential sector increases from 28% in 2031 to 39% by 2040, as participation in residential measures increases.[22]

Exhibit 13: Medium Achievable Demand Reduction Potential by Sector, 2031 (left) and 2040 (right) – Utility-Driven Equipment DR





Conclusions from utility-driven equipment DR potential analysis include:

- In the residential sector, the **smart circuit breakers or smart panel** measure shows the highest peak demand reduction in 2031 (1.4 MW) and 2040 (4.0 MW). This measure impacts most end uses and is broadly applicable. Of the measures targeting the **space heating** end use, the **smart thermostat or switch for baseboards or furnaces** measure shows the highest peak demand reduction in 2040 (0.8 MW). This measure has no incremental cost to the customer and a large opportunity comprising both homes with electric baseboard heating and electric furnaces.
- The commercial sector **backup generation at peak hours** measure shows the highest peak demand reduction by 2040 (4.0 MW). This measure assumes customers have an existing generator, has a small incremental cost and offers relatively high savings (80%). **Thermal storage and heat pump heating** shows the highest peak demand reduction for measures that target **space heating** (1.0 MW in 2031 and 1.5 MW in 2040). This is driven by a higher technical applicability for heat pumps in the commercial sector than other space heating systems.

[22] 2031 is a milestone year for reporting because it is the first year all utility-driven measures show peak savings.

- **All configurations** of **thermal storage** measures in the residential and commercial sectors are **cost-effective** under the PAC screen. Market barriers to adoption could include lack of familiarity with thermal storage, aesthetic considerations for room units, and space constraints.
- The peak demand reduction potential in the **industrial** sector is more evenly distributed across end uses compared to the residential and commercial sectors. Measures targeting the **other motors**, **HVAC fans and pumps**, and **process cooling** end uses offer the highest peak demand reduction potential.

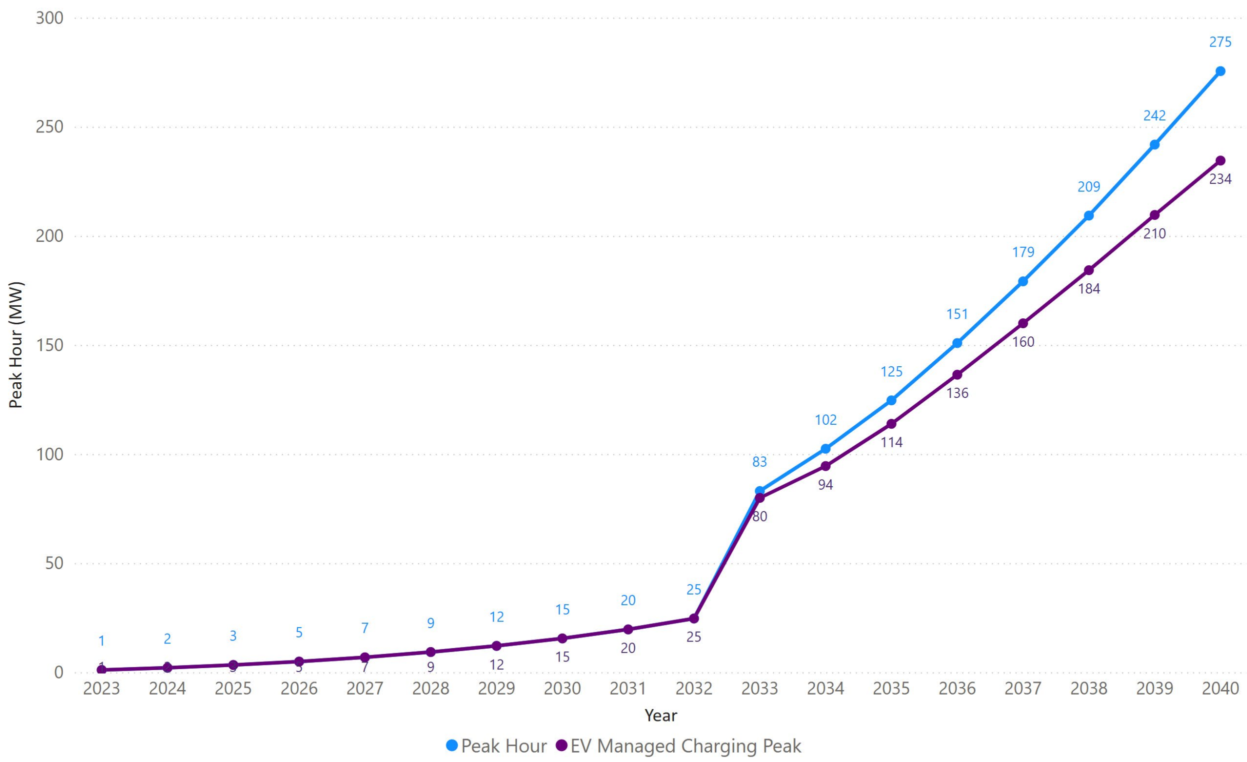
EV Managed Charging

Exhibit 14 shows that peak demand from EV charging is forecast to increase from 1 MW in 2023 to 275 MW by 2040 in the intermediate forecast scenario. This change is driven by the adoption of approximately 162,000 fleet and personal EVs.

In 2033, EV charging causes the IIS peak to switch from morning peak to evening peak. Shifting personal EV at-home charging could reduce the IIS peak. The opportunity to managed fleet EV charging is more limited than for personal EVs based on their duty cycles. However, certain fleet vehicles will have duty cycles that can accommodate managed charging.

Savings from the managed charging measures reach a maximum reduction demand potential of approximately **41 MW** by 2040. This corresponds to a roughly 15% decrease in the EV load during the system peak hour in 2040.

Exhibit 14: Annual EV Peak Hour Demand (MW) – Managed Charging



Thermal Storage with TOU Equipment DR Measures

The thermal storage with TOU equipment measures offer **5 MW** of peak hour demand reduction potential by 2040. Savings for the thermal storage with time-of-use measures are higher than the equivalent utility-driven measures because participation is assumed to be higher when a time-variable rate is involved. All configurations of residential and commercial sector thermal storage measures with TOU are cost-effective under the PAC screen.

Customer Curtailment

The Study Team examined curtailment potential among three customer groups:

- **Existing and prospective Energy Curtailment Program (ECP) participants**: NP's ECP offers an incentive to commercial customers to reduce their demand upon request during the winter peak period.
- **Large customers:** The Utilities may enter short-term or long-term capacity assistance contracts with large commercial or industrial sector customers.

Exhibit 15 shows curtailment potential by customer group. Curtailment potential is not varied annually in the Study.

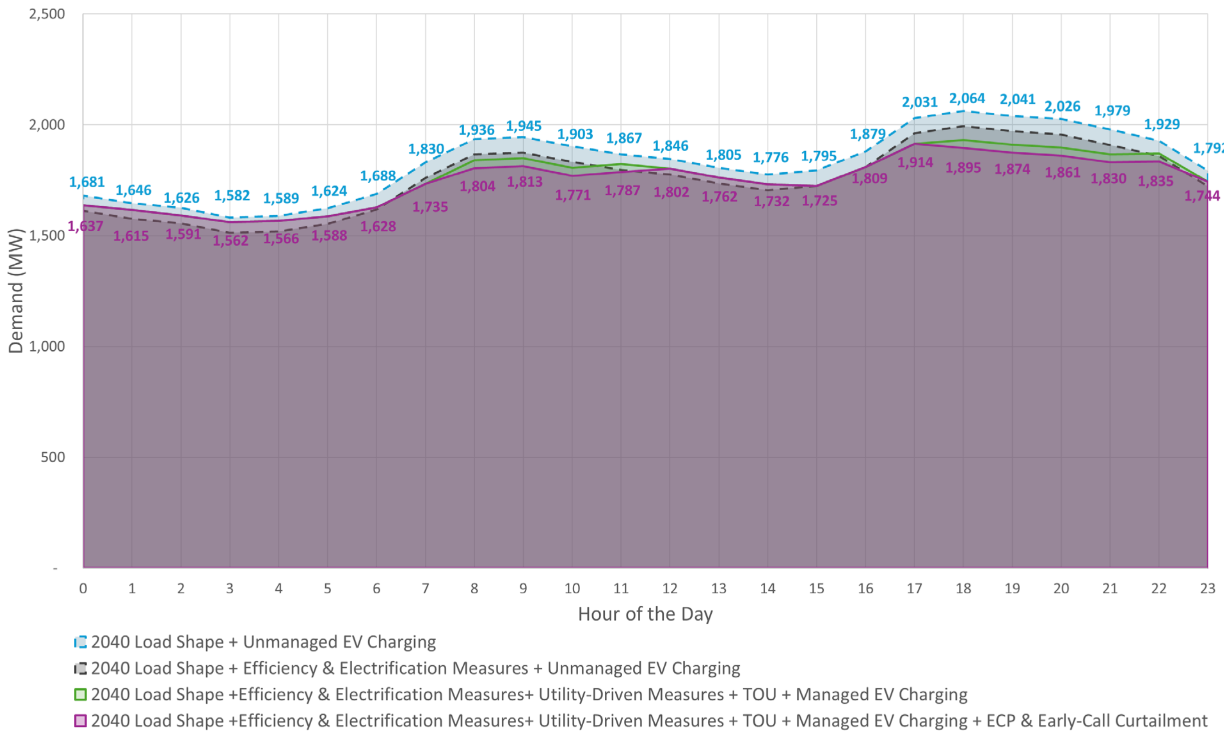
Exhibit 15: Curtailment Potential Results (all years)

Customer Group	Curtailable Load/Customer	Number of Customers	Total Curtailment
2.4 Existing ECP participants	500 kW/participant	24	12.0 MW
2.4 New ECP participants	300 kW/participant (30% of peak demand)	8	2.4 MW
Large Customer Contracts	Contract-Specific	3	120.6 MW
	Total	**35**	**135 MW**

Summary of IIS Peak Day Load Shape Impacts

In the base year, the IIS peak occurs in the morning. By **2040**, the IIS peak is expected to shift to the evening, driven in part by unmanaged EV charging in the intermediate scenario. Exhibit 16 shows the impact of combinations of demand response resources on the IIS peak day load shape.

Exhibit 16: Standard and Resulting Peak Day IIS Load Shapes (2040)



The Study findings reveal the following impacts on the IIS load curve:

- Excluding existing curtailment contracts, **energy efficiency** measures show the highest potential to reduce IIS peak. For example, in 2040, the efficiency measures reduce the winter morning and evening peaks by 70 MW and 69 MW, respectively. In contrast, the utility-driven measures reduce the winter morning and evening peaks by 23 MW and 18 MW, respectively. The TOU electricity rate design measures reduce the winter morning and evening peaks by 6 MW each.
- After the efficiency and electrification measures, the utility-driven equipment DR measures, and managed EV charging are applied, the evening peak period starts at **5 p.m. and ends at 10:59 p.m**. This **lengthens** the evening peak period **by one hour** compared to the reference load shape.
- When the ECP and the early-call curtailment are applied during the evening peak period (i.e., 5 p.m. to 9:59 p.m. denoted by the purple load shape), the peak hour occurs at **5 p.m.**, **one hour earlier** than in the reference load shape.
- For each combination of demand response resources, the addressable peak is equal to the peak reduction. This is because the peak demand is reduced in all cases (i.e., the resources do not create a higher peak than the original peak).

Conclusions

The major conclusions drawn from the study analysis include:

- **Energy Efficiency Potential**: The Study identifies opportunities for energy efficiency across the residential, commercial, and industrial sectors:
  - In the residential sector, measures that affect space heating offer the most potential savings. In the early years of the forecast period, these savings are dominated by envelope measures including air sealing and insulation, but by the end of the forecast period, equipment-based measures including heat pumps and HRVs offer the most potential savings. In addition, home energy reports offer residential sector savings throughout the Study period.
  - Initially, lighting measures dominate the commercial sector potential savings, but their savings potential decreases over time as LED lighting becomes saturated and federal lighting standards are introduced. By the end of the forecast period space heating measures including heat pumps and air sealing offer the most potential savings due to their broad applicability.
  - In the industrial sector, there is a broad-based opportunity for cost-effective conservation across end uses.
- **Impact of EVs**: The Study includes three forecast EV scenarios to explore a range of possible futures: natural adoption, intermediate and government targets. The results presented in the Study focus on the intermediate scenario:
  - In the intermediate scenario, the adoption of approximately 160,000 EVs will cause EV charging to increase from an estimated 9 GWh in 2023 to 1,000 GWh by 2040, and peak period demand to increase from an estimated 1 MW in 2023 to 275 MW by 2040. In 2033, EV charging causes the IIS peak to switch from morning peak to evening peak.
  - Consideration to EV managed charging can mitigate the impacts of EV charging on the IIS peak. By 2040, shifting personal EV charging could reduce the IIS peak by 41 MW. The opportunity to manage fleet EV charging is more limited than for personal EVs based on their duty cycles. However, certain fleet vehicles will have duty cycles that can accommodate managed charging.
- **Fuel Switching and Off-Road Electrification Potential**: Fuel switching potential is limited in the residential, commercial and industrial sectors because of the high relative fuel share of electric space heating in the base year.
  - In the higher achievable potential scenario, 49.6 GWh of load growth due to end-use electrification is forecast by 2040, compared to 13.7 GWh and 12.6 GWh in the medium and lower achievable potential scenarios, respectively. Nearly all this load growth is due to end-use fuel switching in the residential, commercial, and industrial sectors.

- **Demand Response Potential**: The Study assesses demand response potential opportunities across three measure types: electricity rate design, equipment demand response, and customer curtailment.
    - The TOU and CPP electricity rate design measures are not cost-effective, due to the high program costs associated with the installation and operation of the AMI infrastructure required to administer them.
    - Several configurations of thermal storage measures are cost-effective for the residential and commercial sectors, with and without TOU rates. Market barriers to adoption could include lack of familiarity with thermal storage, aesthetic considerations for room units, and space constraints.
- **Overall Impacts on IIS Peak Day Load Curve**: In the base year, the IIS peak occurs in the morning. In 2040, the IIS peak is expected to occur at 6 p.m., driven in part by unmanaged EV charging in the intermediate scenario. The Study findings reveal the following impacts on the IIS load curve:
    - Excluding existing curtailment contracts, energy efficiency measures show the highest potential to reduce IIS peak. For example, in 2040, the efficiency measures reduce the winter morning and evening peaks by 70 MW and 69 MW, respectively. In contrast, the utility-driven DR measures reduce the winter morning and evening peaks by 23 MW and 18 MW, respectively. The TOU electricity rate design measure reduces the winter morning and evening peak by 6 MW.
    - After the efficiency and electrification measures, the utility-driven equipment DR measures, and managed EV charging are applied, the evening peak period starts at 5 p.m. and ends at 10:59 p.m. This lengthens the evening peak period by one hour compared to the reference load shape.
    - When the ECP and the early-call curtailment are applied during the evening peak period the peak hour occurs at 5 p.m., one hour earlier than in the reference load shape.
    - For each combination of demand response resources, the addressable peak is equal to the peak reduction. This is because the peak demand is reduced in all cases (i.e., the resources do not create a higher peak than the original peak).

1 Introduction

The Energy Solutions Potential Study (the Study) assesses the near term and long-term potential for energy efficiency, electrification, and peak demand management activities led by Newfoundland Power and Newfoundland and Labrador Hydro (the Utilities). The Utilities have jointly offered customer energy conservation information and programming under the takeCHARGE energy conservation brand since 2008. The Utilities have historically focused on energy savings but are increasingly considering demand management technologies and their potential to reduce or shift peak demand.

Study Scope

The Study scope is summarized as follows:

- **Study Period**: The base year in the Study model is 2023. The forecast period is 2024-2040. Measures are applied against the reference case starting in 2025.
- **Geographical Coverage**: The Study's geographical scope is the Island Interconnected System (IIS). The Labrador Interconnected System and the Isolated Diesel Generation System are not in scope. The Study includes both Utilities' customers.
- **Sector Coverage**: The Study includes four sectors: residential, commercial, industrial and transportation. The industrial sector includes Newfoundland and Labrador Hydro's six large industrial customers and both Utilities' large customers in the general service rate class. The transportation sector includes personal and fleet EVs.
- **Measures**: The Study examines the potential for efficiency, fuel switching, and demand response measures. Marine and off-road electrification are addressed at a high-level. The demand response measures include time-variable rates, EV managed charging, and thermal storage, among others.

Uses for the Study

The Study will support resource planning, and inform the planning and design of potential electrification, energy efficiency, and demand management programs and initiatives for the Utilities. It provides an estimate of the relative size of energy savings and demand reductions measures but is not intended to serve as a program design document.

Data Sources

The Study relies on the Utilities' knowledge of their customer base, the best available data, and inputs based on extensive research and the Study Team's professional judgement. The results in this report reflect rigorous analysis and provide an estimate of the opportunities available to the Utilities. The Study's data sources are summarized as follows:

- **Utility Customer Data**: The Utilities provided 2023 residential, commercial, and industrial sector customer billing data to inform the Study base year.
- **Long-Term Forecasts**: The Study uses Newfoundland and Labrador Hydro's general service and residential forecasts to inform the reference case.
- **End-Use Surveys**: The Utilities' 2022 Residential and Commercial End-Use Surveys are used to inform end use saturations and fuel shares. An end use survey asks utility customers about the characteristics, equipment, appliances and behaviours that drive energy use in buildings. End

use surveys can support potential studies, provide data to support program design, and support electricity load forecasting.[23]

- **Economic Data**: The Study uses 2023 marginal costs and electricity retail rates, and discount rates to assess cost-effectiveness.
- **Stakeholder Groups**: An external advisory committee of stakeholders provided input at two key steps in the Study workflow: measure identification and achievable potential. This input included desktop review of a list of measures and participation in achievable potential workshops.
- **Publicly Available Data Sources**: Data from publicly available Federal and Provincial websites was collected to inform Study inputs, including the transportation sector EV forecasts, for example.

By integrating these sources, the Study reference case considers the impacts of existing policies, but it does not account for potential future policies. Appendix A provides more details on the data sources and assumptions used in the Study.

Report Structure

The Study is organized and presented as follows:

- Section 2 explains the approach.
- Section 3 profiles the base year and reference case.
- Section 4 identifies the measures and presents cost-effectiveness test results.
- Section 5 presents efficiency savings potential by sector, for energy and peak.
- Section 6 shows fuel switching and off-road electrification potential by sector.
- Section 7 presents demand response potential for electricity rate designs, equipment-based measures, and customer curtailment.
- Section 8 shows the conclusions.

[23] Cadmus Group, "Ontario Residential End-Use Survey," Available: https://ieso.ca/-/media/Files/IESO/Document-Library/research/Ontario-Residential-End-Use-Survey.ashx, (Accessed: March 18. 2025).

2 Approach

Exhibit 17 shows the major analytical steps for the Study and summarizes each one. The base year and reference case were modelled using Posterity Group's Navigator™ Energy and Emissions Simulation Suite (Navigator). Navigator was also used to estimate technical, economic, and achievable potential. The Methodological Approach in Appendix A provides the detailed Study approach.

Exhibit 17: Study Major Analytical Steps

Step	Approach Summary
1. Develop Base Year Energy Use & Peak Demand	• Profile base year energy use using 2023 residential, commercial, and industrial sector customer billing data from the Utilities. • Use end-use peak factors to convert annual electric energy use to electric demand. Modify the peak factors so that peak demand in the base year aligns with the actual 2023 IIS peak. • Determine the base year vehicle stock for the transportation sector using historical vehicle registrations and data on active electric vehicle (EV) stock. Multiply vehicle stock by vehicle efficiency and annual vehicle kilometers travelled to determine annual energy consumption per vehicle.
2. Develop Reference Case Energy Use & Peak Demand	• Create a reference case that represents the baseline against which new potential can be calculated and is calibrated to NLH's long-term forecasts. Use end-use peak factors to convert annual electric energy use to electric demand. • Because EVs are emerging and future adoption is uncertain, create three forecast scenarios instead of one reference case: natural adoption, intermediate, and government targets.
3. Characterize Measures & Programs	• Develop measure list for each sector. Ensure coverage by end use and measure type (efficiency, fuel switching, off-road electrification, and demand response) • Characterize measures: energy and peak impacts; applicable segments; costs and cost-effectiveness.
4. Estimate Technical & Economic Potential	• Estimate the hypothetical technically feasible energy and demand savings potential for the IIS. • Estimate the potential for all cost-effective measures applied in technically feasible applications.
5. Estimate Achievable Potential	• Develop generic adoption curves based on customer payback acceptance and typical market diffusion patterns. Apply curves to each measure in the economic potential to create a simplified achievable potential. • Develop realistic achievable potential by soliciting feedback from stakeholders, input from the Utilities, jurisdictional research, and historical program data from the Utilities.

The rest of this section is structured as follows:

- Section 2.1 presents the model structure.
- Section 2.2 defines the Study base year and explains the scope of the reference case forecast.
- Section 2.3 defines the peak periods and summarizes the method to develop electric peak end use profiles for the base year and reference case.
- Section 2.4 list the types of measures characterized in the Study.
- Section 2.5 defines the potential scenarios.
- Section 2.6 lists caveats and limitations.

Readers are encouraged to consult Appendix A – Methodological Approach for details of the Study approach.

2.1 Model Structure

The Study includes four sectors: residential, commercial, industrial, and transportation. This section shows the model structure for each sector, including segments, end uses, vintages, and rate classes. This information provides important context for readers to understand the rest of this report.

Exhibit 18 shows the residential sector model structure by segment, end use, vintage and rate class. Residential segments are divided by electric and non-electric space heating. This differentiation is important for the reference case and potential assessment, because customer account growth (i.e., the number of customer accounts) and measure applicability vary by space heating fuel. Exhibit 18 also shows two EV charging end uses: battery electric vehicle (BEV) charging and plug-in hybrid electric vehicle (PHEV) charging.

Exhibit 18: Residential Sector Segments, End Uses, Vintages and Rate Classes

Segments (8)	End Uses (20)	Vintages (6)	Rate Classes (1)
• Apartment, electric space heat • Apartment, non-electric space heat • Attached, electric space heat • Attached, non-electric space heat • Other and non-dwellings • Single-Family Detached (SFD), electric space heat • SFD, non-electric space heat • Vacant and partial	• BEV Charging • Clothes Dryer • Clothes Washer • Computer and Peripherals • Cooking • Dehumidifier • Dishwasher • Freezer • Hot Tubs • Lighting • Other Electronics[24] • PHEV Charging • Refrigerator • Small Appliance and Other • Space Cooling • Space Heating • Television • Television Peripherals • Ventilation • Water Heating	• Pre-1965 • 1965 to 1979 • 1980 to 1989 • 1990 to 1999 • 2000 to 2012 • Post-2012	• 1.1

[24] Includes miscellaneous small electronics such as gaming consoles and tablets.

Exhibit 19 shows the commercial sector model structure by segment, end use and rate class. Some segments are differentiated by size (e.g., offices, non-food retail). This differentiation is important for the potential assessment portion of the Study because measure applicability varies by building size. Exhibit 19 also shows six EV segments (personal EV private charging, personal EV public charging, fleet light-duty vehicle (LDV) depot charging, fleet medium-duty vehicle (MDV) depot charging, fleet heavy-duty (HDV) depot charging, and fleet bus depot charging) and two EV end uses (BEV charging and PHEV charging).

Exhibit 19: Commercial Sector Segments, End Uses and Rate Classes

Segments (23)	End Uses (17)	Rate Classes (5)
• Arena	• BEV Charging	• 2.1
• Fleet Bus Depot Charging	• Computer Equipment	• 2.3
• Fleet HDV Depot Charging	• Computer Servers	• 2.4
• Fleet LDV Depot Charging	• Food Service Equipment	• Street Lighting
• Fleet MDV Depot Charging	• General Lighting	
• Food Retail	• High Bay Lighting	
• Healthcare	• HVAC Fans & Pumps	
• Large Accommodation	• Misc Equipment	
• Large Non-Food Retail	• Other Plug Loads	
• Large Office	• Outdoor Lighting	
• Large Other Building	• PHEV Charging	
• Non-Building	• Refrigeration	
• Personal EV Private Charging	• Secondary Lighting	
• Personal EV Public Charging	• Space Cooling	
• Restaurant	• Space Heating	
• School	• Street Lighting	
• Small Accommodation	• Water Heating	
• Small Non-Food Retail		
• Small Office		
• Small Other Building		
• Street Lighting		
• Universities and Colleges		
• Warehouse		

Exhibit 20 shows the industrial sector model structure by segment, end use and rate class. The large industrial segment includes only NLH's six large industrial customers.

Exhibit 20: Industrial Sector Segments, End Uses and Rate Classes

Segments (7)	End Uses (12)	Rate Classes (5)
• Fishing and Fish Processing • Large Industrial • Manufacturing • Mining and Processing • Other Industrial • Pulp and Paper • Water and Wastewater	• Air Compressors • Conveyors • Fans and Blowers • General Lighting • HVAC Fans & Pumps • Other • Other Motors • Process Cooling • Process Heating • Process Specific • Pumps • Hydrogen	• 2.1 • 2.3 • 2.4 • IND-1

Exhibit 21 shows the transportation sector model structure by ownership type, vehicle type, and powertrain.[25] Two EV charging end uses are modelled for the transportation sector, BEV charging and PHEV charging.

Exhibit 21: Transportation Sector Vehicle Segmentation

Ownership Type	Vehicle Type	Powertrain
Personal	LDV	BEV
	LDV	PHEV
Fleet	Bus	BEV
	HDV	BEV
	LDV	BEV
	LDV	PHEV
	MDV	BEV

[25] Electric micro-mobility was excluded from the Study because its impact is limited and due to a lack of Newfoundland-specific data. Hybrid electric vehicles, referring to vehicles that have both an electric motor and an internal combustion engine but are not plugged in, were also excluded from the Study. This is because their batteries charge through regenerative braking and by the internal combustion engine rather than plugging in and being supplied by the electricity grid.

2.2 Base Year and Reference Case Energy Use

This section explains the scope of the Study base year and reference case energy use forecast.

Base Year Electric Energy Use

Base year (2023) electric energy use is calibrated to historical customer billing data provided by the Utilities for the residential, commercial, and industrial sectors. Base year electric energy use for the transportation sector reflects historical vehicle registrations, data on active EV stock, vehicle efficiency and annual vehicle kilometers travelled. It was not possible to calibrate the transportation sector base year because the Utilities do not identify EVs in their historical customer data.

Reference Case Energy Use

The Study reference case (2024-2040) forecasts electricity consumption and peak demand based on exogenous conditions that follow a business-as-usual scenario. That is, it represents the baseline against which new potential can be calculated. Reference case energy use for residential, commercial, and industrial sector reference case forecasts is calibrated to NLH's long term forecast and has the following characteristics:

- It reflects current consumption patterns and known future changes, including expected customer growth, and current and known future changes to codes and standards.
- It considers the natural turnover of equipment and appliances, and changes in space heating and water heating fuel shares.
- It excludes conservation from ECDM activities carried out after 2023 and forecast electric vehicle load.
- It accounts for distribution losses in the 'losses and company use' segment in the commercial sector.

The Study Team created three forecast EV scenarios instead of a single reference case for the transportation sector because EVs are an emerging technology and future adoption is uncertain. This approach provides a range of possible futures for EV adoption in Newfoundland, which is expected to be influenced by government policy and other factors. The forecast EV scenarios are defined as follows:

- The **Natural Adoption Scenario** estimates EV adoption based on current incentives. MHDV and bus adoption in this scenario aligns with global forecasts for all countries, recognizing that Newfoundland will lag adoption in leading jurisdictions.
- The **Intermediate Scenario** includes EV uptake beyond the natural adoption scenario, consistent with additional market interventions like vehicle rebates and accelerated build-out of charging infrastructure for LDV, and/or more favorable EV capital cost declines for MDV and HDV.
- In the **Government Targets Scenario**, Federal Government targets for sales shares of LDVs and MHDVs being ZEVs by 2030, 2035, and 2040 are met. In the natural adoption and intermediate scenarios, the Federal Government targets are not met.

Energy use in each EV scenario reflects the forecast stock in each scenario, vehicle efficiency, and annual vehicle kilometres travelled.

2.3 Base Year and Reference Case Peak Demand

This section presents peak period definitions for the Study and explains the scope of the base year and reference case peak demand forecast.

Peak Period Definitions

Three peak periods are defined in the Study:

- **Peak Hour:** The single highest hour of IIS demand, typically occurring on the coldest day in the winter. Depending on the Study year, the single hour peak can occur in the morning or the evening.
- **Morning Peak Period:** The four-hour period in the morning with the highest average IIS demand, defined as 7 a.m. to 10:59 a.m. for Newfoundland.
- **Evening Peak Period:** The five-hour period in the evening with the highest average IIS demand, defined as 5 p.m. to 9:59 p.m. for Newfoundland.

Base Year Peak Demand

The Study Team used load profiles for each peak period to convert annual electric energy consumption to hourly demand for the residential, commercial, and industrial sectors. Base year peak demand is calibrated to the Utilities' estimate of IIS peak hour demand.

The Study Team also completed a peak day analysis to estimate demand in the hours outside of the peak hour. For the morning and evening peak periods, the Study Team determined the average demand during each period and calibrated the space heating peak factors to align the total with the average demand.[26] The peak day analysis is discussed in further detail in section 7.1.

Base year peak demand for the transportation sector uses 8760 load shapes for each combination of vehicle type and charging location. These load shapes are applied against base year annual energy consumption to determine demand in each hour of the year.

The Study Team identified the day that included the peak hourly EV load, then overlayed that day's 24-hour load shape onto the reference peak day load shape for the residential, commercial and industrial sectors. The overall IIS peak hour is identified based on the resulting aggregated load shape that reflects peak demand for all sectors.

Reference Case Peak Demand

The Study Team used calibrated peak factors from the base year in each year of the reference case forecast. Therefore, for each combination of end-use and building type, the reference case peak load scales with annual energy consumption for the residential, commercial, and industrial sectors. Aggregating the resulting end-use peak loads provides the forecast single peak hour or average peak demand for each year in the reference case.

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[26] The Study Team adjusted peak factors for the space heating end use in the residential and commercial sectors for the morning and evening peak period calibration because overall demand is driven by space heating in those sectors. The peaks for each period in the industrial sector are the same because overall demand is not driven by space heating.

Like the base year peak demand, reference case peak demand for the transportation sector relies on 8760 load shapes for each combination of vehicle type and charging location. The Study Team applied the load shapes against forecast annual reference case consumption to determine hourly demand in each reference case year.

2.4 Measure Characterization

The Study Team assessed the energy savings and peak demand reduction potential for measures in three categories:

1. **Efficiency**: Measure that uses electricity more efficiently than the base case measure.
2. **Fuel Switching**: Measure that uses electric equipment to replace a base case measure that uses another fuel (i.e., oil, propane, or wood). This category also includes measures that use-off road electric equipment (i.e., forklifts, Zambonis) to replace a base case off-road measure that uses propane.
3. **Demand Response**: Measure that uses less electricity during the peak period but has minimal or no impact on annual electric energy consumption. The demand response (DR) measures are further classified as follows:
    - **Electricity Rate Design**: Customers opt into a time-of-use (TOU) or critical peak pricing (CPP) electricity rate at their discretion. This includes TOU rates for EVs.
    - **Equipment DR**: The utility has direct load control (DLC) of customer end use equipment (e.g., water heater smart switch, smart thermostat) during on-peak times. These measures are modelled with opt-in participation and with current rates (i.e., they are not modelled with time variable rates (TVR)).
    - **EV Managed Charging**: Measure that enables utilities to influence charging periods for vehicles via connected hardware and controls. Managed charging measures can be valuable to an electric utility because they can reduce the peak demand associated with EV charging. Peak demand is a main driver of infrastructure investment needs and costs borne by utility ratepayers.
    - **Thermal Storage with TOU**: Customers shift electricity use off peak based on TOU rates only using electric thermal storage (ETS) systems.

In addition, the Study Team determined what market conditions would be required to support the natural adoption, intermediate and government targets scenarios defined in section 2.2.[27] This included an examination of the following transportation sector measures:

- **Adoption Incentives**: Payments to vehicle operators that offset the incremental cost of adopting EVs.
- **Charging Infrastructure**: Charging infrastructure costs include port costs and associated installation costs. Costs exclude distribution system upgrades to host charging loads.

Lastly, the Study Team completed a qualitative assessment of emerging measures transportation sector measures:

- **Emerging Measures**: Connected hardware and controls that enable vehicle batteries to feed energy back to specific loads, dwellings or the grid and allow the Utilities to influence the magnitude and timing of this energy flow.

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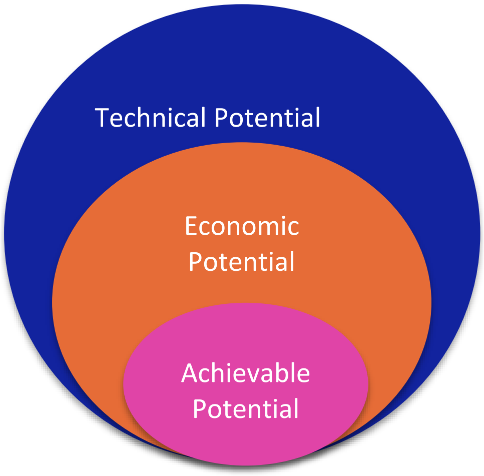
[27] In the Study, charging infrastructure refers to the ports required to support electric vehicle charging in the Transportation sector.

2.5 Potential Assessment

The Study assesses three levels of savings potential: technical, economic, and achievable, described as follows:[28]

1. **Technical Potential:** An estimate of the technically feasible energy and demand savings potential, ignoring measure cost effectiveness or market acceptance.
2. **Economic Potential:** An estimate of the energy and demand savings potential for the measures in the technical potential that also pass the cost effectiveness screening criteria established for the Study. The total resource cost (TRC) test is used to screen efficiency measures. Measures are included in the economic potential if their benefit-cost ratio is 0.8 or higher.[29]



3. **Achievable Potential**: An estimate of the energy and demand savings potential considering feasible adoption rates of cost-effective measures over the study period. Achievable potential considers market barriers, customer payback acceptance, and awareness of energy efficiency measures among other factors. The achievable scenarios are defined as follows:
    - **Lower**: Incentive is 25% of incremental cost for ROB measures and 25% of full cost for RET measures.
    - **Medium**: Incentive is 50% of incremental cost for ROB measures and 50% of full cost for RET measures.
    - **Higher**: Incentive is 100% of incremental cost for ROB measures and 100% of full cost for RET measures.

In all three achievable potential scenarios, non-incentive costs are set to 25% of the measure-level incentive. While 25% is a standard estimate used for the purposes of this Study, non-incentive costs would vary from program to program.

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[28] "Foreword" Independent Electricity System Operator, Available: https://www.ieso.ca/-/media/Files/IESO/Document-Library/conservation/APS/2019-Achievable-Potential-Study-Foreword.pdf (Accessed Dec. 11, 2024).

[29] This ratio was selected instead of 1.0 to allow more measures to be screened into the economic and achievable potential scenarios. The economic potential does not consider incentive or non-incentive program costs.

2.6 Caveats and Limitations

Forecasting and modelling are integral to this Study. Both activities require assumptions and engineering estimates based on extensive research and the professional judgement of the Study Team. The Study Team has made diligent efforts to ensure that any assumptions were in line with the Utilities' knowledge of their customer base and informed by the best available information. The results in this report should therefore be interpreted as estimates.

The Study reference case is calibrated to NLH's 2023 long-term forecasts. The following data sources inform the Study reference case:

- Newfoundland and Labrador Hydro's (NLH) general service forecasts for their customers and for Newfoundland Power's (NP) customers.[30]
- NLH's residential forecasts for their customers and for NP's customers, based on the historic relationship between new customer accounts and housing starts, which inherently reflects demolitions or rebuilds.[30]
- Residential and commercial end use survey results, used to estimate the rate of natural adoption of new, more efficient technology.

By integrating these sources, the Study reference case considers the impacts of existing policies, but it does not account for potential future policies. Any differences in stated values or summations in this report are due to rounding unless otherwise noted.

[30] The General Service forecast for NP's customers was derived using an econometric equation driven by GDP, non-residential building investment, forecast CDM savings, and a forecast for heating degree days.

3 Base Year and Reference Case

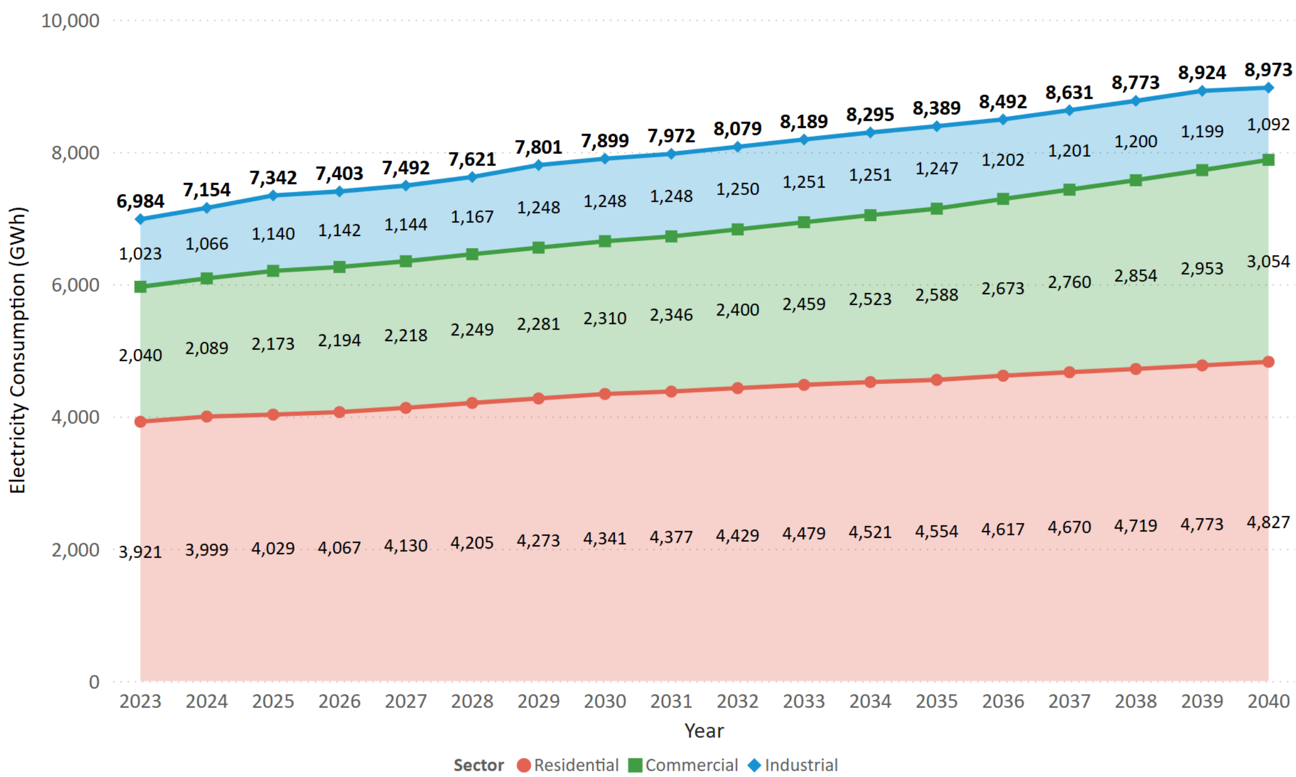
This section shows base year and reference case energy consumption and peak demand at the system-level and by sector. It is structured as follows:

- Section 3.1 shows system-level base year and reference case results.
- Sections 3.2, 3.3, and 3.4 show results by segment, customer accounts and end use for the residential, commercial, and industrial sectors. Results are presented by segment, customer accounts and end use.
- Section 3.5 shows results for the transportation sector, including a comparison of the forecast vehicle stock, consumption and peak demand in the natural adoption, intermediate, and government targets scenarios.

3.1 System-Level Base Year and Reference Case

Exhibit 22 shows base year and reference case IIS electricity consumption by sector.[31] Residential and commercial sector electricity consumption includes EV charging in the intermediate scenario, as defined in section 2.2. The numerical values in bold font (e.g., 6,984) represent total annual IIS consumption.

Exhibit 22: Reference Case IIS Consumption (GWh)



Observations on Exhibit 22 include:

- Total base year electricity consumption is 6,984 GWh. The residential sector represents 56% of this total (3,921 GWh). The commercial and industrial sectors represent 29% (2,040 GWh) and 15% (1,023 GWh) of the total, respectively. In 2040, these contributions are 54% residential, 34% commercial, and 12% industrial.
- Electricity consumption is forecast to increase by 1,989 GWh (28%) between 2023 and 2040. The adoption of 160,699 EVs caused by incentives or more charging infrastructure for LDVs in the

[31] Electricity consumption from losses and company use is excluded. Losses and company use contribute 350 GWh and 458 GWh to IIS electricity consumption in 2023 and 2040, respectively. IIS consumption including losses and company use is 7,334 GWh in 2023 and 9,431 GWh in 2040.

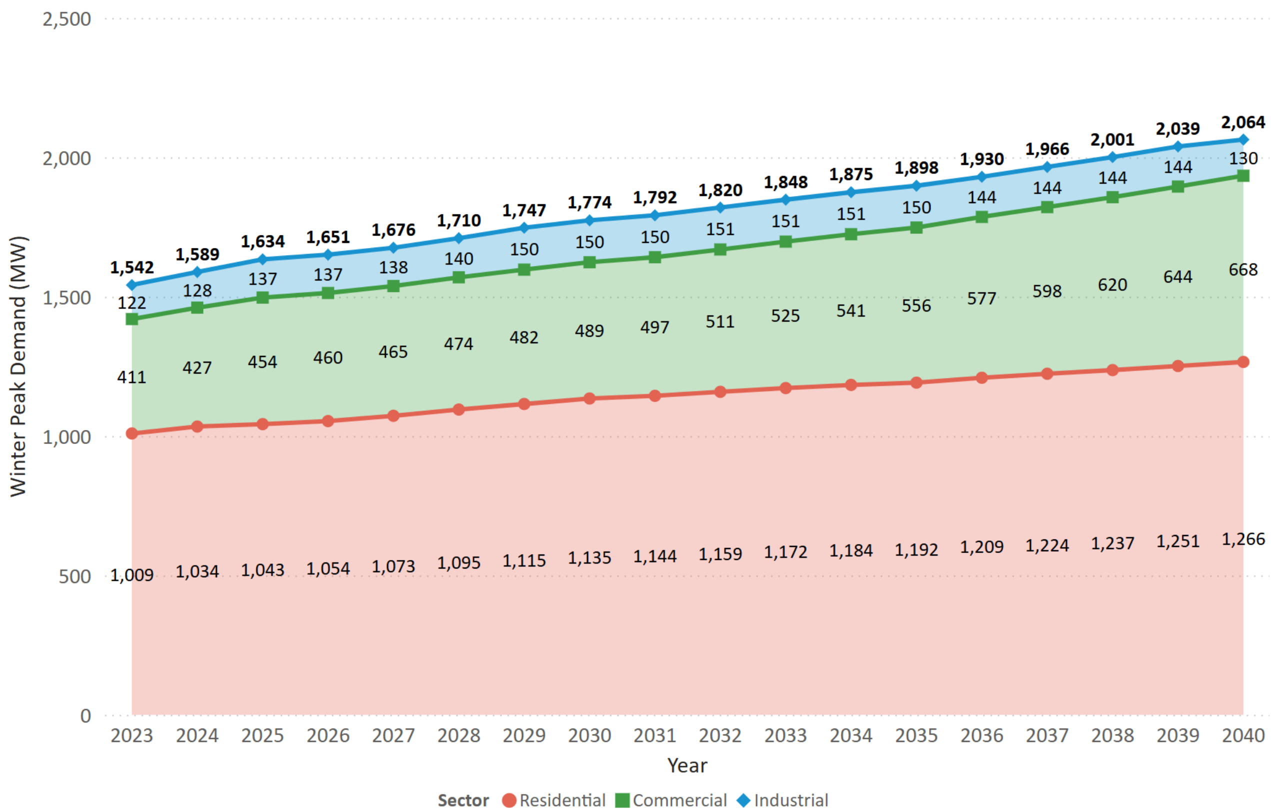
intermediate scenario accounts for 991 GWh of this increase.[32] The rest of the increase is driven by:

- Space heating electrification in the residential and commercial sectors, and,
- An increase in customer accounts in the residential and commercial sectors, and in small and medium customer accounts in the industrial sector.

Exhibit 23 shows base year and reference case winter peak demand (i.e., the single highest hour of system demand, which typically occurs on the coldest day of the winter) by sector for the IIS, including the contributions of EV charging in the intermediate scenario.[33] The numerical values in bold font (e.g., 1,542) represent total annual IIS peak demand.

From 2023 to 2032, the IIS peaks in the morning. In 2033, the peak is forecast to occur in the evening, driven by the adoption of EVs in the intermediate scenario. This change to the evening peak is discussed in detail in section 7.1.

Exhibit 23: Reference Case IIS Winter Peak Demand (MW)



[32] The Study Team integrated the intermediate EV scenario because it is the middle scenario compared to the natural adoption and government targets scenarios, which bookend the EV forecast analysis.
[33] Peak demand from losses and company use is excluded. Losses and company use contribute 55 MW and 72 MW to IIS peak demand in 2023 and 2040, respectively. Total IIS peak demand including losses and company use is 1,597 MW in 2023 and 2,135 MW in 2040.

Observations on Exhibit 23 include:

- Peak demand in the base year is 1,542 MW. The residential sector represents 65% (1,009 MW) of this total, while the commercial and industrial sectors represent 27% (411 MW) and 8% (122 MW) of the total, respectively. By 2040, these contributions shift to 61% residential, 33% commercial, and 6% industrial.
- Peak demand is forecast to increase by 522 MW (34%) between 2023 and 2040. The increase to 2,064 MW by 2040 is largely driven by the adoption of 160,699 EVs between 2030 and 2040 in the intermediate scenario.

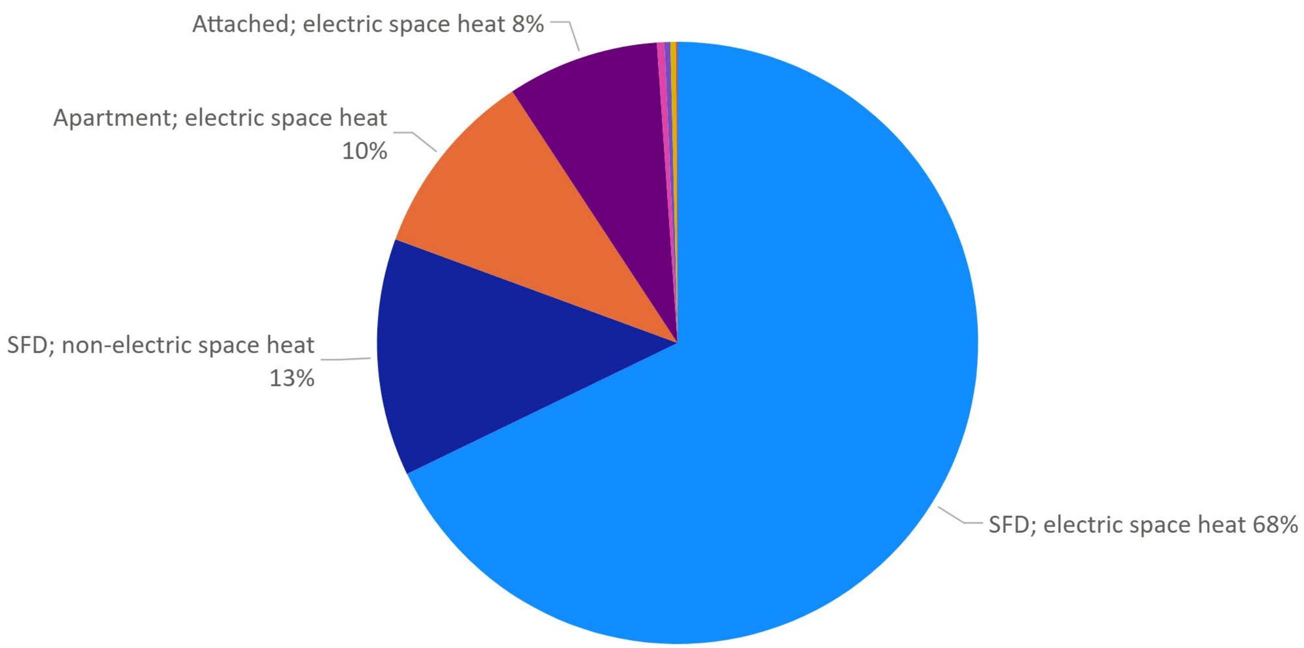
3.2 Residential Sector Base Year and Reference Case

This section presents residential sector results for the base year (2023) and the reference case forecast (2024-2040). The results presented in this section include consumption from unmanaged EV charging in the intermediate scenario.

3.2.1 Base Year Consumption by Segment, Customer Accounts, and End Use

Base year consumption in the residential sector is 3,921 GWh. Exhibit 24 shows that electrically heated single family detached dwellings (SFDs) consume the most electricity (2,660 GWh, 68%), followed by non-electrically heated SFDs (500 GWh, 13%) and electrically heated apartments (398 GWh, 10%).[34] The distribution of customer accounts by segment drives this result (see Exhibit 25).

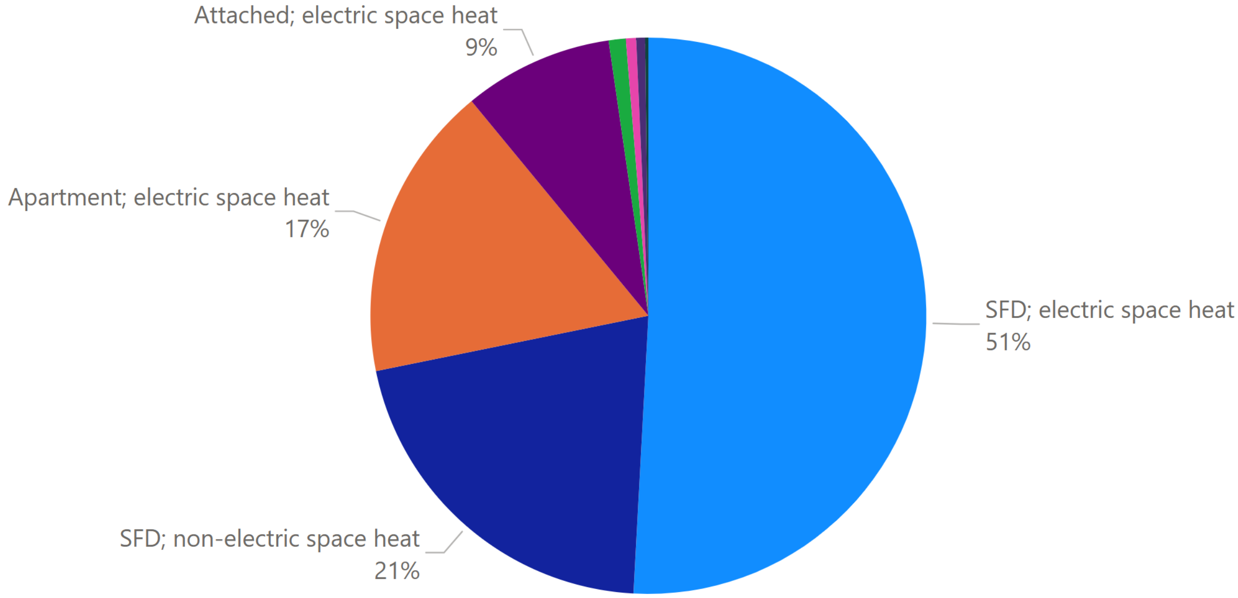
Exhibit 24: Base Year Residential Consumption by Segment



[34] Segments that contribute less than 8% to residential sector consumption are not labelled to improve readability: other and non-dwellings (0.4%), vacant and partial (0.3%), apartment; non-electric space heat (0.3%), and attached; non-electric space heat (0.08%).

The distribution of electricity customer accounts by segment is presented in Exhibit 25.[35] Most of the 259,793 base year customer accounts are in the electrically heated SFD segment (132,124, 51%), followed by the non-electrically heated SFD segment (54,434, 21%).

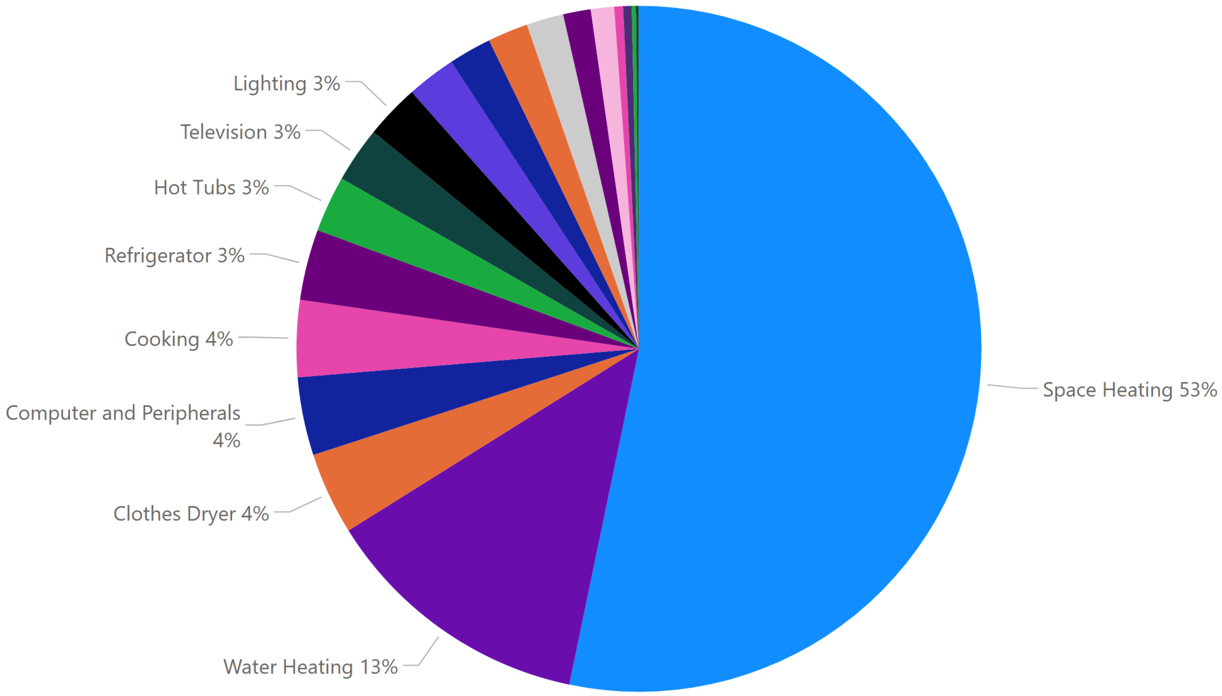
Exhibit 25: Base Year Residential Customer Accounts by Segment



[35] Segments that represent less than 8% of residential sector accounts are not labelled to improve readability: apartment; non-electric space heat (1%), other and non-dwellings (0.6%), vacant and partial (0.5%), and attached; non-electric space heat (0.2%).

Exhibit 26 shows residential sector electricity consumption by end use. Most base year electricity is for space heating (2,088 GWh, 53%) followed by water heating (504 GWh, 13%) and clothes dryers (152 GWh, 4%).[36,37] The contribution of EV charging to total base year energy consumption is 6 GWh, or 0.15%. This EV charging consumption represents 1,520 vehicles.

Exhibit 26: Base Year Residential Consumption by End Use



[36] End uses that represent less than 3% of residential sector base year consumption are not labelled to improve readability: small appliance and other (2%), television peripherals (2%), dehumidifier (2%), freezer (2%), ventilation (1%), other electronics (1%), space cooling (0.4%), dishwasher (0.4%), clothes washer (0.2%), BEV charging (0.1%) and PHEV charging (0.03%).

[37] Television peripherals include the peripheral equipment used with televisions (e.g., DVRs, cable boxes, etc.).

Base Year Consumption per Customer Account

Dividing consumption by the number of customer accounts gives the average electricity consumption per customer account. This calculation reveals the segments with the highest or lowest energy intensities. Base year consumption, customer accounts and consumption per customer account for each segment are displayed in Exhibit 27. Highlights from this exhibit include:

- The most energy intensive segment in the residential sector is electrically heated single-family detached (SFD), which consume 20.1 MWh per customer account, followed by attached dwellings (electric space heat) at 14.2 MWh per customer account and other and non-dwellings at 10.2 MWh per customer account.
- Non-electrically heated dwellings and both electrically- and non-electrically heated apartments are the least energy intensive segments.

Exhibit 27: Base Year Residential Energy Intensity (MWh/Customer Account) by Parent Segment

Segment	2023 Consumption (MWh)	2023 Customer Accounts	2023 Average Consumption (MWh/Customer Account)
SFD; electric space heat	2,659,749	132,124	20.1
Attached; electric space heat	320,225	22,567	14.2
Other and non-dwellings	15,773	1,546	10.2
Vacant and partial	12,421	1,340	9.3
SFD; non-electric space heat	500,202	54,434	9.2
Apartment; electric space heat	397,621	44,720	8.9
Attached; non-electric space heat	3,128	487	6.4
Apartment; non-electric space heat	11,765	2,575	4.6
Total	**3,920,884**	**259,793**	**15.1**

Base Year Peak Demand

Exhibit 28 shows base year residential sector peak demand by end use. Observations for the base year include:

- Space heating is the largest (67%) residential component of peak demand. As shown in the previous section, space heating represents 53% of residential base year electricity consumption. This consumption is concentrated in the winter when the IIS system peaks on a very cold day.
- Water heating is the second largest (14%) residential component of peak demand. Water heating represents 13% of annual electricity consumption in the base year and is on during the winter peak periods.
- EV charging represents 0.1% (1 MW) of residential sector peak demand in the base year. EV charging represents 0.15% of annual electricity consumption in the base year.

Exhibit 28: Base Year Residential Peak Demand (MW)

End Use	2023 Winter Peak Demand (MW)[38]	2023 % of Winter Peak Demand
Space Heating	673	67%
Water Heating	145	14%
Cooking	28	3%
Clothes Dryer	25	2%
Computer and Peripherals	19	2%
Television	17	2%
Lighting	17	2%
Ventilation	16	2%
Hot Tubs	16	1%
Refrigerator	13	1%
Small Appliance and Other	12	1%
Television Peripherals	10	1%
Freezer	7	0.7%
Other Electronics	6	0.6%
Dishwasher	3	0.3%
BEV Charging	1.5	0.1%
Clothes Washer	1	0.1%
PHEV Charging	0.3	0.03%
Total	**1,009**	**100%**

[38] Dehumidifier and space cooling are not shown because they represent less than 0% of base year winter peak demand.

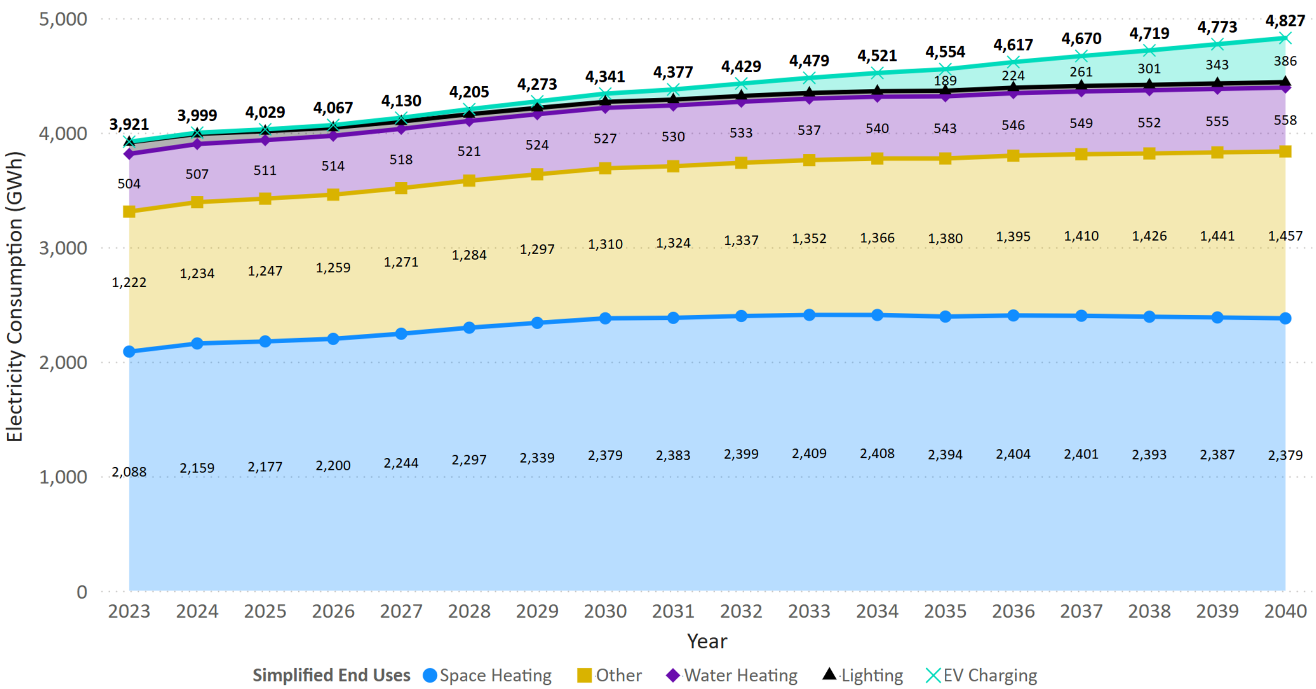
3.2.2 Reference Case Electricity Consumption and Peak Demand

This section profiles the reference case electricity consumption and peak demand forecast for the residential sector. It begins with commentary on high-level trends, then shows how consumption is forecast to change by segment, end use, and in new versus existing homes. It ends with a summary of peak demand results.

Residential Reference Case Consumption Trends

Exhibit 29 shows reference case electricity consumption for the residential sector. The contributions of space heating, water heating, lighting, and unmanaged EV charging to total consumption (represented by numerical values in bold font) are shown explicitly. The contributions of all other end uses are grouped in "Other" to enhance readability.

Exhibit 29: Reference Case Residential Consumption Forecast (GWh)



Residential electricity consumption is forecast to increase by 906 GWh (23%) from 2023 to 2040. The increase to 4,827 GWh in 2040 is explained by the following trends:

- **Space heating electrification**: The number of customer accounts with electric heating are expected to increase by 59,643 between 2023 and 2040, while the number of customer accounts without electric heating are forecast to decrease by 31,599 between 2023 and 2040.[39]

[39] Customer accounts with electric heating use electricity as their main heating source, accounting for at least 50% of their heating, while customer accounts without electric heating use less than 50% electricity for heating.

Between 2014 and 2022, the Residential End Use Survey (REUS) showed an overall increase in electrically heated dwellings from 66% to 78%.[40]

- **An increase in EV charging:** Annual EV charging consumption is forecast to increase by 381 MWh over the forecast period, caused by the adoption of 138,478 EVs.
- **An increase in residential customer accounts:** Residential customer accounts increase by approximately 11% over the forecast period. This is compounded by most new dwellings using electric equipment for space heating compared to older existing dwellings.
- **Increased saturation of space cooling**: The penetration of heat pumps is projected to grow substantially in forecast period. Between 2014 and 2022, the REUS showed that the overall heat pump penetration increased more than seven-fold (from 3.3% to 24.9%). This change is directly correlated with an increase in space cooling saturation because homes in Newfoundland rarely have stand-alone air conditioning equipment (i.e., space cooling is primarily provided by heat pumps).

Consumption by Segment

Exhibit 30 shows the change in electricity consumption by segment over the forecast period. The largest increase in consumption occurs in the electrically heated apartment segment (61%) followed by the non-electrically heated apartment segment (34%) and the electrically heated SFD segment (31%).[41]

Exhibit 30: 2023 vs 2040 Residential Consumption Forecast (GWh) by Parent Segment

Segment	2023 Consumption (GWh)	2040 Consumption (GWh)	Change in Consumption (GWh)	Change in Consumption (%)
Apartment, electric space heat	398	641	243	61%
Apartment, non-electric space heat	12	16	4	34%
SFD, electric space heat	2,660	3,496	836	31%
Attached, electric space heat	320	398	78	24%
Other and Non-Dwellings	16	15	-0.1	-1%
Vacant and Partial	12	12	-0.4	-4%
SFD, non-electric space heat	500	249	-252	-50%
Attached, non-electric space heat	3	0.5	-3	-85%
Total	**3,921**	**4,827**	**906**	**23%**

[40] With increased heat pump uptake, the average efficiency of electric space heating is projected to increase, which balances out the increase in electric space heating penetration across the IIS. Therefore, contribution of space heating consumption to the residential sector total decreases over time in the reference case.
[41] Apartments are expected to see the largest increase in consumption because they are forecast to see the largest increase in customer accounts between 2023 and 2040.

Consumption by End Use

Exhibit 31 shows the expected growth in electricity consumption by end use and highlights space cooling saturation growth trend discussed. Observations on Exhibit 31 include:

- EV charging end uses are expected to grow by 380 GWh between 2023 and 2040, caused by the adoption of 138,478 personal EVs in the intermediate scenario.
- Other electronics and television end uses grow by 106 GWh between 2023 and 2040 due to customer account growth and natural adoption.
- Space cooling consumption is expected increase by 8 GWh (50%) between 2023 and 2040, driven by the rapid adoption of heat pumps.

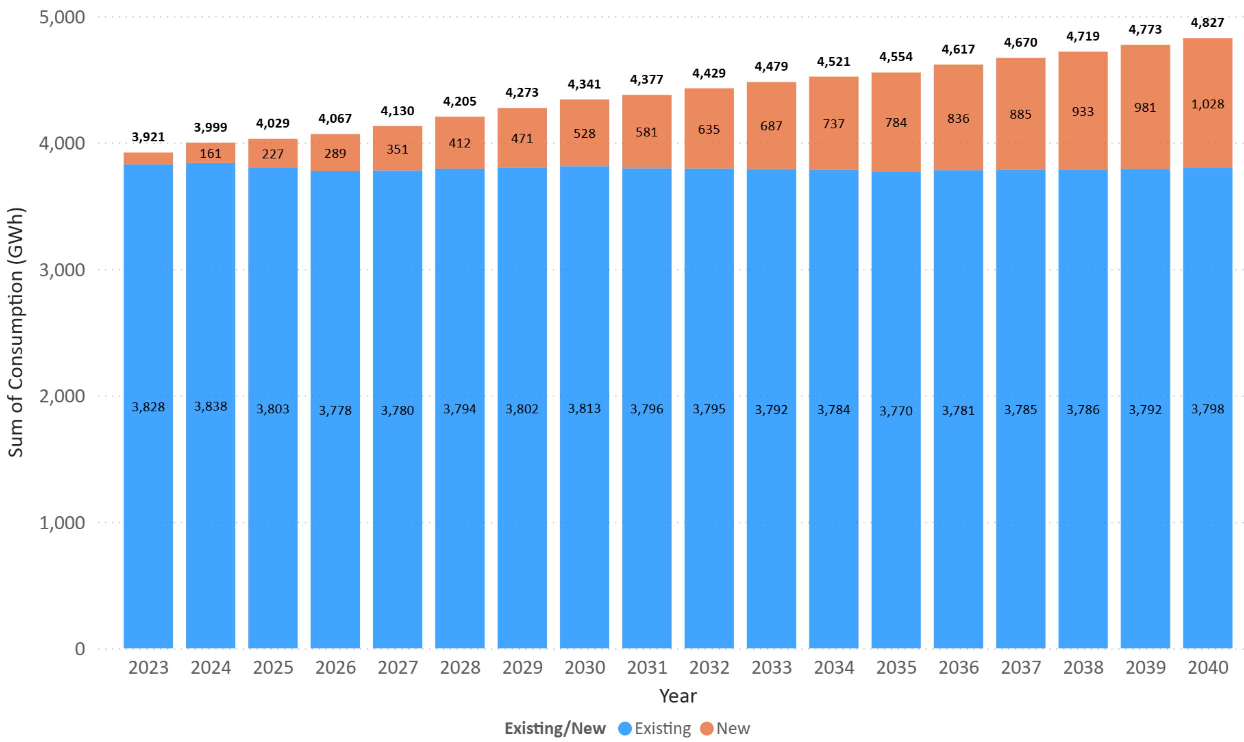
Exhibit 31: 2023 vs 2040 Residential Consumption Forecast by Parent End Use (GWh)

End Use	2023 Consumption (GWh)	2040 Consumption (GWh)	Change in Consumption (GWh)	Change in Consumption (%)
BEV Charging	5	338	333	7,164%
PHEV Charging	1	48	47	6,271%
Other Electronics	43	69	26	59%
Space Cooling	16	24	8	50%
Television Peripherals	79	114	35	44%
Television	103	148	45	44%
Hot Tubs	104	130	26	25%
Freezer	68	84	16	22%
Computer and Peripherals	144	174	30	21%
Dishwasher	16	19	3	20%
Refrigerator	130	156	26	19%
Space Heating	2,088	2,379	291	14%
Water Heating	504	558	54	11%
Dehumidifier	75	83	8	10%
Cooking	142	156	14	10%
Clothes Washer	8	8	0	9%
Small Appliance and Other	91	97	6	8%
Clothes Dryer	152	155	3	2%
Ventilation	51	40	-11	-21%
Lighting	101	47	-54	-53%
Total	**3,921**	**4,827**	**906**	**23%**

Reference Case Electricity Consumption: Existing versus New Buildings

This section compares the electricity consumption in existing versus new residential buildings across the reference case forecast. New constructions are estimated by extrapolating customer forecasts provided by NP and drawing insights from the electricity consumption growth forecasts by rate class. This leads to a decreasing stock of existing building over the reference case forecast period while new dwellings increase, which is reflected in the graph of consumption over time shown in Exhibit 32.

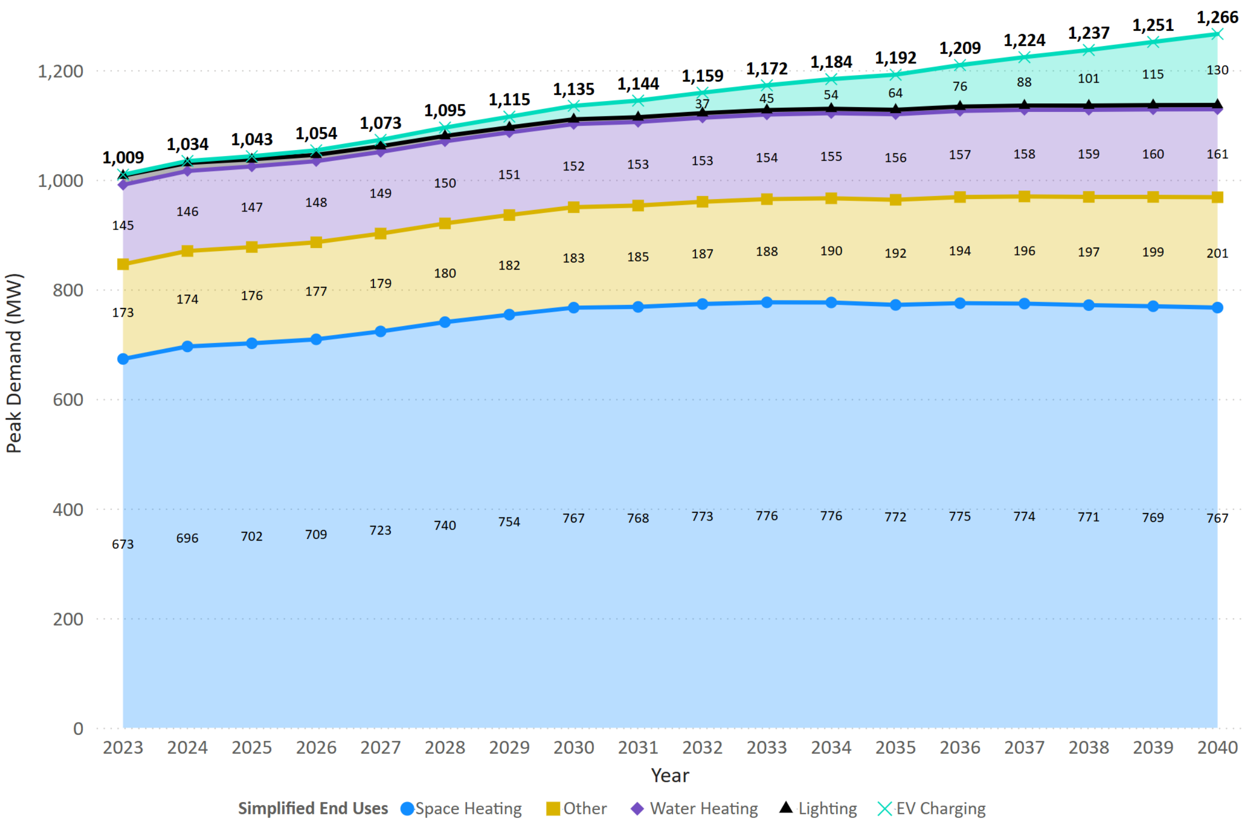
Exhibit 32: Existing vs New Dwelling Residential Consumption Forecast (GWh)



Reference Case Peak Demand

Exhibit 33 shows reference case peak demand for the residential sector. The contributions of water heating, unmanaged EV charging, lighting and space heating to total consumption are shown explicitly while the contributions of all other end uses are grouped in "Other" to enhance readability.

Exhibit 33: Residential Sector Reference Case Peak Demand (MW)



The reference case winter peak demand in the residential sector is forecast to increase by 257 MW (25%), between 2023 and 2040. The increase to 1,266 MW by 2040 is explained by the following trends:

- **Increase in space heating demand**: Space heating demand increases substantially over the forecast period (94 MW, 14%) and comprises the highest demand of all end uses. This increase is explained by the electrification trends for space heating.[42]
- **Increase in EV charging demand**: There is a substantial increase in demand for EV charging, from 1.8 MW in 2023 to 130 MW in 2040. EV charging represents 10% of residential winter peak demand by 2040.

[42] Demand increases are linearly correlated with energy consumption increases.

Exhibit 34 shows residential sector reference case peak demand for all end uses. Observations include:

- EV charging end uses have the highest peak demand growth (128 MW) over the forecast period due to the adoption of 138,478 personal EVs in the intermediate scenario.
- Peak demand increases by 59% in other electronics and by 44% in televisions and peripherals. This is due to projected increases in the saturation of these end uses during peak hours.
- In 2040, space heating contributes the most to the winter peak (61%), followed by water heating (13%), and BEV charging (9%).

Exhibit 34: Residential Sector Reference Case Peak Demand by End Use (MW)

End Use	2023 Winter Peak Demand (MW)	2040 Winter Peak Demand (MW)	Change in Peak Demand (MW)	Change in Peak Demand (%)
BEV Charging	1.5	108	107	7,164%
PHEV Charging	0.3	21	21	6,271%
Other Electronics	6	9	3	59%
Television Peripherals[43]	10	15	5	44%
Television	17	25	8	44%
Hot Tubs	16	20	4	25%
Freezer	7	8	1	22%
Computer and Peripherals[43]	18	22	4	21%
Dishwasher	2.6	3.2	0.5	20%
Refrigerator	13	15	2	19%
Space Heating	673	767	94	14%
Water Heating	145	161	16	11%
Cooking	28	31	3	10%
Clothes Washer	1.3	1.4	0.1	9%
Small Appliance and Other	12	13	1	8%
Clothes Dryer	25	26	1	2%
Ventilation	16	13	-3	-21%
Lighting	17	8	-9	-53%
Space Cooling	0	0	0	N/A
Dehumidifier	0	0	0	N/A
Total	**1,009**	**1,266**	**257**	**25%**

[43] The Study Team derived the growth in end use saturation for these end uses by comparing the 2014 and 2022 NP and NLH REUS. The annual growth in end use saturation is approximately 1.5%. This indicates customers owned more TVs, computers, and associated peripherals in 2024 than in 2014.

3.3 Commercial Sector Base Year and Reference Case

This section presents results and key findings for the commercial sector base year (2023) and reference case forecast (2024-2040). The results include consumption from unmanaged EV charging in the intermediate scenario.

Commercial sector base year and reference case results are presented by parent segment (e.g., Office, Non-Food Retail, Accommodation) and parent end use to enhance readability. A parent segment represents the sum of consumption or customer accounts in the small and large segments where applicable. For example, consumption for the office parent segment represents the sum of consumption in the small and large office segments. Parent end uses represent a combination of like end uses. Specifically:

- Indoor lighting represents general lighting, secondary lighting, and high bay lighting.
- Plug loads represents computer equipment, computer servers and other plug loads.

Section 2 - Approach provides additional details on the commercial sector model structure.

3.3.1 Base Year Electricity Consumption and Peak Demand

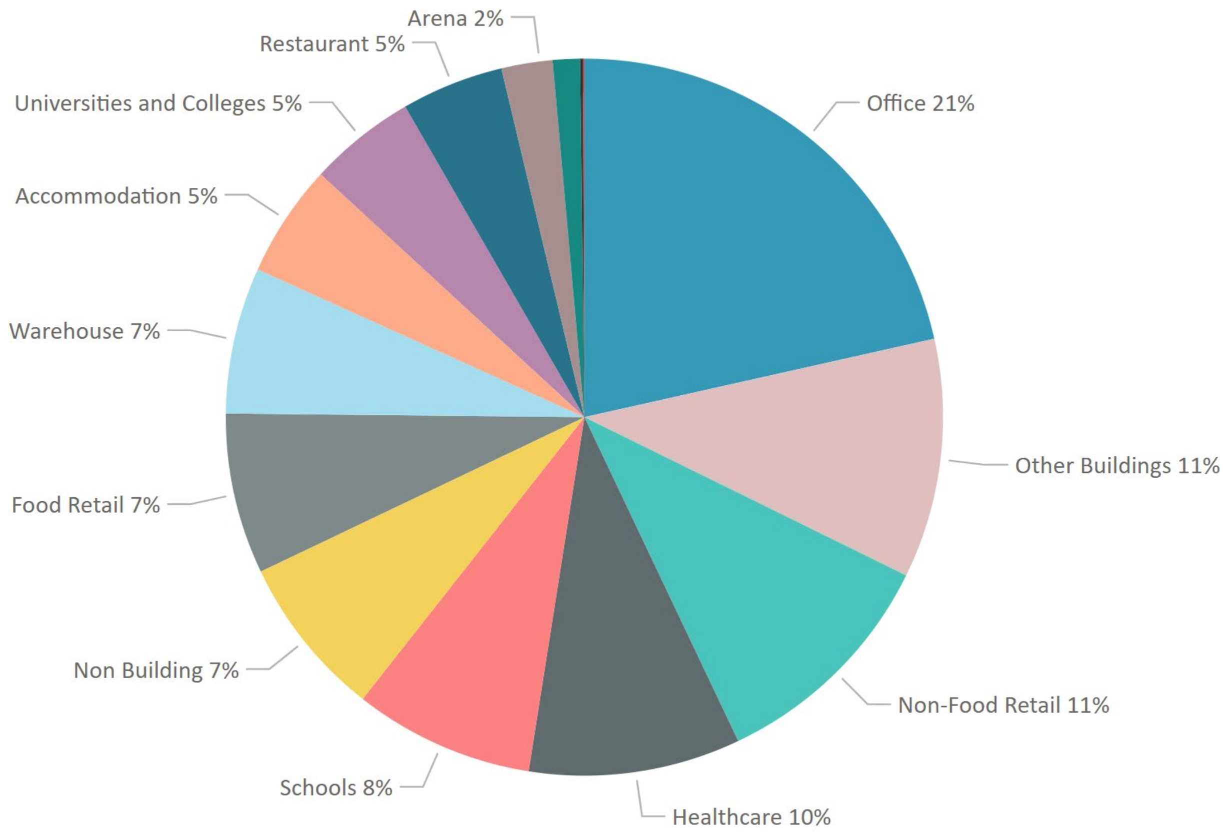
This section profiles base year electricity consumption, customer accounts, consumption per customer account, and peak demand for the commercial sector.

Consumption by Segment, Customer Accounts, and End Use

Base year electricity consumption in the commercial sector is 2,040 GWh. Exhibit 35 shows that electricity consumption is highest in the office segment (438 GWh, 21%) followed by other buildings (220 GWh, 11%) and non-food retail (218 GWh, 11%).[44] Examples of other buildings include churches, community centres, recreation complexes, and buildings that do not fit into the other parent segments.

In the base year, the EV charging segments contribute 3.9 GWh (0.2%) to the commercial sector total. This distribution of customer accounts by segment drives this result (see Exhibit 36).

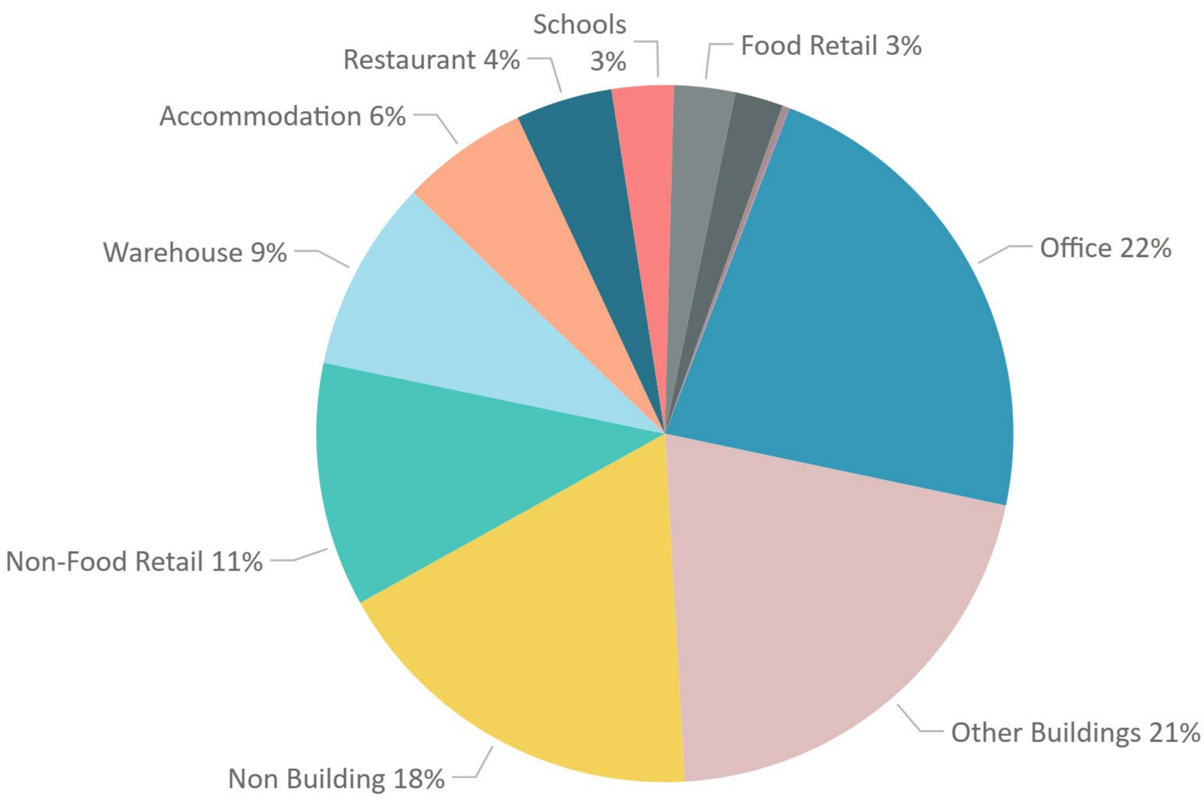
Exhibit 35: Base Year Commercial Consumption by Parent Segment



[44] Segments that represent less than 2% of commercial sector consumption are not labelled to improve readability: street lighting (1%), personal EV charging (0.1%), and fleet depot charging (0.07%).

Base year commercial sector customer accounts are presented by segment in Exhibit 36.[45] Most of the 23,733 base year customer accounts are offices (5,334, 22%), followed by other buildings (4,934, 21%) and non buildings (4,232, 18%). Non buildings include facilities like cell phone towers. Although these facilities may include a building, most of their electricity use is consumed by the unique equipment they house.

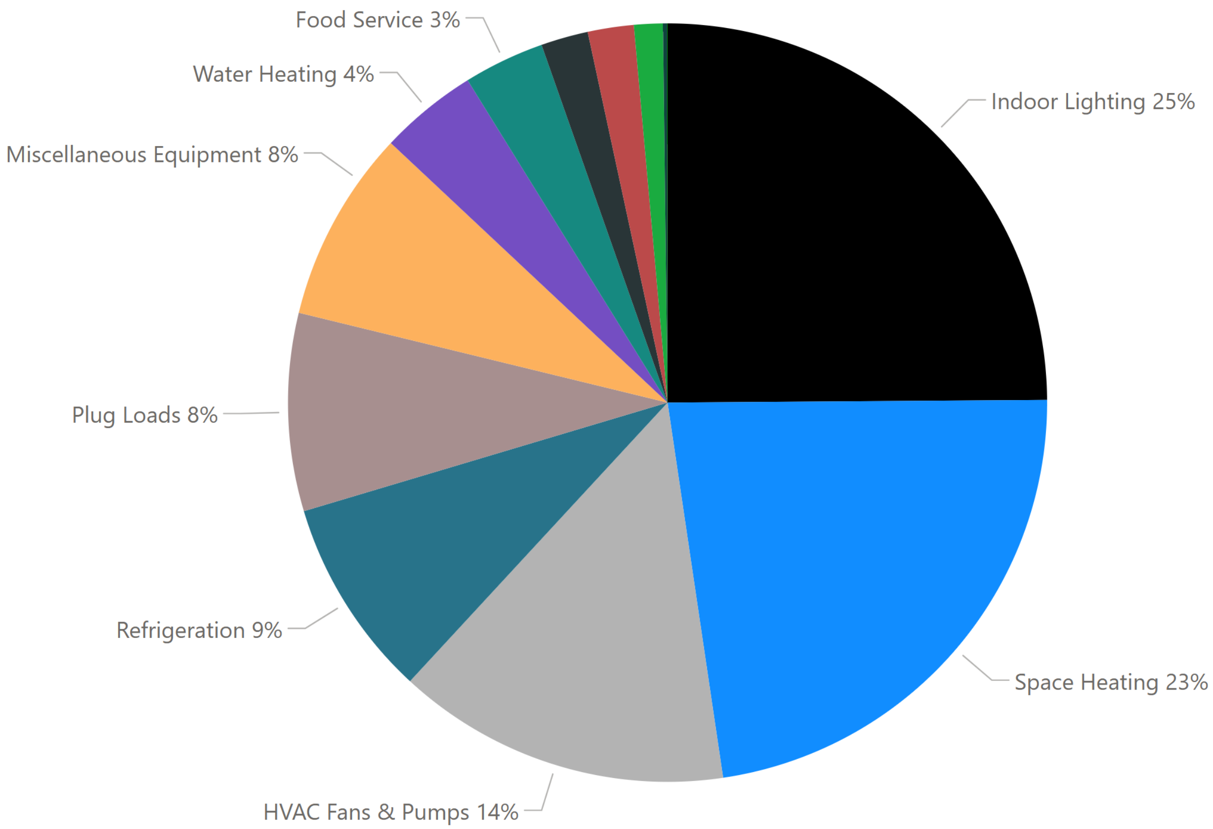
Exhibit 36: Base Year Commercial Customer Accounts by Parent Segment



[45] The street lighting segment is not presented because it includes 11,277 total customer accounts and would skew Exhibit 36. The segments that represent less than 3% of commercial sector accounts are not shown: healthcare (2%), arena (0.3%), and universities and colleges (0.07%).

Exhibit 37 shows commercial sector base year electricity consumption by end use.[46] Space heating and HVAC fans and pumps represent 37% (755 GWh) of total consumption. Indoor lighting, which includes general lighting for the main areas of commercial buildings and secondary lighting for hallways and stairwells, represents 25% (508 GWh) of total consumption.

Exhibit 37: Base Year Commercial Consumption by End Use



[46] The end uses that contribute less than 3% of base year consumption in the commercial sector are not shown to improve readability: outdoor lighting (2%), space cooling (2%), street lighting (1%), BEV charging (0.2%), and PHEV charging (0.02%).

Energy Intensity

Dividing electricity consumption by floor area (in square feet) gives electric energy use intensity. Performing this calculation by segment reveals those with the highest and lowest electric energy use intensities. Base year electricity consumption, floor area, and electric energy intensity for each segment are shown in Exhibit 38. Highlights from this exhibit include:

- In the base year, food retail buildings have the highest electric energy use intensity (54.7 kWh/sq-ft), driven by their refrigeration and indoor lighting electricity use.
- Universities and colleges have the lowest base year electric energy use intensity (8.5 kWh/sq-ft). This result is driven by MUN's fossil fuel space heating in the base year. By 2040 however, the intensity increases to 17 kWh/sq-ft, driven by MUN's conversion to electric space heating.

Exhibit 38: Base Year Commercial Energy Intensity by Segment (kWh/sq-ft)[47]

Segment	Consumption (kWh)	Floor Area (sq-ft)	Electric Energy Use Intensity (kWh/sq-ft)
Food Retail	147,836,000	2,703,691	54.7
Restaurant	94,071,000	2,031,764	46.3
Arena	46,968,000	1,510,680	31.1
Healthcare	194,726,000	6,432,780	30.3
Office	438,470,000	16,698,959	26.3
Non-Food Retail	217,644,000	9,335,288	23.3
Accommodation	103,783,000	4,563,713	22.7
Other Buildings	220,142,000	10,646,105	20.7
Schools	165,741,000	14,102,608	11.8
Warehouse	134,613,000	12,964,268	10.4
Universities and Colleges	98,450,000	11,638,208	8.5

[47] Segments with no associated floor area (i.e., EV charging segments, non-buildings, and street lighting) are omitted from this Exhibit.

Base Year Peak Demand

Exhibit 39 shows the base year peak demand by end use for the commercial sector. Observations include:

- Space heating is the largest commercial component (35%) of peak demand. As shown in the previous section, space heating represents 23% of base year electricity consumption. This consumption is concentrated in the winter when the IIS system peaks. The space heating load shape has more dramatic peaks than other end uses because demand is weather dependent.
- Indoor lighting is the second largest commercial component of peak demand (20%). Indoor lighting represents 25% of annual electricity consumption in the base year and is on during the winter peak periods. The annual lighting load shape is "flatter" than the space heating load shape. Usage patterns exhibit daily/hourly variation and some seasonal variation but are more consistent throughout the year because they are not weather dependent.
- HVAC fans and pumps are the third largest commercial component of peak demand (10%). This is expected since fan and pump operation coincide with space heating equipment operation.

Exhibit 39: Base Year Commercial Peak Demand (MW)

End Use	2023 Winter Peak Demand (MW)	2023 % of Winter Peak Demand
Space Heating	145	35%
Indoor Lighting	84	20%
HVAC Fans & Pumps	42	10%
Water Heating	32	8%
Food Service Equipment	26	7%
Plug Loads	26	6%
Miscellaneous Equipment	25	7%
Refrigeration	20	5%
Outdoor Lighting	6	1%
Street Lighting	4	1%
BEV Charging	1	0.24%
PHEV Charging	0.1	0.02%
Space Cooling	0	0%
Total	**411**	**100%**

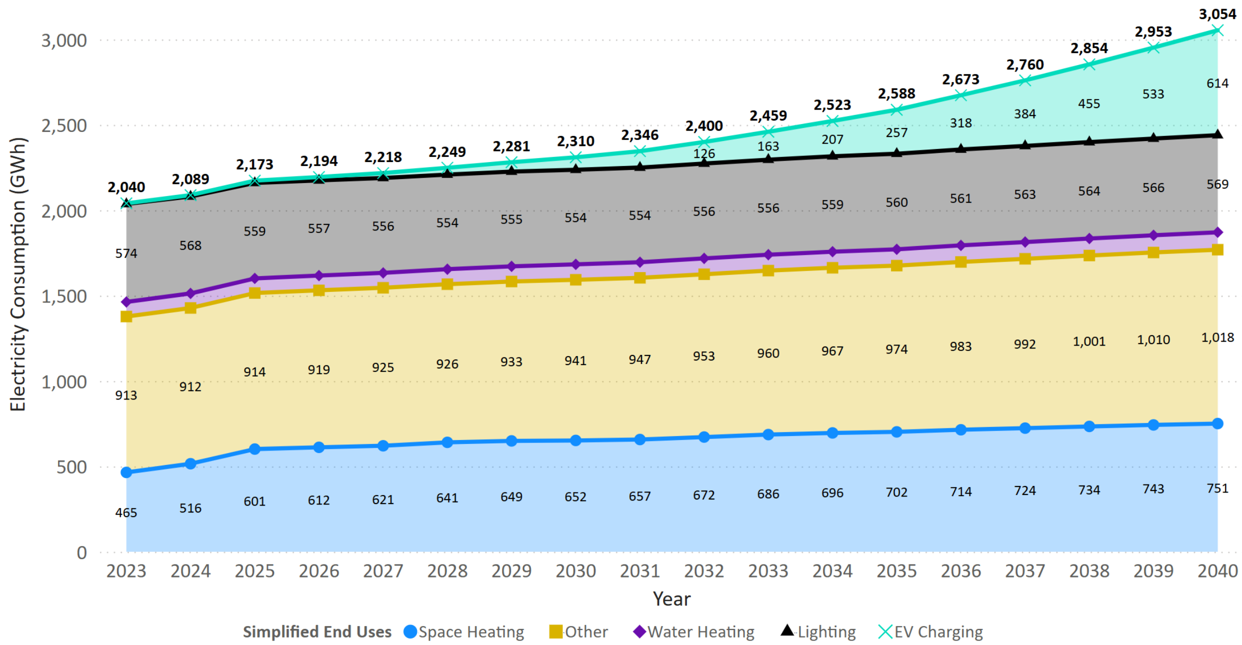
3.3.2 Reference Case Electricity Consumption and Peak Demand

This section profiles the reference case forecast electricity consumption and peak demand for the commercial sector. It begins with commentary on high-level trends, then shows how consumption is forecast to change by segment, end use, and in new versus existing buildings. It ends with a summary of peak demand results.

Commercial Reference Case Consumption Trends

Exhibit 40 shows reference case electricity consumption for the commercial sector. The contributions of space heating, water heating, lighting, and unmanaged EV charging to total consumption (represented by numerical values in bold font) are shown explicitly. The contributions of all other end uses are grouped in "Other" to enhance readability.

Exhibit 40: Reference Case Commercial Consumption Forecast (GWh)



Consumption is expected to increase by 1,014 GWh (50%) over the forecast period. 611 GWh of this increase can be attributed to the adoption of 22,221 EVs in the intermediate scenario. EV charging in the commercial sector includes public and private charging for personal vehicles (all charging that is not done at home) and depot charging for fleet vehicles. The rest of the increase (404 GWh) is explained by the following trends:

- **Space heating electrification**: The number of customer accounts with electric heating are expected to increase while those without electric heating are forecast to decrease.[48] This trend

[48] Customer accounts with electric heating use electricity as their main heating source, accounting for at least 50% of their heating, while customer accounts without electric heating use less than 50% electricity for heating.

reflects a shift towards electric space heating resulting in an overall increase in electricity consumption.[49]

- **An increase in electric energy use intensity in both new and existing buildings**: New buildings are assumed to have more efficient equipment, particularly for lighting and space heating, which leads to reductions in electricity use. However, new buildings are also assumed to have higher penetration of electric space and water heating equipment. This leads to a net increase in electricity use. Over the forecast period, existing buildings also experience a transition towards electric space and water heating, which replace fossil-fired equipment when it reaches end of life.
- **An increase in commercial customer accounts and floor space:** However, at just 6% over the forecast period (excluding street lighting customer accounts), this isn't as significant of a driver as the increased electricity use intensity.

[49] Memorial University of Newfoundland and Labrador's conversion to electric heat is one of the major factors driving the increase in space heating consumption.

Consumption by Segment

Exhibit 41 shows the forecast increase in electricity consumption by segment for the commercial sector. The largest increase in consumption is forecast in the EV charging segments (31,506% and 7,043% for fleet and personal EV charging, respectively) followed by Universities and Colleges (125%) and Restaurants (24%).

Exhibit 41: 2023 vs 2040 Commercial Consumption Forecast (GWh) by Parent Segment

Parent Segment	2023 Consumption (GWh)	2040 Consumption (GWh)	Change in Consumption (GWh)	Change in Consumption (%)
Fleet Depot Charging	0.4	435	434	31,506%
Personal EV Charging[50]	3.5	179	177	7,043%
University and Colleges	98	221	123	125%
Restaurants	94	117	23	24%
Office	438	541	103	23%
Schools	166	193	27	17%
Accommodation	104	120	16	15%
Warehouse	135	154	19	15%
Non-Food Retail	218	248	30	14%
Food Retail	148	166	18	12%
Other Buildings	220	246	26	12%
Healthcare	195	212	17	9%
Non-Building	149	157	8	5%
Arena	47	47	0	1%
Street Lighting	24	18	-7	-30%
Total	**2,040**	**3,054**	**1,014**	**50%**

[50] Commercial sector personal EV charging includes private and public charging away from home. In 2040, personal EV charging away from home represents 32% of total personal LDV electricity consumption in the intermediate scenario, or 179 GWh of 565 GWh.

Consumption by End Use

Exhibit 42 shows the expected increase in electricity consumption by end use, highlighting the space heating electrification trend discussed earlier:

- Other than EV charging, space heating is expected to undergo the largest (62%) increase in electricity consumption. The 286 GWh increase between 2023 and 2040 is driven by the switch to electric heating from fossil fuels.
- The EV charging end uses increase the most over the reference case forecast (19,500% for BEV charging and 6,400% for PHEV charging). The forecast changes in consumption in BEV charging and PHEV charging from 2023 to 2040 are 585 GWh and 26 GWh, respectively.
- Apart from street lighting, the smallest (2 GWh) change in electricity consumption occurs in the indoor and outdoor lighting end uses. Despite expected efficiency gains from conversions to LED lighting, the increase in commercial floor space causes a marginal increase in consumption for these end uses over the forecast period.

Exhibit 42: 2023 vs 2040 Commercial Consumption Forecast (GWh) by Parent End Use

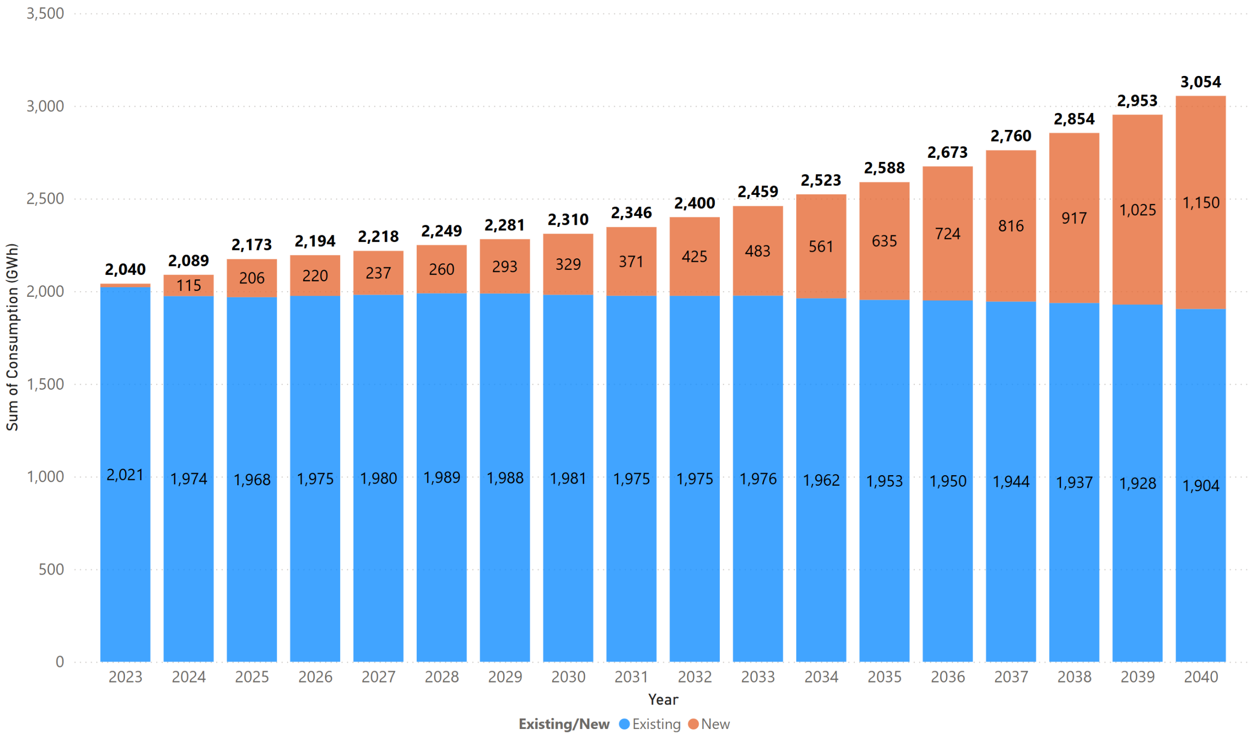
Parent End Use	2023 Consumption (GWh)	2040 Consumption (GWh)	Change in Consumption (GWh)	Change in Consumption
BEV Charging	3.5	588	585	19,500%
PHEV Charging	0.4	26	25.6	6,400%
Space Heating	465	751[51]	286	62%
Water Heating	85	102	17	20%
Food Service	70	80	10	14%
Plug Loads	172	195	23	13%
Space Cooling	40	45	5	13%
HVAC Fans & Pumps	290	328	38	13%
Refrigeration	174	194	20	11%
Miscellaneous Equipment	167	176	9	5%
Indoor Lighting	508	510	2	0.4%
Outdoor Lighting	41	41	0	0%
Street Lighting	24	18	-7	-28%
Total	**2,040**	**3,054**	**1,014**	**50%**

[51] Space heating electrification at Memorial University of Newfoundland customer accounts for 105 GWh of the increase in commercial sector space heating consumption.

Reference Case Electricity Consumption: Existing versus New Buildings

This section compares the consumption in existing versus new commercial buildings across the reference case forecast. The construction of new buildings is estimated by extrapolating customer forecasts provided by NP and drawing insights from the electricity consumption growth forecasts by rate class. Although no demolition rate is applied, a decrease in customer accounts for a given year implies the removal of existing buildings from the system. This leads to a decreasing stock of existing building over the reference case forecast period. Consequently, electricity consumption from existing buildings decreases, while consumption from new buildings, as well as the introduction and growth of EV charging, drives the 1,014 GWh overall increase in electricity consumption, as shown in Exhibit 43.

Exhibit 43: Existing vs New Building Commercial Consumption Forecast (GWh)



Reference Case Peak Demand

Exhibit 44 shows the reference case peak demand forecast for the commercial sector. Commercial sector winter peak demand is forecast to increase by 257 MW (62%) between 2023 and 2040 under unmanaged EV charging. The factors driving this increase are explained on the next page.

Exhibit 44: Commercial Sector Reference Case Peak Demand (MW)

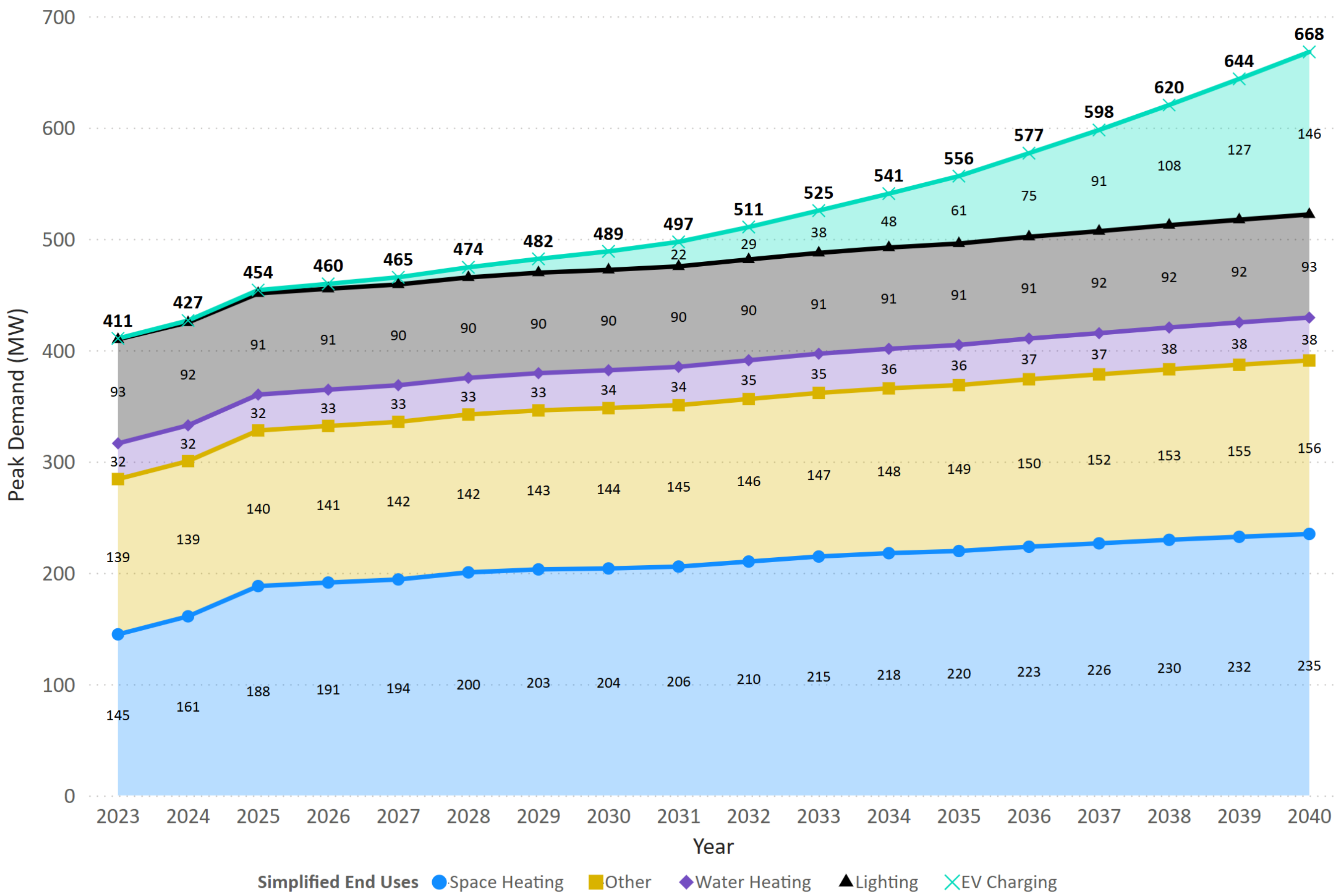


Exhibit 45 shows that commercial sector peak demand increases by 257 MW (62%) between 2023 and 2040, driven by the following factors:

- The adoption of 22,221 fleet EVs in the intermediate scenario. The peak demand from BEV charging and PHEV charging increase by 140 MW and 4.9 MW, respectively.
- The 90 MW increase in space heating peak demand MW caused by the switch to electric heating from fossil fuel heating.

Exhibit 45: Commercial Sector Reference Case Peak Demand by End Use (MW)

End Use	2023 Winter Peak Demand (MW)	2040 Winter Peak Demand (MW)	Change in Peak Demand (MW)	Change in Peak Demand (%)
BEV Charging	1	141	140	14,000%
PHEV Charging	0.1	5	4.9	4,900%
Space Heating	145	235	90	62%
Water Heating	32	38	6	19%
Food Service	26	30	4	15%
Refrigeration	20	23	3	15%
HVAC Fans & Pumps	42	47	5	12%
Plug Loads	26	29	3	12%
Miscellaneous Equipment	25	27	2	8%
Indoor Lighting	84	85	0.4	1%
Outdoor Lighting	6	6	0	0%
Street Lighting	4	2	-2	-50%
Space Cooling	0	0	0	N/A
Total	**411**	**668**	**257**	**62%**

3.4 Industrial Sector Base Year and Reference Case

This section presents industrial sector results for the base year (2023) and reference case (2024-2040), excluding any self-generation. The industrial sector includes NLH's six large industrial customers and both Utilities' large customers in the general service rate class.

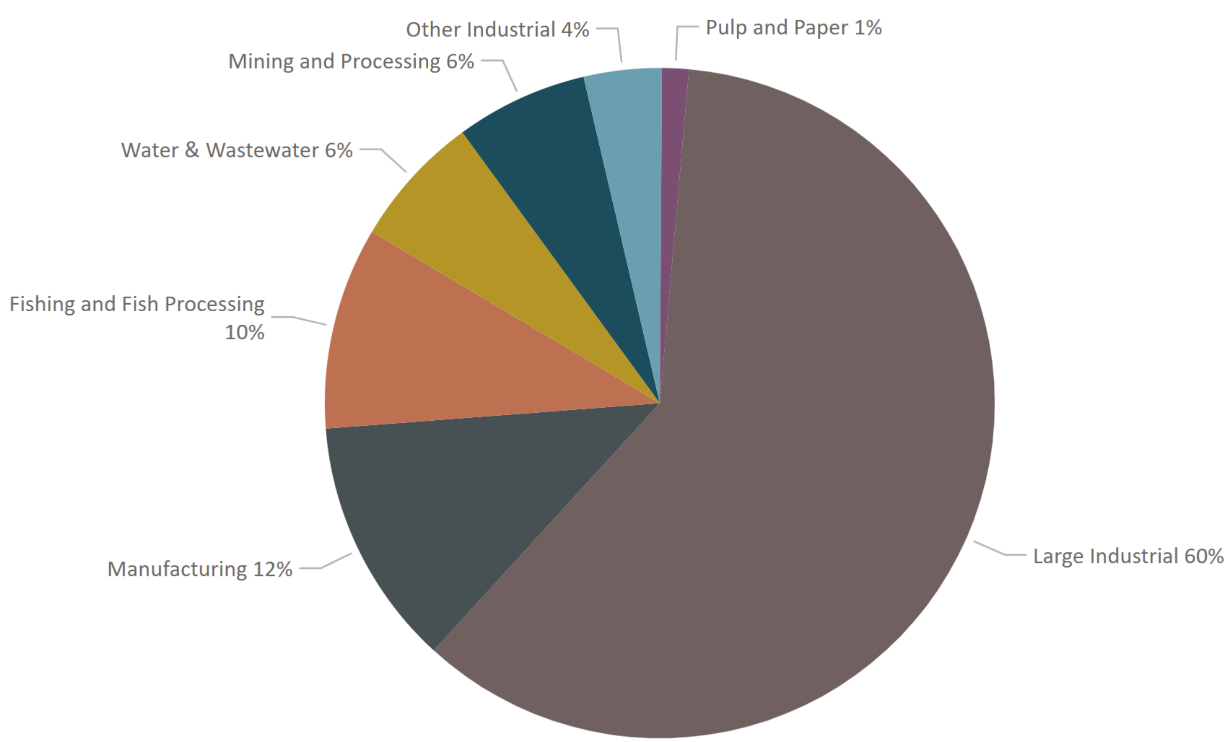
3.4.1 Base Year Electricity Consumption and Peak Demand

This section profiles the base year electricity consumption, customer accounts breakdown, and peak demand for the industrial sector.

Consumption by Segment, Customer Accounts, and End Use

Base year consumption in the industrial sector is 1,023 GWh. Exhibit 46 shows that the large industrial segment, which includes only NLH's six large industrial customers, consumes most (618 GWh, 60%) of the sector's electricity. Consumption in the industrial sector is not driven by the distribution of customer accounts. The water and wastewater segment represents 33% of industrial sector customer accounts (see Exhibit 47), for example, but only 6% of base year consumption.

Exhibit 46: Base Year Industrial Consumption by Parent Segment



There are 3,828 base year customer accounts in the industrial sector. These customer accounts are presented by segment in Exhibit 47. As shown, the largest number of customer accounts is in the water and wastewater (32.9%), manufacturing (29.0%) and other industrial (16.8%) segments.

Exhibit 47: Base Year Industrial Customer Accounts by Parent Segment

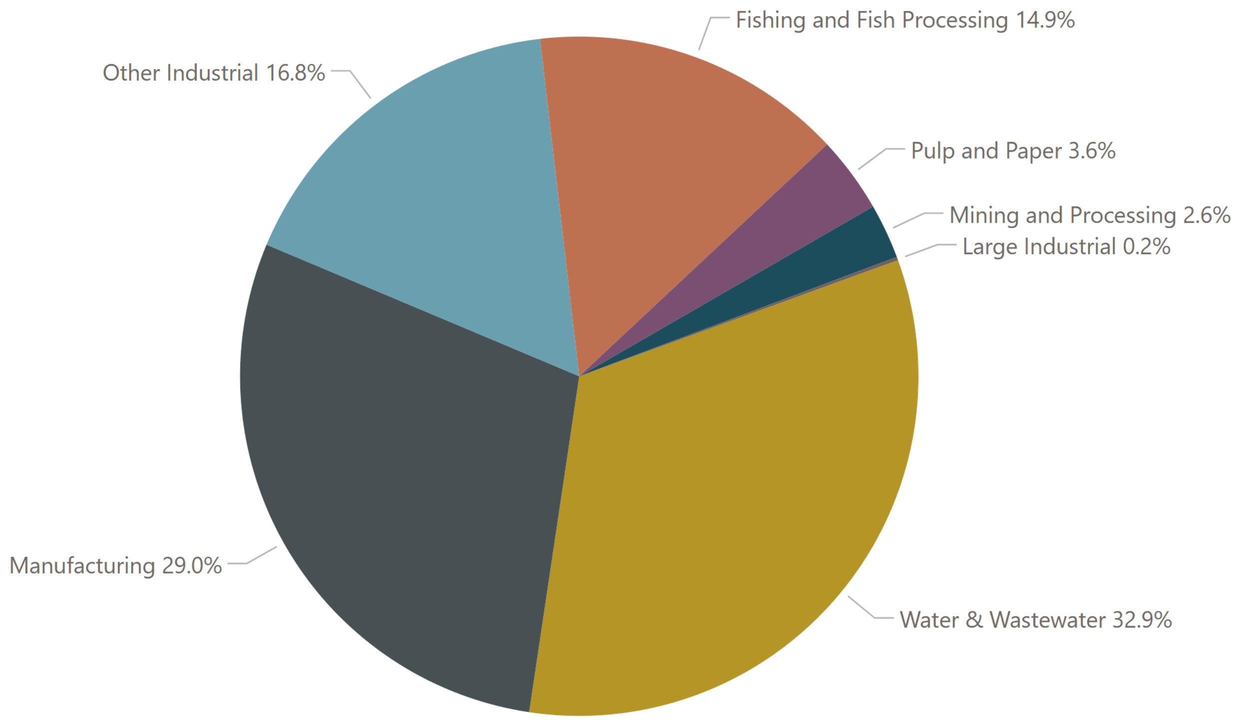
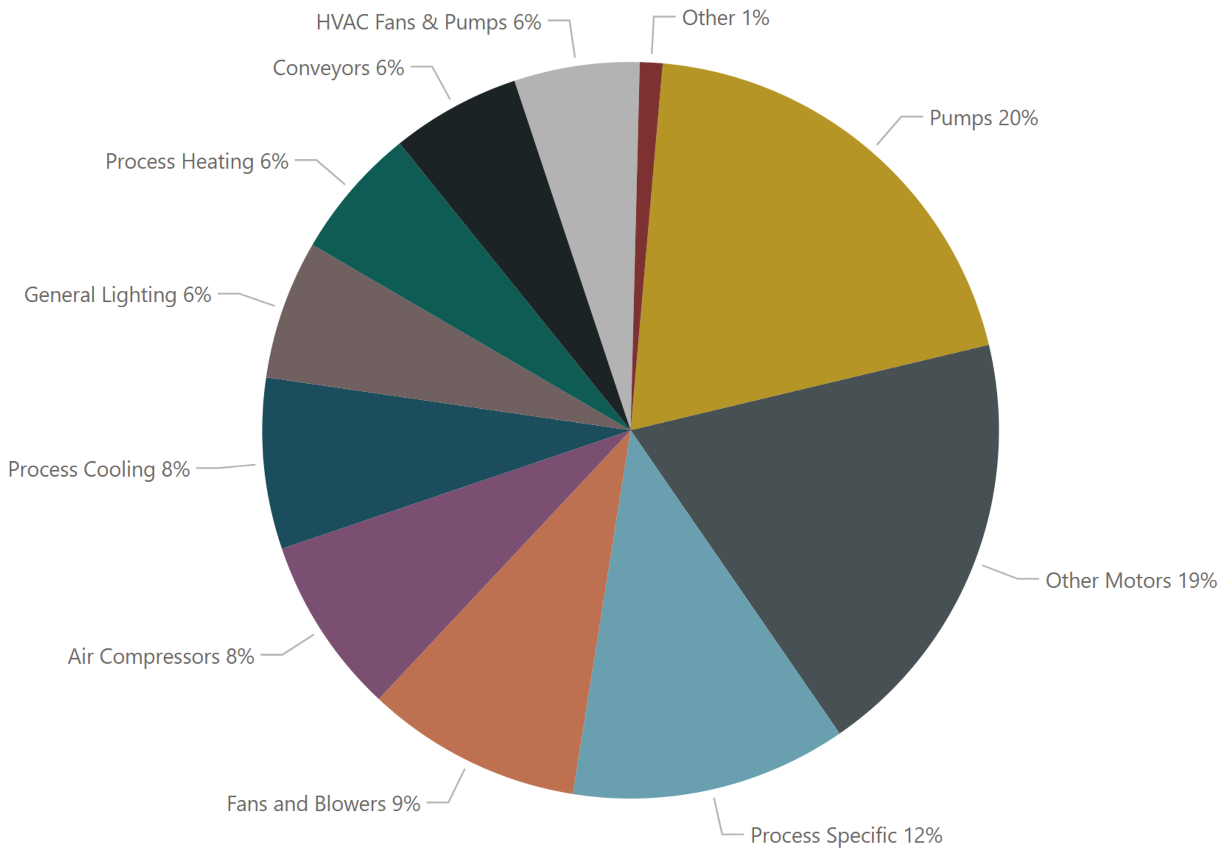


Exhibit 48 shows industrial sector base year consumption by end use. Pumps use the most electricity (203 GWh, 20%), closely followed by other motors (196 GWh, 19%) and process specific end uses (124 GWh, 12%).

Exhibit 48: Base Year Industrial Consumption by End Use



Consumption per Customer Account

Dividing consumption by the number of customer accounts gives the average electricity consumption per customer account. Exhibit 49 shows total base year consumption, customer accounts, and average electricity consumption per customer account for the industrial sector. Highlights from this exhibit include:

- The large industrial segment consumes the most electricity per customer account on average (102,968 MWh/customer account), followed by mining and processing (652 MWh/customer account) and fishing and fish processing (175 MWh/customer account).
- The water and wastewater end use consumes the least electricity per customer account on average (52 MWh/account).

Exhibit 49: Base Year Industrial Energy Intensity by Parent Segment

Segment	2023 Consumption (MWh)	2023 Customer Accounts	2023 Average Consumption per Customer Account (MWh/Customer Account)
Large Industrial	617,810	6	102,968
Mining and Processing	65,183	100	652
Fishing and Fish Processing	99,740	570	175
Manufacturing	122,727	1,109	111
Pulp and Paper	13,177	139	95
Other Industrial	38,460	644	60
Water & Wastewater	65,744	1,260	52
Total	**1,022,841**	**3,828**	**267**

Base Year Peak Demand

Exhibit 50 shows the peak demand by end use for the industrial sector in the base year. Observations include:

- Pumps is the largest industrial component of peak demand. As shown in the previous section, pumps represent 20% of base year electricity consumption.
- Process specific and other motors are the second and third largest industrial components of peak demand.

Exhibit 50: Base Year Industrial Peak Demand (MW)

End Use	2023 Winter Peak Demand (MW)	2023 % of Winter Peak Demand
Pumps	25	20%
Process Specific	20	16%
Other Motors	19	16%
HVAC Fans & Pumps	10	8%
Fans and Blowers	9	7%
Process Heating	9	7%
Air Compressors	8	7%
General Lighting	7	6%
Process Cooling	7	6%
Conveyors	6	5%
Other	2	2%
Hydrogen	0	0%
Total	**122**	**100%**

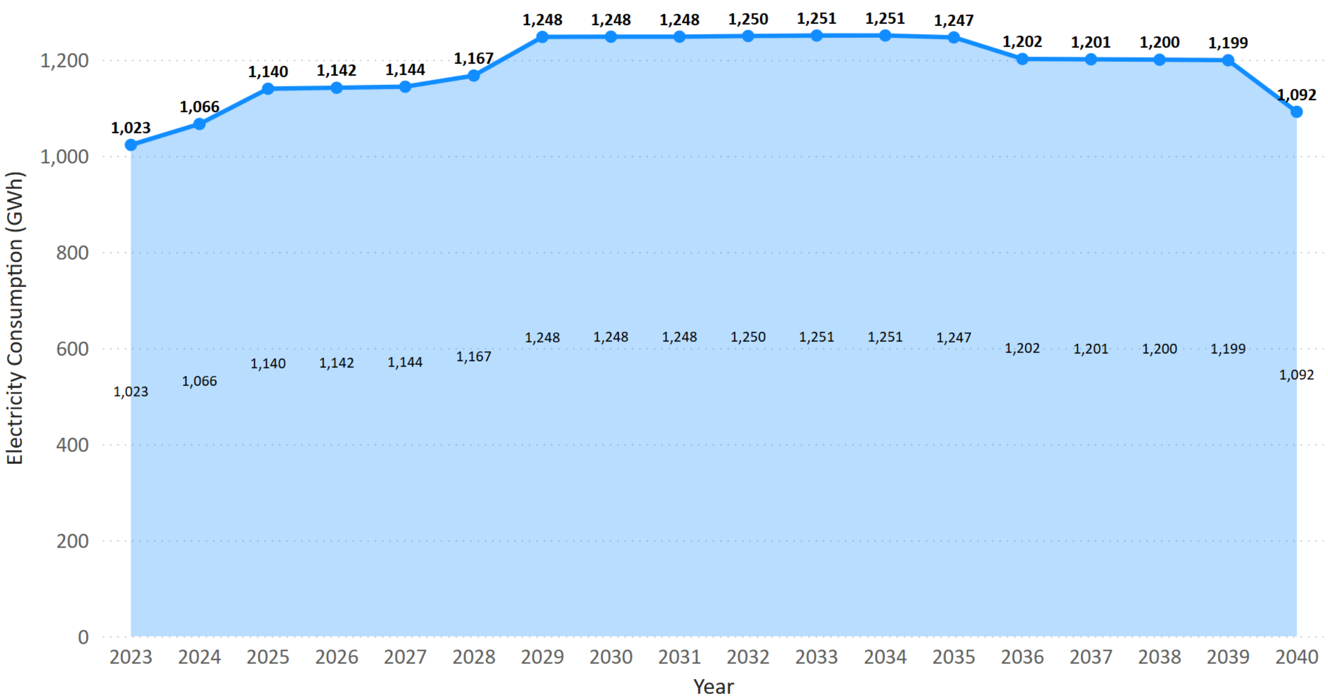
3.4.2 Reference Case Electricity Consumption and Peak Demand

This section profiles the reference case forecast (2024 – 2040) electricity consumption and peak demand for the industrial sector. It begins with commentary on high-level trends, then shows how consumption is forecast to change by segment, end use, and in new versus existing buildings or production. It ends with a summary of peak demand results.

Industrial Reference Case Consumption Trends

Exhibit 51 shows that industrial sector electricity consumption is expected to increase by 69 GWh (6%) between 2023 and 2040. Exhibit 51 also shows that industrial sector consumption is forecast to increase initially, then remain steady between 2029 and 2035 before a decline starting in 2036.

Exhibit 51: Reference Case Industrial Consumption Forecast (GWh)



The reference case trends are due to the following factors:

- **Changes in large industrial production**: The initial increase and subsequent decline of industrial electricity consumption is primarily due to forecast changes in production for the large industrial customers, consistent with NLH's forecast. As shown in section 3.4.1, large industrial customers account for 60% of industrial sector consumption.
- **An increase in industrial customer accounts**: The number of small and medium industrial customers increases by approximately 3% during the forecast period.

Consumption by Segment

Exhibit 52 shows the increase in electricity consumption by segment over the forecast period. The pulp and paper, manufacturing and other industrial segments see largest percent increases in consumption (15%, 11%, and 11%, respectively). These increases are driven by an increase in electric space heating consumption in those segments over the reference case, consistent with NLH's forecast.

Exhibit 52: 2023 vs 2040 Industrial Consumption Forecast (GWh) by Parent Segment

Parent Segment	2023 Consumption (GWh)	2040 Consumption (GWh)	Change in Consumption (GWh)	Change in Consumption (%)
Pulp and Paper	13	15	2	15%
Manufacturing	123	137	14	11%
Other Industrial	38	42	4	11%
Large Industrial	618	678	60	10%
Water & Wastewater	66	65	-1	-2%
Fishing and Fish Processing	100	96	-4	-4%
Mining and Processing	65	59	-6	-9%
Total	**1,023**	**1,092**	**69**	**7%**

Consumption by End Use

Exhibit 53 shows the increase in electricity consumption by end use over the forecast period. Excluding hydrogen production, the largest percentage increases occur in the general lighting, HVAC fans and pumps, and other motors end uses (5%, 4% and 4%, respectively). The increase in HVAC fans and pumps consumption is consistent with the increase in electric space heating consumption forecast by NLH in the pulp and paper, manufacturing, and other industrial segments, as noted previously.

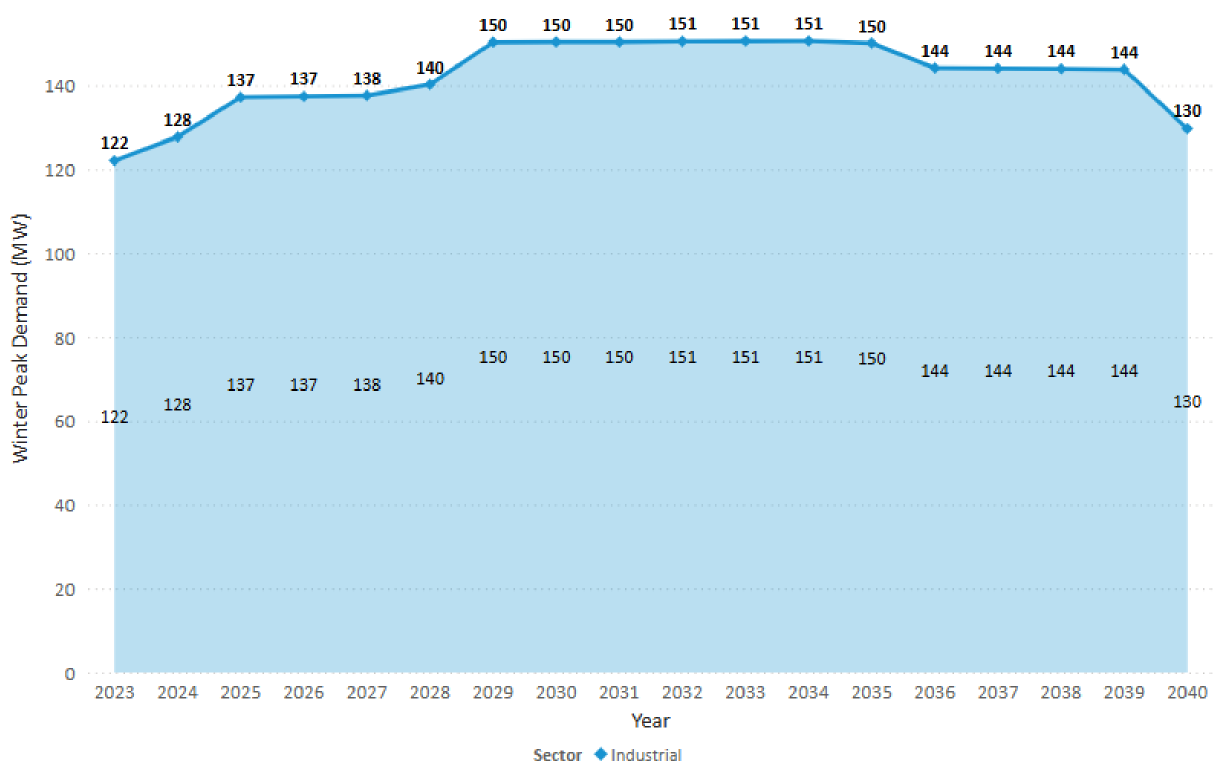
Exhibit 53: 2023 vs 2040 Industrial Consumption Forecast (GWh) by Parent End Use

Parent End Use	2023 Consumption (GWh)	2040 Consumption (GWh)	Change in Consumption (GWh)	Change in Consumption (%)
Hydrogen Production	0	49	49	--
General Lighting	62	65	3	5%
HVAC Fans & Pumps	56	58	2	4%
Other Motors	196	203	7	4%
Fans and Blowers	97	99	2	2%
Pumps	203	207	4	2%
Conveyors	58	59	1	2%
Air Compressors	80	81	1	1%
Process Specific	124	125	1	1%
Other	10	10	0	0%
Process Heating	60	60	0	0%
Process Cooling	77	76	-1	-1%
Total	**1,023**	**1,092**	**69**	**7%**

Reference Case Peak Demand

Exhibit 54 shows the reference case peak demand forecast for the industrial sector.

Exhibit 54: Industrial Sector Reference Case Peak Demand (MW)



Winter peak demand is forecast to increase by 8 MW (7%) between 2023 and 2040. Peak demand is greatest from 2032 to 2034 (151 MW), which represents an increase of 29 MW (24%) compared to 2023 (122 MW). The variations in peak demand correspond to the variations in total electricity consumption because peak demand scales proportionally with consumption. As noted in the observations on Exhibit 51, the increases and decreases in peak demand correspond to NLH's forecast for changes in industrial sector production.

3.5 Transportation Base Year and Forecast Scenarios

This section presents the transportation sector results and key findings, including:

- Base year (2023) stock, electricity consumption and peak demand,
- Forecast sales share, vehicle stock, electricity consumption, and peak demand for the intermediate scenario (2024-2040), and
- A comparison of forecast vehicle stock, electricity consumption and peak demand for the natural adoption, intermediate, and government targets scenarios (2024-2040).

The forecast EV scenarios are defined in the callout that follows.[52,53]

Forecast EV Scenarios

EVs are an emerging technology and there is uncertainty on future adoption, which is expected to be influenced by government policy among other factors. Newfoundland is still in the early stages of the transition from internal combustion engine (ICE) vehicles to EVs. As such, there is limited Newfoundland-specific data on EV registrations and historical trends. For these reasons, the Study Team modelled three forecast EV scenarios to provide a range of possible futures: natural adoption, intermediate, and government targets. The forecast scenarios are defined as follows:

*1. The **Natural Adoption Scenario** estimates EV adoption based on current incentives. MHDV and bus adoption in this scenario aligns with global forecasts for all countries, recognizing that Newfoundland will lag adoption in leading jurisdictions.*

*2. The **Intermediate Scenario** includes EV uptake beyond the natural adoption scenario, consistent with additional market interventions like vehicle rebates and accelerated build-out of charging infrastructure for LDV, and/or more favorable EV capital cost declines for MDV and HDV.*

*3. In the **Government Targets Scenario**, Federal Government targets for sales shares of LDVs and MHDVs being ZEVs by 2030, 2035, and 2040 are met. In the natural adoption and intermediate scenarios, the Federal Government targets are not met.*

The Utilities could monitor several indicators during the forecast period to determine which scenario may be unfolding. These indicators include how customer survey results on EV purchase intentions evolve over time; the extent to which vehicle manufacturers try to achieve government targets evenly in each province versus focused on specific provinces; whether the federal forward regulatory agenda retains government targets after federal elections; and whether studies expect EV price/range parity sooner or later in the analysis horizon. No shift in a single indicator determines a scenario, but collectively, trends in the indicators can reveal how the relative likelihood of each scenario changes over time.

[52] "The 2030 Emissions Reduction Plan: Canada's Next Steps for Clean Air and a Strong Economy," Government of Canada, Available: https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/emissions-reduction-2030/sector-overview.html#sector6 (Accessed Feb. 24, 2025).

As noted in section 3.1, the Study Team integrated the intermediate EV scenario with the residential and commercial sectors because it is the middle scenario compared to the natural adoption and government targets scenarios, which bookend the EV forecast analysis. All the results presented in this section reflect unmanaged EV charging.[54]

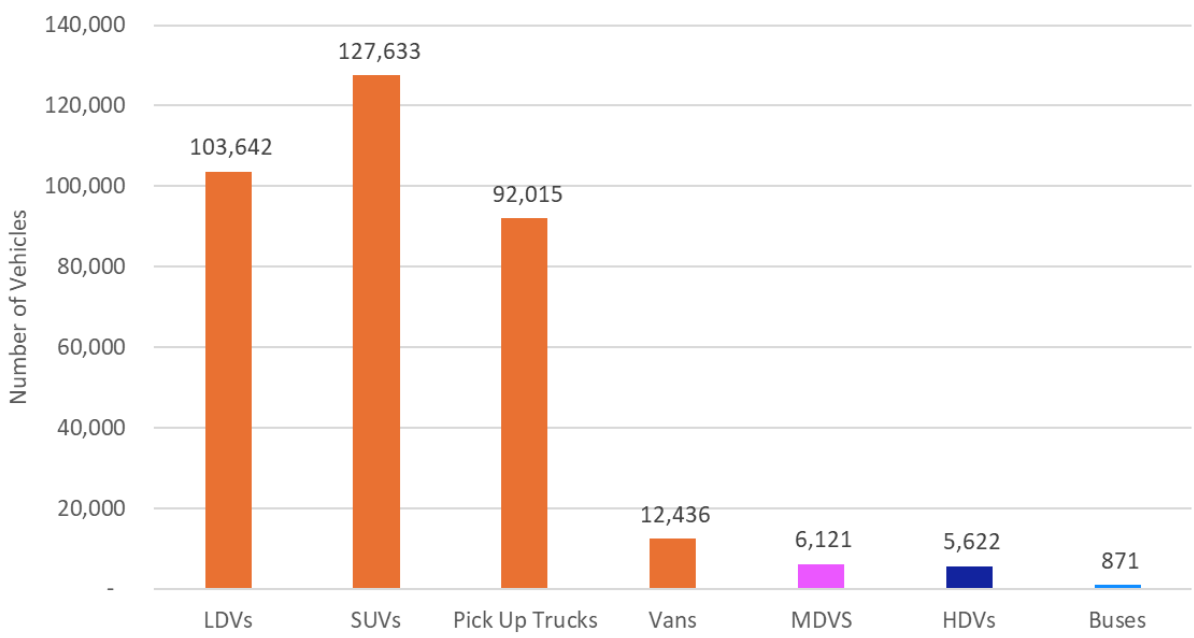
3.5.1 Base Year Stock, Electricity Consumption and Peak Demand

This section profiles the base year stock, electricity consumption, and peak demand for the transportation sector.

Base Year Vehicle Stock

The base year IIS vehicle stock includes approximately 350,000 vehicles. Exhibit 55 shows the stock by vehicle type. In the base year, LDVs make up most of the vehicle stock at 96.4%, while MHDVs and buses make up 3.4% and 0.3%, respectively.

Exhibit 55: Base Year Stock by Vehicle Type



[53] Bloomberg New Energy Finance (BNEF) via Road to zero: Research and industry perspectives on zero-emission commercial vehicles – ScienceDirect, Available: https://www.sciencedirect.com/science/article/pii/S2589004223008283 (Accessed Dec. 19, 2024).

[54] The EV forecast analysis was completed in Q1 and Q2 of 2024. Any headlines on EV manufacturer slowdowns from Q3 2024 onwards are not reflected in the forecast

Exhibit 56 shows the base year stock by vehicle powertrain. Observations include:

- In the base year, internal combustion engine (ICE) vehicles represent 99.5% of total vehicles. BEVs and PHEVs make up only 0.4% and 0.1% of total vehicles, respectively.
- Personal and fleet vehicles represent 86% and 14% of total vehicles, respectively.

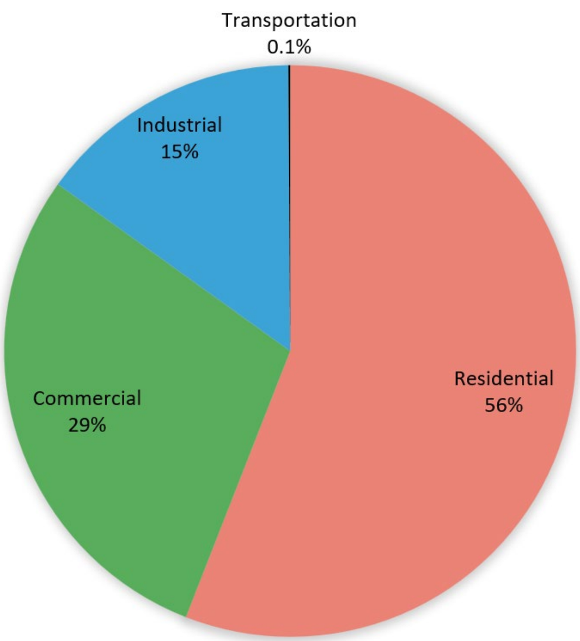
Exhibit 56: Base Year Stock by Powertrain, Ownership Type and Vehicle Type

Powertrain	Total Vehicles	% of Total	% Personal Ownership	% Fleet Ownership
BEV	1,245	0.4%	89%	11%
PHEV	462	0.1%	89%	11%
ICE	346,806	99.5%	86%	14%
Total	**348,513**	**100%**	**86%**	**14%**

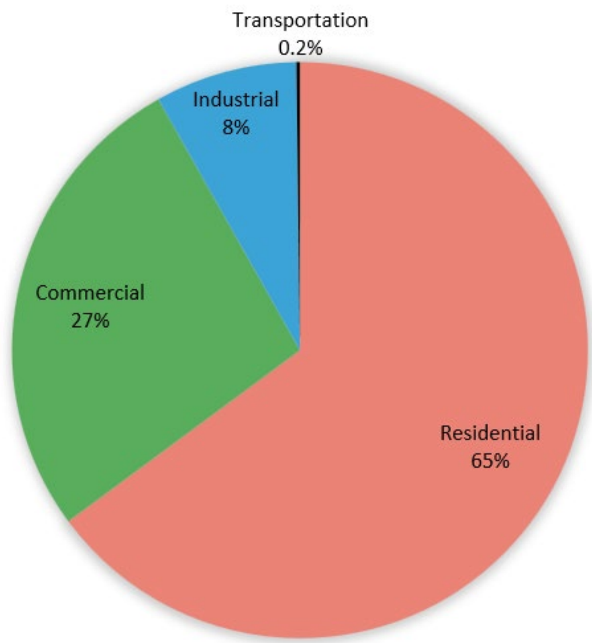
Base Year Electricity Consumption and Peak Demand

Exhibit 57 shows the transportation sector contributions to base year electricity consumption and peak demand. In the base year, the transportation sector represents 0.1% (10 GWh) of total IIS consumption and 0.2% of total IIS peak demand. As shown in the previous section, there are less than 2,000 EVs in Newfoundland in the base year, the majority of which are LDVs with smaller batteries and shorter ranges compared to MHDVs and buses.

Exhibit 57: Base Year Consumption and Peak Demand by Sector



2023 Consumption: 6,984 GWh



2023 Peak Demand: 1,542 MW

3.5.2 Intermediate Scenario Forecast Sales Share, Consumption, and Peak Demand

This section presents the forecast sales share, electricity consumption and peak demand for the intermediate scenario. As explained previously, the intermediate scenario is characterized by EV uptake beyond the natural adoption scenario, consistent with additional market interventions like vehicle rebates and accelerated build-out of charging infrastructure for LDVs.

The Study Team integrated the intermediate EV scenario with the residential and commercial sectors because it is the middle scenario compared to the natural adoption and government targets scenarios, which bookend the EV forecast analysis.

Forecast Sales Share

EV forecasts are often presented as a percentage of annual vehicles sales. This allows for comparison to adoption in other jurisdictions and measurement against targets, like the federal government's mandates for ZEV sales. The rest of this section shows the forecast sales share for LDVs, and MHDVs and buses.

The sales share forecast for BEVs and PHEVs is informed, in part, by the following results from NP's 2023 REUS:

- REUS respondents reported modest interest in adopting a BEV or PHEV in the next two years (2024 and 2025).[55] They cited high costs and lack of charging infrastructure as barriers to adoption.
- REUS respondents reported growing interest in BEVs over the forecast period. In contrast, REUS results suggest that respondents' interest in PHEVs will plateau over the forecast period.

These REUS results suggest the EV market will shift towards BEVs in Newfoundland, as ownership costs decrease and confidence in charging infrastructure increases. These findings align with trends from global studies.[56]

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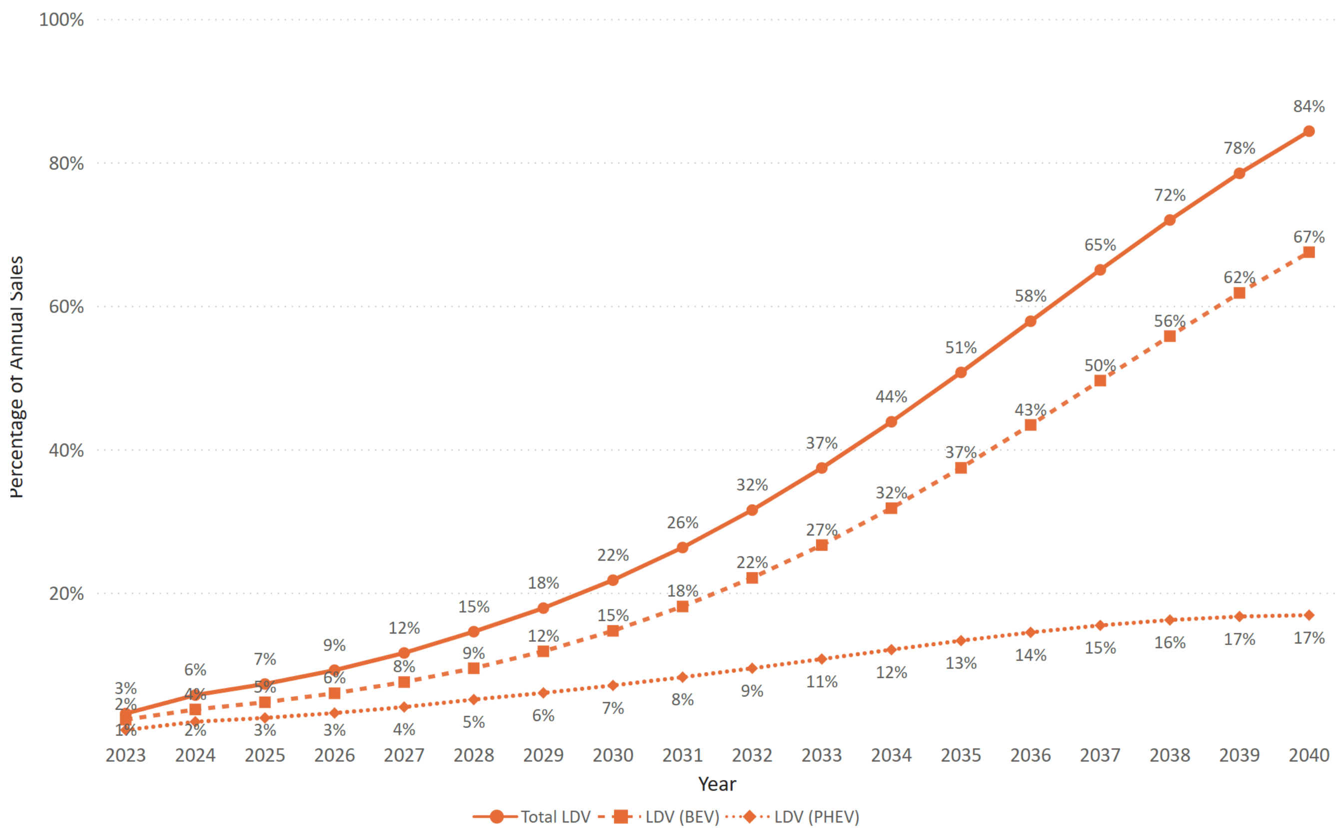
[55] The natural adoption forecast for LDV BEV falls within the range of global forecasts the Study Team compared to.
[56] "Global EV Outlook 2023," IEA, Available: https://www.iea.org/reports/global-ev-outlook-2023 (Accessed Jul. 29, 2024).

Exhibit 58 shows the sales share forecast for LDVs in the intermediate scenario, based on insights from the REUS cited previously, historical EV uptake, and comparisons to jurisdictions ahead of Newfoundland in EV adoption. Observations include:

- In the base year, BEVs and PHEVs represent 2% and 1% of sales, respectively.
- The total share of BEVs and PHEVs is forecast to reach 84% of LDV sales by 2035, which falls short of the government targets scenario goal of 100%.[57] Of the 84% sales share, BEVs are forecast to reach 67% of sales, while PHEVs are forecast to reach 17%.

Exhibit 58: Intermediate Scenario Forecast Sales Share of LDVs (%)



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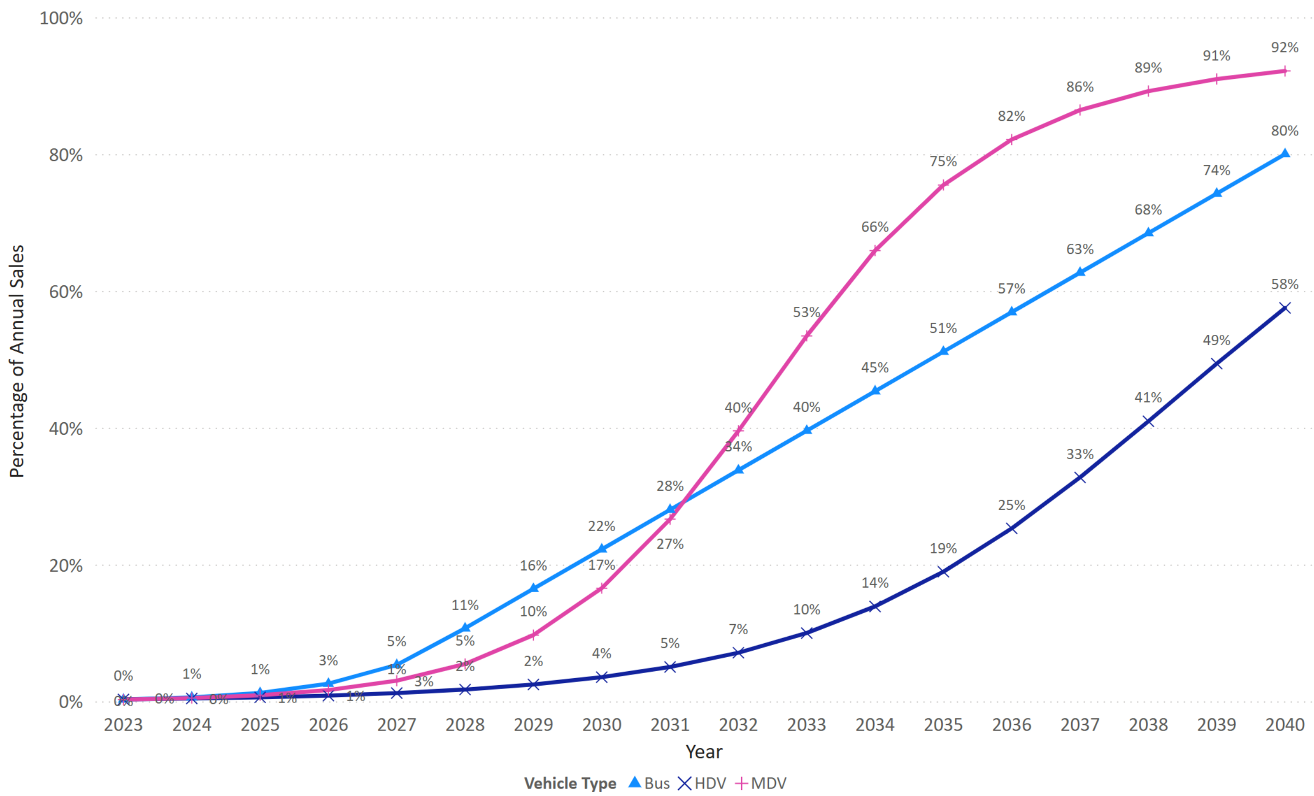
[57] See the callout in section 3.5 for definitions of the forecast EV scenarios.

Exhibit 59 shows the forecast sales share of electric MHDVs and buses for the intermediate scenario. Since the maturity in electric vehicle technology for MHDVs (and buses to a lesser extent) lags behind LDVs, the expected sales share for these three vehicle types is very low (all less than 1%) in the base year and the first few years of the forecast.

However, because MHDVs and buses will typically be operated in fleets, the Total Cost of Ownership (TCO) is a good predictor of long-run market share for new technologies. Additionally, fleet vehicles will largely rely on their own depot charging rather than public infrastructure, further emphasizing that TCO will drive vehicle adoption.

Exhibit 59: Intermediate Scenario Forecast Sales Share of MHDVs and Buses (%)



The sales shares for electric MDVs and HDVs are forecast to increase substantially starting in 2030 and 2035, respectively. This timing aligns with their expected TCO break-even point with medium and heavy-duty ICE vehicles.[58] After becoming economically competitive, the sales shares of electric MDVs and HDVs are forecast to reach 92% and 58% by 2040, respectively.

[58] "Decarbonizing Medium- & Heavy-Duty On-Road Vehicles: Zero-Emission Vehicles Cost Analysis," National Renewable Energy Laboratory, Available: https://www.nrel.gov/docs/fy22osti/82081.pdf (Accessed Jul. 29, 2024).

Battery electric buses are a more mature technology compared to electric MHDVs, highlighted by the earliest initial increase in annual sales share. However, uptake is forecast to increase at a slower, linear rate due to:

- Long lead times for electric buses, specifically for transit agencies, and
- No immediate plans to adopt a significant number of fully electric buses in Newfoundland.

By 2040, the sales share of electric buses is forecast to reach 80%, aligning with global forecasts.[59]

[59] Bloomberg New Energy Finance (BNEF) via Road to zero: Research and industry perspectives on zero-emission commercial vehicles – ScienceDirect, Available: https://www.sciencedirect.com/science/article/pii/S2589004223008283 (Accessed Dec 19, 2024).

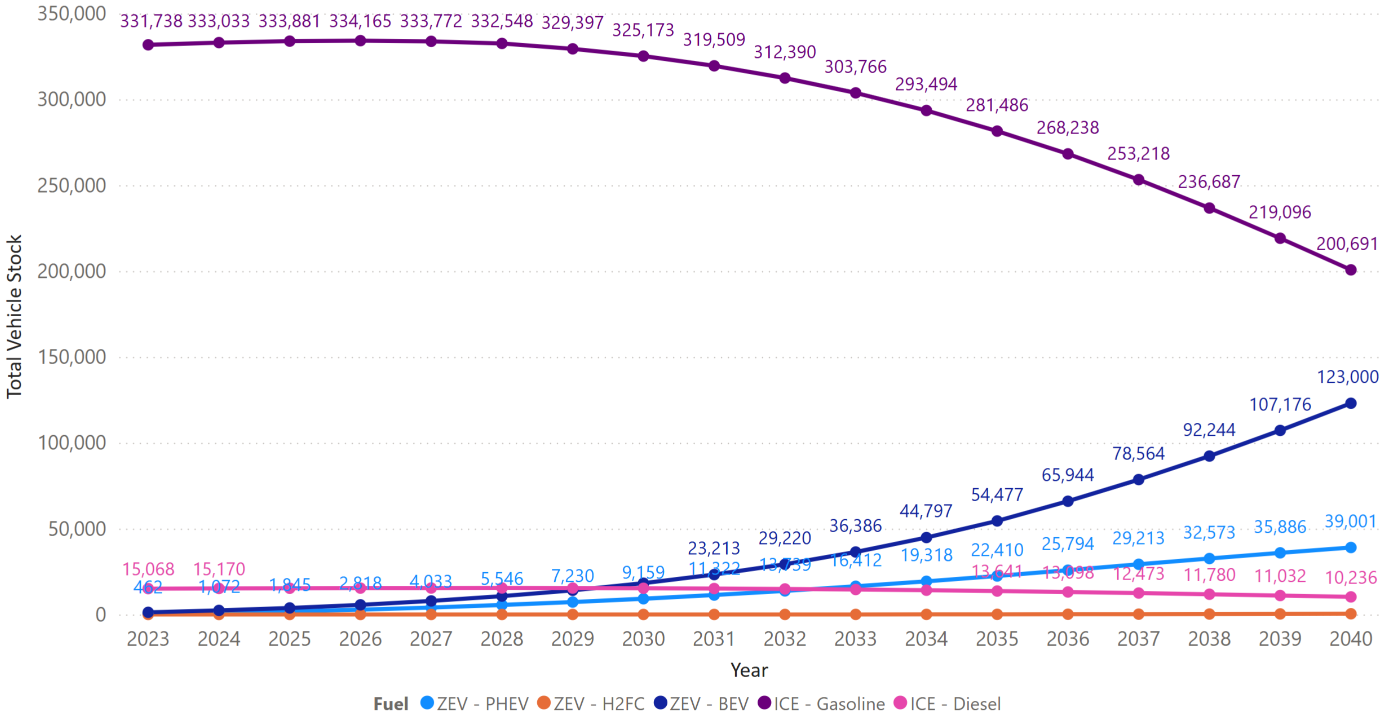
Forecast Vehicle Stock

As annual vehicle sales increase, the EV stock also increases as internal combustion engine vehicles (ICEVs) naturally reach end of life and are replaced by EVs. This results in EVs comprising an increasing percentage of the total vehicle stock in Newfoundland throughout the forecast, culminating in a 43% of the total vehicle stock share by 2040 (33% for BEVs and 10% for PHEVs).

Exhibit 60 shows the forecast vehicle stock by fuel for the intermediate scenario, including all vehicle types. Observations include:

- The total EV stock is forecast to be 123,000 BEVs and 39,001 PHEVs (162,001 total EVs) by 2040.
- The EV stock is forecast to be 18,217 BEVs and 9,159 PHEVs (27,376 total EVs) by 2030. This signifies that that majority of EV uptake occurs in the 2030s.
- ICE vehicles are forecast to decrease from almost 350,000 vehicles in 2023 to approximately 210,000 vehicles by 2040. Their share of the market is reduced from virtually 100% to 57%.

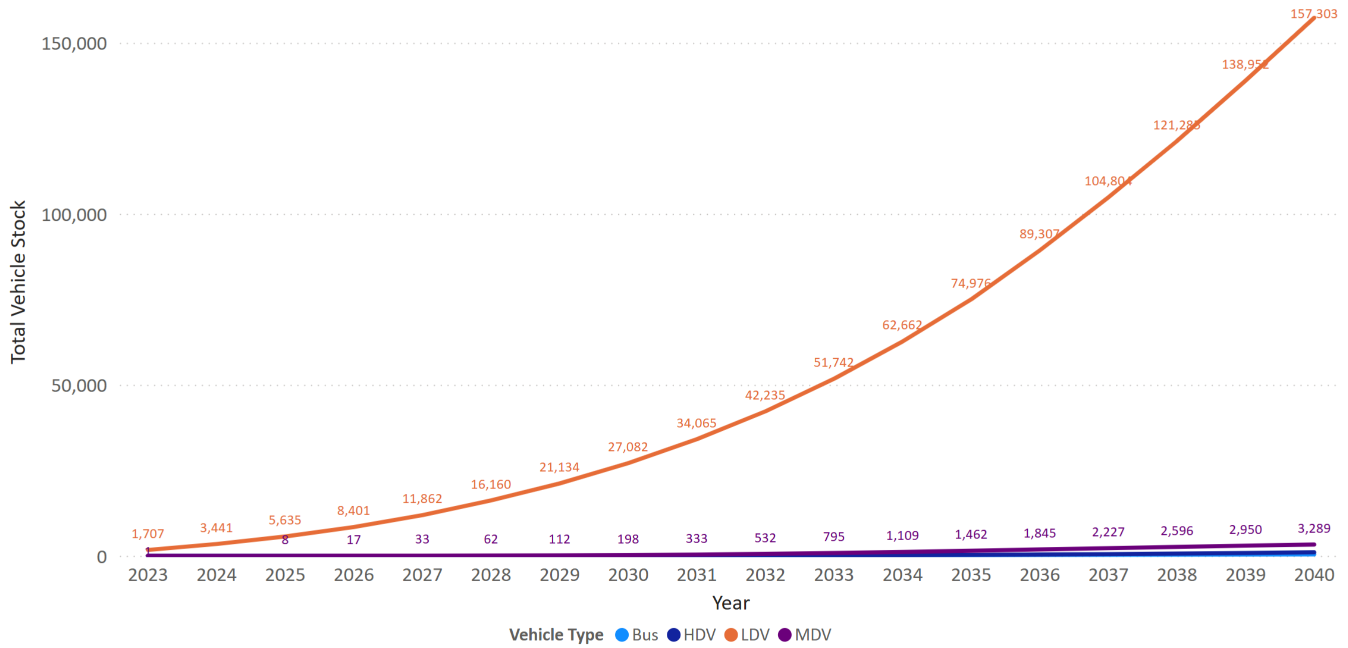
Exhibit 60: Intermediate Scenario Forecast Total Vehicle Stock by Fuel



Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ICE - Diesel	15,068	15,170	15,262	15,341	15,391	15,420	15,364	15,271	15,100	14,853	14,524	14,126	13,641	13,098	12,473	11,780	11,032	10,236
ICE - Gasoline	331,738	333,033	333,881	334,165	333,772	332,548	329,397	325,173	319,509	312,390	303,766	293,494	281,486	268,238	253,218	236,687	219,096	200,691
ZEV - BEV	1,247	2,376	3,805	5,613	7,885	10,717	14,081	18,217	23,213	29,220	36,386	44,797	54,477	65,944	78,564	92,244	107,176	123,000
ZEV - H2FC	0	0	0	1	2	4	6	10	16	27	43	62	94	136	190	253	325	407
ZEV - PHEV	462	1,072	1,845	2,818	4,033	5,546	7,230	9,159	11,322	13,739	16,412	19,318	22,410	25,794	29,213	32,573	35,886	39,001
Total	**348,515**	**351,651**	**354,793**	**357,938**	**361,083**	**364,235**	**366,078**	**367,830**	**369,160**	**370,229**	**371,131**	**371,797**	**372,108**	**373,210**	**373,658**	**373,537**	**373,515**	**373,335**

As highlighted in Exhibit 61, the vast majority of EVs in Newfoundland are expected to be LDVs. By 2040, 157,303 electric LDVs are forecast to be on the road. In contrast, MDVs, HDVs and buses are forecast to reach 3,289, 1,015 and 394 electric vehicles, respectively.

Exhibit 61: Intermediate Scenario Forecast Electric Vehicle Stock by Vehicle Type

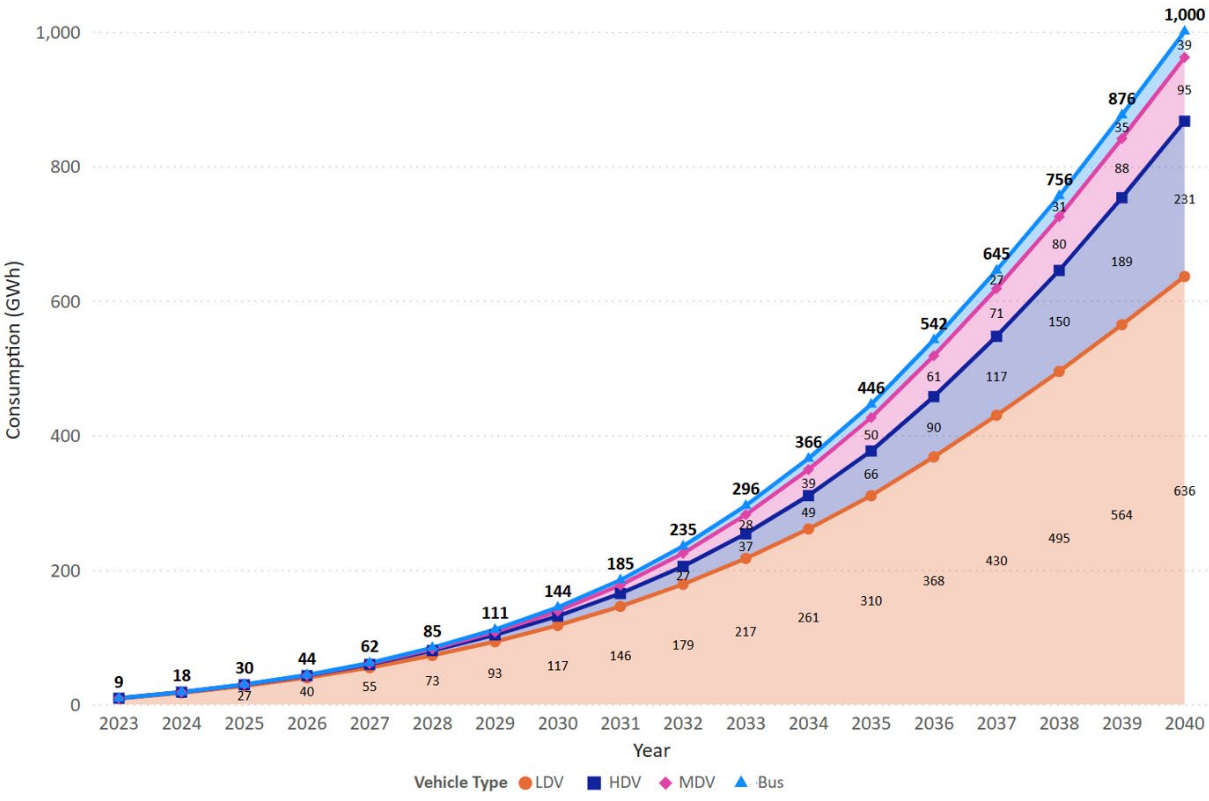


Vehicle Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Bus	0	0	1	3	7	16	29	45	65	91	119	149	183	222	261	303	348	394
HDV	1	3	6	10	16	25	36	51	72	101	142	195	266	364	485	633	812	1,015
LDV	1,707	3,441	5,635	8,401	11,862	16,160	21,134	27,082	34,065	42,235	51,742	62,662	74,976	89,307	104,804	121,285	138,952	157,303
MDV	1	4	8	17	33	62	112	198	333	532	795	1,109	1,462	1,845	2,227	2,596	2,950	3,289
Total	**1,709**	**3,448**	**5,650**	**8,431**	**11,918**	**16,263**	**21,311**	**27,376**	**34,535**	**42,959**	**52,798**	**64,115**	**76,887**	**91,738**	**107,777**	**124,817**	**143,062**	**162,001**

Forecast Electricity Consumption

Exhibit 62 shows forecast electricity consumption for the intermediate scenario by vehicle type. Total consumption is forecast to increase to approximately 1,000 GWh by 2040, which is roughly equivalent to forecast industrial sector consumption in 2040 (1,092 GWh).

Exhibit 62: Intermediate Scenario Forecast Electricity Consumption (GWh)



This growth is driven by two trends:

Trend 1: Increased Sales Share of Electric LDVs

Forecast electricity consumption is driven by consumption from electric LDVs, which are expected to reach approximately 85% sales share by 2040. LDVs also make up most of the total vehicle stock in Newfoundland (96%).

In 2030, LDV charging is forecast at 117 GWh, or 80% of total transportation sector consumption. LDV consumption is expected to increase more than five-fold over ten years, reaching 636 GWh in 2040. This growth is partly driven by BEVs, which dominate the LDV market over the forecast period because their larger batteries consume more electricity compared to PHEVs.

LDVs still make up most (64%) of transportation sector consumption in 2040. However, this represents a decrease in their contribution to the total compared to 2030, caused by the adoption of MHDVs in the last ten years of the forecast.

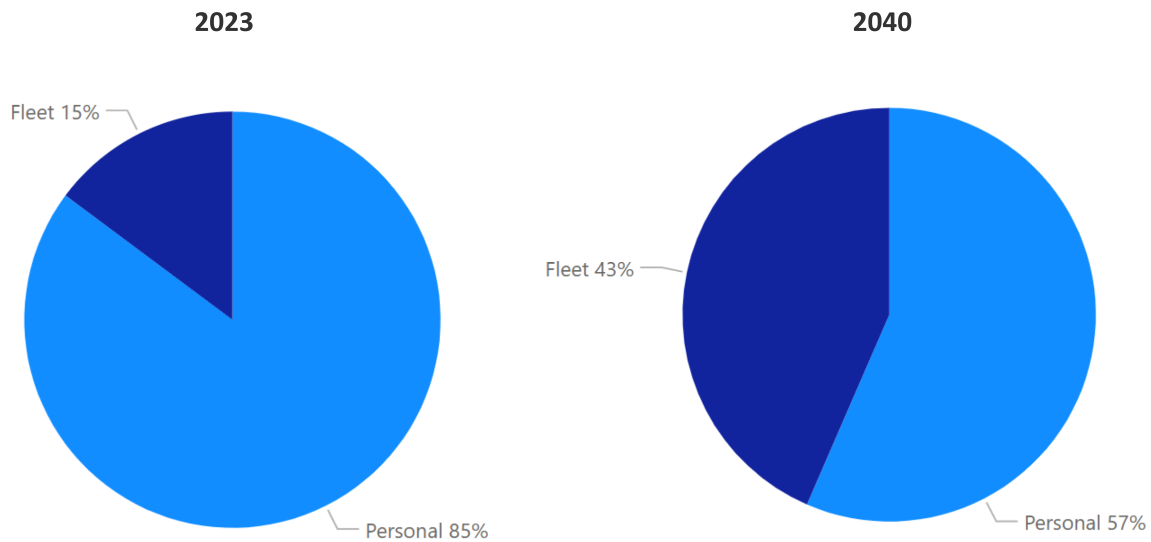
Trend 2: Growth in Fleet MHDVs and Buses

The growth of MHDVs and buses is driven by adoption from companies and fleet owners. In the base year, LDV technology maturity exceeds that of MHDVs and buses. It follows that fleet vehicles contribute modestly (1.4 GWh, 15%) to total EV consumption, as shown in Exhibit 63.[60]

Exhibit 63 shows that by 2040 however, fleet vehicles are forecast to represent 43% (435 GWh) of transportation sector consumption in the intermediate scenario. The causes of this increase include:

- **Economic feasibility**: As mentioned previously, TCO is the main driver of EV adoption in fleets. When electric MHDV and bus technologies become economically feasible in the second half of the forecast period, their contribution to total electricity consumption also increases.
- **Longer driving distances and higher energy intensities compared to personal vehicles**: Fleet vehicles are outnumbered by personal vehicles by a factor of just over six to one. Despite this, fleet vehicles travel farther annually and have higher energy intensities compared to personal vehicles.[61]

Exhibit 63: 2030 vs 2040 Transportation Consumption by Ownership Type

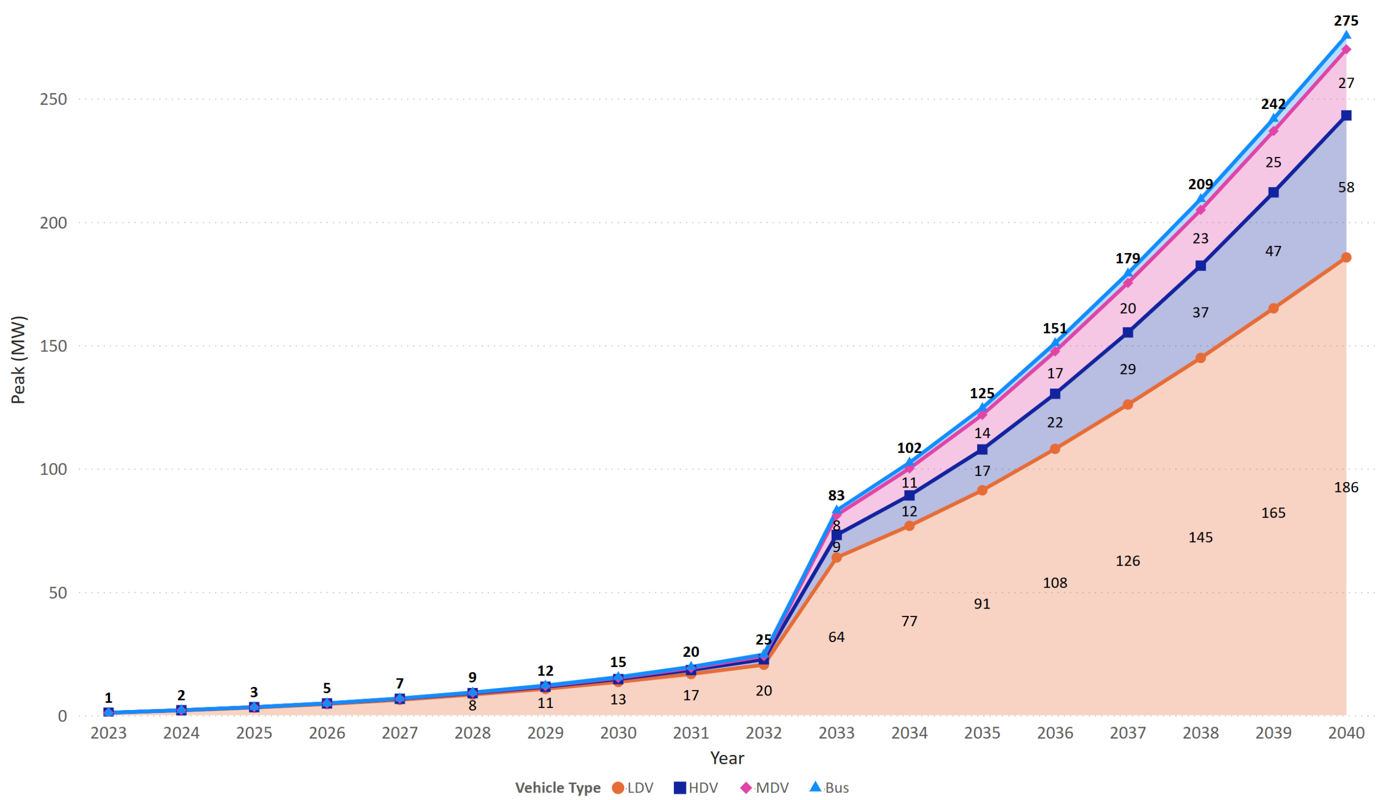


[60] Consumption from fleet vehicles in the base year is almost entirely attributed to commercial LDVs.
[61] "Comprehensive Energy Use Database, Transportation Sector – Newfoundland and Labrador," Natural Resources Canada, Available: https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive/trends_tran_nf.cfm. (Accessed Feb. 25, 2025). See tables Table 21 and 37.

Forecast Peak Demand

Exhibit 64 shows forecast transportation sector peak demand by vehicle type for the intermediate scenario under unmanaged charging. Peak demand is forecast to increase to approximately 275 MW by 2040. This increase is driven by the same trends that drive the increase in electricity consumption. The increase in the EV peak hour seen between 2032 and 2033 is due to the system wide peak hour shifting from the morning to the evening. Prior to 2033, the peak hour is expected to occur in the morning so the EV contribution to peak is much lower since much less charging occurs then. After 2033, the EV contribution to the peak is much higher when the system peak hour occurs much closer to the EV charging peak hour.

Exhibit 64: Intermediate Scenario Forecast Peak Demand (MW) by Vehicle Type, (2040)



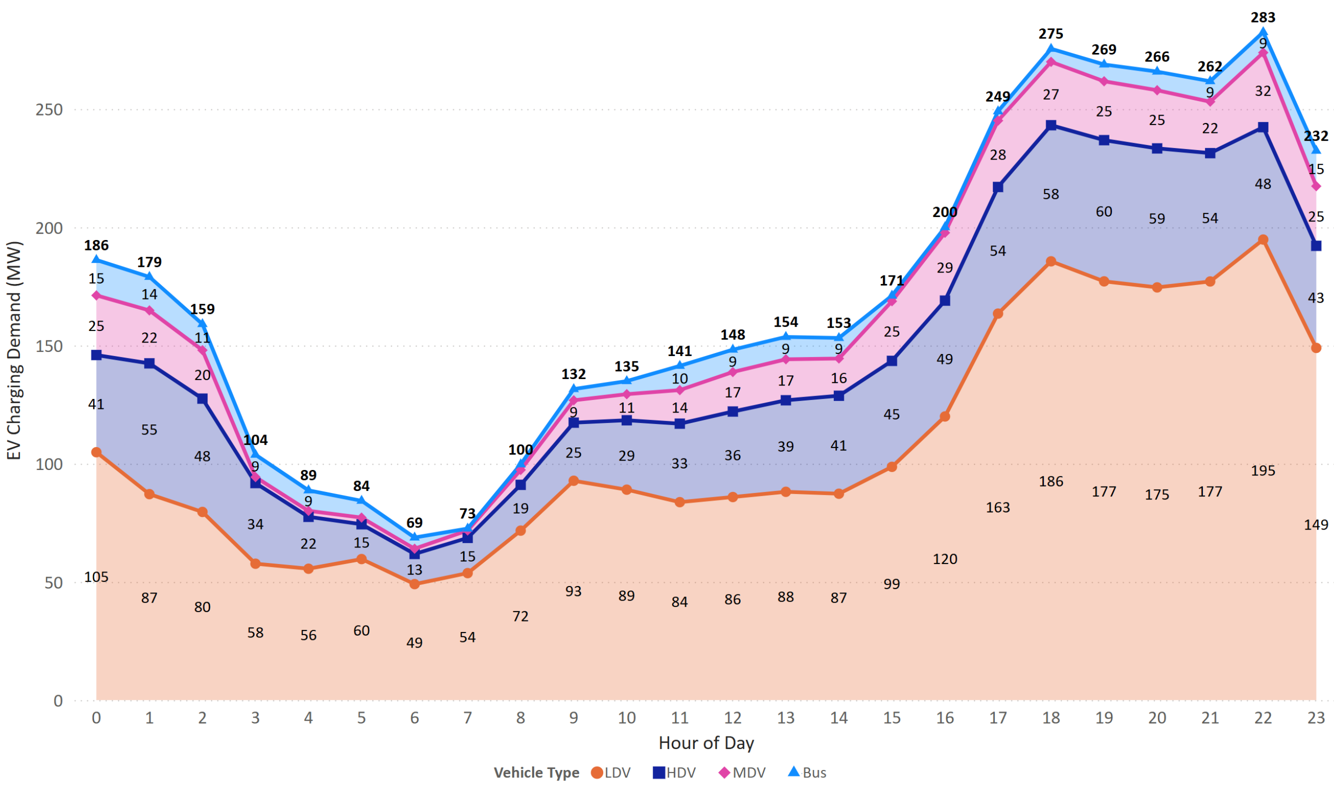
The rest of this section explains when (i.e., hour of the day) and where (i.e., at home chargers, at public chargers, etc.), peak demand is expected to occur in 2040.

Hourly Peak Demand

Exhibit 65 shows the transportation sector demand in each hour of the peak day in 2040 for the intermediate scenario under unmanaged charging. The peak day is expected to occur in the winter, when electric space heating loads peak in the residential and commercial sectors. Observations on Exhibit 65 include:

- The evening peak occurs between 6 p.m. and 10 p.m., which overlaps with the predicted IIS system evening peak at 6 p.m. The absolute transportation sector peak (283 MW) occurs at 10 p.m.
- The nighttime trough occurs between 12 a.m. and 6 a.m. This suggests that shifting EV charging load could also reduce the IIS peak. Opportunities to manage EV charging are discussed in section 4.4.
- Transportation sector demand is lowest between 6 a.m. (69 MW) and 7 a.m. (73 MW), just before the IIS morning peak occurs from 7 a.m. to 10 a.m. Given the shape of the EV charging curve, efforts should be focused on reducing the evening peak.

Exhibit 65: Peak Demand by Hour and Vehicle Type (MW), (2040)

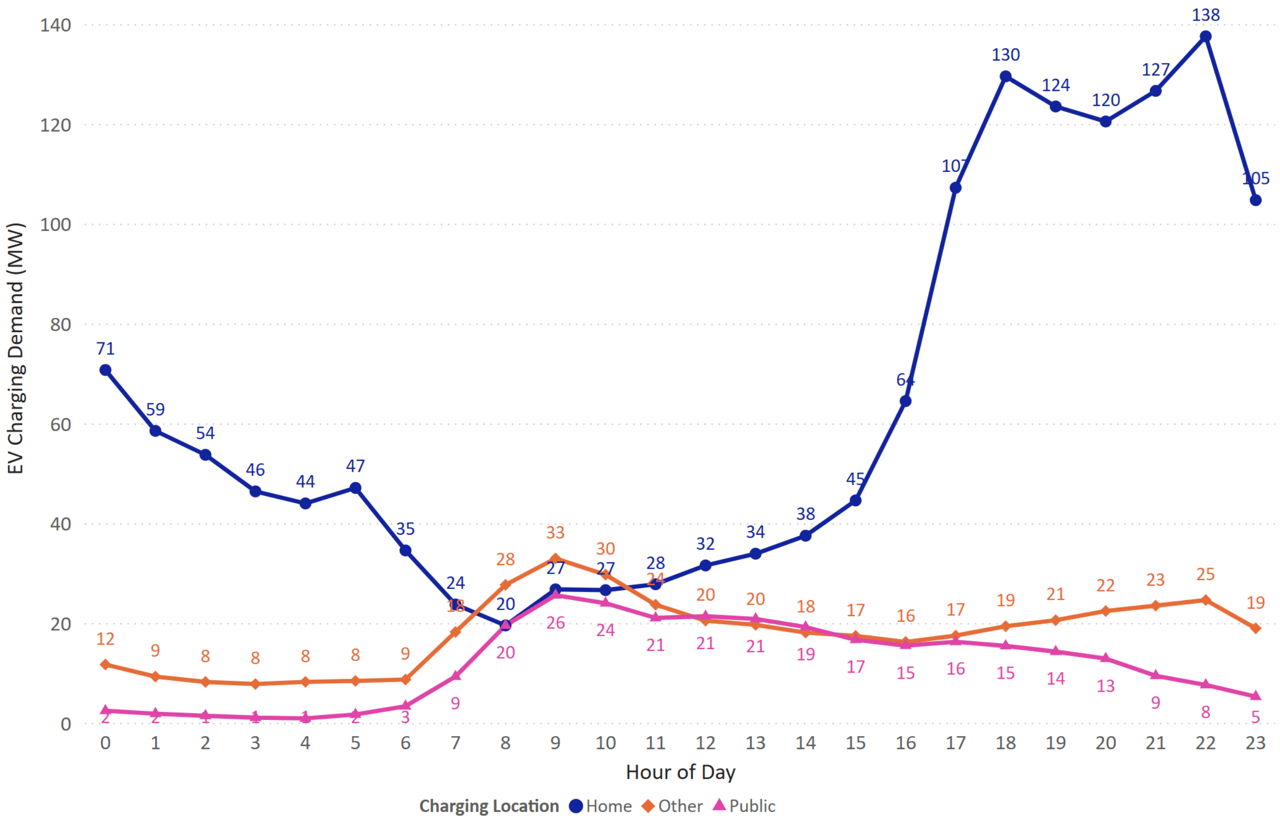


Charging Location

Charging location also influences the magnitude of EV load can be shifted off the IIS peak. Personal EVs are expected to charge at home, at public charging stations and at "other" charging locations (i.e., workplace charging stations or other private charging stations). Data from Geotab's Charge the North study for Canada shows that approximately 68% of personal EV charging occurs at home while 32% occurs away from home (19% at private locations including workplaces or other businesses and 13% at public charging stations).[62] The Study Team maintained these charging splits throughout the forecast period. Fleet vehicles are expected to charge exclusively at their private depots.

Exhibit 66 shows personal EV charging by location in each hour of the peak day in 2040 for the intermediate scenario.

Exhibit 66: Personal EV Charging by Hour and Location (MW), (2040)



[62] "Preparing for EVs: Charge the North EV Case Study," Geotab, Available: https://www.geotab.com/blog/preparing-for-evs/ (Accessed Jan. 30, 2024).

Observations on Exhibit 66 include:

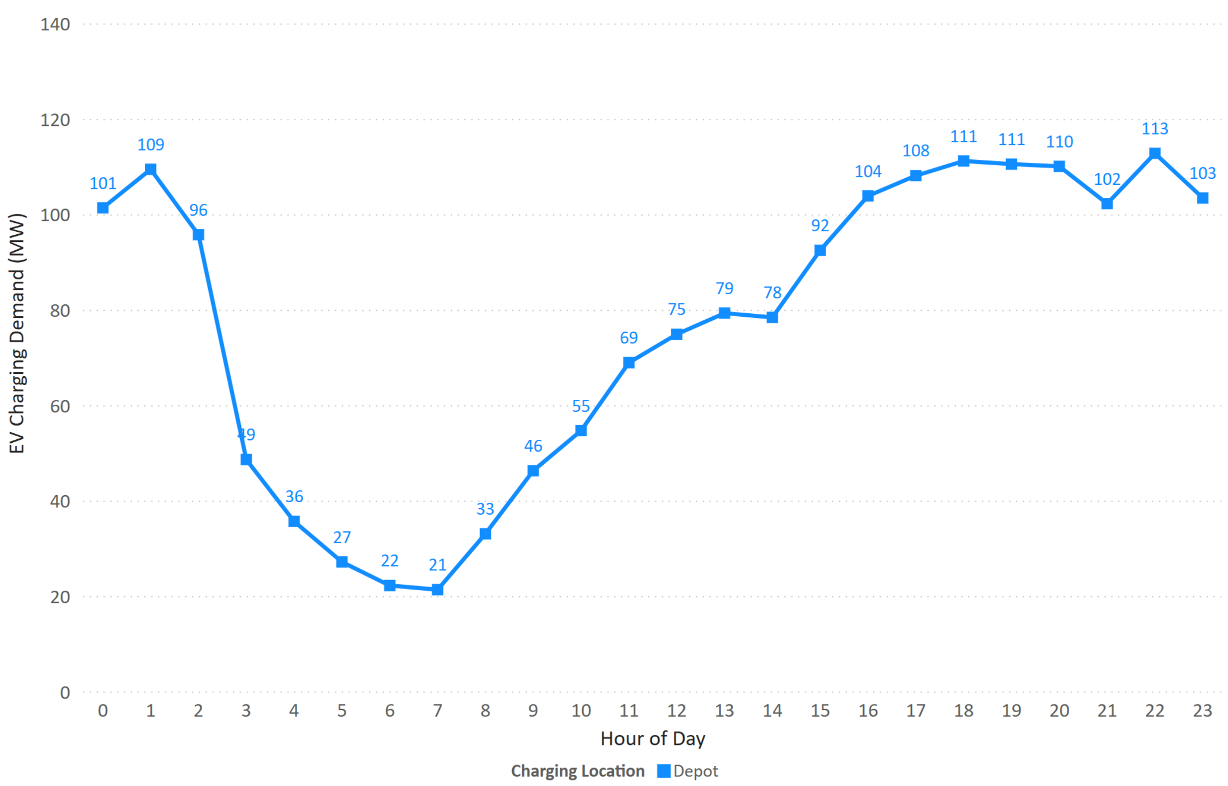
- Home charging contributes the most to the transportation sector evening peak from 6 p.m. to 10 p.m. because drivers typically plug in their vehicles after work.
- Public and other charging peaks between 8 a.m. and 11 a.m., when drivers plug in after their morning commute and are away from their homes.
- Of the three personal vehicle charging locations, home charging is the only one suited to load shifting, because public and other charging is often seen as opportunity charging.[63] Shifting home charging to the nighttime trough from 12 a.m. to 6 a.m. could reduce the IIS peak.

[63] Opportunity charging usually happens mid-route, like refueling an ICE vehicle, so there is less flexibility to shift the load.

Exhibit 67 shows fleet EV charging at depots in each hour of the peak day in 2040 in the intermediate scenario. Observations include:

- The depot charging peak contributes the most to the transportation sector peak between 3 p.m. and 2 a.m. Like the home charging peak, the depot charging peak overlaps with the IIS evening peak.
- The depot charging peak (eleven hours in duration) is seven hours longer than the home charging peak (four hours in duration). This is because fleet vehicles are charged during their downtime, which depends on their duty cycle. MHDV and bus batteries are also larger and take longer to charge compared to LDV batteries, which lengthens the peak.
- The depot charging trough does not begin until after 2 a.m. and reaches its lowest load (21 MW) at 7 a.m. Depot charging load could be shifted off peak into this trough if duty cycles allow, but load shifting potential is likely constrained by vehicle battery sizes.
- The opportunity for the Utilities to manage fleet vehicle charging load is more limited than for personal vehicles. However, certain fleet vehicles will have duty cycles that can accommodate managed charging programs to help reduce the IIS evening peak. Fleet LDVs likely present the best opportunity for utility managed charging due to their smaller batteries and shorter distances driven.

Exhibit 67: 2040 Fleet EV Charging by Hour and Location (MW)



3.5.3 Scenario Comparison

This section compares forecast vehicle stock, consumption and peak demand in the natural adoption, intermediate, and government targets scenarios. Discussion of the incentives, infrastructure (i.e., chargers, and ports) and cost requirements to move from one scenario to another are provided in Appendix A.

Vehicle Stock

Exhibit 68 and Exhibit 69 show the forecast vehicle stock for the natural adoption, intermediate and government targets scenarios for LDVs and MHDVs (including buses) respectively.

Exhibit 68: Forecast EV Stock by Scenario (LDVs)

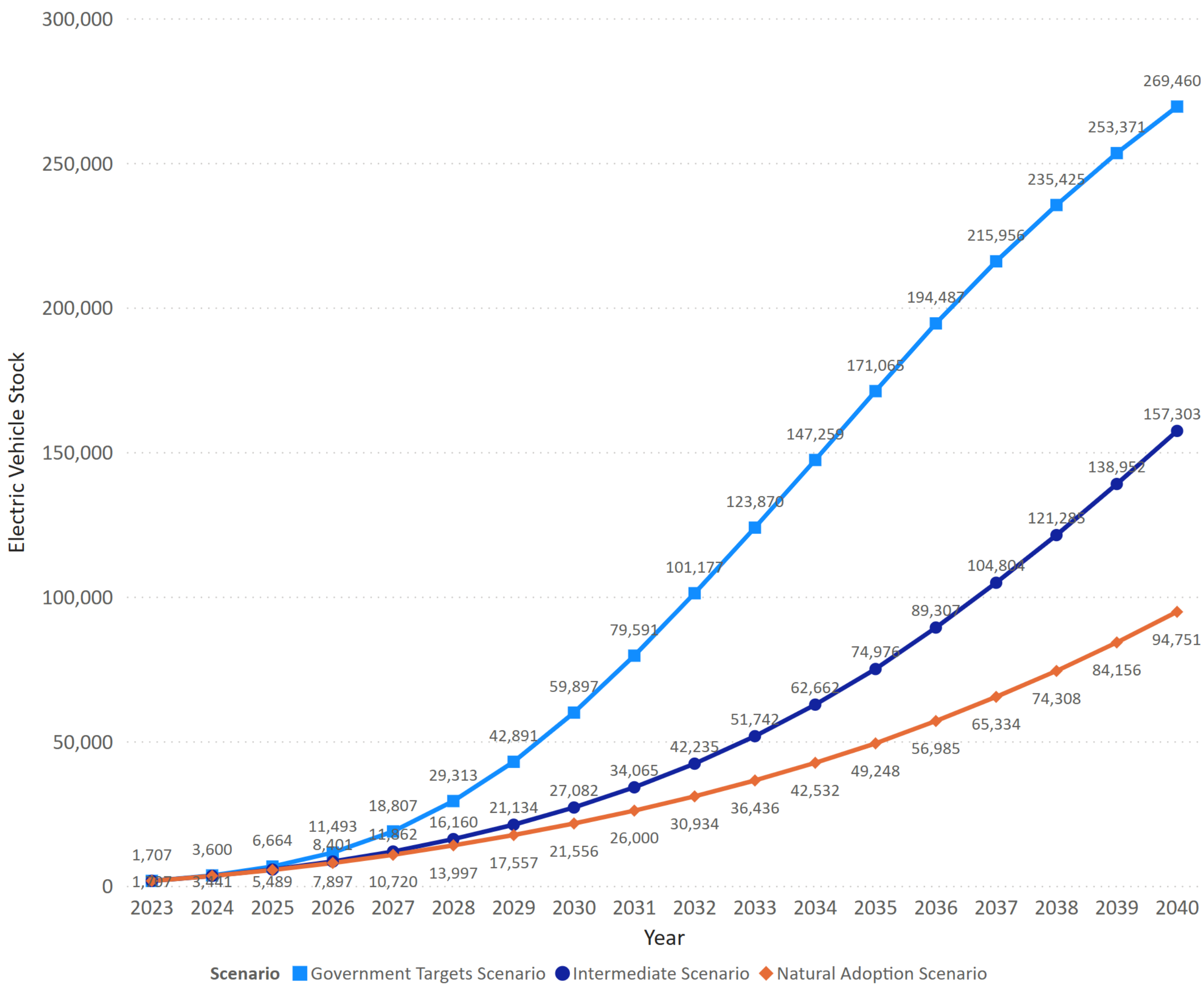
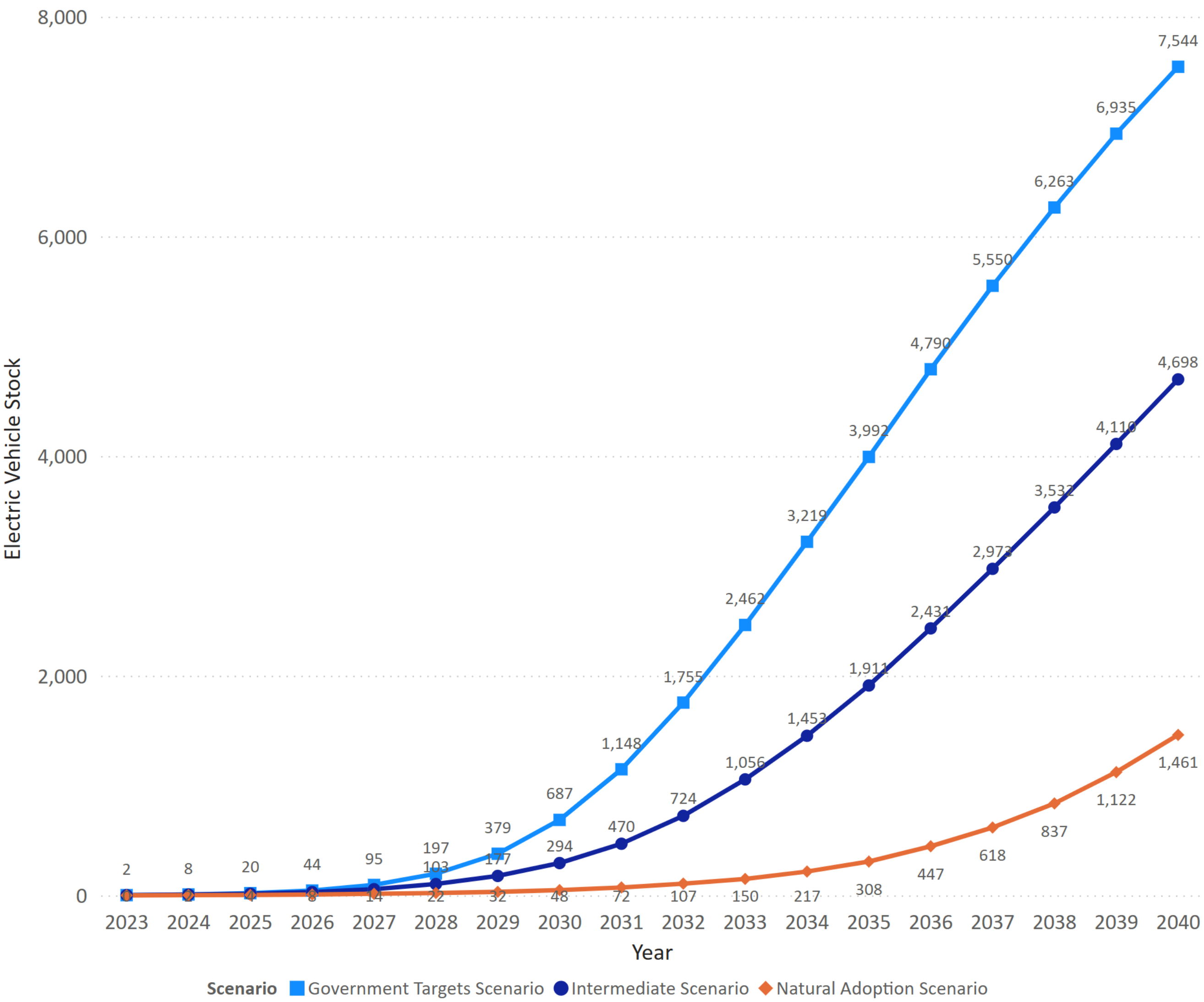


Exhibit 69: Forecast EV Stock by Scenario (MHDVs)



Observations include:

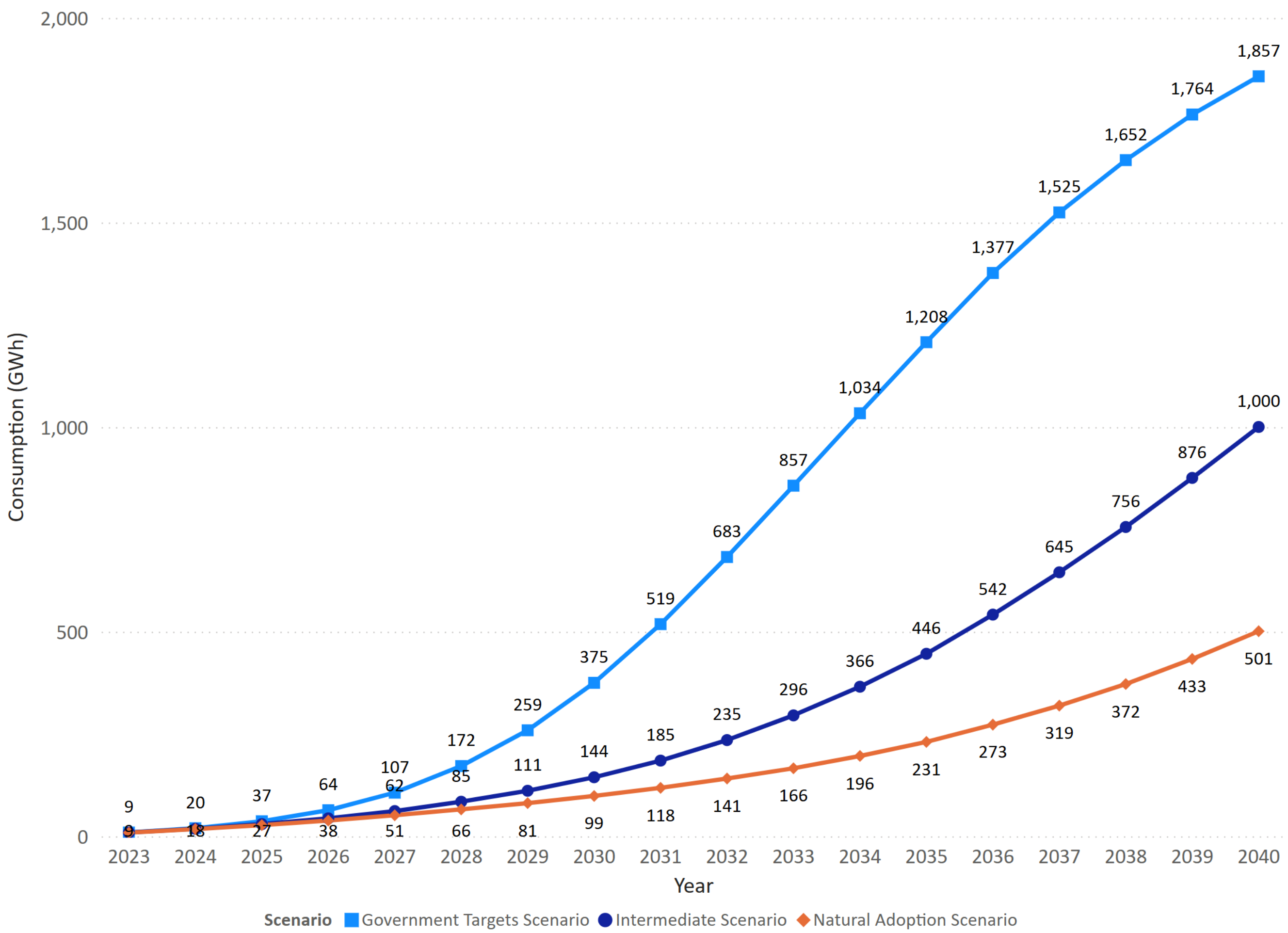
- The government targets scenario forecasts the largest EV stock by 2040, at approximately 270,000 LDVs and 7,500 MHDVs. It also has much earlier uptake in EVs, eclipsing the total 2040 LDV stock of roughly 157,000 forecast in the intermediate scenario before 2035.
- The natural adoption scenario has a much more gradual EV stock trajectory, reaching approximately 95,000 LDVs and 1,500 MHDVs by 2040. Natural adoption MHDV stock lags further behind the other scenarios as adoption only begins to increase in the mid 2030s.
- Across all scenarios, uptake for LDVs begins earlier in the forecast period than MHDVs, due to advancements in technology and lower costs. However, uptake for MHDVs rises at steeper rates as soon as MHDVs are forecast to become cost competitive with the incumbent ICEV technology. This highlights how Total Cost of Ownership (TCO) is expected to be the main driver of EV adoption for MHDVs.

Electricity Consumption

Exhibit 70 shows forecast electricity consumption by scenario. Observations include:

- By 2030, market interventions like additional vehicle rebates or accelerated build-out of charging infrastructure for LDV in the intermediate scenario results in 45 GWh more electricity consumption compared to the natural adoption scenario (144 GWh vs 99 GWh). By 2040, these market interventions are responsible for roughly 500 GWh of additional consumption (1,000 GWh vs 501 GWh).
- By 2040, the government targets scenario predicts nearly twice the electricity consumption from EV charging compared to the intermediate scenario (1,857 GWh vs 1,000 GWh) and nearly four times the electricity consumption compared to the natural adoption scenario (1,857 GWh vs 501 GWh).

Exhibit 70: Forecast EV Consumption by Scenario (GWh)

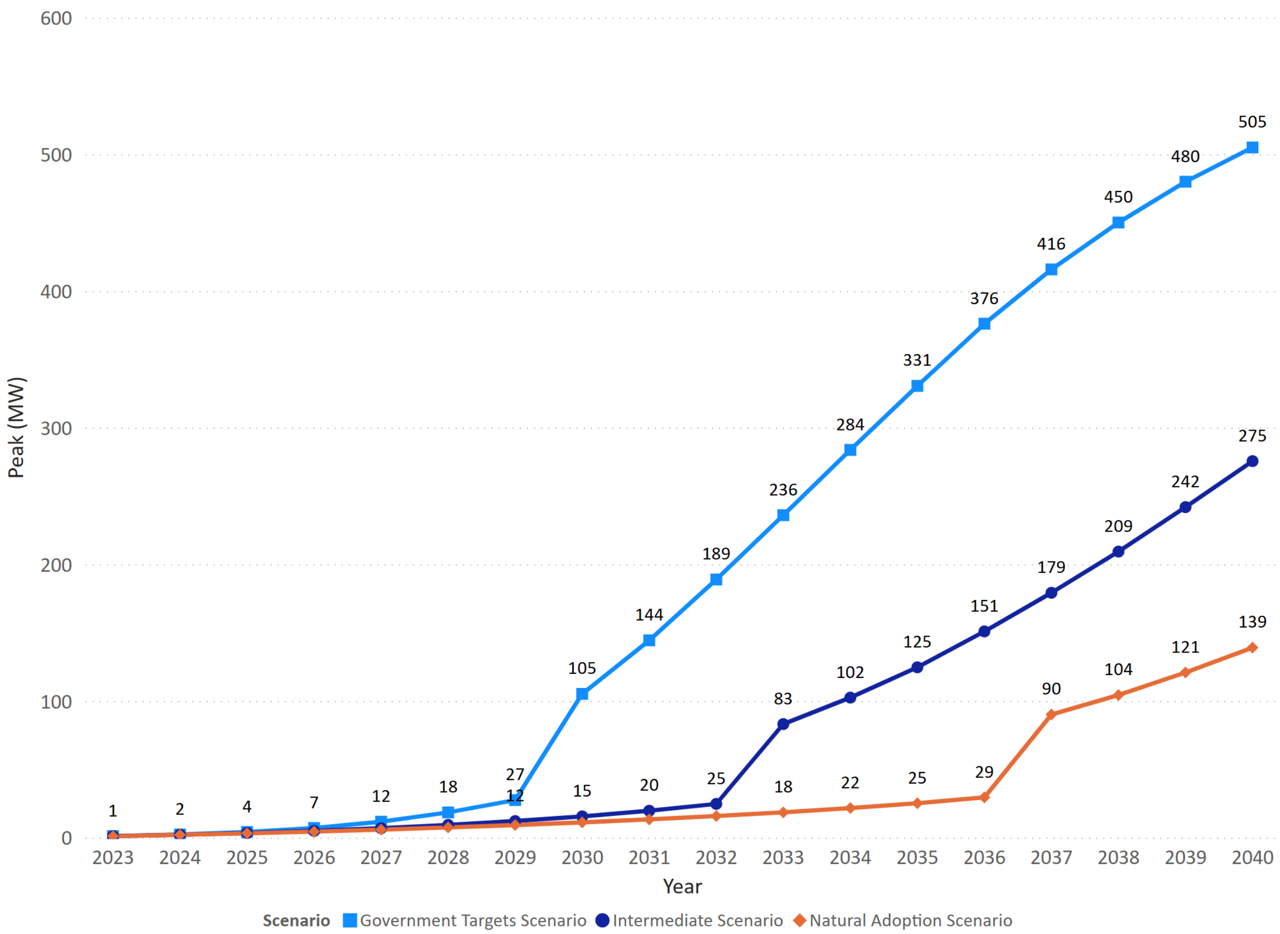


Peak Demand

Exhibit 71 shows forecast EV peak demand by scenario under unmanaged charging. Observations include:

- Like the annual consumption forecast, the government targets scenario predicts over 3.5 times the peak demand (505 MW) from EV charging compared to the natural adoption scenario (139 MW).
- The abrupt increases in EV peak in 2030 (government targets scenario), 2033 (intermediate scenario) and 2037 (natural adoption scenario) represent the switch from a morning peak to an evening peak. This shows that greater EV uptake leads to an earlier transition to an evening IIS peak.
- In the natural adoption, intermediate, and government targets scenarios, EVs contribute 7%, 13% and 22% to the IIS peak, respectively.
- EV peak demand in the government targets scenario (505 MW) falls between peak demand for the industrial (130 MW) and commercial (522 MW) sectors in 2040. This illustrates that EVs could significantly contribute to peak demand in Newfoundland over time.

Exhibit 71: Forecast EV Peak Demand by Scenario (MW)



4 Measure Analysis

The Study Team assessed the energy savings and peak demand reduction potential for efficiency, fuel switching, and demand response measures. The demand response measures are further classified as electricity rate design, equipment demand response, and thermal storage with time-of-use. Exhibit 72 illustrates the Study measure classification and defines each measure type.

Exhibit 72: Measure Classification

Efficiency

Measure that uses electricity more efficiently than the base case measure.

Fuel Switching

Measure that uses electric equipment to replace baseline equipment that uses oil, propane or wood. Includes off-road electrification of forklifts and Zambonis.

Demand Response

Measure that uses less electricity during the peak period but has minimal or no impact on annual electric energy consumption.

- **Electricity Rate Design**

  Customers opt into one of two time-variable rates at their discretion: time of use or critical peak pricing.

- **Equipment Demand Response**

  Utility has direct load control of customer end use equipment like thermostats or water heaters during on-peak times.

- **EV Managed Charging**

  Measure that enables utilities to influence charging periods for EVs via connected hardware and controls.

- **Thermal Storage with Time of Use**

  Customers shift electricity use off peak based on time of use rates using electric thermal storage systems.

Some measures are applicable across two categories. For example, dual fuel oil/electric heating systems may be applied as a fuel switching measure when replacing an oil heating system, or as a demand response measure when the oil-fired equipment is used to replace electric heating during peak periods. In these cases, the Study Team developed two individual measures, one in each category.

In addition to assessing energy savings and peak demand reduction potential for efficiency, fuel switching and DR measures, the Study Team determined what market conditions would be required to support the natural adoption, intermediate and government targets EV forecast scenarios defined in section 2.2.[64] This included an examination of the following transportation sector measures:

- **Adoption Incentives**: Payments to vehicle operators that offset the incremental cost of adopting EVs.
- **Charging Infrastructure**: Charging infrastructure costs include port costs and associated installation costs. Costs exclude distribution system upgrades to host charging loads.

Lastly, the Study Team completed a qualitative assessment of emerging measures transportation sector measures: Connected hardware and controls that enable vehicle batteries to feed energy back to specific loads, dwellings or the grid and allow the Utilities to influence the magnitude and timing of this energy flow.

Readers are encouraged to consult section 2 for additional details of the measure analysis approach. The rest of this section is structured as follows:

- Section 4.1 lists measures by sector. Within section 4.1,
  - Section 4.1.1 shows the rate structures modelled for the electricity rate design measures.
  - Section 4.1.2 shows the frequency and duration of events for the electricity rate design measures and the utility-driven equipment DR measures.
- Section 4.2 presents results for the residential, commercial and industrial sectors.
- Section 4.3 presents results for the transportation sector.

[64] In the Study, charging infrastructure refers to the ports required to support electric vehicle charging in the Transportation sector.

4.1 List of Measures

An illustrative list of the measures for the residential, commercial, and industrial sectors are listed in Exhibit 73, Exhibit 74 and Exhibit 75, respectively. Measures are presented by end use and type. Exhibit 76 shows the transportation sector measures by type. All the transportation measures affect the EV charging end use. See Appendix B for the complete list of measures by sector.

Exhibit 73: Residential Sector Measures

End Use(s) Affected	Measure Name
Water Heating	**Efficiency** • Domestic Hot Water Pipe Insulation • Low Flow Fixtures (faucet aerator, showerhead, thermostatic restrictor shower valve) • Efficient Equipment (heat pump water heater, on demand water heater) **Fuel Switching** • Oil Water Heater to Heat Pump Water Heater • Oil Water Heater to High Efficiency Electric Storage Water Heater **Demand Response** • Water Heater Smart Switch (Utility-Driven)
Lighting	**Efficiency** • Lighting Controls (various) • Efficient Lamps (various) • Efficient Integrated Fixtures (various)
Space Cooling & Space Heating	**Efficiency** • Envelope Improvement (air sealing, insulation, efficient windows and doors) • Air Source Heat Pumps (various standard and cold climate configurations) • Thermostats (digital, programable, and smart) **Fuel Switching** • Oil Boiler to Air to Water Heat Pump (various configurations) • Oil Boiler to Ductless Mini Split Heat Pump (various configurations) • Oil Furnace to Central Ducted Air Source Heat Pump (various configurations) • Oil Furnace to Ductless Mini Split Heat Pump (various configurations) • Wood Furnace to Central Ducted Air Source Heat Pump (various configurations)

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End Use(s) Affected	Measure Name
	• Wood Furnace to Ductless Mini Split Heat Pump (various configurations)
Space Cooling & Space Heating & Ventilation	**Efficiency** • Energy Recovery Ventilator • Heat Recovery Ventilator
Space Heating	**Fuel Switching** • Oil Boiler to Electric Boiler • Oil Furnace to Electric Furnace **Demand Response** • Smart Thermostat or Switch (various electric heating technologies) • Thermal Storage (various configurations)
Four or More End Uses Affected	**Efficiency** • Codes and Standards • Home Energy report • LEED Certified Apartments • Efficient New Homes (ENERGY STAR, Net-Zero Ready) **Demand Response** • Behind-the-Meter Battery Storage (Utility-Driven) • Behind-the-Meter Solar with Smart Inverters (Utility-Driven) • Smart circuit breakers or smart panel (Utility-Driven) • Time-of-Use Rates (TOU) • Critical Peak Pricing (CPP)

Exhibit 74: Commercial Sector Measures

End Use(s) Affected	Measure Name
Water Heating	**Efficiency** • Drain Water Heat Recovery • Efficient Equipment (ENERGY STAR dishwasher, heat pump water heater) • Low-Flow Fixtures (faucet aerator, showerhead, pre-rinse spray valve, thermostatic restrictor shower valve) **Fuel Switching** • Oil Water Heater to Heat Pump Water Heater **Demand Response** • Controllable Water Heaters (Utility-Driven)
General Lighting	**Efficiency** • LED Lamps and Luminaires (various) • Interior Lighting Controls (BAS, daylighting, occupancy sensors)
High Bay Lighting	**Efficiency** • LED High Bay Luminaire
HVAC Fans & Pumps	**Efficiency** • Electrically Commutated Motor (various applications) • Variable Frequency Drive (various applications) • Premium Efficiency Motors • Recirculation Pump with Demand Controls
HVAC Fans & Pumps & Space Cooling	**Efficiency** • Advanced Building Automation Systems • Demand Control Ventilation (general, kitchen) **Demand Response** • HVAC Fans & Pumps Controls (Utility-Driven)
Miscellaneous Equipment	**Efficiency** • ENERGY STAR equipment (ice maker, uninterruptible power supply, vending machine) **Off-Road Electrification** • Electric off-road vehicles (forklift, Zamboni)
Outdoor Lighting	**Efficiency** • LED lamps (various) • LED fixtures (wall pack, parking garage, pole mounted) • Lighting Controls

End Use(s) Affected	Measure Name
Refrigeration	**Efficiency** • Arena Improvements (brine pump controls, low emissivity ceiling, schedule for ice temperature) • ENERGY STAR Refrigerators and Freezers • Refrigerated Display Case Improvements (add doors, anti-sweat door heater controls, case retrofit, LED refrigerated case lighting) • Refrigerated Walk-Ins Improvements (automatic door closers, door strip curtains, EC motor, evaporator fan control, fast acting doors) • Refrigeration System Improvements (floating heat pressure control, high efficiency compressor)
Secondary Lighting	**Efficiency** • LED lamps and luminaires (various)
Space Cooling & Space Heating	**Efficiency** • Envelope Improvement (air sealing) • Air Source Heat Pumps (various standard and cold climate configurations) • Energy Management (whole-building system, guest room) • Ground Source Heat Pumps • Thermostats (programmable, smart)
Space Cooling	**Efficiency** • Dual Enthalpy Economizer Controls • High Efficiency Equipment (chiller, rooftop unit, unitary, packaged)
Space Heating	**Efficiency** • Envelope Improvements (air curtains, efficient windows, window glazing, insulation) • Energy Recovery Ventilator • Radiant Infrared Heaters • Refrigeration Heat Recovery • Solar Wall **Fuel Switching** • Oil Boiler to Electric Heating (baseboard, boiler, furnace, various heat pump configurations) • Oil Furnace to Electric Heating (furnace, various heat pump configurations) **Demand Response** • HVAC Control (Utility-Driven)

End Use(s) Affected	Measure Name
	• Thermal Storage (various configurations)
Street Lighting	**Efficiency** • LED Street Light
Four or More End Uses Affected	**Efficiency** • Energy Management System • New Construction (25% more efficient, 40% more efficient, Net-Zero Ready) • Retro-commissioning Strategic Energy Manager **Demand Response** • Backup Generation (Utility-Driven) • Behind-the-Meter Battery Storage (Utility-Driven) • Behind-the-Meter Solar with Smart Inverters (Utility-Driven) • Critical Peak Pricing • Customer Curtailment • Grid Interactive Efficient Buildings (Utility-Driven) • Time-of-Use Rate

Exhibit 75: Industrial Sector Measures

End Use(s) Affected	Measure Name
Air Compressors	**Efficiency** • Cycling Refrigerated Air Dryer • Premium Efficiency ASD Compressor • System Optimization (various measures)
Conveyors	**Efficiency** • Optimized Conveyor Motor Control • Premium Efficiency Motors - Conveyor
Fans and Blowers	**Efficiency** • Correctly Sized Fans: Impeller Trimming or Fan Selection • Optimized Distribution System (Incl. Pressure Losses) - Fans and Blowers • Premium Efficiency Equipment (various) • Synchronous Belts
General Lighting	**Efficiency** • Automated Lighting Controls • High Efficiency Lighting Design • LED Luminaires (various)
HVAC Fans & Pumps	**Efficiency** • Envelope Improvements (air curtains – HVAC, building insulation, warehouse loading dock seals) • Heat Recovery (air compressor, refrigeration, ventilation) • High Efficiency Packaged HVAC • Solar Thermal Wall • Temperature Management (reduced temperature settings, smart thermostat) • Ventilation Optimization **Fuel Switching** • Comfort HVAC Electrification
HVAC Fans & Pumps, Pumps, Process Cooling, and Process Heating	**Demand Response** • Peak Shifting Through On-Site Storage (Utility-Driven)
Other	**Off-Road Electrification** • Electric Forklift
Other Motors	**Efficiency** • Adjustable or Variable Speed Drives (compressor and fan) • Motor Improvements (correct sizing, controls) • Premium Efficiency Motors - Other

End Use(s) Affected	Measure Name
Pumps	**Efficiency** • Pumping System Improvements (correct sizing, system optimization) • Premium Efficiency Equipment (motors and pumps)
Process Cooling	**Efficiency** • Air Curtains - Process Cooling • Chiller Economizer • Floating Head Pressure Controls • High Efficiency Chiller • Improve Insulation of Refrigeration System • Improved Ice Production System • Optimized Distribution System - Process Cooling • Premium Efficiency Refrigeration Control System and Compressor Sequencing
Process Heating	**Efficiency** • High Efficiency Equipment (dryer, furnace, kiln, over, water heater) • Process Heat Recovery to Preheat Makeup Water
Process Specific	**Efficiency** • Advanced ‘Predictive’ Process Control Systems • Custom Processes • Process Optimization Efforts (fishing and fish processing, mining and processing
Process Heating & Process Cooling	**Efficiency** • Heat Pumps
All End Uses Affected	**Demand Response** • Backup Generation at Peak Hours (Utility-Driven) • Behind-the-Meter Battery Storage (Utility-Driven) • Behind-the-Meter Solar with Smart Inverters (Utility-Driven) • Critical Peak Pricing/ Industrial Flexibility • Energy Management Information System (EMIS) • Time-of-Use (TOU)

Exhibit 76 presents transportation sector measures, all of which affect the EV charging end use.

Exhibit 76: Transportation Sector Measures

Measure Type	Measure Name
Managed Charging	**Personal Ownership** • Electric Vehicle Supply Equipment (EVSE) (BEV, PHEV) • Vehicle Telematics (VT) (BEV, PHEV) **Fleet Ownership** • VT (Bus, HDV, Light Duty BEV, Light Duty PHEV, MDV) • EVSE (Bus, HDV, Light Duty BEV, Light Duty PHEV, MDV)
Time-of-Use	**Personal Ownership** • BEV • PHEV
Adoption Incentives	• Bus • Fleet LDV • HDV • MDV • Personal LDV
Infrastructure	**Personal Ownership** • LDV Direct Current Fast Charging (DCFC) Public Charger • LDV L2 Home Charger – Multi-Unit Residential Building (MURB) • LDV L2 Public Charger • Level 1 (L1) and Level 2 (L2) LDV Home Charger **Fleet Ownership** • DCFC Depot Charger (Bus, HDV, MDV) • L2 Depot Charger (Bus, LDV) • LDV DCFC Public Charger • LDV DCFC Depot Charger • LDV L2 Public Charger **Other Ownership** • DCFC Public Charger (HDV, MDV) • L2 Public Charger (HDV, MDV)

4.1.1 TOU and CPP Rate Structures

The Study Team assessed the impact of the TOU and CPP electricity rate designs in Exhibit 77 on peak demand. Throughout the report, the TOU and CPP electricity rate design measures are referred to as time variable rates (TVR).

Exhibit 77: TOU and CPP Rates

Season	Peak	Time	Residential ($/kWh)[65]	Commercial ($/kWh)	Industrial ($/kWh)
December to March	On-peak	Morning Peak Evening Peak	$0.24	$0.17	$0.18
	Off-peak	Hours Outside of Peak Periods	$0.06	$0.04	$0.04
December to March	Critical Peak	Critical Peak Events	$0.55	$0.83	$0.85
	Off-Peak	Hours Outside of Critical Peak Periods	$0.06	$0.07	$0.07

The TOU and CPP electricity rates are based on the base year electricity retail rates from Newfoundland and TVR from other jurisdictions.[66] These rate structures are representative, and neither is currently offered or under specific consideration by the Utilities. The rate structures are designed as opt-in programs like other jurisdictions in Canada, meaning that only customers who choose to participate will see the time-varying rates in effect.

TOU

- **Mid-Peak**: Reflects the base year residential and commercial customer retail rates ($0.13/kWh for residential, and $0.096/kWh for commercial). The Study Team used the mid-peak retail rates for each sector to determine the on-peak and off-peak rates. This was done by calculating the proportion of annual demand that occurs during each peak period and estimating the corresponding off-peak rate that avoids a loss in revenue to the Utilities from reduced rates during the peak periods.
- **On-Peak**: Reflects a 4:1 rate differential between off-peak and on-peak rates and assumes revenue neutrality. Price differentials within the range of 2:1 to 4:1 are industry standard and

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[65] The residential rate applies to “at home” personal EV charging.
[66] These rate structures demonstrative and not a recommendation of an actual retail rate.

are most likely to show results. A NP pilot found that a 2:1 rate differential was ineffective for Newfoundland, so the Study Team chose a 4:1 differential.[67,68,69]

- **Off-Peak**: Reflects a 4:1 rate differential between the off-peak and on-peak rates and assumes revenue neutrality.[70]

CPP

- **Off-Peak:** Reflects the off-peak rates from Hydro Quebec's Rate Flex D program for the residential sector. The commercial sector off-peak rate reflects the ratio of Hydro Quebec's summer period to winter period reduced pricing for the Rate Flex D program.[71]
- **Critical Peak:** Uses the peak demand event rates from Hydro Quebec's Rate Flex D program for the residential sector. For the commercial and industrial sectors, reflects the IIS mid-peak rates multiplied by the ratio of Hydro Quebec's peak demand event rates to off-peak rates.[71]

4.1.2 Frequency and Duration of TOU and CPP Events

The frequency and duration of peak events for which on-peak rates are used are as follows:

- **TOU:** The TOU rate is modelled as being in effect during the morning (4 hours) and evening (5 hours) peak periods on weekdays from December to March (i.e. a total of 89 days per year).
- **CPP:** The CPP rate is modelled as being in effect during critical peak events, as determined by the Utilities. For the purposes of estimating customer benefit, this analysis assumes that events are called 12 times per year during the morning and evening peak periods.

The IIS has seen weekend peaks in the past; however, the Study Team modelled a weekday-only TOU rate structure. Daily TOU has been found to lead to customer fatigue in some cases, and a weekday only structure is consistent with TOU rate implementation in Nova Scotia and Ontario.[72,73]

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[67] Personal interview, Nov 16, 2024, Joseph Lopes, Senior Principal Consultant, "Load Shape and Rate Design Programs." Conducted by: Sydney Mendoza.
[68] NP conducted a pilot with a 2:1 rate differential and concluded that it was not effective. Newfoundland Power, "Time of Day Rates Study Results" (Accessed Jan. 29, 2025).
[69] Synapse Energy Economics, Inc., "Time-of-Use Rates for Delivery and Standard Offer Response to the Maine Public Utilities Commission's Request for Comments," Available: https://www.synapse-energy.com/sites/default/files/22-086%20Comments%20on%20TOU%20Rates.pdf (Accessed Mar. 5, 2025).
[70] As requested by NP in Sept. 2024.
[71] Hydro Québec, "Rate Flex D", Available: https://www.hydroquebec.com/residential/customer-space/rates/rate-flex-d-billing.html (Accessed Oct 2, 2024).
[72] Nova Scotia Power, "Time-of-Use Rate Pilot," Available: https://www.nspower.ca/your-home/residential-rates/time-of-use (Accessed Sept 5., 2024).
[73] Ontario Energy Board, "Electricity Rates", Available: https://www.oeb.ca/consumer-information-and-protection/electricity-rates (Accessed Sept. 5, 2024).

4.2 Results – Residential, Commercial, and Industrial Sectors – Efficiency and Electrification Measures

Exhibit 78, Exhibit 79 and Exhibit 80 show measure-level cost-effectiveness test results for the top ten efficiency and electrification measures by medium TRC for the residential, commercial, and industrial sectors, respectively. In addition to the TRC, the exhibits show the measure-level program administrator cost (PAC) test results that include an incentive set to offset 50% of the incremental measure cost for ROB measures, and 50% of the full cost for RET measures. The measure-level cost-effectiveness test results are also a function of non-incentive program costs where applicable. The non-incentive program cost reflects 25% of the measure-level incentive.[74]

Exhibit 78 shows that low-cost measures like faucet aerators and LED lamps are among the top ten residential sector measures by TRC.

Exhibit 78: Residential Sector Cost-Effectiveness Test Results (2025)

Measure	Medium TRC	Medium PAC
Faucet Aerator	49.9	89.9
LED Linear Tube	16.6	10.2
Programmable Thermostat (Central)	16.1	29.0
ENERGY STAR Ceiling Fan	15.8	28.5
Domestic Hot Water Pipe Insulation	13.2	23.8
Duct Insulation	11.1	19.9
Interior ENERGY STAR LED A-Lamp	Instant Payback	19.4
External ENERGY STAR LED A-Lamp	Instant Payback	18.5
Interior ENERGY STAR LED Reflector Lamp	Instant Payback	15.2
Exterior ENERGY STAR LED Reflector Lamp	Instant Payback	14.4

[74] The non-incentive program costs do not reflect detailed program design and are assumptions for the purposes of this analysis.

Like the residential sector, low-cost measures including faucet aerators, low-flow showerheads, and thermostatic restrictor shower valves are among the top ten by TRC in the commercial sector as shown in Exhibit 79. LED lamps and fixtures are also among the top ten measures by TRC.

Exhibit 79: Commercial Sector Cost-Effectiveness Test Results (2025)

Measure	Medium TRC	Medium PAC
Faucet Aerator	103.4	186.2
Low-Flow Showerhead	52.4	94.2
Thermostatic Restrictor Shower Valve	19.5	35.1
LED High Bay Luminaire	18.3	33.0
ENERGY STAR Dishwasher	15.8	28.4
High Efficiency Compressor	14.5	26.2
ENERGY STAR Vending Machine	10.7	19.3
LED Reflector (Exterior)	Instant Payback	56.4
LED Reflector (Interior General)	Instant Payback	42.5
LED Reflector (Interior Secondary)	Instant Payback	42.1

Exhibit 80 shows the top ten industrial sector measures by TRC. A range of measures is included in the top ten, including LED high bay luminaire, refrigeration heat recovery, and insulation.

Exhibit 80: Industrial Sector Cost-Effectiveness Test Results (2025)

Measure	Medium TRC	Medium PAC
LED High Bay Luminaire	22.7	40.9
Refrigeration Heat Recovery	17.8	32.1
Insulation	15.7	28.3
Reduced Temperature Settings	Instant Payback	Instant Payback
Process Optimization Efforts - Mining and Processing	Instant Payback	Instant Payback
High Efficiency Chiller	9.3	16.8
Adjustable or Variable Speed Drive (Pump)	8.9	16.0
Use Cooler Air from Outside for Make Up Air	7.7	13.9
Correctly Sized Fans: Impeller Trimming or Fan Selection	6.6	11.8
Air Curtains - Process Cooling	6.3	11.4

4.3 Results – Residential, Commercial, and Industrial Sectors – DR Measures

This section shows program costs and measure-level cost-effectiveness test results for the residential, commercial, and industrial sector DR measures. See section 4.4 for transportation sector DR measure results.

4.3.1 Program Costs for Electricity Rate Design and Equipment DR Measures

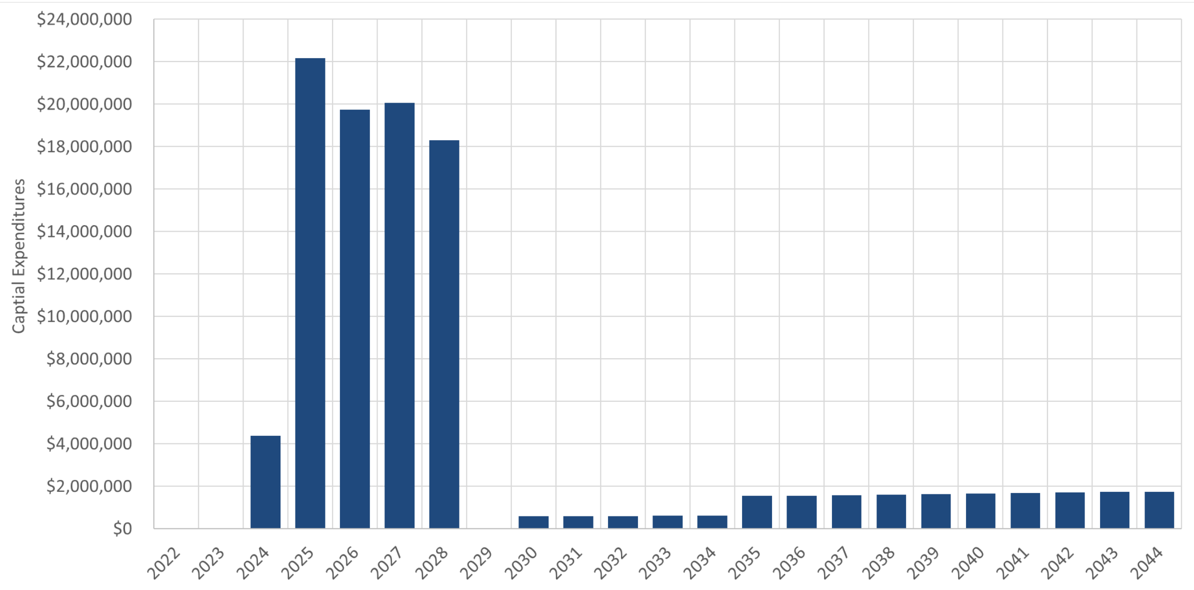
Program costs for DR measures include non-incentive program costs to develop and administer programs and incentive costs paid directly to customers. Advanced metering infrastructure (AMI) implementation costs can also form part of the non-incentive costs for DR measures (i.e., electricity rate design) if the infrastructure is not already in place.

To account for how DR programs may be administered, the Study Team developed incentive and non-incentive program costs for each DR measure in consultation with the Utilities and informed by jurisdictional research.[75] These costs are discussed under two headings that follow, advanced metering infrastructure implementation, and summary of electricity rate design and equipment DR program costs.

Advanced Metering Infrastructure Implementation

Time variable rates (TVR) are not in effect in Newfoundland but exist elsewhere in Canada, including in Ontario, Quebec and Nova Scotia. Smart meters, data management systems, and communication networks form the AMI infrastructure necessary for a utility to implement TVR like time-of-use (TOU) and critical peak pricing (CPP). Exhibit 81 shows the expected capital expenditures to install AMI in Newfoundland.[76]

Exhibit 81: Capital Expenditures for AMI in Newfoundland



[75] These costs are research-based estimates developed for the analysis.

[76] AMI costs provided by NP on November 12, 2024. Costs assume smart meters are installed starting in 2029. In the Study, costs are discounted assuming year one is 2025 to ensure consistency with the other measures.

The capital expenditures shown in Exhibit 81 include costs for smart meters in all rate classes. The following assumptions are embedded in the expenditures:

- The expected useful life of a smart meter is 20 years.
- Smart meters are installed from 2025-2029.
- Customers can opt-into TOU or CPP rates starting in 2029.
- Capital expenditures after 2029 are to replace smart meters that fail.
    - The annual smart meter failure rate is 0.5% from 2030 to 2035.
    - From 2036 to 2040, the failure rate is 2%.

In addition to capital expenditures, there are upfront and annual operational costs associated with AMI.[77,78] Annual operating expenditures of $1.5M are expected starting in 2025.

Summary of Electricity Rate Design and Equipment DR Program Costs

Exhibit 82 shows the non-incentive program cost assumptions for the residential (res), commercial (com) and industrial (ind) sector electricity rate design, utility-driven and thermal storage with TOU DR measures.

Exhibit 82: Non- Incentive Program Costs for DR Measures

Measure Type	Sector	Non-Incentive Program Costs
Electricity Rate Design (TOU and CPP)	Res	$3,132 AMI meter cost/dwelling + Other Non-Incentive Program Costs
	Com	$0.65 AMI meter cost/ft^2 + Other Non-Incentive Program Costs
	Ind	$1.6M/segment + Other Non-Incentive Program Costs
Equipment DR (Utility-Driven)	Res	20% of the total incentive
	Com	40% of the total incentive
	Ind	$15/kW of savings
Equipment DR (Thermal Storage with TOU)	Res	$3,132 AMI meter cost/dwelling[79] + Other Non-Incentive Program Costs
	Com	$0.65 meter cost/ ft^2 + Other Non-Incentive Program Costs

The electricity rate design and equipment DR measure costs include AMI infrastructure costs discussed previously. In the residential sector, the Study Team assumes there is one electricity meter per dwelling.

[77] Nova Scotia Power, "Time-Varying Pricing Project Submission", Available: https://www.brattle.com/wp-content/uploads/2021/05/19479_nova_scotia_utility_and_review_board_-_time-varying_pricing_project_submission.pdf (Accessed Sept. 5, 2024).
[78] Hydro Québec, "Rate Flex D", Available: https://www.hydroquebec.com/residential/customer-space/rates/rate-flex-d-billing.html (Accessed Oct 2, 2024).
[79] Thermal storage with TOU equipment DR measures are modelled with TOU rates separate from the electricity rate design measures, so program costs also need to include the operational and metering infrastructure costs.

In the commercial sector, there could be several meters associated with the same building, so costs are expressed on a gross floor area basis. In the industrial sector, the number of buildings and the gross floor area is unknown, so costs are expressed on a per segment basis.

Exhibit 83 shows the annual customer enrollment and year one customer equipment incentives for the equipment DR measures. The annual enrollment incentive encourages customers to participate in DR events, and the year one incentive offsets the costs to purchase the equipment required to participate. No annual enrollment is paid to customers who participate in the thermal storage with TOU equipment DR measures because they benefit from utility bill cost savings from shifting electricity use and demand to off-peak times. There are no annual customer enrolment or year one incentives for the electricity rate design measures, so they are omitted from Exhibit 83.

Exhibit 83: Incentive Program Costs for DR Measures

Measure Type	Sector	Annual Customer Enrolment Incentive	Year One Customer Equipment Incentive
Equipment DR (Utility-Driven)	Res	$100/customer/yr.[80, 81]	• For BTM Solar: $0.30/Watt installed DC capacity, up to $3,000.[82] • For Battery Storage: $300/kWh of installed energy storage capacity, up to $2,500.[82] • For Grid Interactive Efficient Buildings (GEB): 5% of the incremental cost.[83] • For thermal storage measures: $2,000 per central system; $540 per room unit.[84] • For all other measures: Utility pays 100% of the incremental cost of the measure.
	Com	$0.04/ ft^2/yr.	
	Ind	$50/kW of savings[85]	
Equipment DR (Thermal Storage with TOU)	Res	$0	• For thermal storage measures: $2,000 per central system; $540 per room unit.
	Com	$0	

[80] Southern California Edison, "Save up to $115 with a Smart Thermostat", Available: https://www.sce.com/residential/demand-response/smart-energy-program (Accessed Sept. 5, 2024).
[81] Pacific Gas and Electric Company, "SmartAC™ program," Available: https://bit.ly/4idzkro (Accessed Sept. 5, 2024).
[82] Efficiency Nova Scotia, "SolarHomes Program," Available: https://www.efficiencyns.ca/residential/services-rebates/solar-homes/ (Accessed Sept. 5, 2024).
[83] Rocky Mountain Institute, "Value Potential for Grid-Interactive Efficient Buildings in the GSA Portfolio: A Cost-Benefit Analysis", Available: https://bit.ly/3FK2d0c / (Accessed Sept. 5, 2024).
[84] Efficiency Nova Scotia, "Electric Thermal Storage (ETS) System Rebate Guide," Available: https://www.efficiencyns.ca/tools-resources/guide/ets-system-rebate-guide/ (Accessed Sept. 5, 2024).
[85] British Columbia Hydro and Power Authority, "Demand response for business", Available: https://bit.ly/4l9TLaM (Accessed Sept. 5, 2024).

4.3.2 Cost-Effectiveness Test Results for Electricity Rate Design Measures

Exhibit 84 shows the medium achievable PAC results by sector for the electricity rate design measures, none of which pass the PAC due to high program costs associated with AMI installation and operation. The PAC is used to assess cost-effectiveness of the DR measures because utilities typically pay all incremental equipment costs in a DR program, and because incentives to participants are typically an expense to the utility over and above the incremental equipment costs. This differs from efficiency programs where the incentives usually cover a portion of the participant's incremental costs for the efficiency upgrade.[86]

The results reflect costs and benefits incurred during the four-year AMI meter installation period and the 20-year smart meter lifetime. These measures assume an opt-in rate structure where participation ramps up to a maximum of 15% in the later years of the study. Potential results and participation rates for the electricity rate design measures are presented in section 7.2.1.

Exhibit 84: Medium PAC Cost-Effectiveness Test Results – Electricity Rate Design Measures

Measure	Residential	Commercial	Industrial
CPP	0.19	0.39	0.43
TOU	0.12	0.29	0.39

[86] "Conservation Potential Study, Final Report (Volume 2 – Appendices)," Dunsky Energy Consulting (2019).

4.3.3 Cost-Effectiveness Test Results for Equipment DR Measures

In the Study, the equipment DR measures are modelled with opt-in participation and with current rates (i.e., they are not modelled with TVR). Exhibit 85 shows the measure-level cost-effectiveness test results for the top residential sector equipment demand response measures by PAC. As stated previously, the PAC is used to assess cost-effectiveness of DR measures in the Study because utilities typically pay all incremental equipment costs in a DR program, and because incentives to participants are typically an expense to the utility over and above the incremental equipment costs.[87] Exhibit 85 also shows the medium TRC for each top ten measure.

All smart thermostat or switch measures and all thermal storages measures are in the top ten by PAC for the residential sector. The utility-driven thermal storage measures show higher PAC results than the equivalent thermal storage with TOU measures, which include the AMI costs incurred during the four-year AMI meter installation period and the 20-year smart meter lifetime.

Exhibit 85: Residential Sector Cost-Effectiveness Test Results – Equipment DR Measures

Measure	Medium PAC	Medium TRC
Smart Thermostat or Switch for Baseboards or Furnaces	7.4	44.2
Thermal Storage and Electric Furnace	Utility-Driven: 6.7 Thermal storage with TOU: 4.7	Utility-Driven: 1.0 Thermal storage with TOU: 1.0
Thermal Storage and Electric Baseboard Heating	Utility-Driven: 5.5 Thermal storage with TOU: 4.0	Utility-Driven: 0.9 Thermal storage with TOU: 0.9
Behind-the-Meter Battery Storage	4.6	0.7
Smart Thermostat or Switch for Ductless Mini-Split Heat Pumps	3.1	18.7
Smart Thermostat or Switch for Central Air Source Heat Pumps	3.0	18.0
Thermal Storage and Air Source Heat Pump	Utility-Driven: 2.3 Thermal storage with TOU: 1.7	Utility-Driven: 0.4 Thermal storage with TOU: 0.3
Thermal Storage and Ductless Mini-Split Heat Pump	Utility-Driven: 2.3 Thermal storage with TOU: 1.7	Utility-Driven: 0.4 Thermal storage with TOU: 0.4
Smart Circuit Breakers or Smart Panel	0.8	1.0

[87] "Conservation Potential Study, Final Report (Volume 2 – Appendices)," Dunsky Energy Consulting (2019).

Exhibit 86 shows the top ten commercial sector equipment demand response measures by PAC. Backup generation has the highest PAC due to its relatively low incremental cost and incentive and only applies to customers with existing backup generators. Like the residential sector, all commercial sector thermal storage measures are in the top ten by PAC.

Exhibit 86: Commercial Sector Cost-Effectiveness Test Results – Equipment DR Measures

Measure	Medium PAC	Medium TRC
Backup Generation at Peak Hours	38.6	83.1
Behind-the-Meter Battery Storage	11.7	1.8
Thermal Storage and Electric Furnace Heating	Utility-Driven: 10.9 Thermal storage with TOU: 13.3	Utility-Driven: 7.0 Thermal storage with TOU: 8.3
Thermal Storage and Heat Pump Heating	Utility-Driven: 10.9 Thermal storage with TOU: 13.3	Utility-Driven: 7.0 Thermal storage with TOU: 8.3
Large Commercial Dual-Fuel Water Heater	10.9	30.9
Grid Interactive Efficient Buildings (GEB)	7.9	0.6
HVAC Control	7.1	24.8
Thermal Storage and Electric Baseboard Heating	Utility-Driven: 4.6 Thermal storage with TOU: 4.6	Utility-Driven: 1.8 Thermal storage with TOU: 2.2
HVAC Fans & Pumps Controls	4.2	14.8

Exhibit 87 shows the measure-level cost-effectiveness test results for the industrial sector equipment demand response measures that pass the PAC screen.[88] Behind-the-meter battery storage has the highest due to its longer expected useful life (20 years) compared to other measures with similar savings.

Exhibit 87: Industrial Sector Cost-Effectiveness Test Results – Equipment DR Measures

Measure	Medium PAC	Medium TRC
Behind-the-Meter Battery Storage	5.3	0.5
Backup Generation at Peak Hours	5.2	21.5

[88] The only measure that fails the screen is peak shifting through on-site storage.

4.4 Results – Transportation Sector Measures

This section presents measure-level results for the transportation sector measures, starting with managed charging.

4.4.1 Managed Charging

The Study Team used hourly load shapes to examine the peak impact of EV charging and the effectiveness of different DR measures in shifting EV charging load. Load shapes for LDV come from the Geotab Charge the North dataset which uses data logged on light-duty EVs across Canada.[89,90] The load shapes for MHDV and buses are based on fleet vehicle data from California.[91]

Exhibit 88 shows results for managed charging measures in order of decreasing PAC. Like the rest of the Study DR measures, the PAC is used to assess the cost-effectiveness of the EV managed charging measures. Managed charging can be accomplished using electric vehicle supply equipment (EVSE) or vehicle telematics (VT).[92]

Exhibit 88: Transportation Sector Managed Charging Measures (2040)

End Use(s) Affected	Ownership Type	Managed Charging Method	Measure Name	kW Savings[93]	Medium PAC	Medium TRC
EV Charging	Fleet	VT	HDV – VT	19.85	86.1	430.5
	Fleet	VT	Bus – VT	7.00	30.4	151.9
	Fleet	EVSE	HDV – EVSE	19.85	18.8	12.9
	Fleet	VT	MDV – VT	4.07	17.7	88.4
	Fleet	EVSE	Bus – EVSE	7.00	14.8	14.2
	Fleet	EVSE	MDV - EVSE	4.07	5.3	4.0
	Fleet	VT	Light Duty BEV – VT	0.76	3.3	16.5
	Personal	VT	BEV – VT	0.66	2.9	14.3
	Personal	EVSE	BEV EVSE	0.66	2.6	6.3
	Personal	VT	PHEV – VT	0.52	2.3	11.3
	Personal	EVSE	PHEV – EVSE	0.52	2.0	5.0
	Fleet	EVSE	Light Duty BEV – EVSE	0.76	1.6	1.5
	Fleet	VT	Light Duty PHEV – VT	0.26	1.1	5.3
	Fleet	EVSE	Light Duty PHEV – EVSE	0.26	0.6	0.5

[89] The dataset contains tracking and charging data from over 1,000 EV drivers across Canada. IT provides EV load profiles insights and actions to minimize charging infrastructure upgrades.
[90] A CPP rate was not considered because Geotab Charge the North dataset does not include CPP analysis.
[91] Load shape data is limited, and there is no data available for Newfoundland.
[92] EVSE and VT are defined in the Definitions section.
[93] Savings are reported on a per vehicle basis.

Key findings include:

- All measures pass the TRC except for Fleet Managed Charging – LD PHEV – EVSE, which also fails the PAC screen. The poor performance of this PHEV measures is due to the limited peak impact of individual PHEVs compared to BEVs for the same measure cost.[94]
- For Personal Managed Charging, evidence from pilot programs across North America suggests annual enrolment incentives in the range of $50 to $200. The Study Team's analysis reflects $80 per year, but the Personal Managed Charging – BEV – EVSE measure would pass the PAC with an annual enrolment incentive of up to $164. All EVSE measures also include an upfront incentive of half the incremental cost of installing a smart charger.
- VT measures are the most cost-effective because there are no incremental hardware costs to upgrade from a non-smart charging capable vehicle to a smart charging capable vehicle.

4.4.2 Time-of-Use Rates

Exhibit 89 shows the transportation sector TOU rate measures by ownership type.

Exhibit 89: Transportation Sector TOU Rate Measures

End Use(s) Affected	Ownership Type	Measure Name
EV Charging	Personal	TOU - BEV
	Personal	TOU - PHEV

The Study Team examined the potential impact of a TOU rate to incentivize personal vehicle owners to charge outside of peak periods. The analysis relies on data from the Charge the North dataset for jurisdictions that already have a residential TOU in place.[95] The jurisdictions under study had AMI and employed TOU rates with "Off-Peak" rates beginning at 7:00 p.m. at the time of data collection. Applying the resulting load shapes to the forecast EV load in Newfoundland had little overall impact: the peak time shifted to later in the evening, but the amplitude of the peak remained similar.

This issue was addressed by studying the effects of the generic residential TOU rate structure described in section 4.1.1. The impacts of the TOU rates on EV load shapes from the Charge the North dataset were applied to estimate how EV load would behave for a TOU rate structure that had "Off-Peak" rates beginning at 10 p.m.[96] The resulting load shape was used to estimate the potential for peak savings for

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[94] Fleet PHEVs are estimated to have 0.50 kW less peak reduction potential than fleet BEVs. The difference in peak reduction potential between personal PHEVs and BEVs is smaller at 0.14 kW. This is largely due fleet PHEVs having a much lower utility factor (the percentage of kilometres driven that are powered by the electric motor) than personal PHEVs.
[95] "Preparing for EVs: Charge the North EV Case Study," Geotab, Available: https://www.geotab.com/blog/preparing-for-evs/ (Accessed Jan. 30, 2024).
[96] The EV TOU load shapes in the Study are informed by GeoTab Charge the North data for EV charging in Ontario, where TOU rates are in effect. Despite the potential differences in the timing of TOU price periods between Ontario and Newfoundland, the Study Team deemed this was the best available information in the absence of Newfoundland-specific data.

TOU electricity rate design measures under two EV participation scenarios: opt-in and opt-out. These scenarios are defined in the callout that follows.

Personal EV TOU Participation Scenarios

The Study Team modelled two personal EV participation scenarios to assess the potential peak reduction from EV TOU rates: opt-in participation and opt-out participation. Both scenarios represent a future where the intermediate EV forecast scenario plays out. The opt-in and opt-out scenarios form lower and upper bounds for peak reduction potential, and are defined as follows:

*- **Opt-in participation scenario:** Reflects a 15% participation rate, which matches the one used for the residential sector TOU measure.*

*- **Opt-out participation scenario:** 100% of EVs are on a time-of-use rate.*

Because EV charging loads are flexible, EV owners are likely to make up a higher portion of the 15% of residential sector customers who participate in the TOU rate, compared to non-EV owners. In the early forecast years, when the number of EVs in Newfoundland is less than 15% of the number customers, the opt-out scenario represents a future where all personal EV owners participate in the EV TOU rate. For example, if there are 100,000 residential customers, and 10,000 EVs in Newfoundland, all personal EV owners participate in the EV TOU rate.

In later forecast years, when more than 15% of customers are expected to own an EV, the opt-out scenario represents a future where a separate EV rate may be offered to allow for more than 15% of all customers to be on an EV TOU rate (i.e., so that EV TOU participation could exceed whole-home TOU participation). For example, if there are 100,000 residential customers, and 20,000 EVs, 20% of residential customers would participate in the EV TOU rate.

Neither participation scenario assumes all EVs charge off-peak on a given night. The Study Team used aggregate load shapes (i.e., load shapes that reflect the charging patterns of thousands of vehicles) to assess the impact of each scenario. In addition, neither scenario assumes there is a separate meter for EVs charging. Virtual submetering or metering through EVSE could be leveraged to offer an EV TOU rate separate from the whole home TOU rate.

Fleet TOU measures were excluded from the Study because limited data exists on the impact of dedicated TOU rates for commercial fleets. In addition, commercial customers are already subject to a demand charge which acts as an incentive to limit local peak impacts at individual sites. As seen in Exhibit 67, the fleet vehicle charging peak overlaps with the IIS evening peak. This suggests that reductions in local peak impacts attributed to demand charges would also provide benefits for the IIS system.

A TOU rate can have a much larger effect on EV charging compared to any other end use in the residential, commercial and industrial sectors because EV charging is flexible (depending on the number of EVs participating). Exhibit 90 shows the medium achievable PAC results by sector for the TOU measure. Three results are shown for the residential sector: excluding EVs, including EVs with opt-in participation, and including EVs with opt-out participation. The results reflect costs and benefits incurred during the four-year AMI meter installation period, and the 20-year smart meter lifetime.

The PAC is less than 1 for all sectors, though the residential sector result including EVs with opt-out participation meets the PAC screening threshold of 0.8.

Exhibit 90: Medium Achievable PAC Cost-Effectiveness Test Results – Electricity Rate Design Measures

Measure	Residential (Excl. EVs)	Residential (Incl. EVs, Opt-In)	Residential (Incl. EVs, Opt-Out)	Commercial	Industrial
TOU	0.12	0.20	0.95	0.29	0.39

4.4.3 Adoption Incentives

Exhibit 91 shows the transportation sector adoption incentive measures. These measures represent the incremental per-vehicle incentive required to lift EV adoption from the natural adoption scenario to reach the intermediate and government targets scenarios. See Appendix E for details of the Study Team's approach to assessing the adoption incentive measures.

Exhibit 91: Transportation Sector Adoption Incentive Measures

End Use(s) Affected	Measure Name
EV Charging	• Personal LDV • Fleet LDV • MDV • HDV • Bus

Personal LDV

Exhibit 92 shows that, compared to the natural adoption scenario, a median annual per-vehicle incremental incentive of $23,833 would be required to achieve the EV adoption levels in the government targets scenario.[97] To reach the EV adoption levels in the intermediate scenario, a $4,691 incremental incentive would be required.

Exhibit 92: Results - Transportation Sector Personal Vehicle Adoption Incentives

Incremental Step	Median Annual Per-Vehicle Incremental Incentive[98]	Median Annual Incentive Program Budget (millions)
To reach the government targets scenario from the natural adoption scenario	$23,833	$303
To reach the intermediate scenario from the natural adoption scenario	$4,691	$30

[97] If government targets for EV adoption are mandated, the Utilities would not provide incentives.

[98] This is the median of the incentive values that newly purchased EVs would receive across all years of the Study forecast period.

Fleet LDV, MDV, and HDV

There is no literature to support sales market share uplift of fleet vehicles due to purchase incentives. This could be because fleet vehicles are earlier in their adoption curve compared to personal BEV, so sample sizes are limited. The Study Team offers the following thoughts:

- Fleet LDV and lighter-duty MDV may behave like personal LDV based on their incremental capital costs, vehicle kilometres travelled (VKT), and reliance on L2 chargers.[99]
- HDV probably behave differently than personal LDV based on their incremental capital costs, VKT, and reliance on DCFC chargers in many cases.[99] Directionally, the absolute per-vehicle incentive values and total annual incentive budgets may need to be much higher for HDV than for personal LDV.

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[99] National Renewable Energy Laboratory, "Transportation Annual Technology Baseline (ATB) Data", Available: https://atb.nrel.gov/transportation/2022/data (Accessed: Nov. 30, 2024).

4.4.4 Infrastructure Requirements

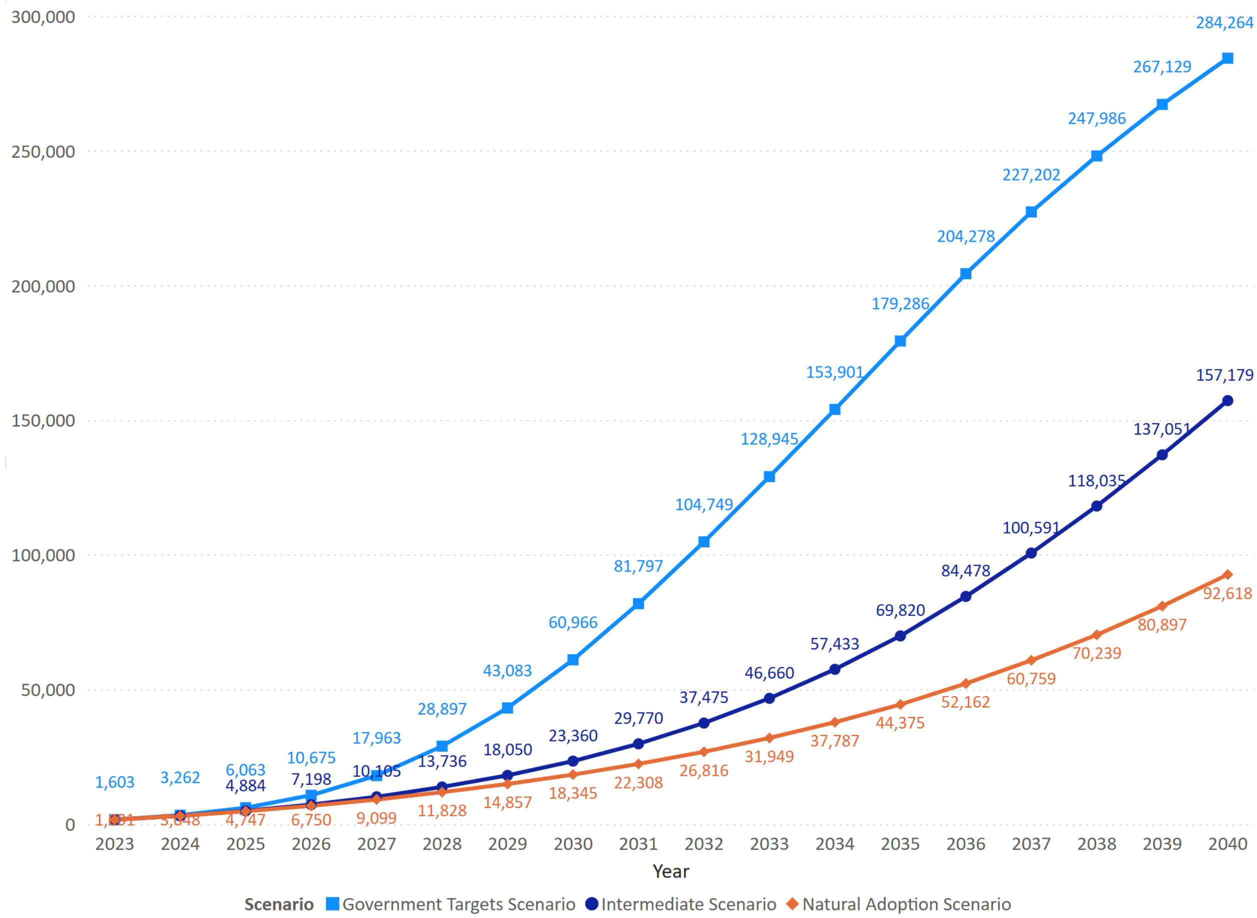
Exhibit 93 shows the transportation sector charging infrastructure measures. The Study Team calculated the number of charging ports and the investment required to support vehicle counts in the natural adoption, intermediate, and government targets scenarios. Results are shown in Exhibit 94 and Exhibit 95. See Appendix E for details of the Study Team's approach to these calculations.

Exhibit 93: Transportation Sector Charging Infrastructure Measures

End Use(s) Affected	Measure Name
EV Charging	• Personal LDV Level 1 (L1) Home Charger • Personal LDV Level 2 (L2) Home Charger • Personal LDV L2 Home Charger – Multi-Unit Residential Building (MURB) • Personal LDV L2 Public Charger • Personal LDV DCFC Public Charger • Fleet LDV L2 Depot Charger • Fleet LDV L2 Public Charger • Fleet LDV Direct Current Fast Charger (DCFC) Depot Charger • Fleet LDV DCFC Public Charger • MDV L2 Depot Charger • MDV L2 Public Charger • MDV DCFC Depot Charger • MDV DCFC Public Charger • HDV L2 Public Charger • HDV DCFC Deport Charger • HDV DCFC Public Charger • Bus L2 Depot Charger • Bus DCFC Depot Charger

Exhibit 94 shows the cumulative number of ports (including L1, L2, and DCFC) required per forecast EV scenario.[100] By 2040, 284,264 ports are required in the government targets scenario, compared to 157,179 ports in the intermediate scenario and 92,168 in the natural adoption scenario.

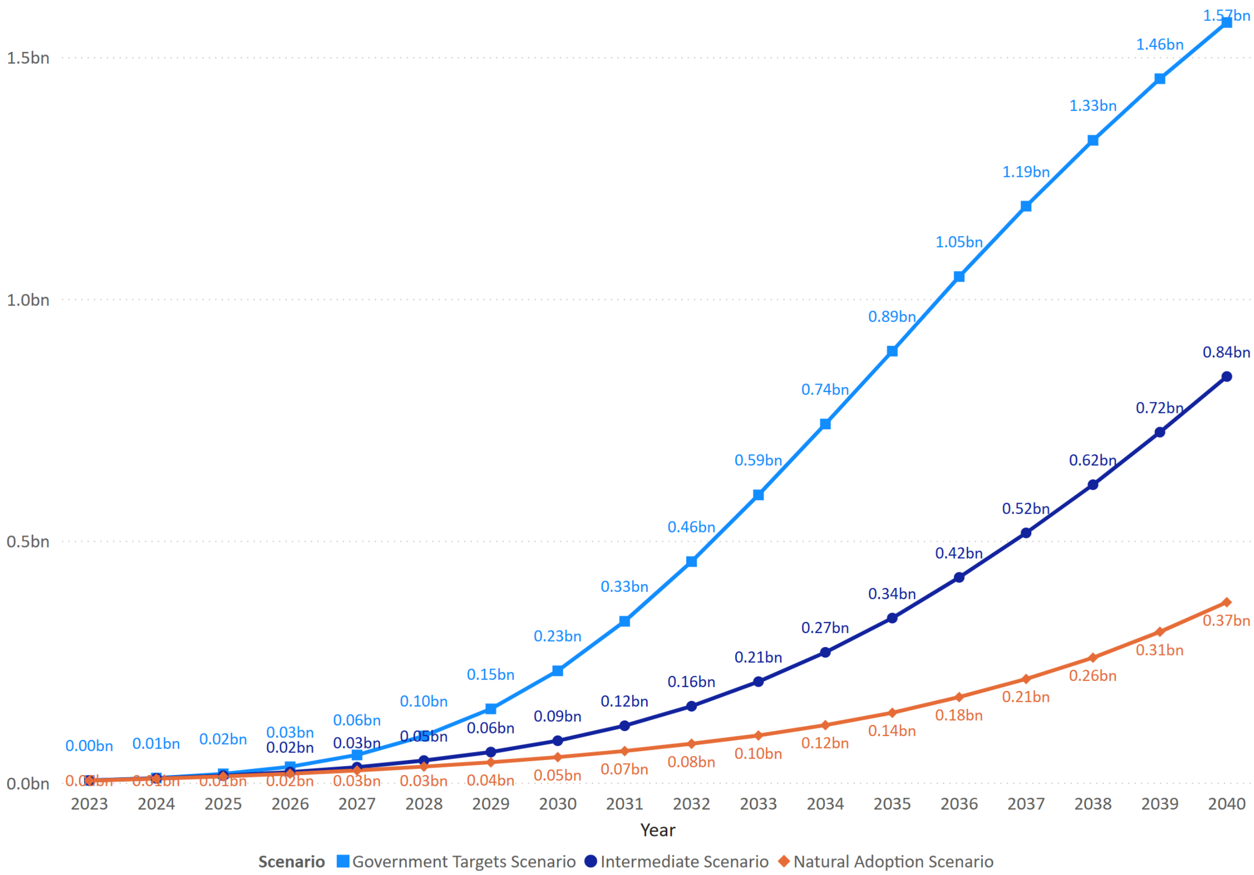
Exhibit 94: Results - Transportation Sector Charging Infrastructure Port Count by Scenario



[100] The values in each year represent the sum of the infrastructure requirements for all preceding years and the year in question.

Exhibit 95 shows the cumulative investment required for each forecast EV scenario. By 2040, an estimated $1.57 billion in cumulative charging infrastructure investments is required to reach the government targets scenario, compared to $0.84 billion in the intermediate scenario and $0.37 billion in the natural adoption scenario.[101]

Exhibit 95: Transportation Sector Charging Infrastructure Investment Required by Scenario ($)



[101] In the Study, charging infrastructure refers to the ports required to support electric vehicle charging in the Transportation sector. Charging infrastructure costs include port costs and associated installation costs. Costs exclude distribution system upgrades to host charging loads.

Exhibit 96 and Exhibit 97 show the distribution of charging infrastructure investment and the distribution of port count across charger types, respectively. By the end of the forecast period, infrastructure investment is almost evenly split between DCFC chargers and L2 chargers (L1 chargers are assumed to be provided by the vehicle manufacturer at point of vehicle sale).

Exhibit 96: Transportation Sector Charging Infrastructure Investment (Intermediate Scenario)

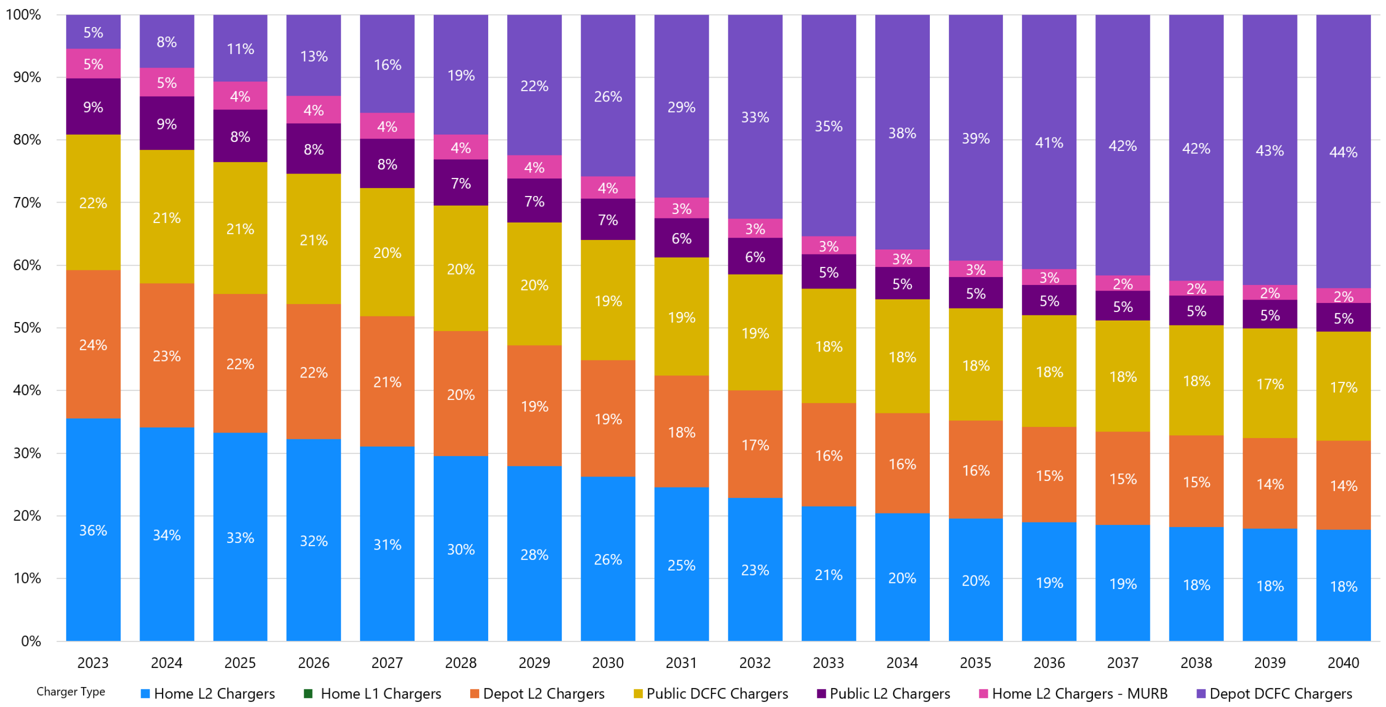
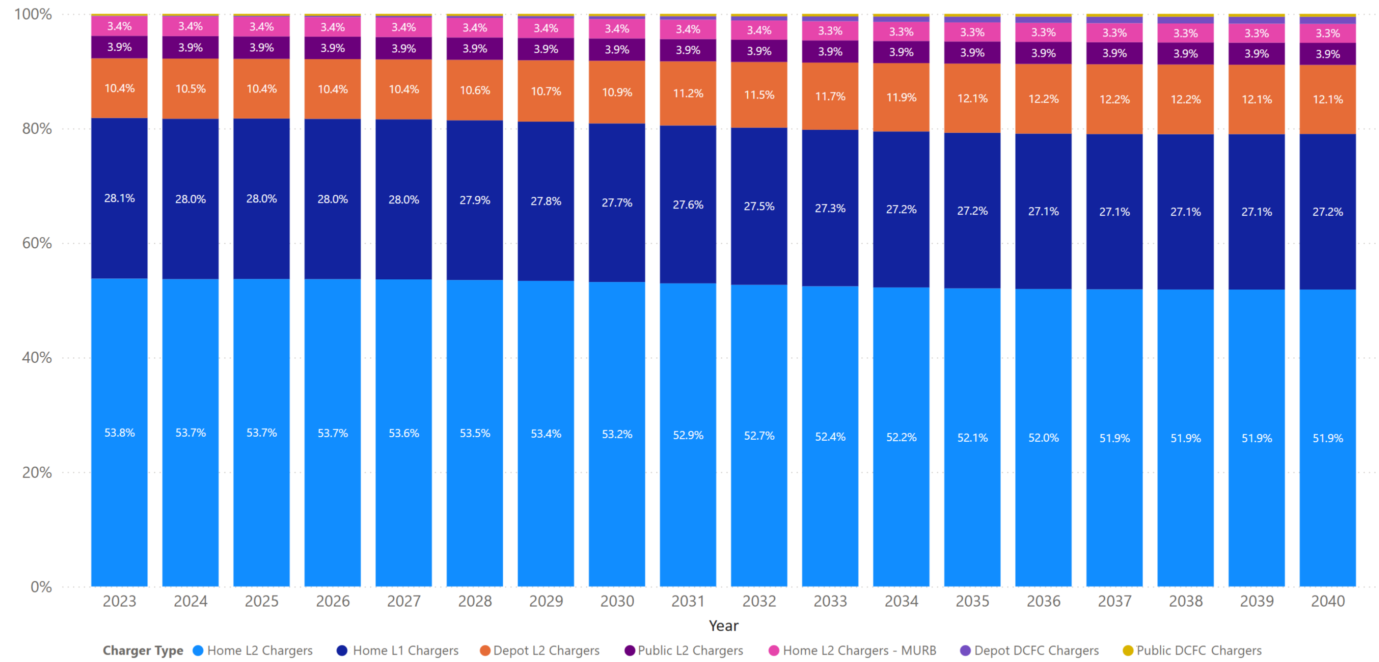


Exhibit 97 reveals the following:

- L1 and L2 home chargers dominate the port count compared to DCFC chargers, even though the investment is split more evenly for infrastructure investment due to the high cost of DCFC chargers versus L2 chargers as noted previously.
- Overall, home or depot chargers outnumber public chargers, though the per-unit cost of DCFC chargers attenuates this effect for charging infrastructure investment.[102]

Exhibit 97: Transportation Sector Port Count (Intermediate Scenario)



Charger Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Home L2 Chargers	53.8%	53.7%	53.7%	53.7%	53.6%	53.5%	53.4%	53.2%	52.9%	52.7%	52.4%	52.2%	52.1%	52.0%	51.9%	51.9%	51.9%	51.9%
Home L1 Chargers	28.1%	28.0%	28.0%	28.0%	28.0%	27.9%	27.8%	27.7%	27.6%	27.5%	27.3%	27.2%	27.2%	27.1%	27.1%	27.1%	27.1%	27.2%
Depot L2 Chargers	10.4%	10.5%	10.4%	10.4%	10.4%	10.6%	10.7%	10.9%	11.2%	11.5%	11.7%	11.9%	12.1%	12.2%	12.2%	12.2%	12.1%	12.1%
Public L2 Chargers	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%
Home L2 Chargers - MURB	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%
Depot DCFC Chargers	0.1%	0.1%	0.2%	0.2%	0.3%	0.3%	0.4%	0.5%	0.6%	0.7%	0.8%	0.9%	1.0%	1.1%	1.1%	1.2%	1.2%	1.2%
Public DCFC Chargers	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%

[102] The Public category includes, L2 chargers for personal (i.e., not fleet) use that are situated at commercial sector buildings.

4.4.5 Emerging Measures

Exhibit 98 shows emerging measures for the transportation sector. Emerging measures allow EVs to send energy back to the electricity grid, which can be useful when the grid is constrained, and additional generation is required.[103]

Exhibit 98: Transportation Sector Emerging Measures

End Use Affected	Measure Name
EV Charging	Vehicle to Load (V2L)
	Vehicle to Building (V2B)
	Vehicle to Grid (V2G)

Emerging measures can be categorized into three classes:

1. **Vehicle to load** applications use vehicle battery power as a backup source for localized loads within a site.
2. **Vehicle to building** applications enable feeding battery power from the vehicle to serve end uses in the building and are expected to primarily serve for building resilience but may also reduce building peak power demand.
3. **Vehicle to grid** applications enable feeding battery power from the vehicle back to the grid during peak periods.

These emerging measures are at the preliminary research and demonstration project stage in North America. Most research occurs in California. Generally, V2G and V2B applications are expected to be more complex and later to scale compared to V2L applications.[104] Focus segments are LDV and school buses.

A limited but growing number of LDV manufacturers include bidirectional charging capabilities in their vehicles.[105] Research suggests that the value of emerging measures to the power grid could ultimately exceed the value of managed charging.[106] Reliable data on measure costs and the relationship between

[103] Electric Vehicle Association of Alberta, "The Current State of Bidirectional EV Charging in Canada", Available: https://albertaev.ca/bidirectional-ev-charging-in-canada/#:~:text=This%20bidirectional%20energy%20transfer%20allows,economic%20benefits%20to%20EV%20owners (Accessed: Nov. 30, 2024).
[104] Smart Electric Power Alliance, "The State of Managed Charging in 2021", Available: https://sepapower.org/resource/the-state-of-managed-charging-in-2021/ (Accessed: Nov. 30, 2024).
[105] The following manufacturers appear to currently offer or plan to offer bidirectional charging capabilities in their vehicles by 2026: Ford, Nissan, Hyundai, Kia, Volkswagen, General Motors, Tesla, and Mitsubishi.
[106] American Public Power Association, "Public power utilities, others, pursue vehicle-to-grid opportunities", Available: https://www.publicpower.org/periodical/article/public-power-utilities-others-pursue-vehicle-grid-opportunities (Accessed: Nov. 30, 2024).

participant uptake and program costs does not exist yet.[107] The Study Team recommends that the Utilities monitor pilot study results to develop this data over time.

The Utilities can consider the following activities to prepare their grids to realize the benefits of bidirectional charging, with consideration also given to the costs and barriers required to implement the activities:[108, 109, 110]

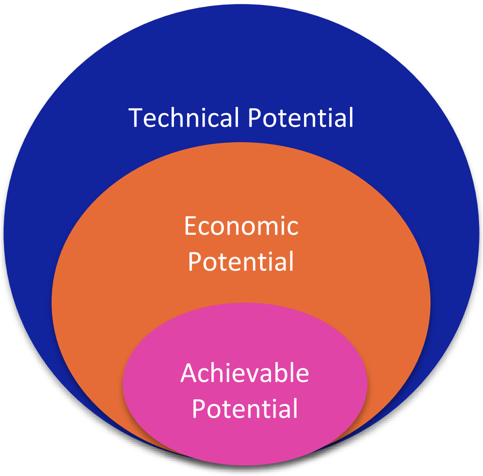
- Deploy smart meters,
- Require utility customers to register EV chargers with the utility, and,
- Develop and adopt standardized privacy-compliant communication protocols between the utility grid control system, the vehicles, and the chargers.

[107] For these reasons, the Study Team did not assess the cost-effectiveness of emerging measures.
[108] "Vehicle-to-Grid: Can This Tech Save the Planet and Make Drivers Money?" Just Energy, Available: https://justenergy.com/blog/vehicle-to-grid/ (Accessed Jul. 2024).
[109] Preparing for the Vehicle-to-Grid (V2G) Revolution | GE Digital
[110] "Vehicle to Grid Readiness Worldwide," Berylls, Available: https://www.berylls.com/vehicle-to-grid-readiness-worldwide/, (Accessed Jul. 2024).

5 Efficiency Savings Potential

This section presents energy efficiency savings potential results for the IIS. The Study Team assessed three levels of savings potential: technical, economic, and achievable, described as follows:[111]

1. **Technical Potential:** An estimate of the technically feasible energy and demand savings potential, ignoring measure cost effectiveness or market acceptance.
2. **Economic Potential:** An estimate of the energy and demand savings potential for the measures in the technical potential that also pass the cost effectiveness screening criteria established for the Study.[112] The total resource cost (TRC) test is used to screen efficiency measures. Measures are included in the economic potential if their benefit-cost ratio is 0.8 or higher.
3. **Achievable Potential**: An estimate of the energy and demand savings potential considering feasible adoption rates of cost-effective measures over the study period. Achievable potential considers market barriers, customer or end-user payback acceptance, and awareness of energy efficiency measures among other factors. The achievable scenarios are defined as follows:
    - **Lower**: Incentive is 25% of incremental cost for ROB measures and 25% of full cost for RET measures.
    - **Medium**: Incentive is 50% of incremental cost for ROB measures and 50% of full cost for RET measures.
    - **Higher**: Incentive is 100% of incremental cost for ROB measures and 100% of full cost for RET measures.



In all three achievable potential scenarios, non-incentive costs are set to 25% of the measure-level incentive. While 25% is a standard estimate used for the purposes of this Study, non-incentive costs would vary from program to program.

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[111] "Foreword" Independent Electricity System Operator, Available: https://www.ieso.ca/-/media/Files/IESO/Document-Library/conservation/APS/2019-Achievable-Potential-Study-Foreword.pdf (Accessed Dec. 11, 2024).

[112] The economic potential does not consider incentive and non-incentive costs.

The rest of this section presents results and analysis for the medium achievable potential scenario, except otherwise noted. As explained in section 2, all savings are presented in at-the-meter terms, instead of at-the-generator terms. Therefore, savings results exclude line losses in the transmission and distribution network. Line losses are added to the at-the-meter savings to calculate at-the-generator savings, which are used in the TRC calculations.[113] In addition, all savings presented are cumulative.

Adoption Rates for Achievable Potential Scenarios - Efficiency

The Study Team developed measure-level adoption rates for each achievable potential scenario with consideration to:

1. Savings the Utilities have achieved historically for measures common to the Study and their historical programs.

2. Feedback from the Utilities and the EAC regarding current and 2040 expected market share for measures discussed in the achievable potential workshops.

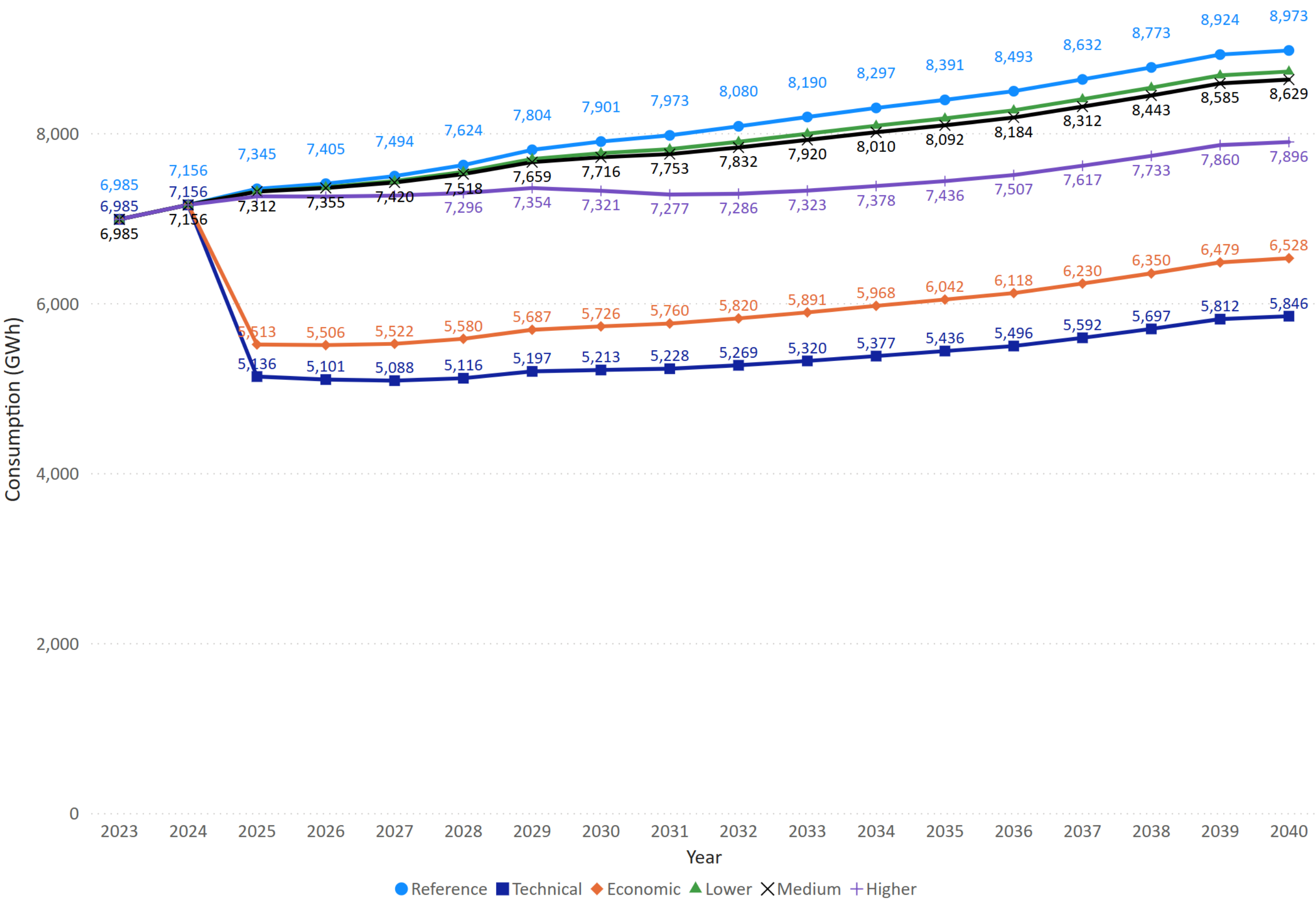
3. How results from items 1 and 2 could be extrapolated for like-measures in the Study.

[113] "Reliability and Resource Adequacy Study – 2024 Update," Newfoundland and Labrador Hydro, Available: https://nlhydro.com/wp-content/uploads/2024/07/2024-07-09_NLH_RRA-Study_2024-RAP.pdf (Accessed Nov 29, 2024).

5.1 Aggregate Efficiency Results – Annual

Exhibit 99 shows annual consumption in the reference case and by potential scenario.[114] The difference between the reference case consumption and the consumption in each of the technical, economic and achievable scenarios represents cumulative potential savings. For example, savings in 2025 represent potential for measures adopted that year, whereas savings in 2040 represent savings for measures adopted that year, plus the savings for all measures adopted between 2025 and 2039, provided they did not reach end of life in that period.

Exhibit 99: Annual Consumption by Scenario - Efficiency



The following observations can be made on Exhibit 99:

- The technical potential consumption is the lowest of all potential scenarios, since it represents the adoption of all measures if cost-effectiveness and market barriers are ignored. Technical potential savings represent 2,209 GWh (30%) and 3,127 GWh (35%) compared to the reference case in 2025 and 2040, respectively.
- The economic potential offers approximately 1,832 GWh (25%) and 2,445 GWh (27%) of savings compared to the reference case in 2025 and 2040, respectively. This means there are 377 GWh

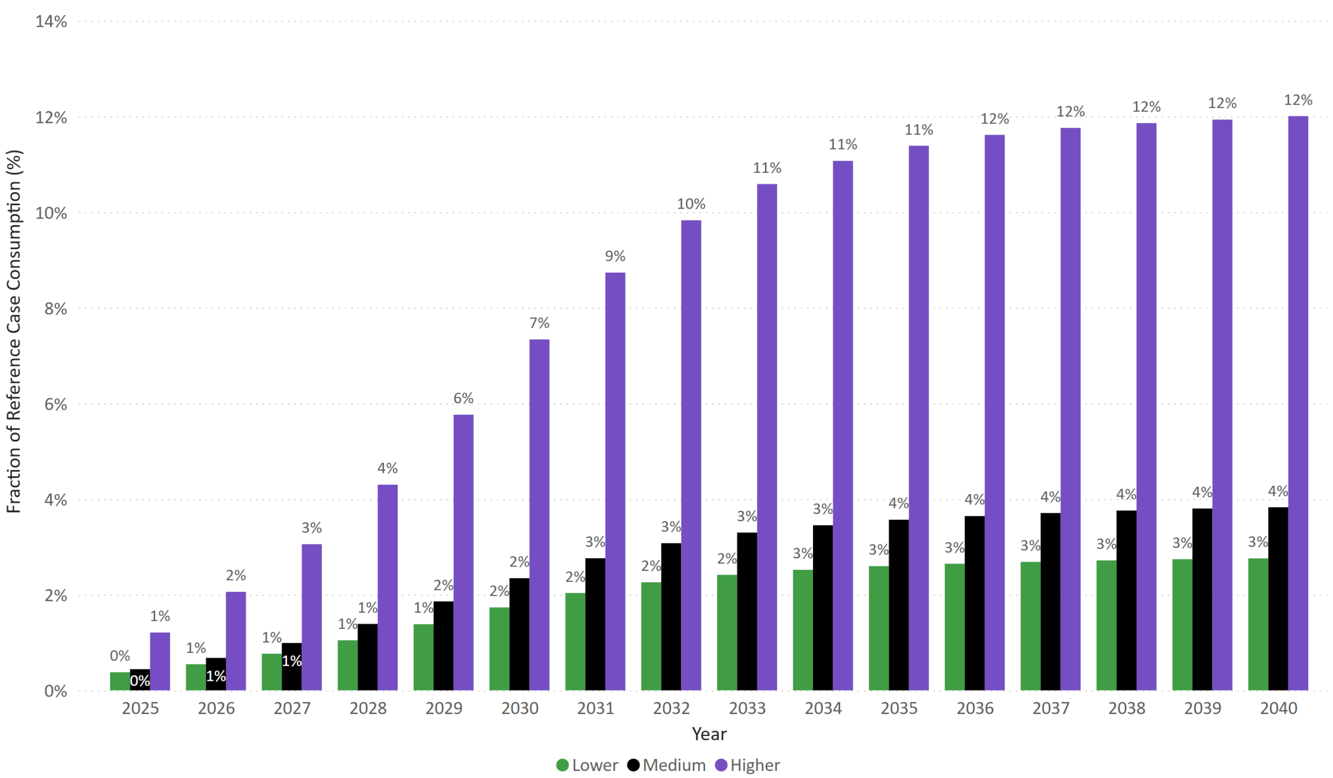
[114] The reference case in Exhibit 99 and Exhibit 100 includes intermediate scenario EV consumption.

and 682 GWh of technical potential savings that are not cost-effective in 2025 and 2040, respectively.

- The difference in consumption between the lower and medium achievable potential scenarios is approximately 100 GWh by 2040, while the difference in consumption between the medium and higher achievable potential scenarios is approximately 700 GWh by 2040. This suggests that doubling the incentive between the lower and medium achievable scenarios has a smaller impact on measure adoption than doubling the incentive between the medium and higher achievable scenarios.[115]

Exhibit 100 shows annual achievable potential savings as a fraction of reference case consumption.

Exhibit 100: Aggregate Savings Potential – Efficiency



The results in Exhibit 100 show the following:

- Potential savings increase most dramatically from 2025 to 2032, before leveling off starting in 2033. This is a result of some measures (e.g., smart and programmable thermostats and insulation in the residential sector) approaching market saturation in later study years.
- By 2040, achievable potential savings in the higher scenario (1,077 GWh) reach 12% of reference case consumption, and 3% (248 GWh) and 4% (343 GWh) in the lower and medium scenarios, respectively.[115]

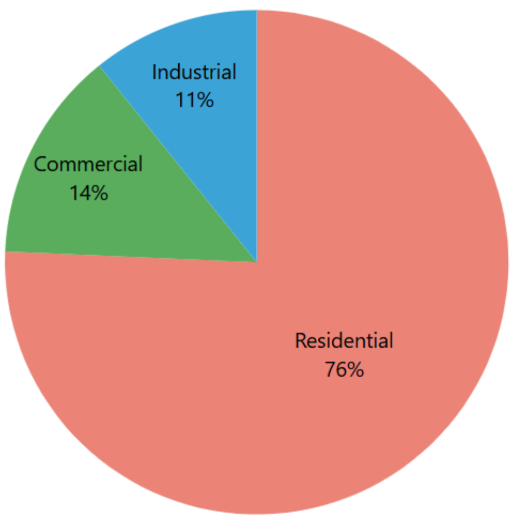
[115] As stated in the introduction to section 5, incentives in the lower, medium and higher achievable potential scenarios offset 25%, 50% and 100% of measure cost, respectively.

5.2 Efficiency Savings Potential by Sector – Annual

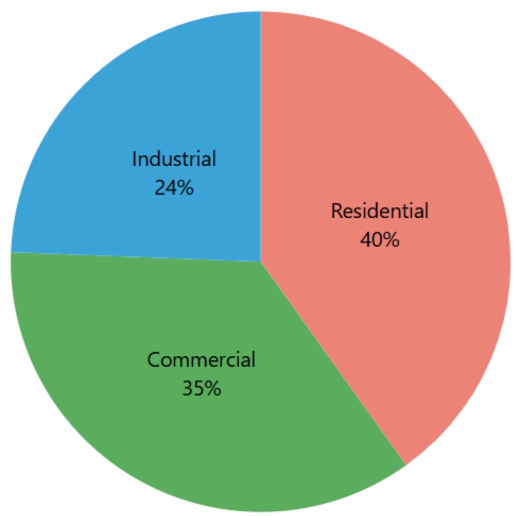
Exhibit 101 shows medium achievable potential savings by sector in 2025 and 2040. As noted previously, all savings are cumulative starting in 2025. Potential savings increase from 32 GWh in 2025 to 344 GWh by 2040. In both milestone years, the highest potential exists in the residential sector. The 2025 potential savings allocation by sector is directionally consistent with recent ECDM program results, in which residential sector programs contributed 88% of total energy savings in 2023.

By 2040, potential savings by sector are more consistent with the reference case electricity consumption forecast by sector: the residential sector is forecast to contribute 54% of reference consumption and 40% of medium achievable savings; commercial 34% of consumption, 35% of savings; and the industrial sector contributing higher relative savings levels with 12% of reference consumption and 24% of savings.

Exhibit 101: Medium Achievable Potential Savings by Sector, 2025 (left) and 2040 (right) – Efficiency



2025 Energy Savings Potential: 32 GWh



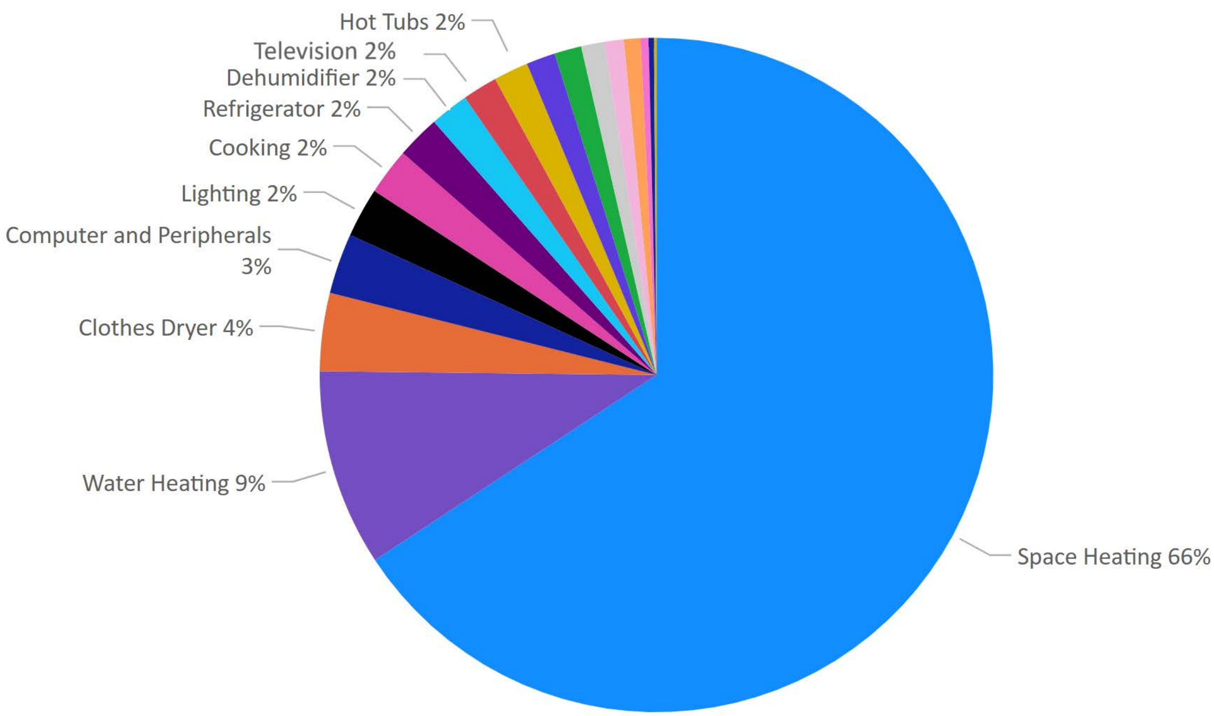
2040 Energy Savings Potential: 344 GWh

This results presented in sections 5.2.1, 5.2.2 and 5.2.3 that follow show medium achievable potential savings results by sector.

5.2.1 End Use Breakdown and Top Energy Savings Measures – Residential Sector

Exhibit 102 shows cumulative residential sector medium achievable potential energy savings by end use in 2025. Space heating offers most of the potential savings (66%), followed by water heating (9%) and clothes drying (4%).[116] Most of the residential sector efficiency measures (48%, or 31 of 64) target the space heating end use, and space heating contributes the most to total sector consumption (53% in 2023).

Exhibit 102: Residential Potential Savings by End Use – Efficiency (2025)

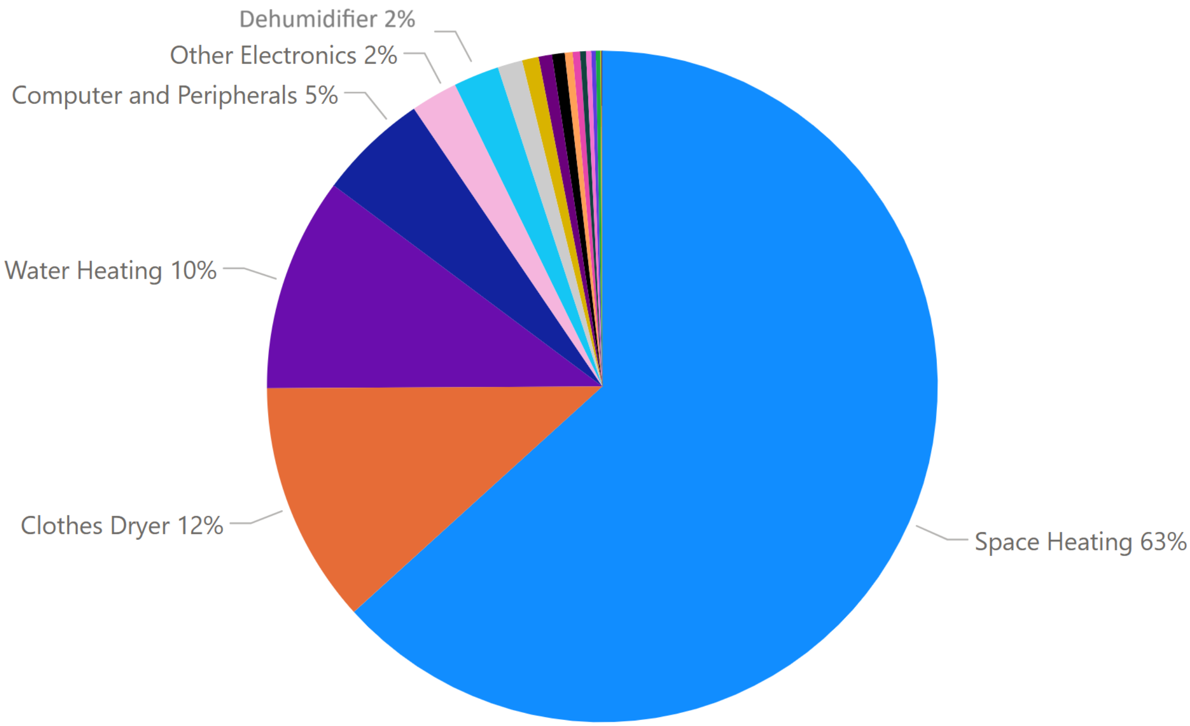


2025 Residential Energy Savings Potential: 25 GWh

[116] End uses that contribute less than 2% to the medium achievable potential savings are not labelled to improve readability: hot tubs (1%), small appliance and other (1%), television peripherals (1%), freezer (1%), other electronics (1%), ventilation (1%), space cooling (0.4%), dishwasher (0.3%), and clothes washer (0.1%).

Exhibit 103 shows cumulative residential sector medium achievable potential energy savings by end use in 2040.[117] The contributions of space heating and water heating to total potential savings change by 3% or less compared to 2025.

Exhibit 103: Residential Potential Savings by End Use – Efficiency (2040)



2040 Residential Energy Savings Potential: 138 GWh

[117] End uses that contribute less than 2% to the medium achievable potential savings are not labelled to improve readability: freezer (1%), hot tubs (1%), refrigerator (1%), lighting (1%), ventilation (0.4%), cooking (0.4%), television (0.3%), space cooling (0.3%), small appliance and other (0.2%), television peripherals (0.2%), clothes washer (0.05%), and dishwasher (0.04%).

Exhibit 104 shows savings for the top ten residential sector efficiency measures in 2025 and 2040.

Exhibit 104: Residential Top Ten Efficiency Measures by Potential Savings - Annual

Measure	2025 Savings (GWh)	Measure	2040 Savings (GWh)
Home Energy Report	16.16	Ductless Mini Split Air Source Heat Pump[118]	28.53
Air Sealing	2.43	Clothes Lines and Drying Racks	16.09
Basement Ceiling Insulation	1.64	Home Energy Report	14.12
Ductless Mini Split Air Source Heat Pump	0.94	Heat Recovery Ventilator (Ductless) – Standard to High Efficiency	11.87
Basement Wall Insulation	0.74	Advanced Smart Strips and Plugs	10.05
Attic Insulation	0.60	Heat Pump Water Heater[119]	7.63
Smart Thermostat (Multiple)	0.37	Central Ducted Air Source Heat Pump	7.11
Programmable Thermostat (Multiple)	0.35	Air Sealing	7.04
Clothes Lines and Drying Racks	0.35	Heat Recovery Ventilator (Ducted) – Standard to High Efficiency	4.44
Efficient Windows	0.26	Duct Insulation	3.98

Observations on Exhibit 104 include:

- Home energy reports offer the highest savings potential in 2025 (16.16 GWh), driven by a high adoption rate and no cost to participants. Adoption rates remain high throughout the Study period, so home energy reports are among the top ten measures in 2040.
- In 2025, one of the top ten efficiency measures is equipment-based (ductless mini split air source heat pumps). In 2040, this increases to three of the top ten efficiency measures (ductless mini split air source heat pumps, heat pump water heaters, and central ducted air source heat pumps). This result is attributed to the slower adoption ramp up for expensive measures, and an expected increase in heat pump adoption during the forecast period.[120]

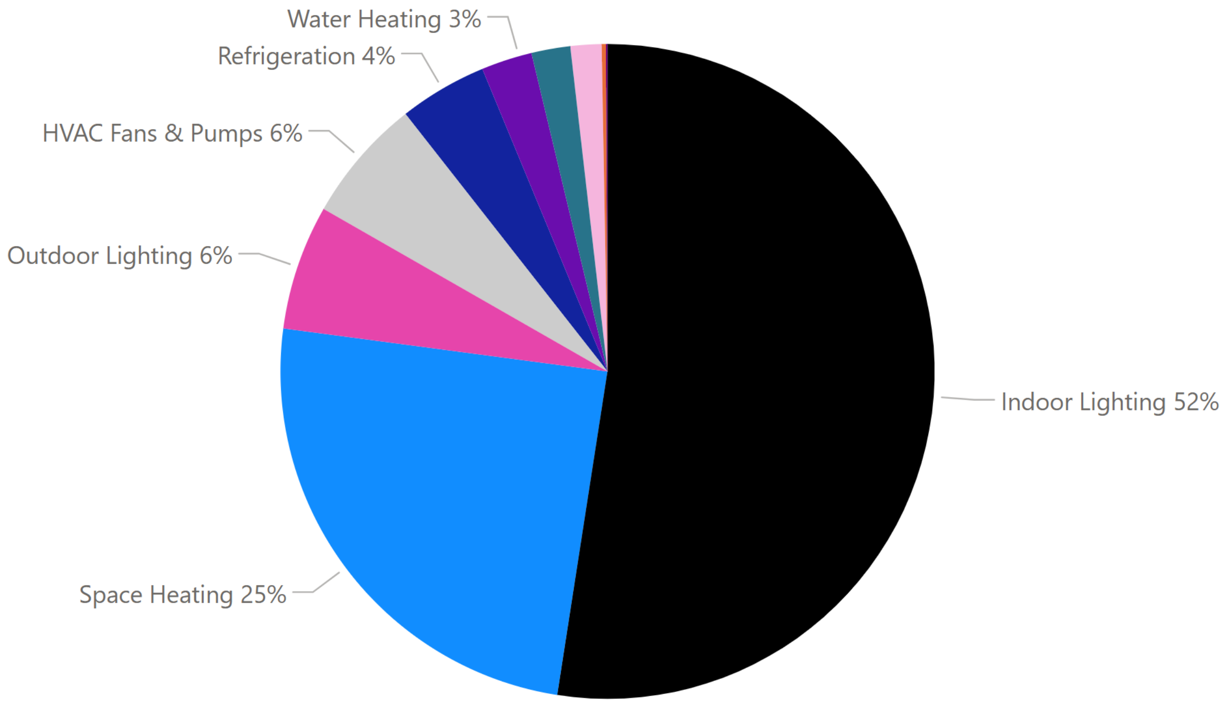
[118] This measure upgrades a baseline electric baseboard heating system to an air source ductless mini-split heat pump with an electric baseboard heat back up.
[119] The Study Team assumed the interactive effect of heat pump water heater technologies with total dwelling space heating consumption was negligible.
[120] Achievable potential workshop participants expect that ductless mini split heat pumps will become saturated in the market by 2040.

- Envelope measures (air sealing, insulation, windows, etc.) comprise five out of the top ten efficiency measures in 2025, but only one of the top ten efficiency measures in 2040. This result is driven by the relatively low-cost barrier for some of these measures and the relatively high opportunity for others, causing rapid ramp up. Most of the available opportunity is forecast to be captured by 2040.

5.2.2 End Use Breakdown and Top Energy Savings Measures – Commercial Sector

Exhibit 105 presents cumulative medium achievable potential energy savings for the commercial sector by end use in 2025. In 2025, lighting offers over half of the potential savings (52%).[121,122]

Exhibit 105: Commercial Potential Savings by End Use – Efficiency (2025)



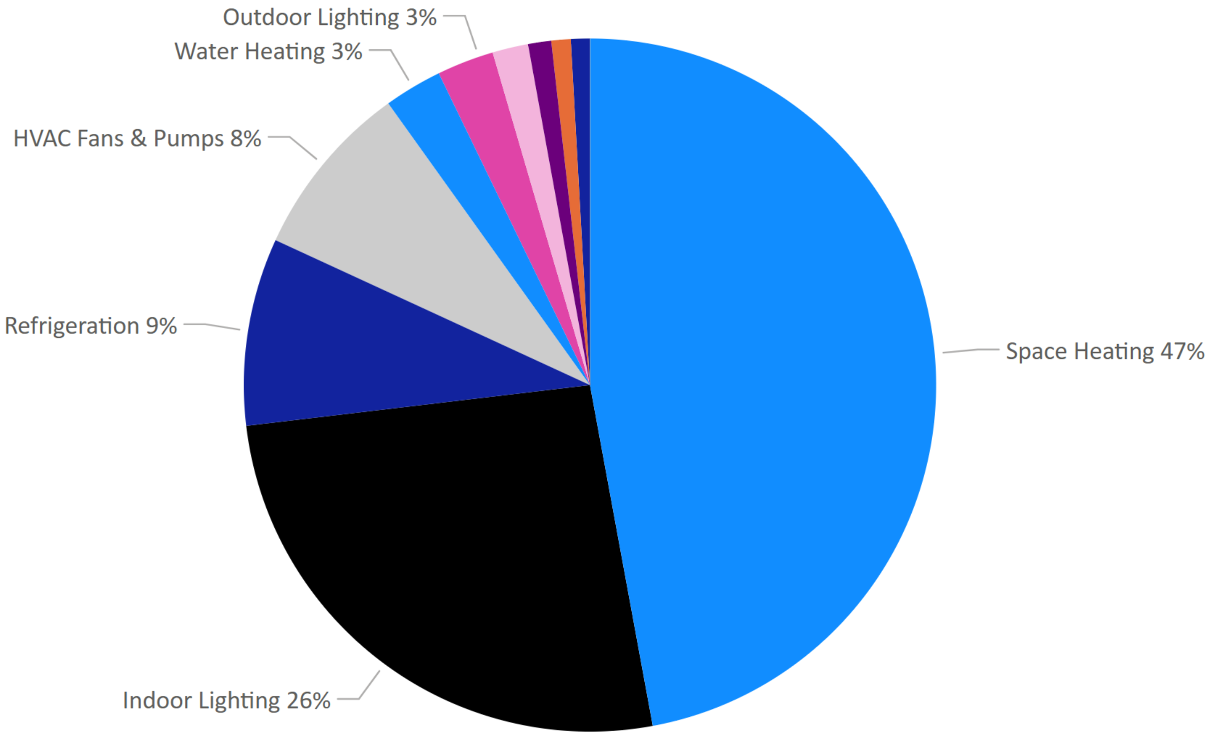
2025 Commercial Energy Savings Potential: 4 GWh

[121] Indoor lighting includes general lighting, secondary lighting and high bay lighting.
[122] End uses that contribute less than 3% to the medium achievable potential savings are not labelled to improve readability: street lighting (2%), space cooling (2%), plug loads (0.2%), food service equipment (0.08%), and miscellaneous equipment (0.003%).

Exhibit 106 shows that by 2040, indoor lighting's contribution to potential savings for the sector drops to 26%.[123] The decrease in lighting's contribution to total potential can be attributed to the following factors:

- The reference adoption of interior LED lighting in 2025 is already high at approximately 60%, meaning that only 40% of commercial floor space is lit by non-LEDs.[124,125]
- No adoption of LED lamps from 2028 onwards because of Natural Resources Canada's Amendment 18, as described in the callout that follows.[126]

Exhibit 106: Commercial Potential Savings by End Use – Efficiency (2040)



2040 Commercial Energy Savings Potential: 122 GWh

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[123] End uses that contribute less than 3% to the medium achievable potential savings are not labelled to improve readability: space cooling (2%), food service (1%), plug loads (1%), street lighting (1%), and miscellaneous equipment (0.01%).
[124] "NL Power Comm Survey – Weighted Dataset Codebook," Newfoundland Power, St. John's, NL, Canada. 2024.
[125] Stakeholder input from the Commercial Sector Achievable Potential Workshop held May 24, 2024.
[126] "Amendment 18," Natural Resources Canada, Available: https://natural-resources.canada.ca/energy-efficiency/energy-efficiency-regulations/amendment-18 (Accessed: Dec. 3, 2024).

Lighting Standards: Fluorescent and General Service Lamps

*The federal minimum energy performance standard for general service **fluorescent lamps** currently requires a minimum average lamp efficacy of approximately 90 lumens/watt. Many fluorescent T8 lamps meet this requirement, so a T8 baseline is used for light fixtures in the commercial sector throughout the forecast period.*

*An amendment to the federal minimum energy performance standards, Natural Resources Canada's Amendment 18, is expected to come into force by 2026 that will require a minimum efficacy of 45 lumens/watt for **general service lamps** (i.e., A-lamps and reflector lamps). The requirement will apply to lamps manufactured after a specific date, which has not yet been set. The Study Team assumes that this requirement will be met by limiting the availability of non-LED general service lamps, and any general service lamp measures for the residential and commercial sectors are applicable only in the first three years of the forecast period (2025, 2026, and 2027), at which point Amendment 18 is expected to be in place.*

Exhibit 107 shows savings for the top ten commercial sector efficiency measures in 2025 and 2040.

Exhibit 107: Commercial Top Ten Efficiency Measures by Potential Savings - Annual

Measure	2025 Savings (GWh)	Measure	2040 Savings (GWh)
Linear LED T8 Tube (General Lighting)	1.14	Electric Furnace to Air Source Heat Pump	33.55
Linear LED T8 Tube (Secondary Lighting)	0.64	Linear LED T8 Tube (General Lighting)	17.60
Baseboard to Ductless Mini-Split Heat Pump	0.28	New Construction (25% More Efficient)	9.78
Air Sealing	0.25	Linear LED T8 Tube (Secondary Lighting)	8.88
LED High Bay Luminaire	0.22	Baseboard to Ductless Mini-Split Heat Pump	7.98
LED Reflector (Interior General)	0.18	High Efficiency Windows Glazing	5.67
LED A-Lamp (Interior General)	0.18	Air Sealing	5.27
LED Luminaire (General)	0.17	New Construction (40% More Efficient)	3.78
High Efficiency Window Glazing	0.16	Demand Control Ventilation	3.77
Retrocommissioning	0.15	New Construction (Net-Zero Ready)	3.56

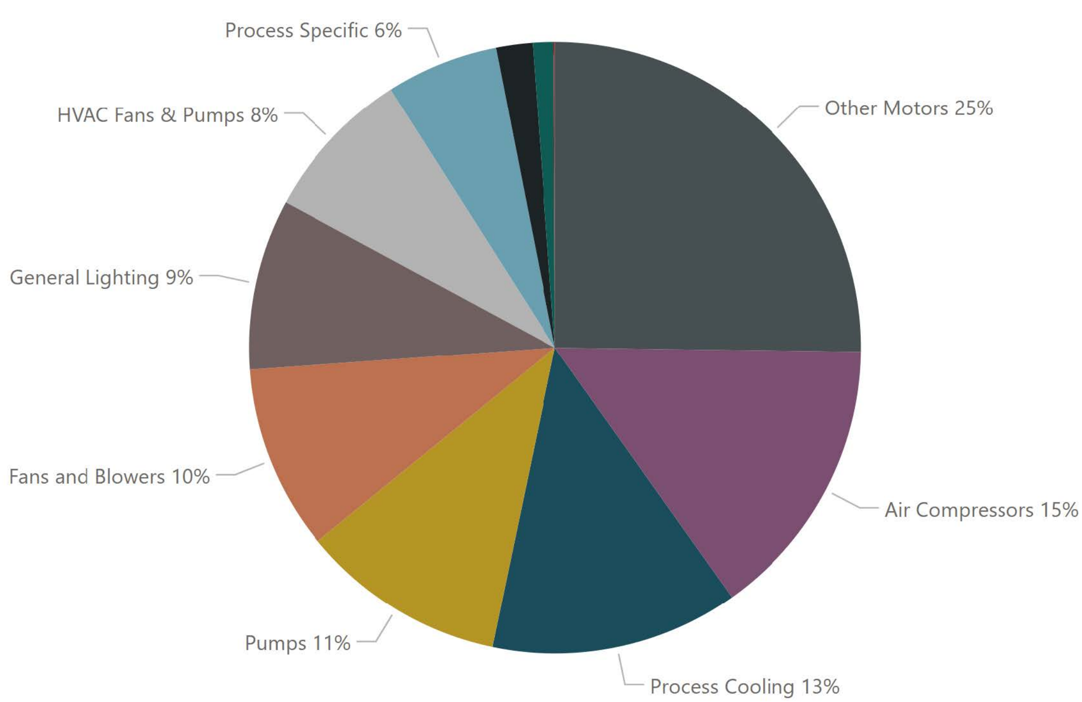
Observations on Exhibit 107 include:

- In 2025, indoor lighting measures account for 6 of the top 10 measures, but by 2040, 8 of the top 10 measures affect space heating.
- Air sealing is among the top ten measures in both milestone years, due to its broad applicability, high measure-level savings, and the fact that it is a retrofit measure, with the opportunity to undertake air sealing at any time as opposed to only when equipment is being replaced.
- By 2040, new construction measures enter the top ten, based on the increased portion of commercial sector consumption occurring in new buildings (1% of total in 2025 compared to 38% in 2040).

5.2.3 End Use Breakdown and Top Energy Savings Measures – Industrial Sector

Exhibit 108 shows cumulative medium achievable potential energy savings for the industrial sector by end use in 2025.[127] Measures affecting the other motors end use (i.e., motor controls, adjustable speed drives on motors, correctly sized motors, and EMIS) offer 25% of the total potential savings. This contribution changes to 22% of total potential for the sector in 2040 due to varying adoption rates by measure.

Exhibit 108: Industrial Potential Savings by End Use – Efficiency (2025)

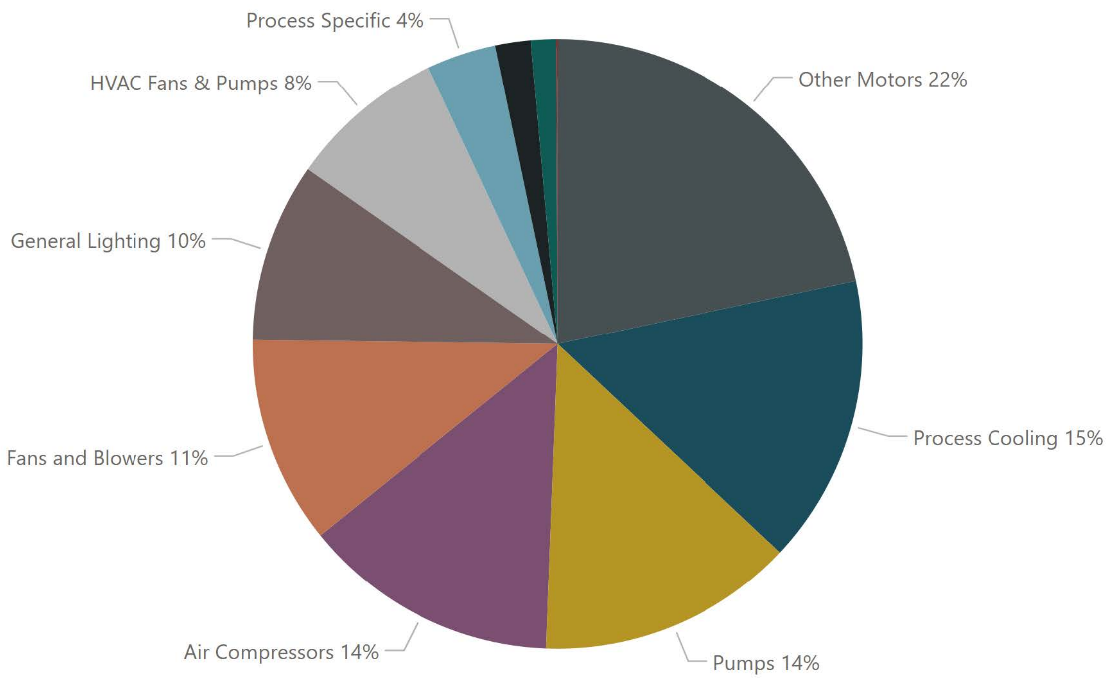


2025 Industrial Energy Savings Potential: 3 GWh

[127] End uses that contribute less than 6% to the medium achievable potential savings are not labelled to improve readability: conveyors (2%), process heating (1%), and other (0.07%).

Exhibit 109 shows cumulative medium achievable energy savings potential by end use in 2040.[128] While savings increase dramatically from 2025 to 2040, the end use breakdown of savings remains relatively consistent between 2025 and 2040. This suggests a broad-based opportunity for cost-effective conservation within the industrial sector.

Exhibit 109: Industrial Potential Savings by End Use – Efficiency (2040)



2040 Industrial Energy Savings Potential: 84 GWh

[128] End uses that contribute less than 4% to the medium achievable potential savings are not labelled to improve readability: conveyors (2%), process heating (1%), and other (0.08%).

Exhibit 110 shows savings for the top ten industrial sector efficiency measures in 2025 and 2040.

Exhibit 110: Industrial Top Ten Efficiency Measures by Potential Savings - Annual

Measure	2025 Savings (GWh)	Measure	2040 Savings (GWh)
Motor Controls – Process	0.48	Motor Controls – Process	9.76
Adjustable or Variable Speed Drive (Motors)	0.26	Optimization of Pumping Systems	7.07
Optimization of Pumping Systems	0.22	Energy Management Information System (EMIS)	5.86
Energy Management Information System (EMIS)	0.20	Adjustable or Variable Speed Drive (Motors)	5.34
Air Leak Survey and Repair	0.18	Optimized Distribution System – Fans and Blowers	5.17
LED Luminaire	0.17	Chiller Economizer	4.12
Optimized Distribution System – Fans and Blowers	0.16	Premium Efficiency Refrigeration Control System and Compressor Sequencing	3.52
Chiller Economizer	0.16	Adjustable or Variable Speed Drive (Pump)	3.31
Adjustable or Variable Speed Drive (Pump)	0.13	LED Luminaire	2.81
Premium Efficiency Refrigeration Control System and Compressor Sequencing	0.12	Adjustable or Variable Speed Drive (Compressor)	2.64

Observations on Exhibit 110 include:

- Measures targeting the other motors and pumps end use represent four of the top ten efficiency measures in both 2025 and 2040.
- EMIS is among the top ten measures in 2025 and 2040 because it is broadly applicable and targets all industrial sector end uses.

5.3 Aggregate Efficiency Results – Peak

Exhibit 111 shows the IIS winter morning and evening average peak demand, and the average annual peak demand reduction from efficiency measures in the medium achievable potential scenario relative to the reference case.[129] From 2025 to 2031, the IIS peaks in the morning based on average demand. In 2032, the IIS switches to an evening peak based on average demand due to EV adoption in the intermediate scenario.[130]

Exhibit 111: Annual Demand Reduction for Medium Achievable Potential Scenario – Efficiency

Year	Winter Morning Average Peak Demand (MW)	Winter Morning Peak Reduction, Medium Achievable (MW)	Morning Reduction (%)	Winter Evening Average Peak Demand (MW)	Winter Evening Peak Reduction, Medium Achievable (MW)	Evening Reduction (%)
2025	1,592	8	0.5%	1,556	7	0.4%
2026	1,606	11	0.7%	1,581	11	0.7%
2027	1,627	16	1.0%	1,605	15	0.9%
2028	1,656	22	1.3%	1,637	21	1.3%
2029	1,689	29	1.7%	1,673	28	1.7%
2030	1,709	37	2.2%	1,698	36	2.1%
2031	1,720	43	2.5%	1,715	43	2.5%
2032	1,739	49	2.8%	1,742	48	2.8%
2033	1,757	54	3.1%	1,769	53	3.0%
2034	1,772	57	3.2%	1,794	56	3.1%
2035	1,782	60	3.4%	1,817	59	3.2%
2036	1,798	62	3.4%	1,848	61	3.3%
2037	1,816	64	3.5%	1,881	63	3.3%
2038	1,833	67	3.7%	1,915	65	3.4%
2039	1,851	69	3.7%	1,952	67	3.4%
2040	1,855	70	3.8%	1,975	69	3.5%

[129] Results reflect unmanaged EV charging. In 2025, EVs contribute 4 MW to the winter morning peak and 8 MW to the winter evening peak in the intermediate scenario. In 2040, they contribute 110 MW and 264 MW to the morning and evening peaks, respectively.
[130] In 2033, EVs cause the absolute IIS peak to shift from the morning to the evening. See section 7 for more details.

The peak demand reductions represent cumulative average savings starting in 2025 during the four-hour morning peak starting at 7 a.m. on a weekday in February; and the five-hour evening peak starting at 5 p.m. on a weekday in February. By 2040, the efficiency measures reduce the winter morning and evening peaks by 70 MW and 69 MW, respectively.[131]

The morning peak reduction is higher than the evening peak in each year of the forecast period, though the difference is less than five megawatts annually. The reduction in each peak period depends on the mix of measures in each forecast year. Space heating contributes more to peak demand in the morning than in the evening. This means that measures that affect space heating save more in the morning than in the evening.

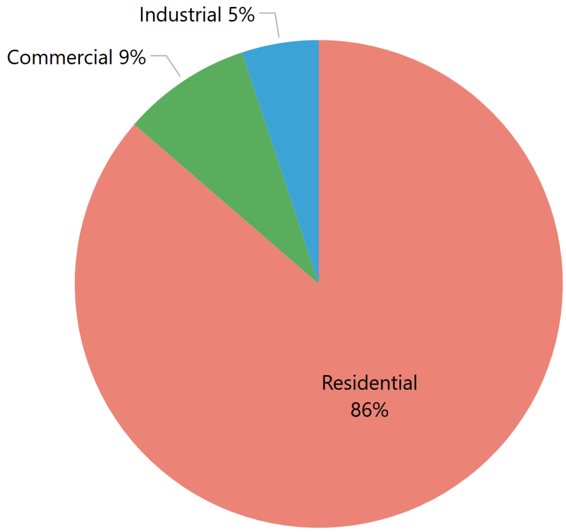
[131] Peak demand savings from efficiency measures shift the peak load vertically downwards. Some measures (e.g., heat pumps) also change the shape of the peak load depending on their energy performance on peak compared to off peak.

5.4 Efficiency Savings Potential by Sector – Peak

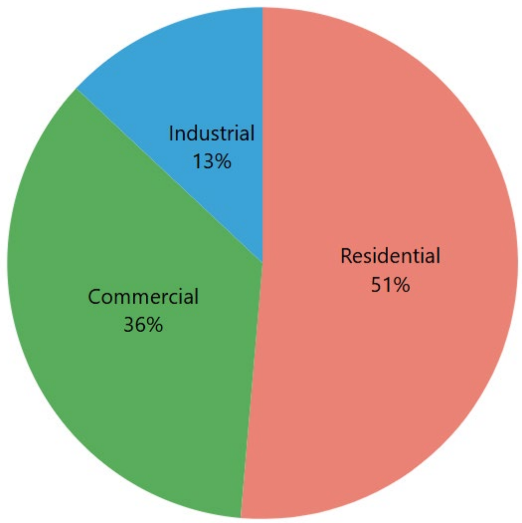
Exhibit 112 shows medium achievable potential savings for the peak hour by sector in 2025 and 2040. As noted previously, all savings are cumulative starting in 2025. Potential savings increase from 7,719 kW in 2025 to 71,738 kW by 2040. In both milestone years, the highest peak reduction potential exists in the residential sector. The 2025 potential savings allocation by sector is directionally consistent with recent ECDM program results, in which residential sector programs contributed 88% of total energy savings in 2023.

By 2040, potential savings by sector are more consistent with the reference case peak demand forecast by sector: the residential sector is forecast to contribute 54% of reference peak demand and 51% of medium achievable savings; commercial 34% of peak demand, 36% of savings; and industrial 12% of peak demand 13% of savings.

Exhibit 112: Medium Achievable Peak Demand Reduction Potential by Sector (kW), 2025 (left) and 2040 (right) – Efficiency



2025 Demand Reduction Potential: 7,719 kW



2040 Demand Reduction Potential: 71,738 kW

This rest of this section presents medium achievable potential peak savings by sector.

5.4.1 Top Peak Savings Measures – Residential Sector

Exhibit 113 shows the top ten residential sector efficiency measures by peak hour demand reduction.

Exhibit 113: Residential Top Ten Efficiency Measures by Potential Reduction – Peak (kW)

Measure	2025 Peak Hour Savings (kW)	Measure	2040 Peak Hour Savings (kW)
Home Energy Report	4,180	Air Source Heat Pump – Ductless Mini Split (DMSHP)	9,161
Air Sealing	777	Heat Recovery Ventilator (Ductless) – Standard to High Efficiency	3,773
Basement Ceiling Insulation	529	Home Energy Report	3,669
Air Source Heat Pump – Ductless Mini Split (DMSHP)	301	Clothes Lines and Drying Racks	2,676
Basement Wall Insulation	237	Central Ducted Air Source Heat Pump	2,283
Attic Insulation	191	Air Sealing	2,249
Smart Thermostat (Multiple)[132]	119	Heat Pump Water Heater (HPWH)	2,196
Programmable Thermostat (Multiple)[133]	113	Heat Recovery Ventilator (Ducted) – Standard to High Efficiency	1,411
Efficient Windows	82	Advanced Smart Strips and Plugs	1,295
Heat Recovery Ventilator (Ductless) – Standard to High Efficiency	77	Duct Insulation	1,270

Observations on Exhibit 113 include:

- Home energy report, air sealing, ductless mini split air source heat pumps, and ducted heat recovery ventilators (standard to high efficiency) are among the top ten measures in both milestone years, due to their broad applicability and relatively low incremental costs. All these measures impact space heating and save more during the morning peak compared to the evening peak.
- In 2025, all top ten measures affect the space heating end use, and by 2040, measures for non-space heating end uses (clothes lines and drying racks, heat pump water heaters, and advanced smart strips and plugs) enter the top ten. This is because some of the 2025 top ten measures (e.g., smart and programmable thermostats, insulation) will approach saturation by 2040.

[132] The 2021 Thermostat Evaluation Study from the Utilities indicates that programmable and smart thermostats have positive peak savings in the Utilities' jurisdiction. This may differ from other jurisdictions where programmable and smart thermostat adoption may drive an increase in peak.
[133] Ibid.

5.4.2 Top Peak Savings Measures – Commercial Sector

Exhibit 114 shows the top ten commercial sector efficiency measures by peak hour demand reduction.

Exhibit 114: Commercial Top Ten Efficiency Measures by Potential Reduction – Peak (kW)

Measure	2025 Peak Hour Savings (kW)	Measure	2040 Peak Hour Savings (kW)
Linear LED T8 Tube (General Lighting)	198	Electric Furnace to Air Source Heat Pump	10,635
Linear LED T8 Tube (Secondary Lighting)	94	Linear LED T8 Tube (General Lighting)	3,059
Baseboard to Ductless Mini-Split Heat Pump	89	Baseboard to Ductless Mini-Split Heat Pump	2,525
Air Sealing	71	New Construction (25% more efficient)	2,110
High Efficiency Window Glazing	49	High Efficiency Window Glazing	1,733
Electric Furnace to Air Source Heat Pump	46	Air Sealing	1,531
LED Reflector (Interior General)	31	Linear LED T8 Tube (Secondary Lighting)	1,317
LED A-Lamp (Interior)	31	Demand Control Ventilation	1,107
Demand Control Ventilation	31	New Construction (40% more efficient)	808
LED High Bay Luminaire	30	Energy Recovery Ventilator	771

Observations on Exhibit 114 include:

- In 2025, indoor lighting measures account for 5 of the top 10 measures, but by 2040 measures that affect space heating measures account for 7 of the top 10. The indoor lighting measures have the same peak reduction potential for the morning, evening and absolute peaks. In contrast, the space heating measures save more during the morning peak compared to the evening peak.
- Air sealing is among the top ten measures in both milestone years, due to its broad applicability, high measure-level savings, and the fact that it is a retrofit measure, with the opportunity to undertake air sealing at any time as opposed to only when equipment is being replaced.
- By 2040, new construction measures enter the top ten, based on the increased portion of commercial sector consumption occurring in new buildings (1% of total in 2025 compared to 38% in 2040).

5.4.3 Top Peak Savings Measures – Industrial Sector

Exhibit 115 shows the top ten industrial sector efficiency measures by peak hour demand reduction.

Exhibit 115: Industrial Top Ten Efficiency Measures by Potential Reduction – Peak (kW)

Measure	2025 Peak Hour Savings (kW)	Measure	2040 Peak Hour Savings (kW)
Motor Controls - Process	46	Motor Controls - Process	930
Optimization of Pumping System	27	Optimization of Pumping System	879
Adjustable or Variable Speed Drive (Motor)	25	Energy Management Information System (EMIS)	688
Energy Management Information System (EMIS)	24	Adjustable or Variable Speed Drive (Motor)	509
Process Optimization Efforts - Mining and Processing	21	Optimized Distribution System (Incl. Pressure Losses) - Fans and Blowers	476
LED Luminaire	20	Air Compressor Heat Recovery	452
Air Leak Survey and Repair	18	High Efficiency Packaged HVAC	442
Refrigeration Heat Recovery	18	Adjustable or Variable Speed Drive (Pump)	413
Adjustable or Variable Speed Drive (Pump)	16	Chiller Economizer	378
Air Compressor Heat Recovery	15	LED Luminaire	328

Observations on Exhibit 115 include:

- Measures targeting the other motors and pumps end use represent four of the top ten efficiency measures in both 2025 and 2040.
- EMIS is among the top ten measures in 2025 and 2040 because it is broadly applicable and targets all industrial sector end uses.

6 Fuel Switching and Off-Road Electrification Potential

This section presents space heating, water heating, and cooking fuel switching and off-road electrification potential results for the IIS. Results shown here exclude the impact of EVs.

The fuel switching and off-road electrification potential assessment mirrors the efficiency potential assessment in structure and economic screening criteria:

- Three levels of fuel switching and off-road electrification savings potential are assessed: technical, economic, and achievable.
- The total resource cost (TRC) test is used to screen fuel switching and off-road electrification measures, and measures are included in the economic potential if their benefit-cost ratio is 0.8 or higher.[134]
- The achievable potential includes lower, medium and higher scenarios, with incentive levels of 25%, 50% and 100%, respectively.

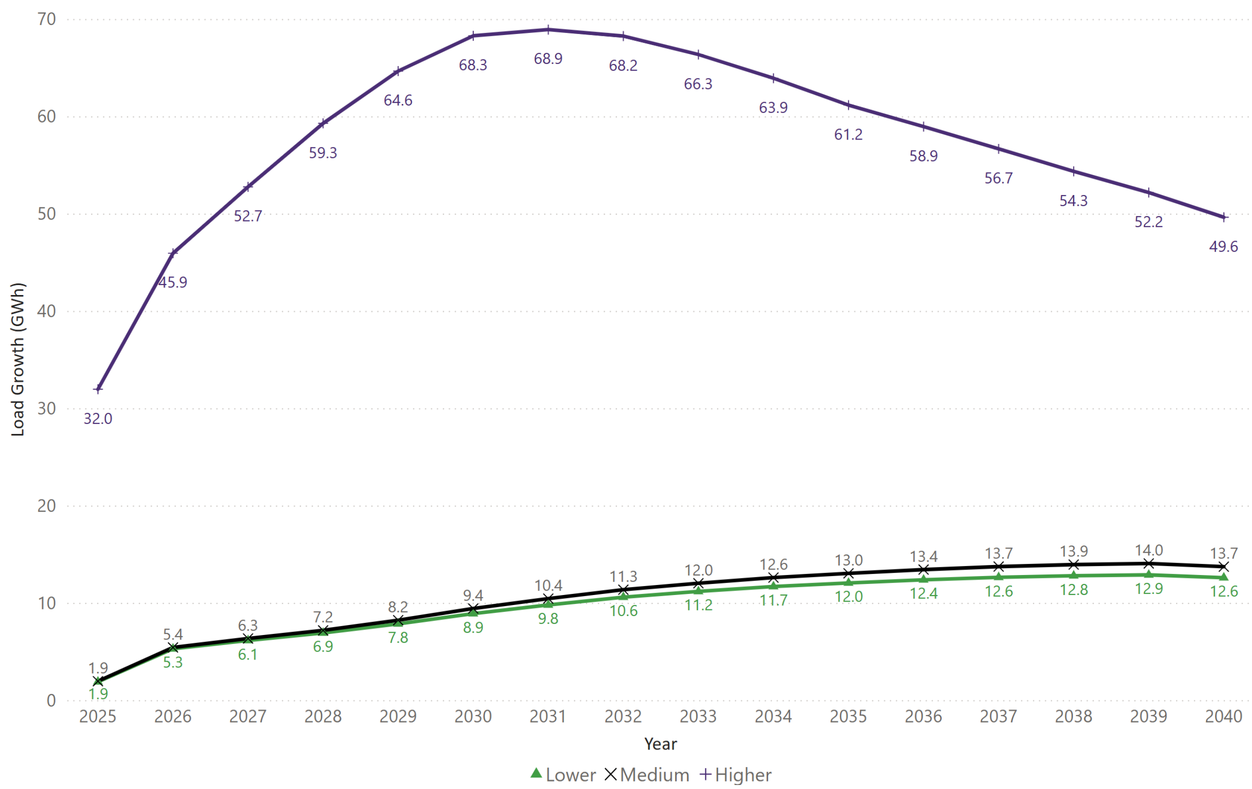
Readers are encouraged to revisit the list of fuel switching and off-road electrification measures shown in section 4.1 for context.

[134] Three residential sector fuel switching measures with TRC less than 0.8 were included in the analysis: oil furnace to cold climate air source heat pump, oil furnace to air source heat pump (partial switch), and oil furnace to electric furnace. These measures are being adopted in Newfoundland Power's Oil to Electric program.

6.1 Aggregate Fuel Switching and Off-Road Electrification Potential – Annual

The impacts of fuel switching and off-road electrification in the lower, medium and higher achievable potential scenarios are shown in Exhibit 116. By 2040, measures in the higher achievable potential scenario cause 49.6 GWh of load growth, compared to 13.7 GWh and 12.6 GWh in the medium and lower scenarios, respectively. Reference case consumption is forecast to be roughly 9,000 GWh in 2040, so this growth represents an increase of less than one percent of annual consumption for all scenarios.[135] Fuel switching potential is limited in all three sectors because of the high relative fuel share of electric space heating in the base year and because of natural fuel switching that occurs in the reference case.[136]

Exhibit 116: Fuel Switching and Off-Road Electrification Impacts by Achievable Scenario



Load growth from fuel switching increases year over year in all scenarios between 2025 and 2031 but decreases from 2031 to 2032 in the higher achievable potential scenario. This result is driven by forecast space heating conversions in the Oil to Electric program, and natural fuel switching from oil to electricity included in the reference case which erodes the impact of these space heating conversions. The callout that follows explains the higher achievable potential scenario result in more detail.

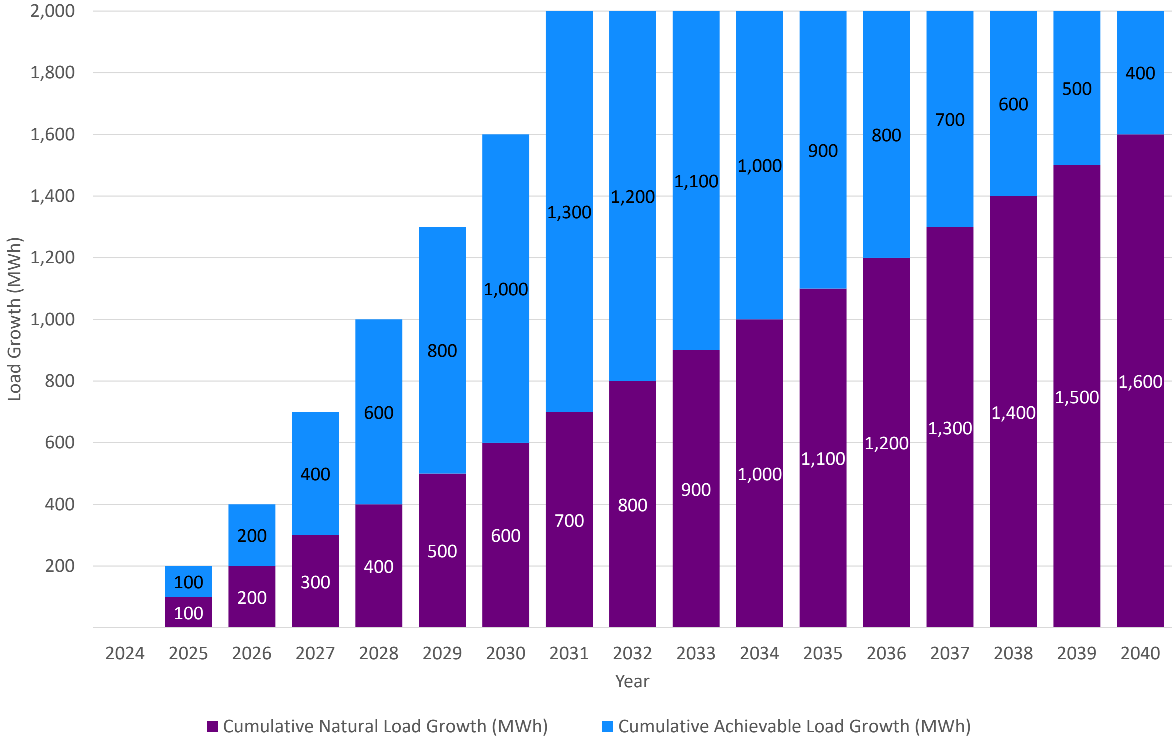
135 9,000 GWh is the approximate forecast consumption in 2040 including the impact of EVs in the intermediate scenario. Excluding the impact of EVs in the intermediate scenario, the approximate forecast consumption in 2040 is 1,000 GWh.

136 MUN's conversion to electric heat is included in the reference case forecast.

Impacts of Reference Case Fuel Switching on Achievable Potential

The fuel switching measure impacts shown in sections 6.1 and 6.2 are incremental to the natural fuel switching that occurs in the reference case. Measure-level achievable fuel switching potential is limited by the number of dwellings that use fossil fuel for space or water heating, and the rate of naturally occurring fuel switching.

For example, consider a portfolio of 200 existing oil heated dwellings, where each dwelling that fuel switches either naturally or by adopting a fuel switching measure contributes 10 MWh of load growth. In the absence of demolition and new construction, the figure below shows what happens when natural fuel switching and fuel switching measure adoption occur in parallel. In the figure, the purple bars represent cumulative load growth from naturally occurring fuel switching, and the blue bars represent cumulative load growth from fuel switching measure adoption.



By 2030, 60 dwellings have fuel switched naturally for a total of 600 MWh of load growth, and 100 dwellings have adopted a fuel switching measure for a total of 1,000 MWh of load growth. In 2031, 10 more dwellings fuel switch naturally for a total of 70 and 700 MWh of load growth, and 30 more dwellings adopt a fuel switching measure for a total of 130 and 1,300 MWh of load growth.

In 2032, another 10 dwellings would have naturally fuel switch compared to 2031, for a total of 80 and 800 MWh of load growth. In 2032, only 1,200 MWh of the 1,300 MWh of load growth from dwellings that adopted a fuel switching measure by 2031 can still be considered incremental and count towards the achievable load growth. The remaining 100 MWh of load growth would have occurred naturally. Therefore, load growth from fuel switching measures in 2032 is lower than in 2031.

A similar phenomenon is responsible for the decrease in load from fuel switching measures between 2031 and 2032 in the higher achievable potential scenario shown in Exhibit 116.

6.2 Fuel Switching and Off-Road Electrification Impacts by Sector – Annual

Exhibit 117 shows fuel switching and off-road electrification impacts by sector in 2025 and 2040. The higher achievable potential scenario results are shown for the residential sector to align with current Oil to Electric program practice.[137] Medium achievable potential results are shown for the commercial and industrial sectors to align with typical ECDM program practice.

Fuel switching potential is limited in all three sectors because of the natural fuel switching that occurs in the reference case, and the high relative fuel share of electric space heating in the base year.[138] For example, in the commercial sector, 61% of floor area is associated with buildings heated primarily with electricity in the base year.[139] The 39% of floor area in buildings primarily heated with another fuel still includes substantial electric heating: the electric fuel share for these buildings is 40% in 2023 and increases to 50% by 2033 in the reference case.

Exhibit 117: IIS Achievable Fuel-Switching and Off-Road Electrification Impacts (GWh)

Sector (Scenario)	2025	2040
Residential (Higher)	31.7	42.9
Commercial (Medium)	0.2	5.1
Industrial (Medium)	0.002	0.5
Total	**31.9**	**48.5**

Electrification of Non-Road Vehicles

The Study Team assessed the electrification impacts of two non-road vehicles: forklifts and Zambonis. Electrification of these vehicles from propane offers indoor air quality benefits to warehouse and arena occupants.

Forklift electrification*: The Study Team estimates there are between 2,000 and 3,000 forklifts in Newfoundland. Approximately ten percent of CEUS respondents indicated they planned to purchase a non-road battery EV in the next five years. Using this data, the Study Team estimated an increase of 2% annually over the Study period. This leads to a total market penetration of 40% in 2040, based on a reference adoption of 6%. The impact of this additional load is approximately 200 MWh in 2040.*

Zamboni electrification*: There are 48 arenas in Newfoundland. The Study Team assumes that most of these arenas have one ice pad, and one Zamboni per ice pad, for a total of 48 Zambonis. Using the same assumptions from the CEUS as applied to forklift electrification (i.e., 2% adoption annually), this leads to a total market penetration of 40% for electric Zambonis in 2040. The impact of this additional load is approximately 65 MWh in 2040.*

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[137] Under the program, customers with low to moderate income can receive 100% of the cost of their oil to electric conversion in incentives. Approximately 65% of past program participants qualified as low to moderate income.
[138] MUN's conversion to electric heat is included in the reference case forecast.
[139] This percentage reflects NP customers only. The main heating fuel for NLH customers was not available.

6.2.1 Residential Sector Results

In the residential sector, incentives under the higher achievable potential scenario result in the adoption of full and partial space heating fuel switching measures, including electric heat pumps, boilers, furnaces, and water heaters. Exhibit 118 shows the number of dwellings forecast to be converted from oil to electric space or water heating in the higher achievable potential scenario in 2025 and 2040.[140] By 2040, 5,618 incremental dwellings are forecast to be heated electrically or have electric water heating compared to 2025. This forecast includes the 3,000 space heating fuel switching projects forecast to be completed under the Oil to Electric program in 2025.[141]

Exhibit 118: Dwellings with Electric Space or Water Heating, Higher Achievable Potential[142]

Conversion Type	2025	2040	Difference[143]
Space heating	3,249	5,898	2,649
Water heating	27	2,996	2,969
Total	**3,276**	**8,894**	**5,618**

[140] Adoption is split between homes with sufficient electrical service capacity to accommodate electric space heating equipment and homes that require a service upgrade. The Study Team, in consultation with the Utilities, estimate that 50% of residential dwellings have enough service capacity to accommodate electric space heating equipment.

[141] Data provided from the Utilities in Nov. 2024.

[142] This exhibit combines the service upgrade and non-service upgrade versions of measures.

[143] A decrease in the number of dwellings between 2025 to 2040 indicates that the available opportunity for a measure has decreased over time because it reached saturation.

6.2.2 Commercial Sector Results

Incentives in the medium achievable potential scenario result in the uptake of full and partial space heating fuel switching measures in the commercial sector, including electric heat pumps and boilers. Adoption is limited to buildings with enough electrical service capacity to accommodate electric space heating equipment.[144] Exhibit 119 shows that an incremental 1.1 million additional square feet of commercial sector floor area are forecast to be heated electrically in 2040 compared to 2025 in the medium achievable scenario.

Exhibit 119: Electrically Heated Floor Area, Medium Achievable Potential (sq-ft)

Parameter	2025	2040	Difference
Electrically heated floor area	60,010	1,165,159	1,105,149

Impact of Dockside Electrification for Marine Vessels

Dockside electrification allows marine vessels to use electricity in port instead of diesel engines for on-board power. Thus, it has the potential to reduce ship emissions during port calls if enough electrical energy is available. Various dockside electrification opportunities exist for NL including cruise ships, cargo ships and ferries. The best candidates for dockside fuel switching are vessels that make frequent port calls with long stays and high energy consumption patterns.[145]

Data is available to estimate the dockside electrification opportunity for cruise ships in NL. The St. John's Port Authority reported 30 cruise ship visits in 2022 and 36 visits in 2023. 39 visits were expected in 2024.[146] The size of these ships varied from less than 200 passengers to more than 3,500 passengers and time in port was 10 hours, on average. Diesel- or oil-fired generators currently power cruise ships in port. The Study Team estimates a 1,300 MWh/year electrification impact if these ships were connected to shore power in port. This estimate is based on the average energy consumption of 3 kWh per passenger-hour, 36 cruise ship visits per year, 10 hours in port per cruise ship, and 1,200 passengers per cruise ship.[147]

There is currently limited data available on ferry and cargo ships to support an in-depth analysis of the fuel switching potential for these marine vessels. The Utilities can continue to work with the appropriate parties to see if collection of this information is possible for future analysis.

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[144] The Study assumes 50% of commercial buildings have sufficient capacity.
[145] "Study and Update on Dock Electrification Technologies in Quebec," Innovation Maritime (2022).
[146] Port of St. John's, "The Port of Choice for Cruise Ships," Available: https://sjpa-apsj.com/industries/cruise/ (Accessed: Aug. 2024).
[147] "Options for Establishing Shore Power for Cruise Ships in Port of Copenhagen Nordhavn," City & Port Development, City of Copenhagen, Available: https://www.danskehavne.dk/wp-content/uploads/2015/12/GP-CMP-Shoreside-Report.pdf (Accessed: Aug. 2024).

6.3 Aggregate Fuel Switching and Off-Road Electrification Impacts – Peak

Exhibit 120 shows the annual peak impacts of fuel switching and off-road electrification in the medium achievable potential scenario for the commercial and industrial sectors, and for the higher achievable potential scenario for the residential sector.[148] The peak demand impacts represent averages during the four-hour morning peak and the five-hour evening peak. As illustrated, the electrification measures have a limited impact on the morning and winter average peak demand.

Exhibit 120: Annual Achievable Potential Demand Impacts for Residential (Higher), Commercial (Medium), and Industrial (Medium) Sectors – Fuel Switching and Off-Road Electrification

Year	Winter Morning Average Peak Demand, Reference (MW)	Winter Morning Peak Impact (MW)	Morning Impact (%)	Winter Evening Average Peak Demand, Reference (MW)	Winter Evening Peak Impact (MW)	Evening Impact (%)
2025	1,592	9.9	0.6%	1,566	9.5	0.6%
2026	1,606	14.1	0.9%	1,581	13.6	0.9%
2027	1,627	16.2	1.0%	1,605	15.6	1.0%
2028	1,656	18.2	1.1%	1,637	17.6	1.1%
2029	1,689	19.7	1.2%	1,673	19.1	1.1%
2030	1,709	20.8	1.2%	1,698	20.1	1.2%
2031	1,720	20.9	1.2%	1,715	20.2	1.2%
2032	1,739	20.7	1.2%	1,742	20.0	1.1%
2033	1,757	20.0	1.1%	1,769	19.4	1.1%
2034	1,772	19.3	1.1%	1,794	18.7	1.0%
2035	1,782	18.4	1.0%	1,817	17.8	1.0%
2036	1,798	17.7	1.0%	1,848	17.1	0.9%
2037	1,816	16.9	0.9%	1,881	16.4	0.9%
2038	1,833	16.2	0.9%	1,915	15.6	0.8%
2039	1,851	15.5	0.8%	1,952	15.0	0.8%
2040	1,855	14.8	0.8%	1,975	14.3	0.7%

[148] The winter morning and evening average peak demand values include the impact of EVs in the intermediate scenario.

7 Demand Response Potential

This section presents demand response potential results for three IIS resources:

1. **Electricity Rate Designs**: The Study Team examined the impact of two behaviour driven time-variable rates (TVR), TOU and CPP, on peak demand. The methods by which customers shift their load are not specified. These TVR are not currently offered in Newfoundland or the nearby provinces of New Brunswick and Prince Edward Island, but exist in other Canadian jurisdictions including Nova Scotia, Quebec, and Ontario. Nova Scotia currently has a time-of-day rate plan in place that is only available to customers with electric thermal storage systems, as well as pilots for TOU and CPP.[149,150]
2. **Equipment Demand Response Measures**: The Study Team assessed utility-driven, managed charging and thermal storage with TOU equipment DR measures. These measures are defined as follows:
    - **Utility-Driven**: The utility has direct load control (DLC) of customer end use equipment (e.g., water heater smart switch, smart thermostat) during on-peak times. These measures are modelled with current rates (i.e., they are not modelled with TVR).
    - **EV Managed Charging**: The utility has DLC of EV charging during the evening peak period.[151]
    - **Thermal Storage with Time-of-Use**: Customers shift electricity use off peak based on TOU rates only using electric thermal storage (ETS) systems.
3. **Customer Curtailment**: Select customers, including those in rates 2.3 and 2.4, large commercial customers, and large industrial customers curtail their energy use when NP or NLH issues a request for curtailment.

Like for efficiency and electrification, the Study Team assessed three levels of demand response savings potential for each resource: technical, economic, and achievable. However, the demand response potential assessment differs in the following ways:

- Measure-level incentives and non-incentive program costs are not varied, so there is only one achievable potential scenario. Throughout this section, this scenario is referred to as the medium achievable potential scenario.
- Participation rates are based on research and consultation with the Utilities. The only demand resource response currently in market in Newfoundland is customer curtailment, so there are no historical savings to benchmark against for the electricity rate design and equipment DR measures.

[149] Nova Scotia Power, "Residential Rates," Available: https://www.nspower.ca/your-home/residential-rates (Accessed Mar. 7, 2025).
[150] Nova Scotia Power, "Time-Varying Pricing Rate Pilot Program,", Available: https://www.nspower.ca/time-of-day-rate-plans-business (Accessed Mar. 7, 2024).
[151] The morning peak period represents the lowest load for EV charging, resulting in much more limited peak reduction potential.

- Unless otherwise noted, results include the following:
  - Peak impacts from efficiency and fuel switching measures in the medium achievable potential scenario. This approach avoids overestimating demand response potential during the forecast period that will most likely include the adoption of efficiency and fuel switching measures.
  - EV charging demand in the intermediate scenario.

The rest of this section is structured as follows:

- Section 7.1 shows the IIS load curve in the absence of demand response activities. This curve is a reference to contextualize the shape of the curve after potential is applied.
- Section 7.2 shows demand response potential for the electricity rate design measures.
- Section 7.3 shows demand response potential for the equipment DR measures.
- Section 7.4 shows customer curtailment potential.
- Section 7.5 discusses interactive effects between demand response resources. These interactive effects occur when two resources target the same peak savings. Section 11.5 also explains the Study Team's approach to avoid double-counting savings.
- Section 7.6 shows the IIS load curve after potential is applied.

7.1 Peak Day Load Curve Analysis

To fully assess the potential impact of the demand response resources, the Study Team first established a reference load shape for the system on the IIS peak day. Exhibit 121 shows the steps completed to identify the reference load shape.

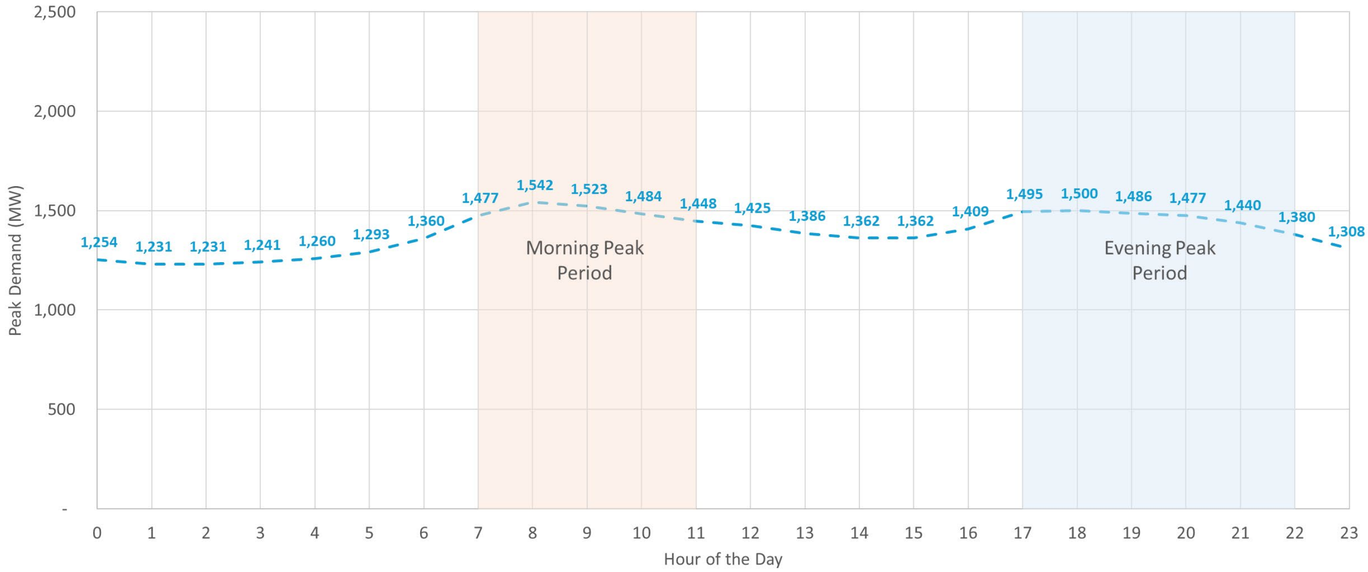
Exhibit 121: Peak Day Load Curve Analysis Approach

Step	Approach Summary
1. Analyze historical IIS hourly load data	• Analyze IIS hourly load data from 2019-2023 to determine the shape and distribution of hourly loads for the highest-demand days.
2. Determine reference load shape for the peak day	• Generate an initial load shape for the peak day using the mean hourly demand from all days in the IIS hourly load data scaled by three standard deviations. • Normalize the initial load shape to express hourly load as a fraction of daily load. • The Study Team selected this approach rather than selecting the load shape of a representative day in the 2019-2023 data because it is grounded in statistics (i.e., the representation of extremes in relation to the mean) and enables the model to be calibrated to base year peak day or hour demand.
3. Assess demand response windows	• Overlay the expected daily load shape of EV charging in the intermediate scenario (from analysis completed for this Study) on the initial load shape. • Define two peak period “demand response windows” (morning and evening) that include most of the top peak hours across the initial load shape and expected EV charging demand in the intermediate scenario. • Based on consultation with the Utilities, these demand response windows are 7 a.m. to 10:59 a.m. for the morning peak, and 5 p.m. to 9:59 p.m. for the evening peak. • Weight the initial load shape and expected EV charging load shape in the intermediate scenario according to their relative contribution to peak to create a reference load shape.
4. Identify addressable peak	• Defined the “addressable peak” as the peak hour consumption in the demand response windows that can be shifted outside each window without creating a new peak hour.

The Study Team evaluated demand response potential for the highest winter peak hour and all other peak day hours. This was important since demand response measures can create new peaks through load shifting or bounce-back effects.

Exhibit 122 and Exhibit 123 show the reference load shape and the demand response windows for the peak day in 2023 and 2040, respectively. These load shapes were created by scaling the reference load shape to match the forecast 2023 and 2040 peak hourly demand values of 1,542 MW and 2,064 MW, respectively.[152] Both load shapes include the impacts of unmanaged EV charging in the intermediate scenario.[153] As explained in the peak day analysis approach presented in Exhibit 121, the reference load shape does not reflect an actual historical peak day. Instead, the Study Team generated a calibrated reference load shape using a method grounded in statistics.

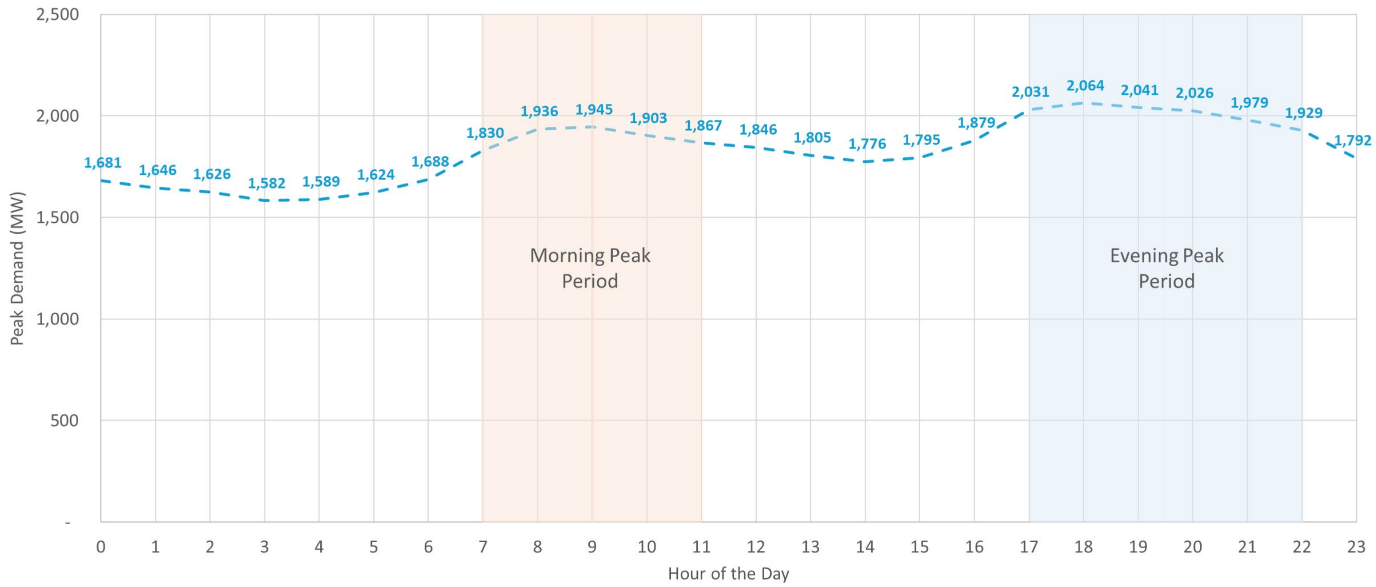
Exhibit 122: Reference Load Shape (2023)



152 The annual peak demand forecast can be found in section 3.

153 Unless otherwise specified, any comparisons between potential results and the system peak demand in the following sections are based on the peak hourly demand including the impact of unmanaged EV charging in the intermediate scenario.

Exhibit 123: Reference Load Shape (2040)



In 2023, the IIS peaks in the morning but in 2040 it peaks in the evening. This change is partly driven by the impact of EV charging in the intermediate scenario, which causes the shift from morning (8 a.m.) to evening (6 p.m.) peak in 2033. The switch to evening peak is expected in 2037 in the natural adoption scenario and in 2030 for the government targets scenario.

7.2 Electricity Rate Design Measure Potential

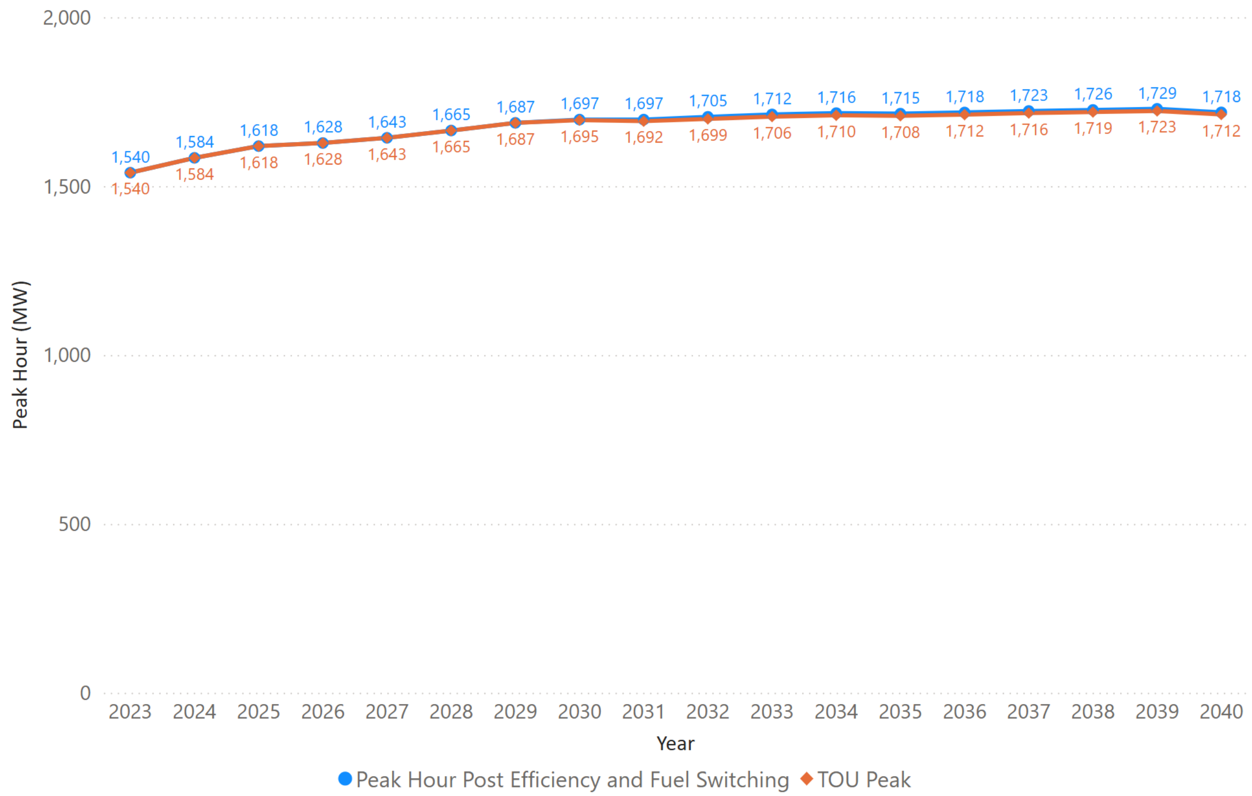
This section presents demand response peak reduction potential for the IIS from the electricity rate design measures in the medium achievable scenario. Section 7.2.1 shows results for the TOU and CPP measures for all non-EV loads. Section 7.2.2 shows results for EV TOU. Exhibit 131 and Exhibit 132 in section 7.2.2 show how EV load shifts from the rate design measures overlayed on the non-EV load shape.

7.2.1 Electricity Rate Design Measure Results

Exhibit 124 shows the medium achievable peak hour demand for the TOU electricity rate design measure (orange line) compared to the reference peak hour demand that includes impacts from efficiency and fuel switching measures (light blue line). The difference between the lines represents the potential peak demand reductions from TOU. The results exclude the impacts of TOU rates on EV charging.[154]

Savings from TOU start in 2029, once AMI infrastructure is in place.[155] Opt-in participation to the TOU rate increases from 2029 to 2033, then remains constant at 15% until 2040. In 2029, the peak demand reduction is 0.2 MW. Between 2032 and 2040, the peak demand reduction is approximately 6 MW.

Exhibit 124: Medium Achievable Peak Demand – TOU

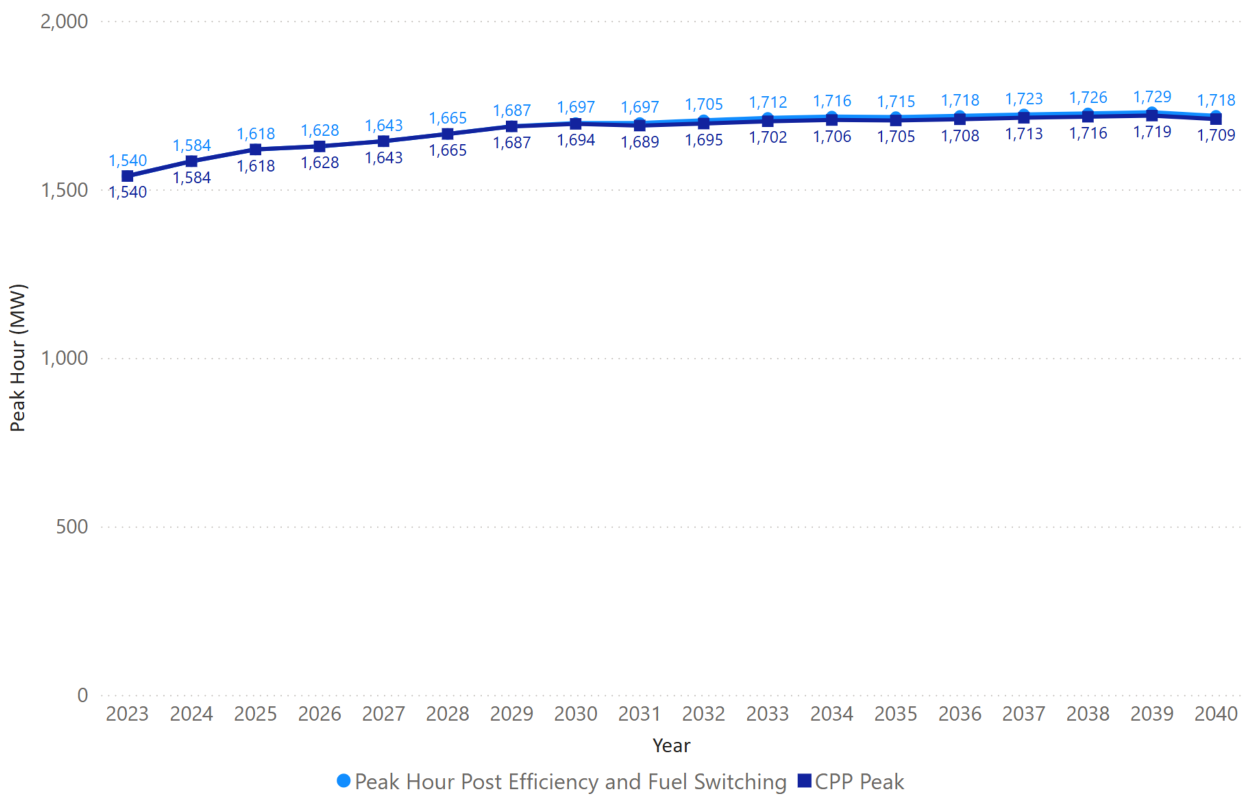


[154] Section 7.2.2 shows EV TOU measure results and compares them to results shown in section 7.2.1.
[155] As stated in section 4.3.1, AMI infrastructure, including smart meters, data management systems, and communication networks, is required for a utility to implement TVR like TOU and CPP.

Exhibit 125 shows the medium achievable peak hour demand for the CPP electricity rate design measure (dark blue line) compared to the reference peak hour demand that includes impacts from efficiency and fuel switching measures (light blue line). The difference between the lines represents the potential peak demand reductions from CPP.

Savings from CPP start in 2029, once AMI infrastructure is in place.[156] Opt-in participation to the CPP rate increases from 2029 to 2033, then remains constant at 15% until 2040. In 2029, the peak demand reduction is 0.4 MW. Between 2032 and 2040, the peak demand reduction is approximately 10 MW.

Exhibit 125: Medium Achievable Peak Demand – CPP



[156] As stated in section 4.3.1, AMI infrastructure, including smart meters, data management systems, and communication networks, is required for a utility to implement TVR like TOU and CPP.

As explained in section 4.1.1, the savings results for the TVR measures are informed by opt-in participation rates (15%) and per-customer savings (3% and 5% of peak hour demand for TOU and CPP, respectively) from jurisdictional research. Savings would increase with higher participation, but the Study Team's research found that a 15% participation for opt-in programs was typical.[157,158,159]

Exhibit 126 shows the medium achievable potential peak reduction for the electricity rate design measures by sector, excluding savings from EV TOU. 77% and 81% of the potential peak reductions exist in the residential sector for the TOU and CPP measures for all study years. This result is driven by the assumption that residential customers are more likely than commercial customers to alter their space heating patterns based on TVR. For reference, the residential sector accounts for 65% of the reference case peak demand in 2040. The commercial and industrial sectors contribute 27% and 8% to the total, respectively.

Exhibit 126: Medium Achievable Potential Sector Breakdown – Electricity Rate Design (2040)

Measure	Sector	Winter Peak Hour Reduction (MW)	% Contribution to Total Measure Peak Reduction
TOU	Residential	4.80	77%
	Commercial	1.11	18%
	Industrial	0.32	5%
	TOU Total	**6.23**	**100%**
CPP	Residential	7.93	81%
	Commercial	1.49	15%
	Industrial	0.35	4%
	CPP Total	**9.77**	**100%**

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[157] This 15% maximum participation rate is consistent with findings from other jurisdictions in Canada where opt-in time varying rates were studied, including Nova Scotia and British Columbia.
[158] Nova Scotia Power, "Time-Varying Pricing Project Submission", Available: https://www.brattle.com/wp-content/uploads/2021/05/19479_nova_scotia_utility_and_review_board_-_time-varying_pricing_project_submission.pdf, (Accessed Sept. 5, 2024).
[159] British Columbia Hydro and Power Authority, "BC Hydro Optional Residential Time-of-Use Rate Application", Available: https://docs.bcuc.com/documents/proceedings/2023/doc_70443_b-1-bch-optional-residential-tou-rate-application.pdf (Accessed Oct. 29, 2024).

Exhibit 127 shows the demand reduction potential for both electricity rate design measures by peak period and sector for 2029 and 2040. The following observations can be made on Exhibit 127:

- TOU and CPP in the residential sector show the highest savings potential for all three peak periods because of the potential savings for space heating in the residential sector.
- CPP shows higher savings potential than TOU in all sectors and peak periods because peak events are less frequent, and the on-peak retail rate is higher.

Exhibit 127: Medium Achievable Peak Demand Reduction – Electricity Rate Design

Measure	Sector	2029 Winter Peak Hour Reduction (MW)	2029 Winter Morning Average Peak Reduction (MW)	2029 Winter Evening Peak Average Reduction (MW)	2040 Winter Peak Hour Reduction (MW)	2040 Winter Morning Average Peak Reduction (MW)	2040 Winter Evening Average Peak Reduction (MW)
TOU	Residential	0.17	0.17	0.16	4.80	4.66	4.55
	Commercial	0.04	0.04	0.04	1.11	1.11	1.11
	Industrial	0.01	0.01	0.01	0.32	0.32	0.32
	Total	**0.22**	**0.22**	**0.21**	**6.23**	**6.09**	**5.98**
CPP	Residential	0.28	0.28	0.27	7.93	7.70	7.51
	Commercial	0.05	0.05	0.05	1.49	1.49	1.49
	Industrial	0.01	0.01	0.01	0.35	0.35	0.35
	Total	**0.34**	**0.34**	**0.33**	**9.77**	**9.54**	**9.35**

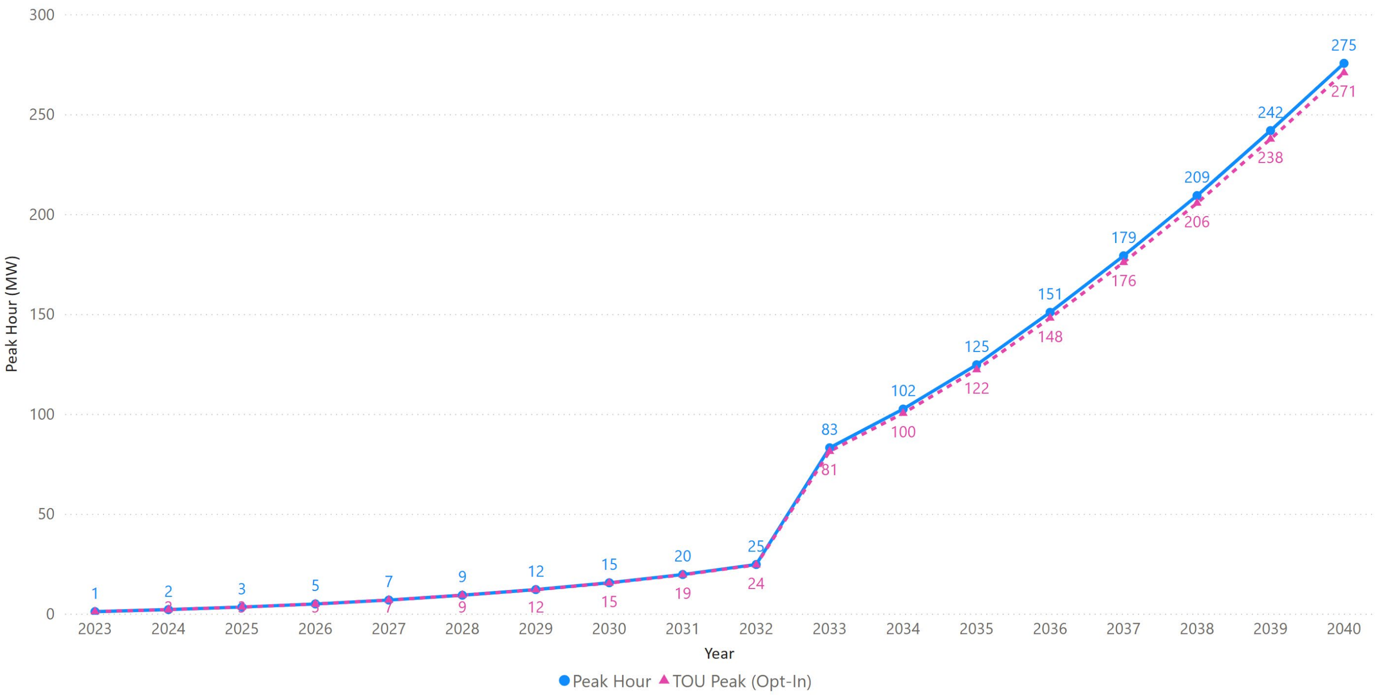
Peak impacts from the electricity rate design measures are much smaller than those from the efficiency measures. For example, for the 2040 morning peak, savings from the CPP measure are approximately 0.5% of the average winter morning peak demand, compared to 3.8% for the efficiency measures. In contrast, savings from the electricity rate design measures are higher than the impacts of electrification measures on the average winter morning peak, which is 0.2% in the same example.

7.2.2 EV Electricity Rate Design Measure Results

Exhibit 128 shows the unmanaged EV charging demand during the peak hour for each year of the forecast period (light blue line), and the charging demand with a 15% opt-in participation to the TOU rate (pink dashed line). The following observations can be made on Exhibit 128:

- Reductions to the peak hour occur each year after the introduction of the TOU rates in 2029.
- Between 2029 and 2032, the savings increase from 0.1 MW to 0.2 MW annually. The IIS peaks in the morning until 2033, when most EVs are not charging so there is limited load to shift.
- Between 2033 and 2040, the IIS peaks in the evening. Savings increase from 1.8 MW to 4.7 MW annually over this period.[160]
- The higher savings from 2033 to 2040 compared to between 2029 and 2033 occur because the TOU measure affects more EVs and because most EVs charge in the evening so there is more load to shift.
- In 2029, the peak demand reduction is 0.1 MW (0.8% of EV charging load). By 2040, the peak demand reduction is 4.7 MW (1.7% of EV charging load).

Exhibit 128: Annual EV Peak Hour Demand, Opt-In TOU[161]



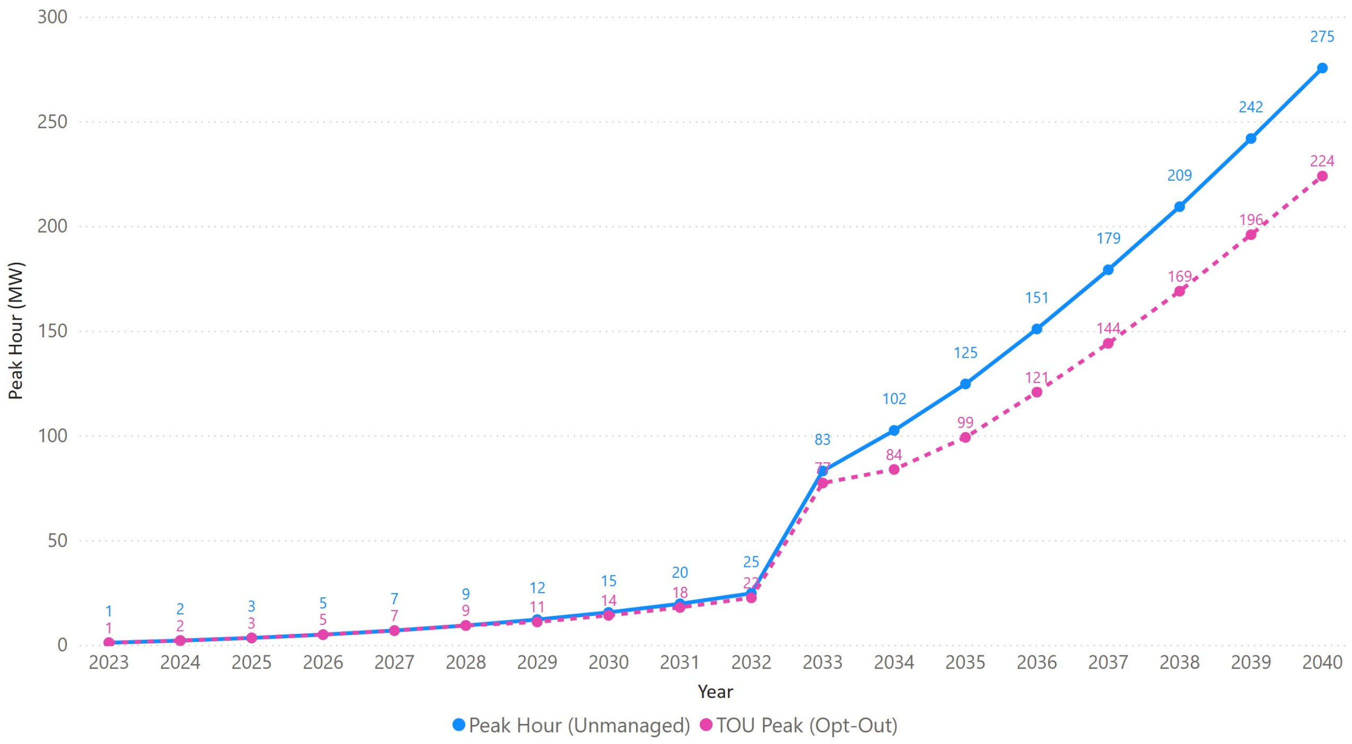
[160] Larger peak reduction potentials are realized in the evening than in the morning so when the IIS system peak is estimated to shift from the morning to the evening in 2033, peak reduction potential increases from 0.2 MW to 1.8 MW in one year.

[161] The increase in EV load during the peak hour seen between 2032 and 2033 is due to the system wide peak hour shifting from the morning to the evening. For the years before 2033, the peak hour is expected to be in the

Exhibit 129 shows unmanaged EV charging demand (light blue line) and EV charging demand with an opt-out TOU rate (pink dashed line). As explained previously, charging demand in the opt-out TOU participation scenario represents a future where the intermediate EV forecast plays out, and where 100% of EVs are on a TOU rate. The following observations can be made on Exhibit 129:

- The peak reduction potential for an opt-out TOU rate is significantly higher than the peak reduction potential for the opt-in TOU rate, especially once the IIS peak shifts to the evening. Peak reductions for the opt-out TOU rate are approximately 1 MW higher than reductions for the opt-in TOU rate in 2029 and almost 47 MW higher in 2040.
- In 2029, the peak demand reduction is 1.12 MW (9.3% of EV charging load). By 2040, the peak demand reduction is 51.60 MW (18.7% of EV charging load).

Exhibit 129: Annual EV Peak Hour Demand, Opt-Out TOU



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morning and thus the EV contribution to peak is much lower as much less charging occurs then. After 2033, the EV contribution to the peak is much higher with the system peak hour now occurring much closer to the EV charging peak hour.

Exhibit 130 shows demand reductions for personal BEVs and personal PHEVs during the morning and evening peak periods, and for the peak hour. Demand reductions are shown for both the opt-in and the opt-out TOU rates. The 51.60 MW peak hour reduction from EVs based on an opt-out TOU rate in 2040 is more than eight times higher than the TOU rate reduction potential from the residential, commercial, and industrial sectors combined (6.23 MW - see Exhibit 127). This result highlights the flexibility of the EV charging load and the value to the IIS of managing the load.

Exhibit 130: Medium Achievable Peak Demand Reduction - EV TOU[162]

Measure	Vehicle Type	2029 Winter Peak Hour Reduction (MW)	2029 Winter Morning Peak Reduction (MW)	2029 Winter Evening Peak Reduction (MW)	2040 Winter Peak Hour Reduction (MW)	2040 Winter Morning Peak Reduction (MW)	2040 Winter Evening Peak Reduction (MW)
Opt-In TOU	Personal BEV	0.07	0.09	0.38	2.98	0.61	2.82
	Personal PHEV	0.03	0.03	0.34	1.71	0.16	1.54
	Total	**0.10**	**0.12**	**0.72**	**4.69**	**0.77**	**4.36**
Opt-Out TOU	Personal BEV	0.97	1.21	5.59	43.23	8.85	40.86
	Personal PHEV	0.15	0.17	1.65	8.37	0.77	7.53
	Total	**1.12**	**1.38**	**7.24**	**51.60**	**9.62**	**48.39**

[162] Reductions in load can be higher for the morning or evening periods when compared to the peak hour because the system peak hour doesn't coincide with the highest EV load. The value for the peak hour is the value that the overall system peak is reduced by.

Exhibit 131 shows the impact of an opt-in TOU rate on the IIS peak day load shape in 2040 and the resulting shift in EV charging load. The IIS peak excluding EV load (light blue line), includes the effects of energy efficiency and fuel switching measures. Limited savings from the opt-in TOU rate (pink dashed line) result in a peak reduction of approximately 4.7 MW during the IIS peak hour at 6:00 pm when compared to unmanaged EV load (black dashed line).

Exhibit 131: Impacts on Daily Load Shape – Opt-In TOU (2040)

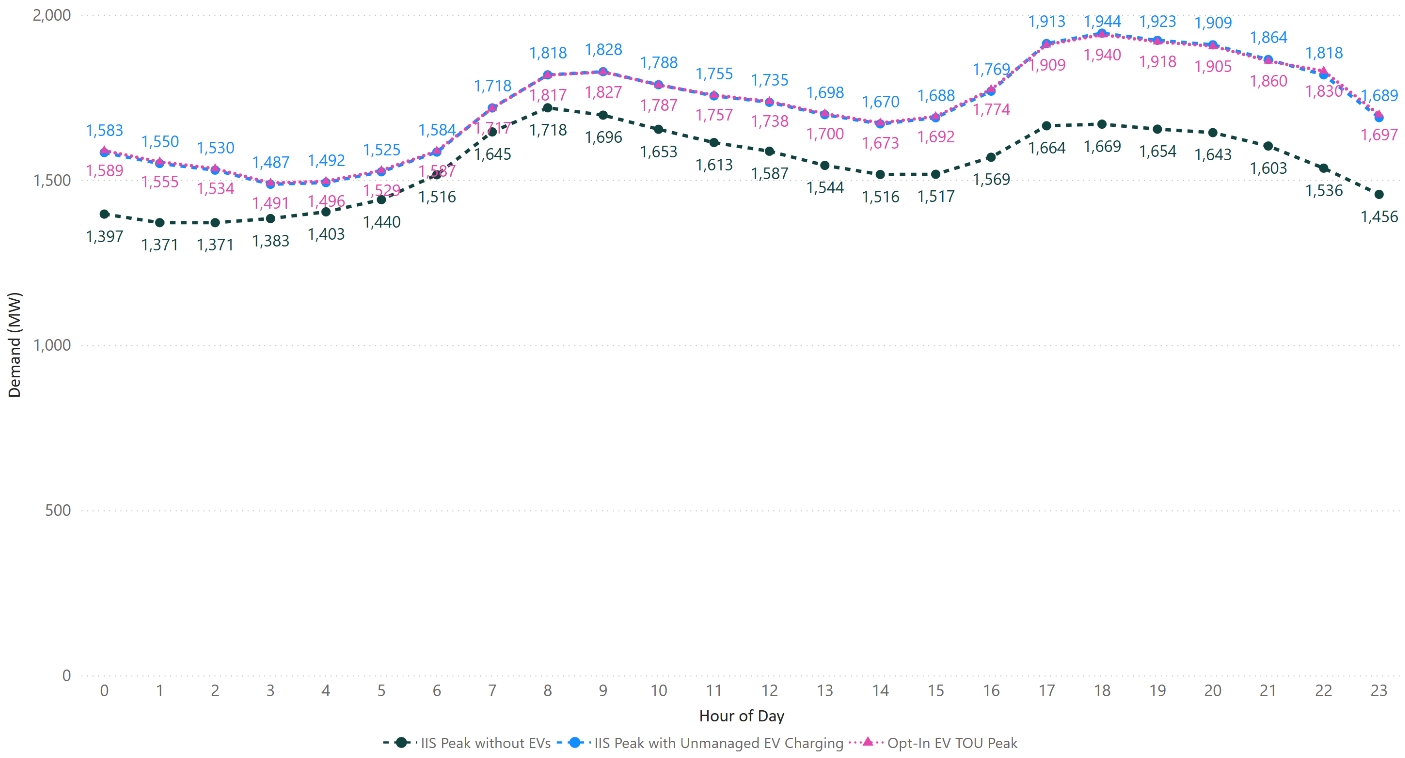
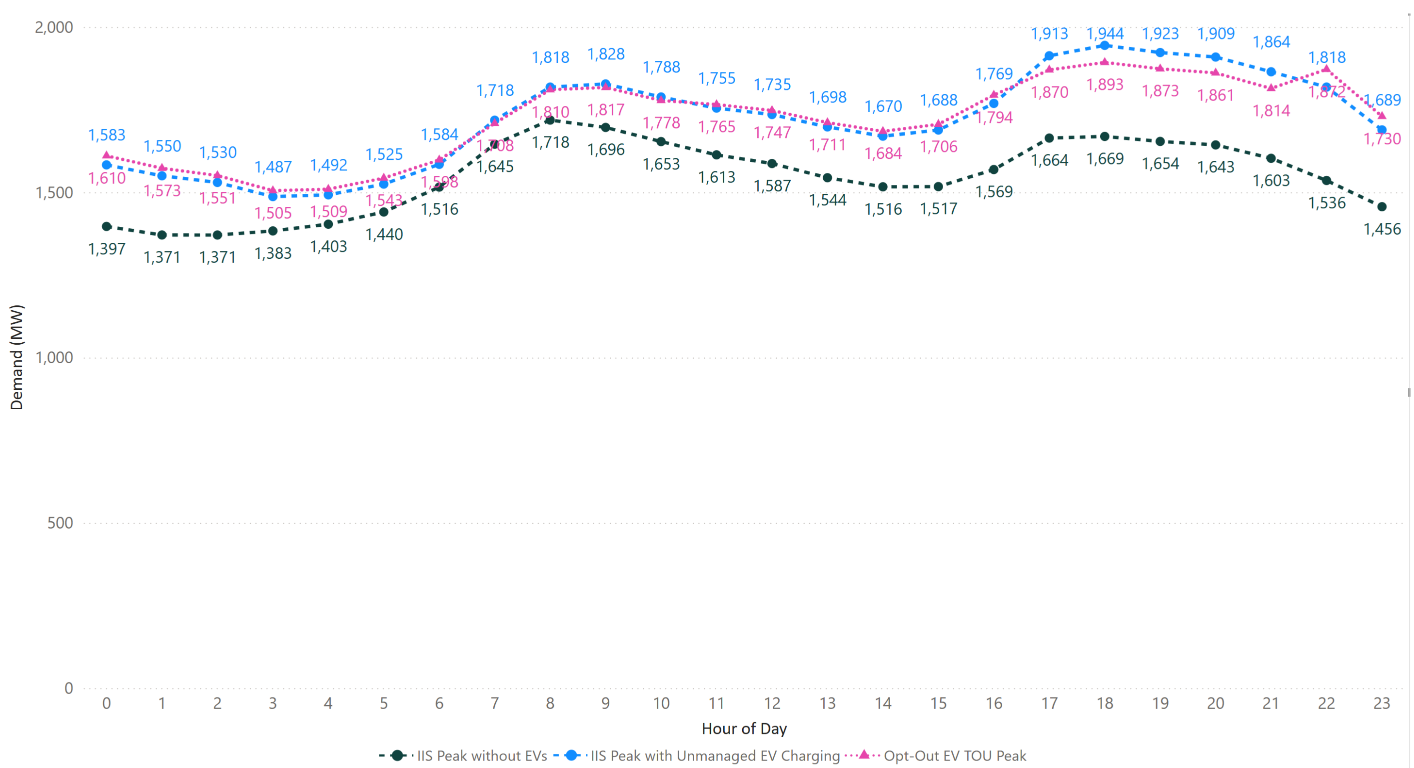


Exhibit 132 shows the impact of an opt-out TOU rate on the IIS peak day load shape in 2040 and the resulting shift in EV charging load. Observations include:

- The opt-out TOU rate is successful at encouraging personal EV owners to charge later in the evening, providing savings of 51 MW and resulting in a new peak of 1,893 MW at 6:00 p.m.
- The opt-out TOU rate also provides 11 MW of peak savings during the morning peak period.
- However, there is a large peak bounce-back at the beginning of the "Off-Peak" period at 10:00 p.m., when many of the vehicles begin to simultaneously charge again. In scenarios where the uptake of EVs is higher, or in cases where the underlying system load shape has a longer evening peak, there is a risk of creating a new, higher peak later in the evening. Implementation of a managed charging program can help mitigate this risk.[163]

Exhibit 132: Impacts on Daily Load Shape – Opt-Out TOU (2040)



[163] Managed charging programs allow utilities to have more control over the bounce back effects that may occur with widespread TOU participation.

7.3 Equipment DR Measures Potential

The Study Team also assessed the impact of equipment DR measures. The measures are split into two categories, utility-driven and thermal storage with TOU. The smart circuit breakers or smart panel measure is an example of a utility-driven measure. Each thermal storage measure has a utility-driven version and a thermal storage with TOU version.

Customer Staggering to Minimize Bounce-Back Effects

The Study Team assumed that for most measures, a reasonable number of hours for which a customer participates in demand response is four hours. This is consistent with the length of demand response events for programs from other Canadian jurisdictions including Nova Scotia and British Columbia. The evening peak period defined in section 7.1 is five hours. To avoid bounce back within the peak period, the Study Team conducted the evening peak analysis assuming the following:

- Customers are split into two groups. In-market demand response programs are assumed to stagger the onset of demand response measures in more than two groups to smooth out the response. The use of two groups is a simplification.

- Savings for group 1 start in the first hour and savings for group 2 start in the second hour.

In this way, rebound in the fifth hour for group 1 is cancelled out by the savings from group 2.

The Study Team used this method to calculate savings for the utility-driven equipment DR measures for which demand reduction over a five-hour period is unlikely. For these measures, the average demand savings for the evening peak period are reduced. Evening peak demand reduction results for these measures reflect this approach throughout the report.

7.3.1 Frequency and Duration of Equipment DR Measure Events

The Study Team modelled the equipment DR measures at the following frequency and peak event durations:

- **Equipment DR Measures (Utility-Driven):** The utility shifts customer load 12 times annually, for four hours during the morning peak period and five hours during the evening peak period.
- **Electric Vehicle Managed Charging:** The utility shifts customer EV charging for five hours during the evening peak period. Managed charging programs are not modelled at a system wide scale until 2029 (coinciding with the introduction of TOU rates).[164,165]

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[164] EV managed charging measures are modelled in the absence of TOU rates as studies from other jurisdictions have indicated that if the equipment and enrolment incentives are rich enough, participation in managed charging programs are not dependent on having an underlying TOU rate structure.
[165] "PG&E Electric Vehicle Automated Demand Response Study Report," Opinion Dynamics, Available: https://opiniondynamics.com/wp-content/uploads/2022/03/PGE-EV-ADR-Study-Report-3-16.pdf (Accessed Feb. 24, 2025).

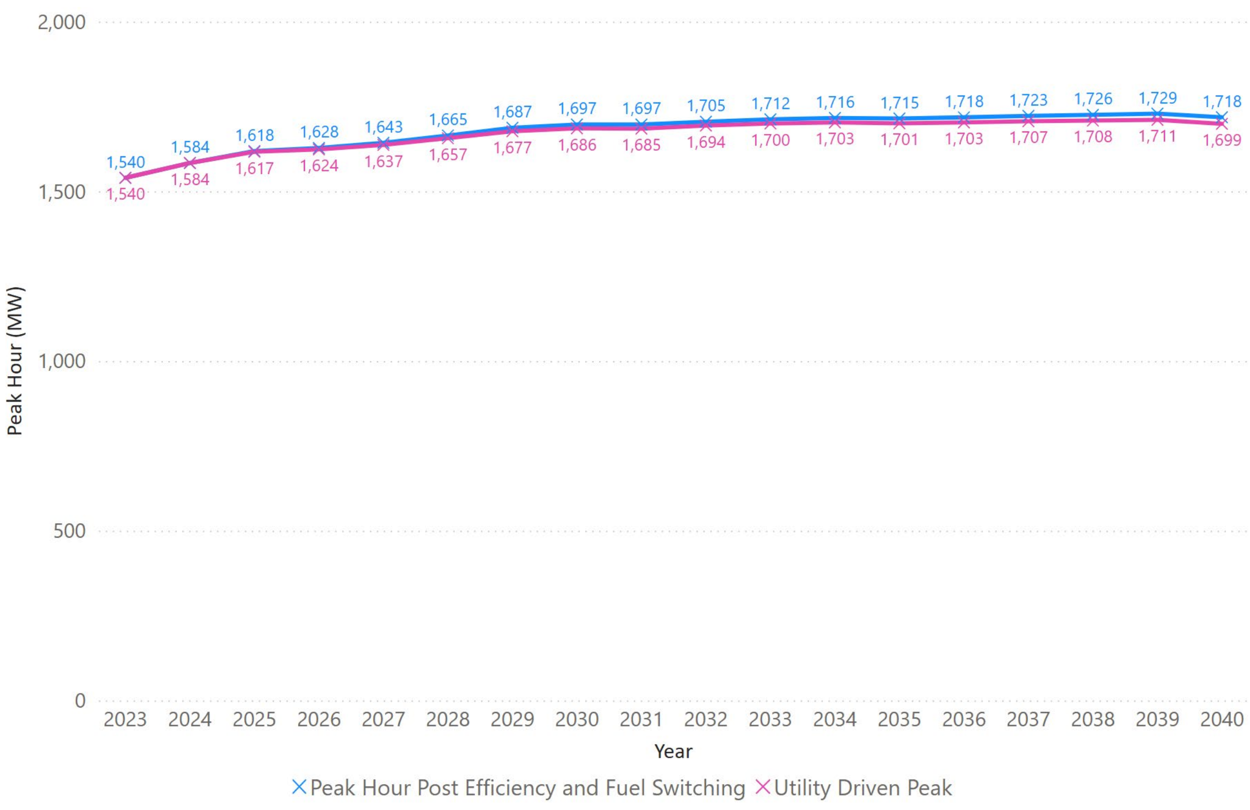
- **Equipment DR Measures (Thermal Storage with TOU):** Customers shift load off the peak periods on weekdays from December to March, for a total of 89 events per year.

7.3.2 Utility-Driven Measure Results

This section presents peak demand reduction results for the utility-driven measures, excluding EV managed charging, in the medium achievable potential scenario.[166] Participation rates for the utility-driven measures are based on rates from other jurisdictions that have been adjusted to reflect the likely participation in Newfoundland. Participation rates for the utility-driven measures are lower on average than those of the rate design measures due to customers being less likely to give the utility control of the equipment in their home or building.

Exhibit 133 shows the medium achievable peak hour demand for the utility-driven peak (pink line) compared to the reference peak hour demand that includes impacts from efficiency and fuel switching measures (light blue line). The difference between the lines represents the potential peak demand reductions from the utility-driven equipment DR measures. The demand reduction increases from 1 MW in 2025 to 19 MW by 2040.

Exhibit 133: Medium Achievable Peak Demand – Utility-Driven Equipment DR Measures



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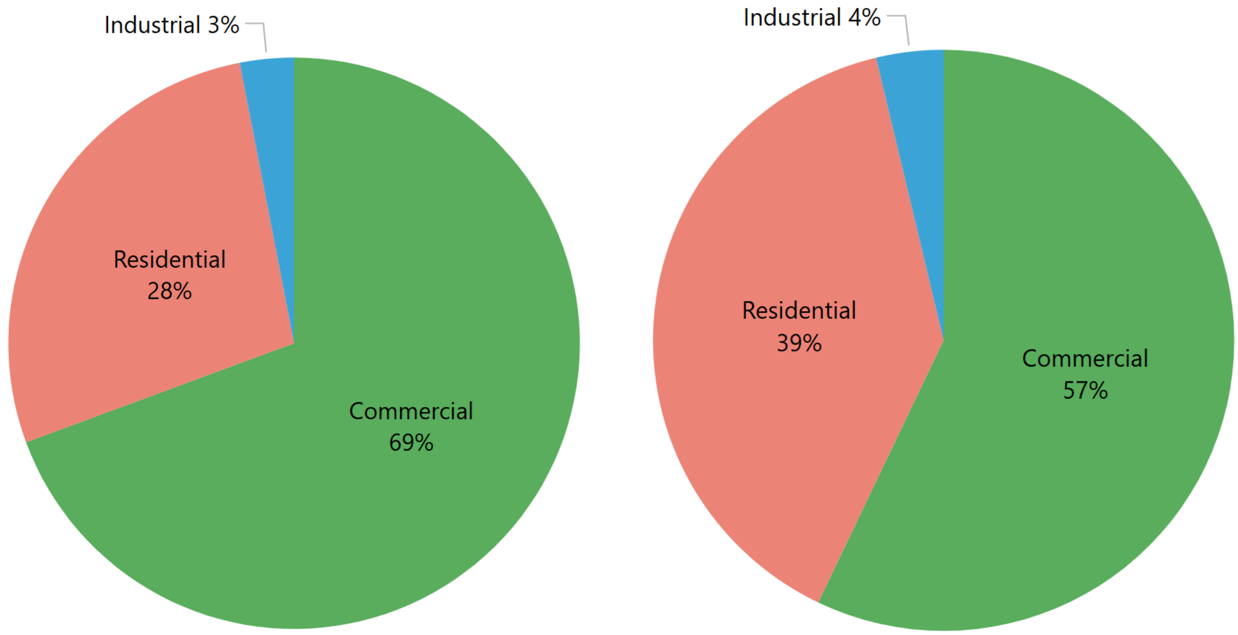
166 The following measures are included in the medium achievable potential, even though they failed the PAC screen: electric thermal storage, battery storage, smart thermostats, substation battery, and EV managed charging. Measures that failed the PAC screen and are not cost-effective include smart thermostat or switch for ductless mini-split heat pumps and smart thermostat or switch for central air source heat pumps.

Exhibit 134 shows the medium achievable peak hour demand reduction potential for the utility-driven measures by sector. Potential peak demand reduction increases from 12.2 MW in 2031 to 19.4 MW by 2040. The commercial sector shows the most peak demand reduction in both milestone years. The proportion of peak demand reduction attributed to the residential sector increases from 28% in 2031 to 39% by 2040, as adoption of residential sector measures increases.[167]

Exhibit 134: Medium Achievable Demand Reduction Potential by Sector, 2031 (left) and 2040 (right) – Utility-Driven Equipment DR



2031 Demand Reduction Potential: 12.2 MW **2040 Demand Reduction Potential: 19.4 MW**

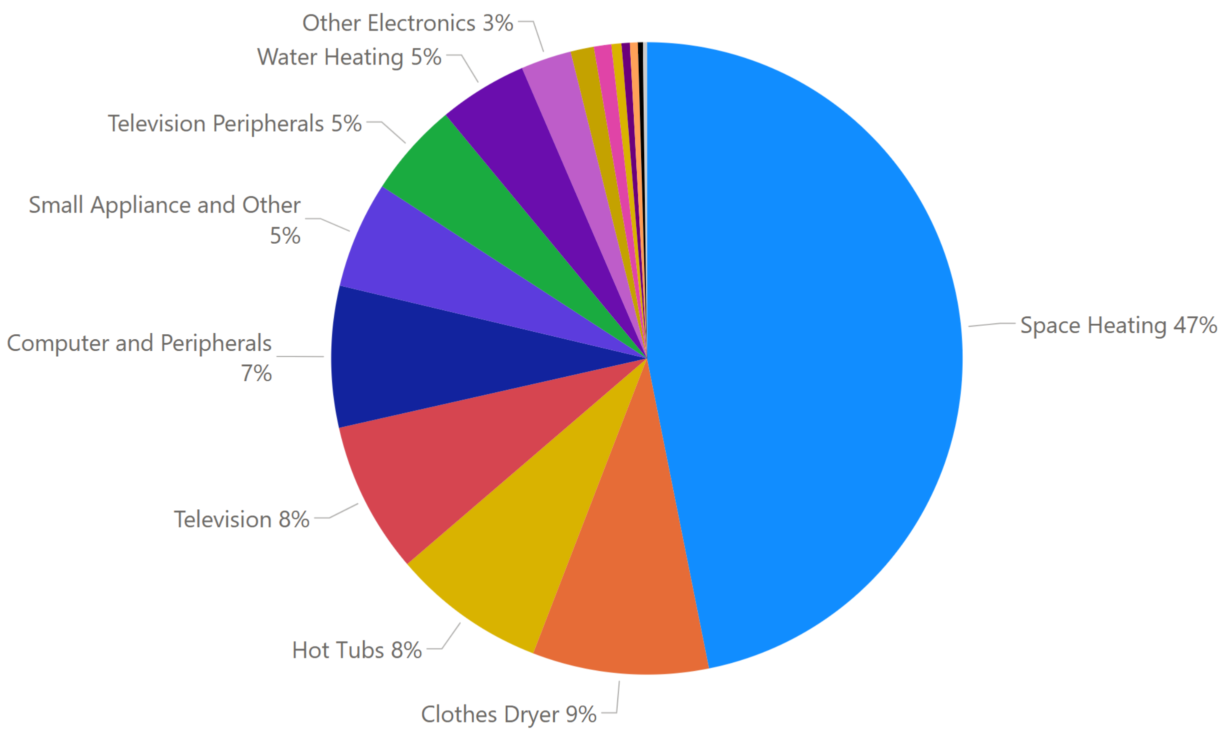
The rest of this section presents medium achievable potential peak demand reduction by sector.

[167]2031 was chosen as a milestone year for reporting purposes because it is the first year in which all utility-driven measures show peak savings.

Residential Sector

Exhibit 135 shows the 2031 peak hour demand reduction potential by end use for the residential sector.[168] Space heating offers 47% of the total potential peak demand reduction in 2031. Nine of the fourteen (64%) residential measures impact the space heating end use, which makes up 69% of the 2031 residential sector winter peak demand excluding EVs.

Exhibit 135: Residential Medium Achievable Demand Reduction Potential by End Use (2031) – Utility-Driven Equipment DR

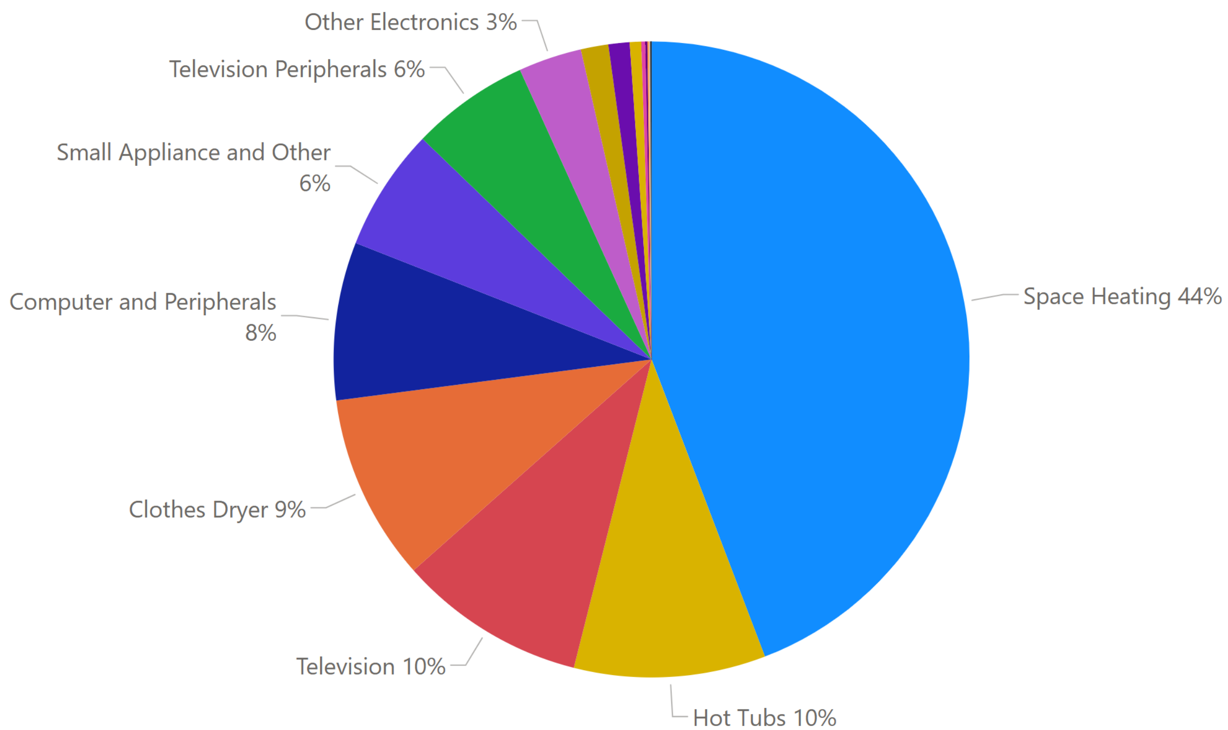


2031 Residential Demand Reduction Potential: 3.4 MW

[168] End uses that represent less than 3% of demand reduction potential are not labelled to improve readability: dishwasher (1%), cooking (1%), clothes washer (1%), refrigerator (0.4%), ventilation (0.4%), lighting (0.3%), and freezer (0.2%).

Exhibit 136 shows the 2040 peak hour demand reduction potential by end use for the residential sector.[169] Demand reduction potential by end use remains consistent because the relative measure participation rates remain consistent year over year.

Exhibit 136: Residential Medium Achievable Demand Reduction Potential by End Use (2040) – Utility-Driven Equipment DR



2040 Residential Demand Reduction Potential: 7.6 MW

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[169] End uses that represent less than 3% of demand reduction potential are not labelled to improve readability: dishwasher (1%), water heating (1%), clothes washer (1%), cooking (0.2%), refrigerator (0.1%), ventilation (0.09%), lighting (0.06%), and freezer (0.06%).

Exhibit 137 shows 2031 and 2040 savings for the top residential sector utility-driven measures.

Exhibit 137: Residential Top 10 Utility-Driven Equipment DR Measures

Measure	2031 Peak Hour Demand Reduction (MW)	Measure	2040 Peak Hour Demand Reduction (MW)
Smart Circuit Breakers or Smart Panel	1.4	Smart Circuit Breakers or Smart Panel	4.0
Behind-the-Meter Solar with Smart Inverters	0.9	Smart Thermostat or Switch for Baseboards or Furnaces	0.8
Smart Thermostat or Switch for Baseboards or Furnaces	0.3	Thermal Storage and Ductless Mini-Split Heat Pump	0.7
Behind-the-Meter Battery Storage	0.2	Thermal Storage and Electric Baseboard Heating	0.6
Thermal Storage and Ductless Mini-Split Heat Pump	0.2	Behind-the-Meter Battery Storage	0.6
Smart Thermostat or Switch for Ductless Mini-Split Heat Pumps	0.2	Smart Thermostat or Switch for Ductless Mini-Split Heat Pumps	0.4
Thermal Storage and Electric Baseboard Heating	0.1	Thermal Storage and Air Source Heat Pump	0.2
Thermal Storage and Air Source Heat Pump	0.04	Smart Thermostat or Switch for Central Air Source Heat Pumps	0.1
Smart Thermostat or Switch for Central Air Source Heat Pumps	0.03	Thermal Storage and Electric Furnace	0.03
Thermal Storage and Electric Furnace	0.01	Behind-the-Meter Solar with Smart Inverters	0.0

Observations include:

- Measures that impact all or most end uses (3 of 10) and measures that target space heating (7 of 10) comprise the top ten peak reduction measures. Measures that impact specific appliance end uses like clothes drying or clothes washing do not show medium achievable potential peak demand reduction because they are not cost-effective and do not pass the PAC screen.
- Behind-the-meter solar with smart inverters shows no savings starting in 2032 when the IIS peak shifts from the morning to the evening.

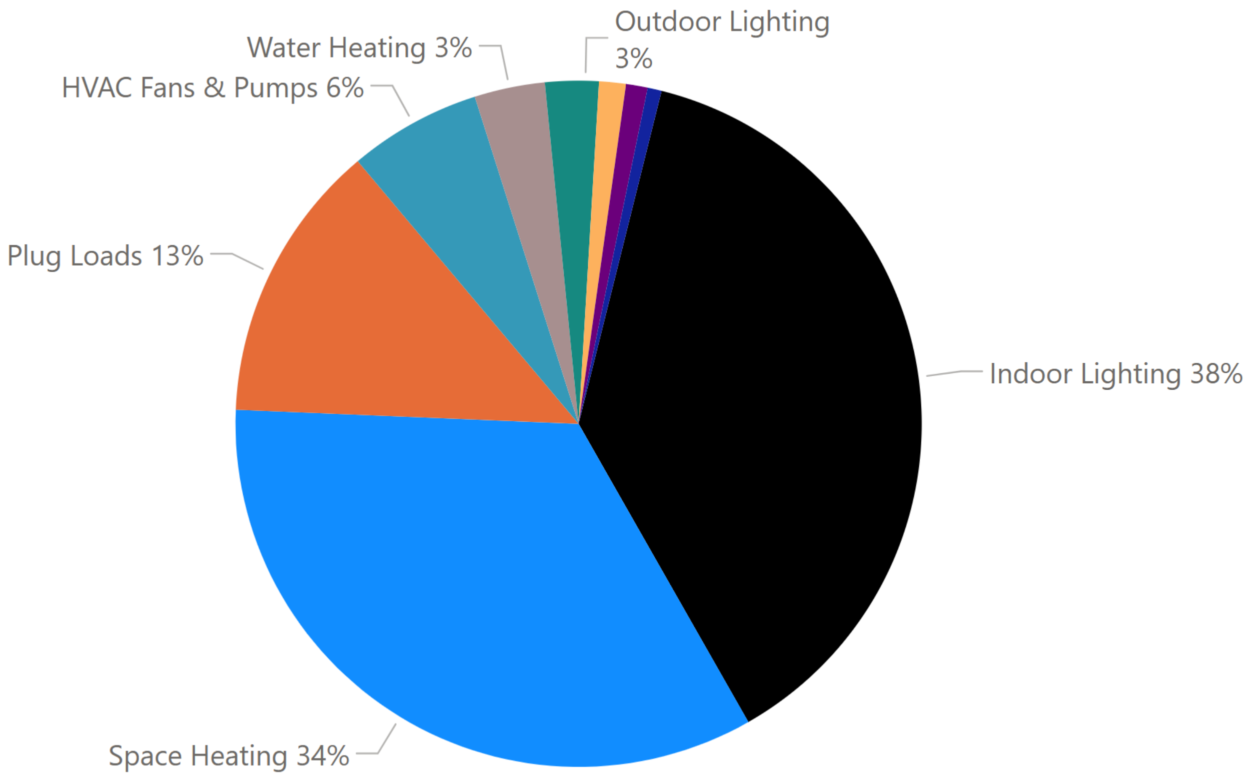
- Total savings are low relative to the peak hour demand. For example, the total space heating savings make up less than 1% of space heating demand in the residential sector by 2040. This is because of the participation rates for measures that impact the space heating end use. For example, participation rates for the thermal storage and ductless mini split heat pump measures only reach 0.5% of available units by 2040. Across all residential utility-driven measures, the average participation rate in 2040 is 3%.
- The smart circuit breakers or smart panel measure shows the highest peak demand reduction in 2031 (1.4 MW) and 2040 (4.0 MW). This is because the measure impacts most end uses and is applicable to all customers.
- Out of the measures targeting the space heating end use, the smart thermostat or switch for baseboards or furnaces measure shows the highest peak demand reduction in 2040 (0.8 MW). This measure has no incremental cost to the customer and a large opportunity comprising both homes with electric baseboard heating and electric furnaces.[170]
- Thermal storage and ductless mini split heat pumps and thermal storage and electric baseboard heating show similar potential peak demand reduction in 2040. They perform better than the thermal storage measures for central heating systems because they have a larger opportunity in Newfoundland and have a lower incremental cost.

[170] This measure assumes the customer already has a smart thermostat installed.

Commercial Sector

Exhibit 138 shows 2031 peak hour demand reduction potential by end use for the utility-driven measures in the commercial sector.[171] Indoor lighting and space heating offer 38% and 34% of the potential peak demand reduction in 2031, respectively. Ten of the eleven (91%) commercial measures impact either indoor lighting or space heating, which make up 61% of the total 2031 commercial sector winter peak demand excluding EVs.

Exhibit 138: Commercial Medium Achievable Demand Reduction Potential by End Use (2031) – Utility-Driven Equipment DR

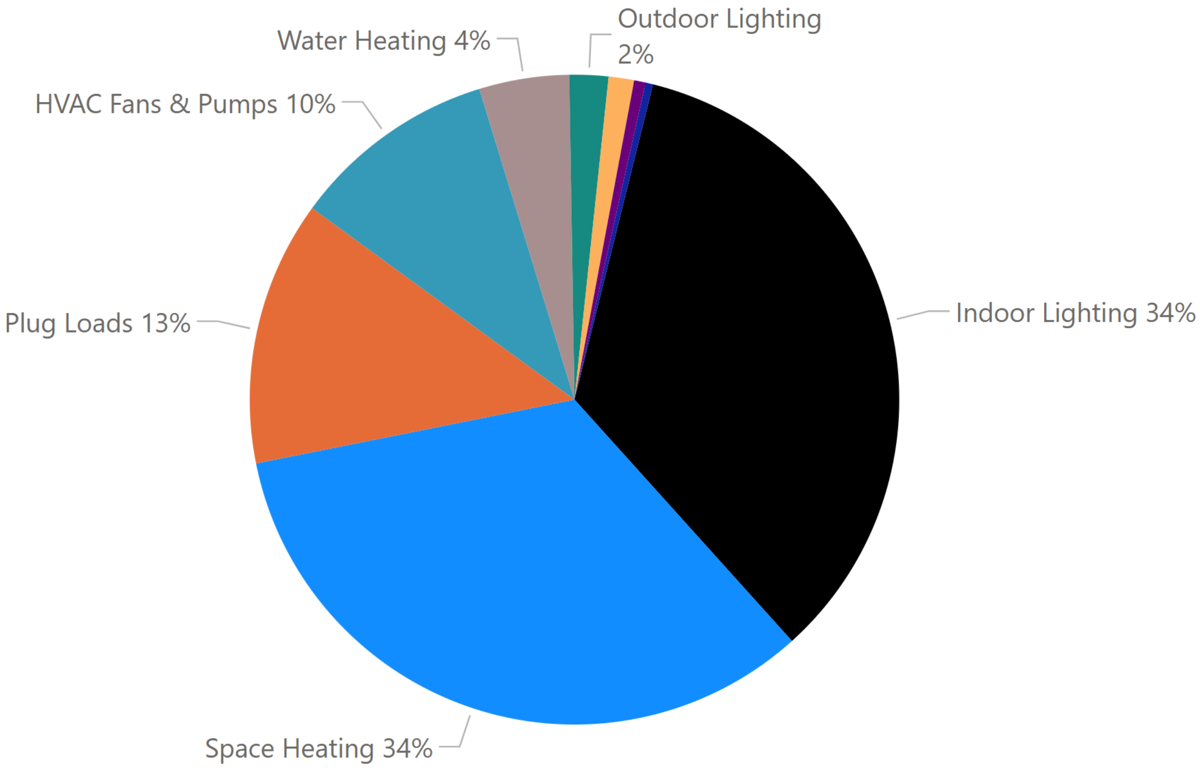


2031 Commercial Demand Reduction Potential: 8.4 MW

[171] End uses that represent less than 3% of demand reduction potential are not labelled to improve readability: miscellaneous equipment (1%), food service (1%), and refrigeration (0.7%).

Exhibit 139 shows 2040 peak hour demand reduction potential by end use for the utility-driven measures in the commercial sector.[172] Six of the eleven (55%) commercial measures impact the space heating end use, which makes up 45% of the total 2040 commercial sector winter peak demand excluding EVs. Demand reduction potential by end use remains consistent because the relative measure participation rates remain consistent year over year.

Exhibit 139: Commercial Medium Achievable Demand Reduction Potential by End Use (2040) – Utility-Driven Equipment DR



2040 Commercial Demand Reduction Potential: 11.1 MW

[172] End uses that represent less than 2% of demand reduction potential are not labelled to improve readability: miscellaneous equipment (1%), food service (0.6%), and refrigeration (0.4%).

Exhibit 140 shows 2031 and 2040 peak hour demand reduction potential for the top ten commercial sector utility-driven measures.

Exhibit 140: Commercial Top 10 Utility-Driven Equipment DR Measures

Measure	2031 Peak Demand Reduction (MW)	Measure	2040 Peak Demand Reduction (MW)
Backup Generation at Peak Hours	3.6	Backup Generation at Peak Hours	4.0
Behind-the-Meter Battery Storage	1.8	Behind-the-Meter Battery Storage	1.9
Thermal Storage and Heat Pump Heating	1.0	Grid Interactive Efficient Buildings (GEB)	1.9
Behind-the-Meter Solar with Smart Inverters	0.8	Thermal Storage and Heat Pump Heating	1.5
Grid Interactive Efficient Buildings (GEB)	0.5	HVAC Control	0.9
HVAC Control	0.3	HVAC Fans & Pumps Controls	0.5
HVAC Fans & Pumps Controls	0.2	Thermal Storage and Electric Furnace Heating	0.1
Thermal Storage and Electric Furnace Heating	0.1	Thermal Storage and Electric Baseboard Heating	0.04
Thermal Storage and Electric Baseboard Heating	0.03	Large Commercial Dual-Fuel Water Heater	0.01
Large Commercial Dual-Fuel Water Heater	0.004	Behind-the-Meter Solar with Smart Inverters	0.0

Observations include:

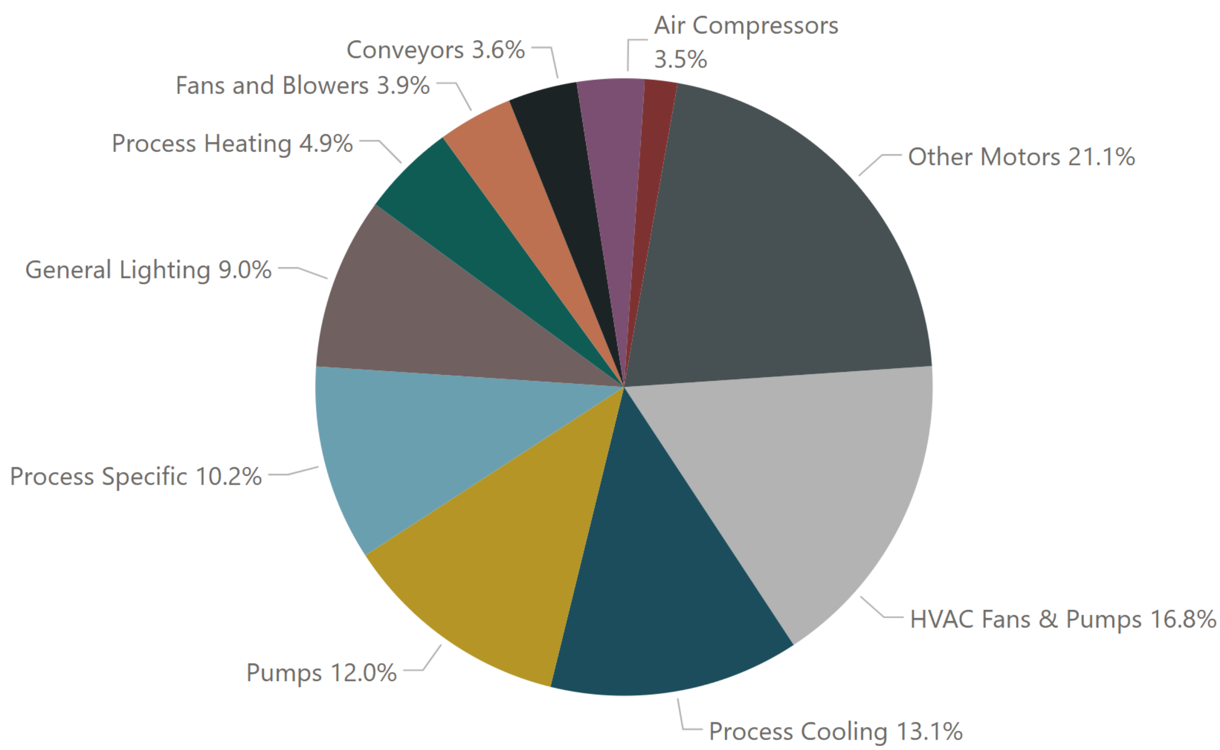
- Measures that target all or most end uses show the highest potential peak demand reduction followed by the measures that target space heating.
- Behind-the-meter solar with smart inverters shows no savings starting in 2032 when the peak shifts from the morning to the evening.
- Like the residential sector, savings for commercial utility-driven measures are low compared to the overall winter peak demand. For example, by 2040, space heating savings make up 2% of the space heating winter peak demand. Participation rates for the different utility-driven measures range from 3% to 8% by 2040.

- Backup generation at peak hours shows the highest peak demand reduction by 2040 (4.0 MW). This measure assumes customers have an existing generator and has a small incremental cost and relatively high savings (80%).
- Thermal storage and heat pump heating shows the highest peak demand reduction for measures that target space heating (1.0 MW in 2031 and 1.5 MW in 2040). This is driven by a higher technical applicability for heat pumps in the commercial sector than other space heating systems.

Industrial Sector

Exhibit 141 shows the peak hour demand reduction potential by end use for industrial sector utility-driven measures in 2031.[173] The other motors end use offers 21.1% of the potential peak demand reduction in 2031. Three of the six (50%) utility-driven measures impact the other motors end use, which makes up 15% of the total industrial winter peak demand in 2031.

Exhibit 141: Industrial Medium Achievable Demand Reduction Potential by End Use (2031) – Utility-Driven Equipment DR

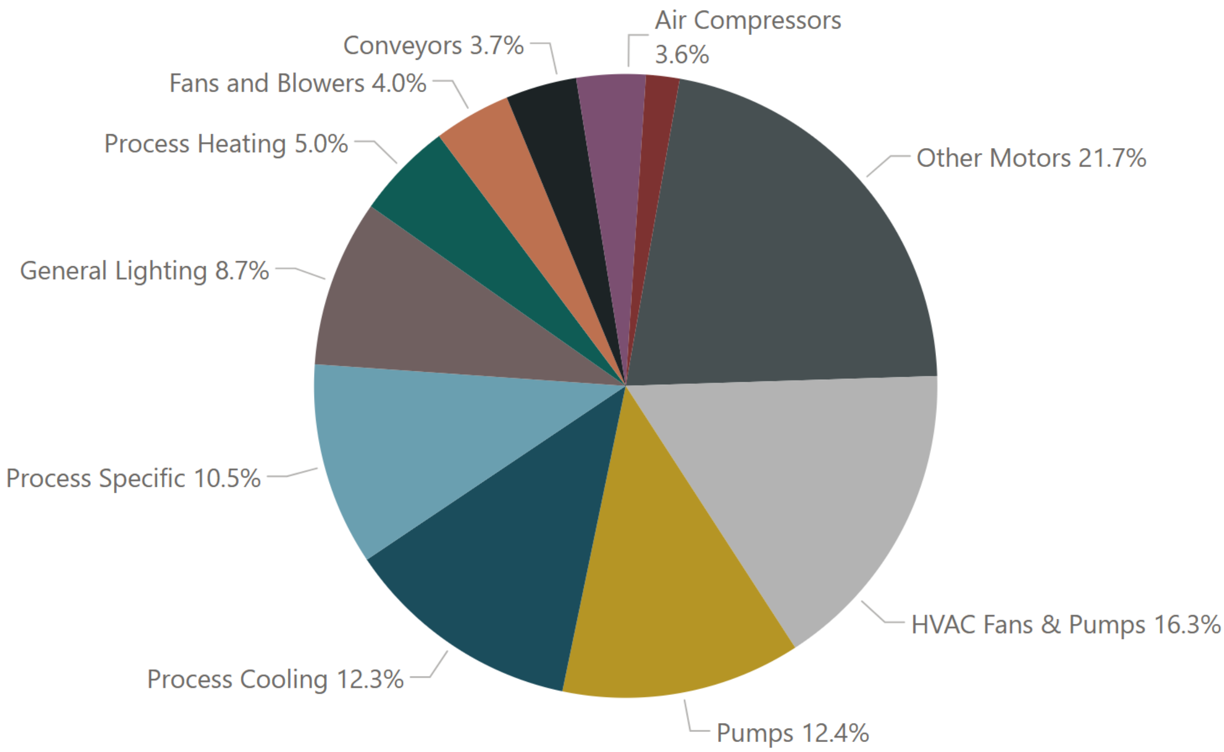


2031 Industrial Demand Reduction Potential: 0.4 MW

173 The Other end use represents 1.7% of demand reduction potential is not labelled to improve readability.

Exhibit 142 shows the peak hour demand reduction potential by end use for industrial sector utility-driven measures in 2040.[174] Demand reduction potential by end use remains consistent because the relative measure participation rates remain consistent year over year.

Exhibit 142: Industrial Medium Achievable Demand Reduction Potential by End Use (2040) – Utility-Driven Equipment DR



2040 Industrial Demand Reduction Potential: 0.7 MW

[174] The Other end use represents 1.7% of demand reduction potential is not labelled to improve readability.

Exhibit 143 shows 2031 and 2040 peak hour demand reduction potential for the industrial sector utility-driven measures.

Exhibit 143: Industrial Utility-Driven Equipment DR Measures

Measure	2031 Peak Hour Demand Reduction (MW)	Measure	2040 Peak Hour Demand Reduction (MW)
Behind-the-Meter Battery Storage	0.2	Behind-the-Meter Battery Storage	0.6
Backup Generation at Peak Hours	0.1	Backup Generation at Peak Hours	0.1
Behind-the-Meter Solar with Smart Inverters	0.0002	Behind-the-Meter Solar with Smart Inverters	0.0

Observations include:

- There is a more even distribution of peak demand reduction between the different industrial end uses compared to the residential and commercial sectors. The top three peak demand reducing end uses are other motors, HVAC fans and pumps, and process cooling. Three of the four (75%) industrial sector utility-driven measures impact all end uses, so the relatively high savings are driven by higher winter peak demand for those end uses.
- Savings for the industrial utility-driven measures make up less than 1% of the total industrial demand. As in the residential and commercial sectors, participation rates for the industrial utility-driven measures are assumed to be low even out to 2040, ranging from less than 1% to 13%, depending on the measure.
- Behind-the-meter solar with smart inverters shows no savings starting in 2032 when the peak shifts from the morning to the evening.
- Behind-the-meter battery storage shows the highest peak demand reduction in 2031 (0.2 MW) and 2040 (0.6 MW), driven by a high technical applicability and relatively high percent savings compared to other similar measures.

Substation Battery

Exhibit 144 shows the frequency, duration and savings for the substation battery measure.

Exhibit 144: Frequency, Duration, and Peak Demand Reduction for the Substation Battery Measure

Measure	Frequency of Peak Events	Duration of Peak Events	Peak Hour Demand Reduction (MW)
Substation Battery	12	Morning Peak: 4 hours Evening Peak: 5 hours	12 MW per battery

The results shown are for a single battery at one substation, however, they could be scaled to include additional batteries at multiple substations. For a single substation battery, considering only the incremental cost of the battery, the PAC result is 3.0, showing that this measure is cost-effective.

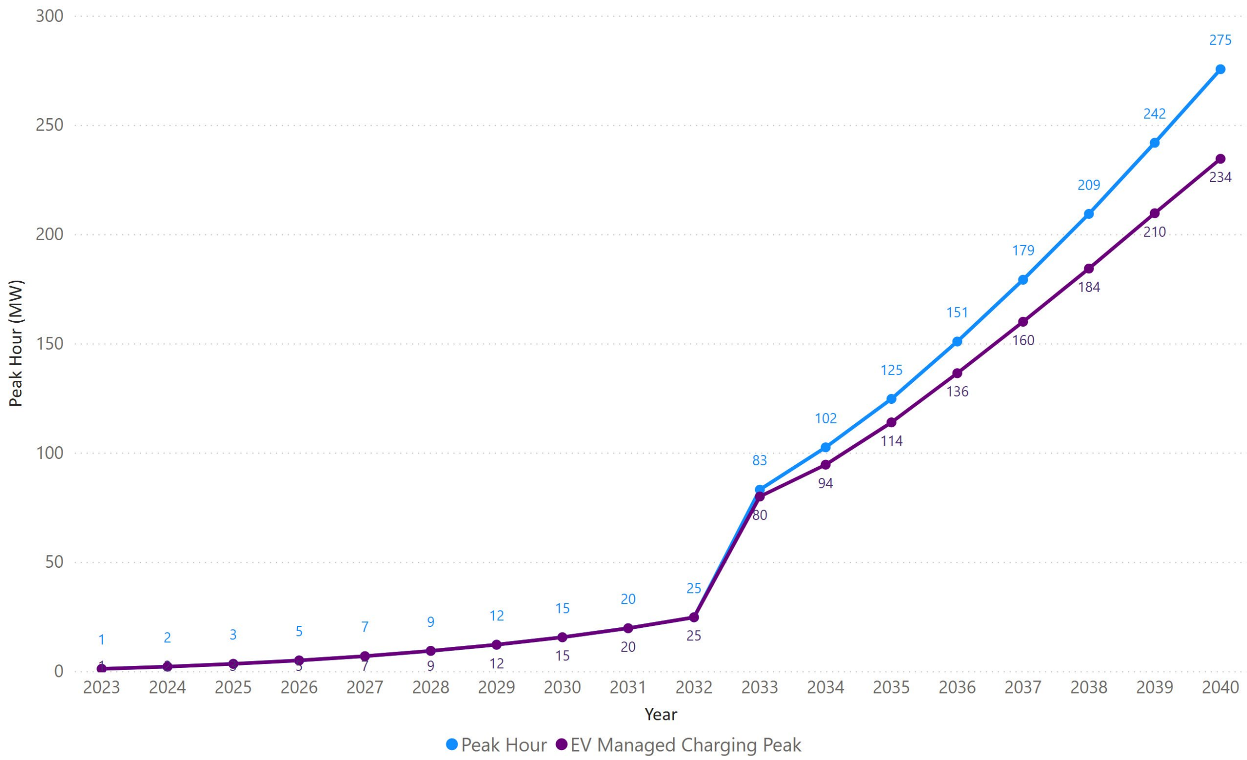
However, there are jurisdiction-specific costs to connect batteries to the grid. Further research beyond the scope of this Study is required to estimate these costs and their impact on the PAC.

7.3.3 Electric Vehicle Managed Charging Results

This section presents peak demand reduction results for the EV managed charging measures, including electric vehicle supply equipment (EVSE) and vehicle telematics (VT). Appendix F shows a sample calculation that explains how the managed charging results were calculated.

Exhibit 145 shows the unmanaged EV load during the peak hour for each year of the forecast period (light blue line), and the resulting reduction in EV load due to the achievable potential for managed charging measures (dark purple line). Because the system peak hour is estimated to occur in the morning until 2033, on-peak reductions from managed charging are not realized until 2033. After 2033, savings from the managed charging begin to gradually increase, reaching a maximum reduction potential of approximately 41 MW by 2040. This corresponds to a roughly 15% decrease in the EV load during the system peak hour in 2040.

Exhibit 145: Annual EV Peak Hour Demand – Managed Charging[175]



[175] The increase in EV load during the peak hour between 2032 and 2033 is due to the system wide peak hour shifting from the morning to the evening. See Exhibit 128 in section 7.2.2 for a detailed explanation.

Exhibit 146 displays the EV load reduction during the evening peak period from managed charging measures. Load reductions are minimal, due to low achievable potential participation rates earlier in the forecast period, but there are still some peak reductions that can be realized in the evening period, beginning in 2029. While the managed charging measures will not influence the system wide peak before 2033, they may still have effects on local distribution networks that may be experiencing evening peaks earlier in the forecast period. However, it should be noted that the managed charging measures never result in savings during the morning peak period due to the measures not being viable during that time of day.

Exhibit 146: Annual Average EV Evening Peak Demand – Managed Charging

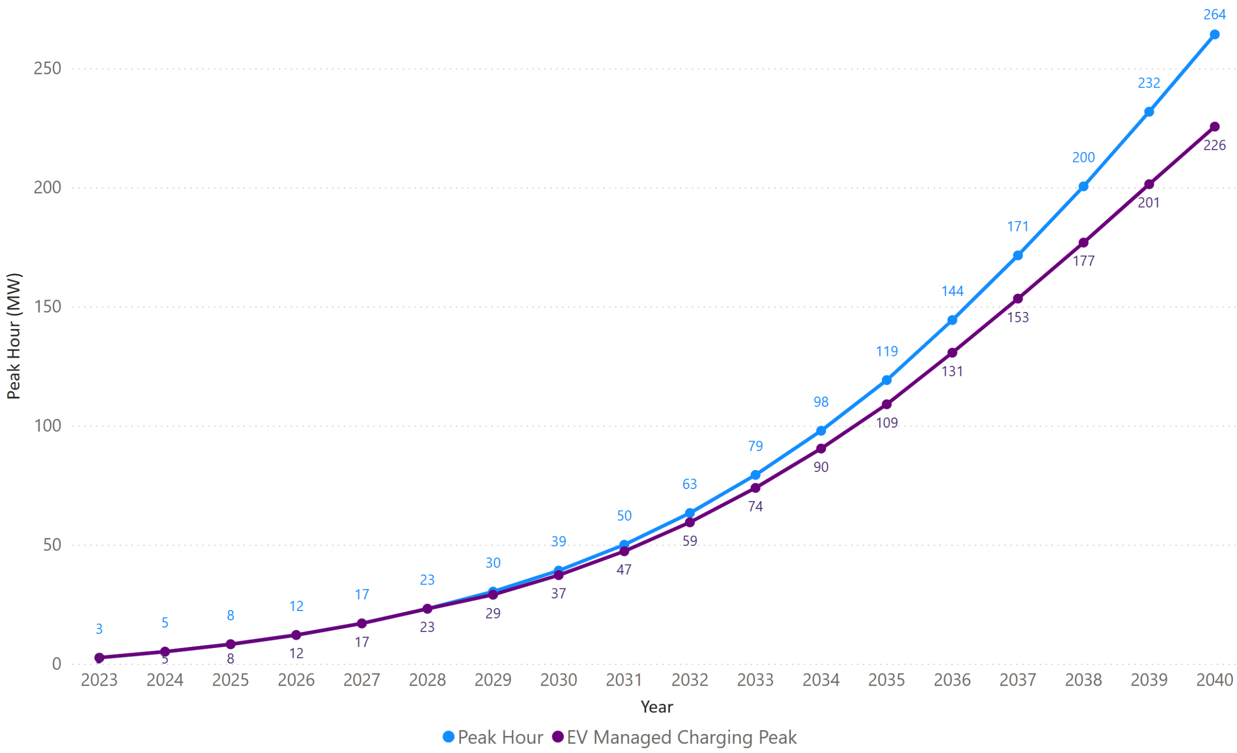


Exhibit 147 displays the breakdown of managed charging peak savings in 2040 by EVSE and VT measure.

- VT accounts for 70% (29 MW) of the total managed charging load reductions by 2040. As vehicle telematics become more standard in EVs, the lack of necessary hardware upgrade costs for EV owners who opt to participate in a managed charging program results in higher participation in the VT measure.
- However, at 30% (12 MW) of the potential demand reduction, there remains a market for the EVSE measure. Reducing hardware costs as charging technologies mature as well as privacy concerns about access to vehicle telematics systems may lead participants to join programs using their EVSEs.

Exhibit 147: EV Peak Hour Reduction by Measure Type (2040)

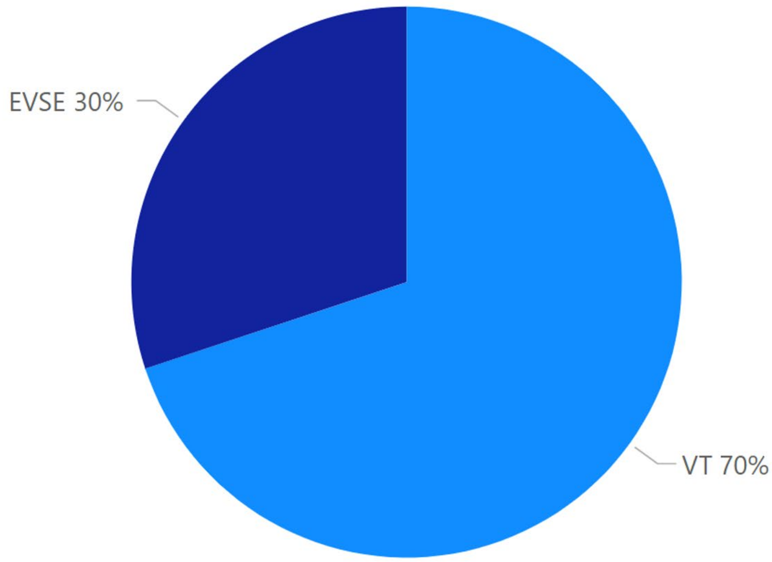
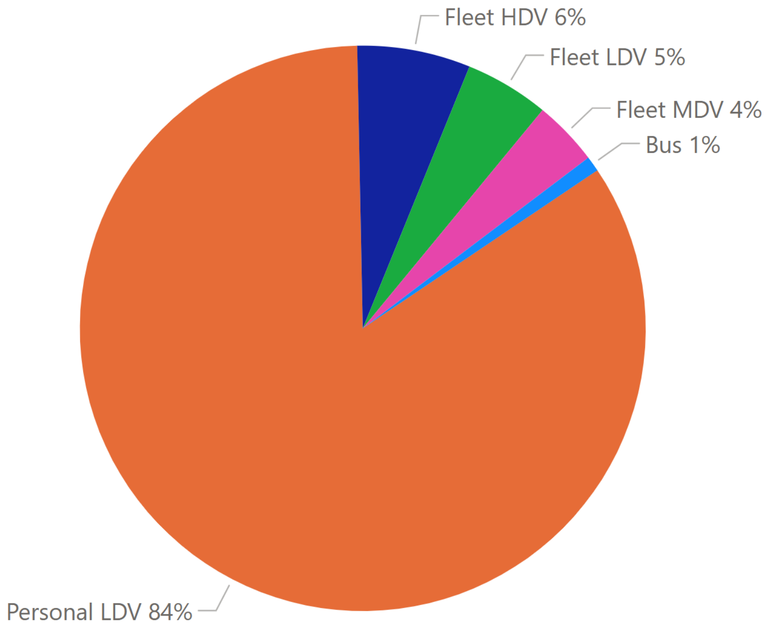


Exhibit 148 shows the peak hour demand reduction potential for managed charging in 2040 by vehicle type.

- Personal LDVs dominate the peak reductions, accounting for 84% of all EV reductions.
- The remaining 16% is distributed among the four fleet vehicle types, with 6% from HDVs, 5% from LDVs, 4% from MDVs and 1% from buses. [176]

These results are due to the number of vehicles estimated to participate in the measures from each vehicle type. Personal LDVs represent the most EVs across all categories and do not have regular duty cycles that limit when they can shift their charging load. Fleet MHDVs also have much larger batteries and longer daily routes that require high powered chargers, which also limits how much peak load they can shift.

Exhibit 148: EV Peak Hour Reduction by Vehicle Type (2040)



[176] Transit buses were not considered in the managed charging program because their operating schedules often dictate that charging already occurs overnight (i.e., outside the evening peak period). Only school buses contribute to the managed charging program for the bus category.

Exhibit 149 shows 2040 EV peak reduction by measure. The results reflect the findings highlighted in Exhibit 147 and Exhibit 148.

Exhibit 149: EV Managed Charging Measures (2040)

Measure	Peak Hour Demand Reduction (MW)
Personal BEV - Telematics	18.9
Personal BEV – EVSE	10.7
Personal PHEV – Telematics	4.9
Fleet HDV – Telematics	2.0
Fleet LDBEV – Telematics	1.3
Fleet MDV – Telematics	1.1
Fleet HDV – EVSE	0.7
Fleet LDBEV – EVSE	0.5
Fleet MDV – EVSE	0.4
Bus – Telematics	0.3
Fleet LDPHEV – Telematics	0.2
Bus - EVSE	0.1
Total	**41.1**

Because the achievable potential for load shifting through EV managed charging measures is forecast to exceed 40 MW, it is important for the Utilities to know where that load is shifted to. This helps avoid a peak bounce-back, which can occur when many vehicles begin charging simultaneously after a managed charging period has ended. This bounce-back effect has the potential to shift the peak to a new hour and potentially cause a new peak if not managed properly. Exhibit 150 shows the impact of the achievable potential managed charging measures layered onto the IIS system peak day load shape (which includes the effects of energy efficiency and fuel switching measures).

- The unmanaged 24-hour load shape (light blue line) shows hourly peak demand in the absence of any managed charging program or TOU rates. The evening peak (1,944 MW) occurs at 6:00 p.m.
- The managed 24-hour load shape (dark purple line) shows hourly peak demand with the achievable potential for the managed charging measures. The managed charging programs are successful in shifting EV load from the evening peak period into the troughs overnight and ensuring that no other large spikes in load are created. The peak hour remains at 6:00 p.m. but is reduced by 41 MW to 1,903 MW.

Exhibit 150: Achievable Potential Impacts on Daily Load Shape (2040) – Managed Charging

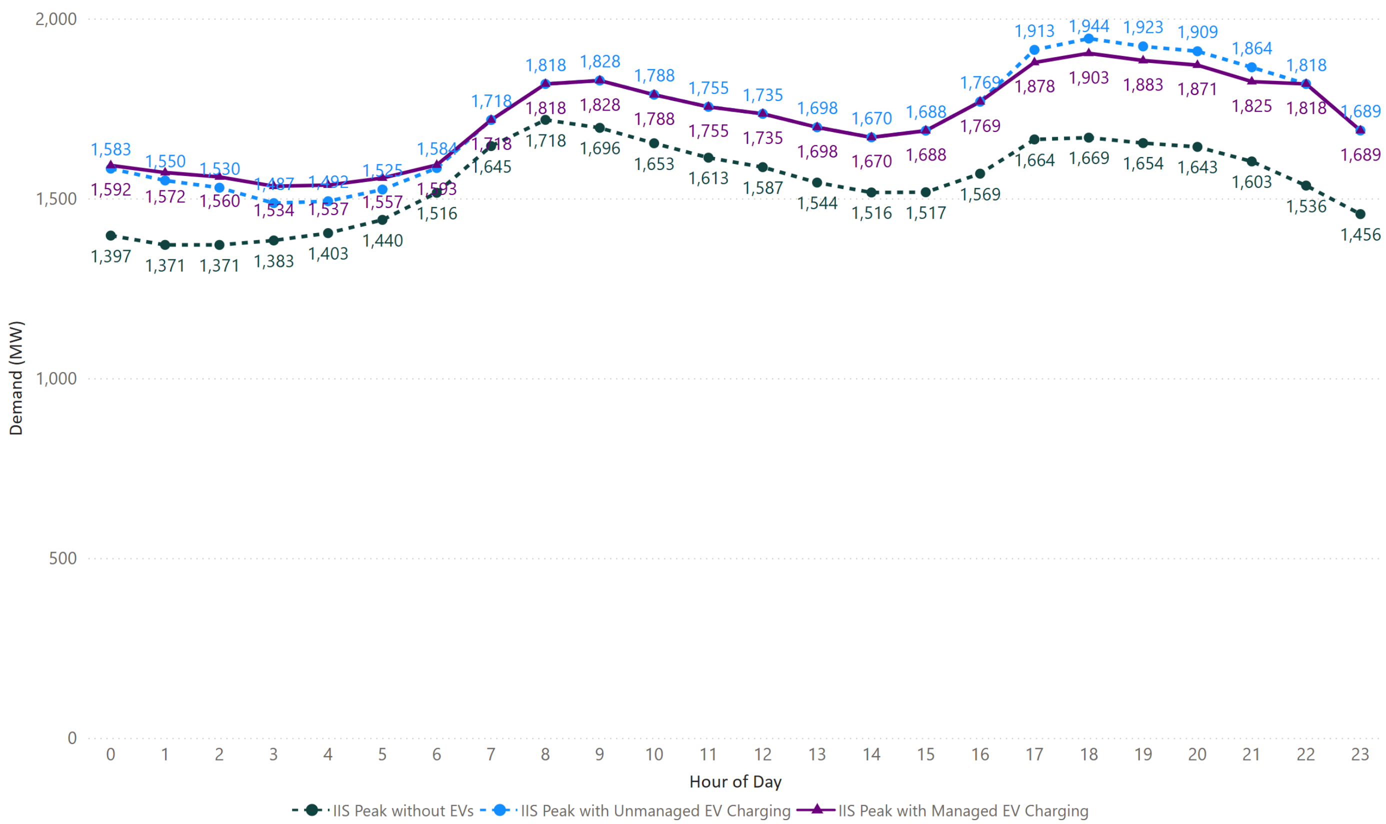
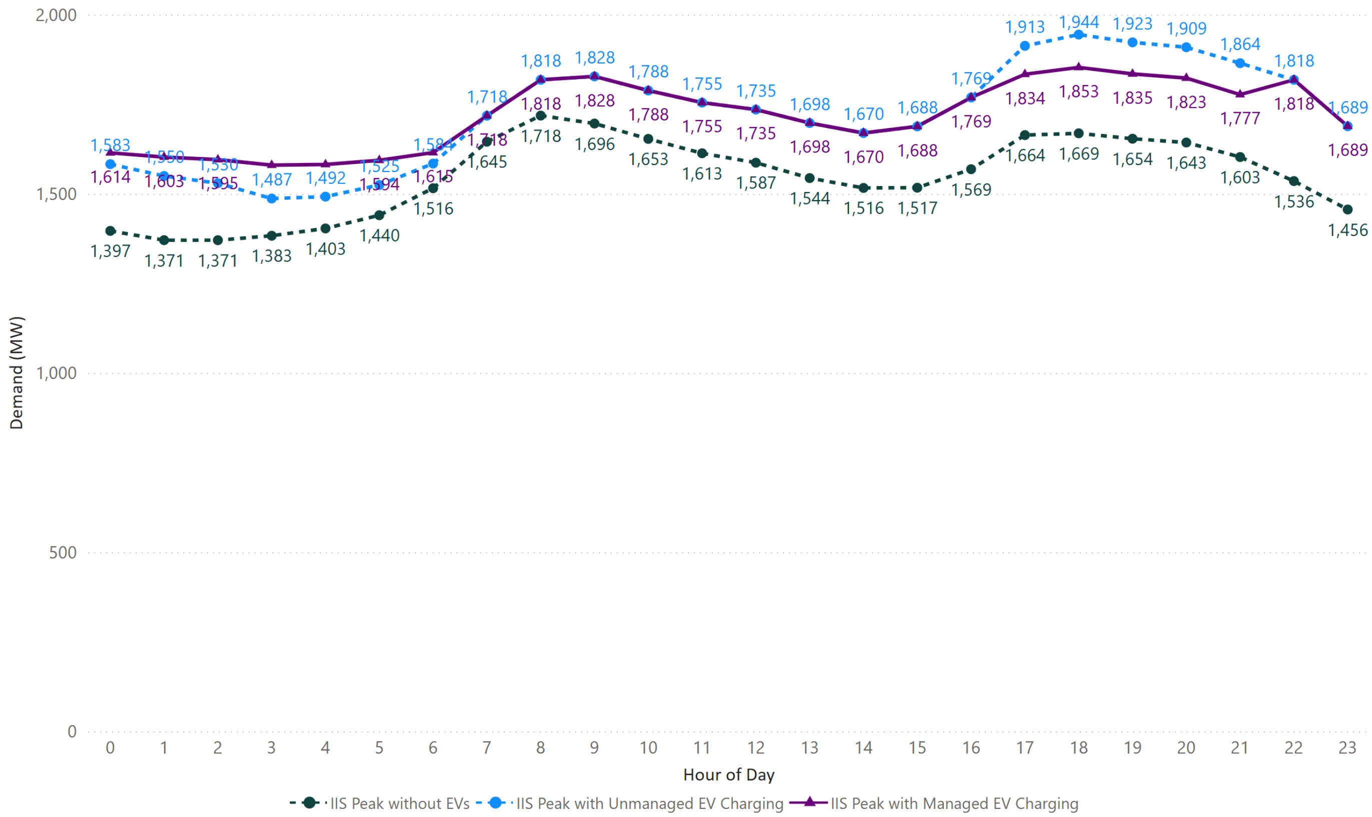


Exhibit 151 shows the impact of the technical potential managed charging measures on the system peak day load. The technical potential explores the peak reduction possible if all personal vehicles with access to at-home charging adopted the measure and all fleet vehicles with duty cycles permitting participation also adopted the measure.

- The technical potential of the managed charging measures results (dark purple line) in a system peak of 1,853 MW at 6:00 p.m., a reduction of over 90 MW compared to the unmanaged EV load (light blue line). This results in a further reduction of more than 50 MW when compared to the achievable potential.[177]
- A load reduction of this magnitude begins to raise the possibility of creating a new peak at a different time in the day. As participation rates for the measures increase, the period in which the measure occurs may need to be adjusted (highlighted by the spike in load at 10:00 p.m.) and more optimized managing of load might be required to avoid creating a new peak.

Exhibit 151: Technical Potential Impacts on Daily Load Shape (2040) – Managed Charging



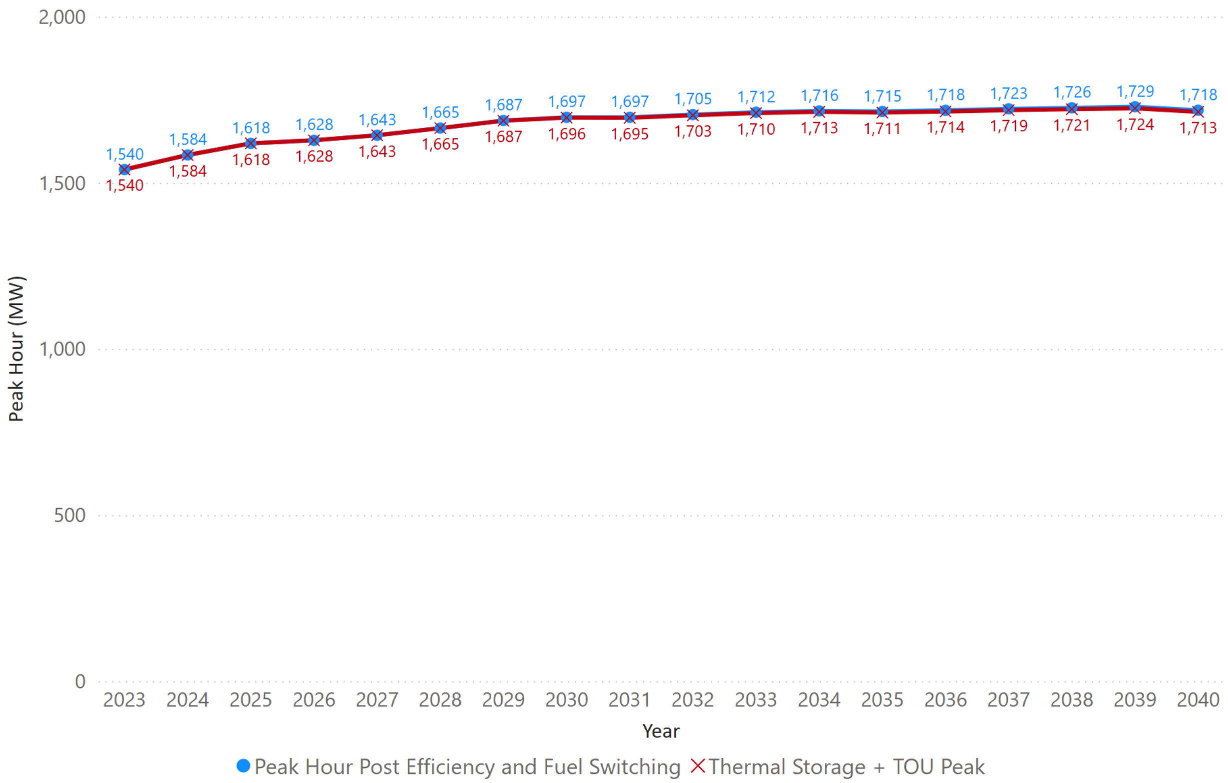
[177] Since EVs are an emerging technology, measure participation will take time to increase, even for vehicles where managed charging is feasible. This is due to access to at home charging or duty cycles that permit participation.

7.3.4 Thermal Storage with TOU Measure Results

Exhibit 152 shows the medium achievable peak hour demand for the thermal storage with TOU measures (red line) compared to the reference peak hour demand that includes impacts from efficiency and fuel switching measures (light blue line). The difference between the lines represents demand reduction potential for the thermal storage with TOU measures in the medium achievable potential scenario. By 2040, the thermal storage with TOU measures offer 5 MW of peak reduction potential.

The thermal storage with TOU measures are separate from the behaviour-based TOU design measures where customers use any method to shift peak. For the thermal storage with TOU measures, customers use an electric thermal storage system to shift their space heating load. Overlap and interactive effects between the two measure types are discussed in section 7.5.

Exhibit 152: Medium Achievable Peak Demand – Thermal Storage with TOU



When the thermal storage with TOU measures are first implemented, all (100%) of the medium achievable potential peak reduction potential comes from the commercial sector due to low participation rates in the residential sector. The peak reduction potential in the residential sector increases over the Study period as more customers participate. By 2040, the peak reduction is 1.6 MW in the residential sector and 3.5 MW in the commercial sector. The rest of this section presents medium achievable potential peak demand reduction by sector.[178]

[178] No thermal storage with TOU measures are modelled for the industrial sector.

Residential Sector

Exhibit 153 shows the peak reduction by measure for the residential sector in 2034 and 2040.[179]

Exhibit 153: Residential Thermal Storage with TOU Equipment DR Measures

Measure	2034 Peak Hour Demand Reduction (MW)	Measure	2040 Peak Hour Demand Reduction (MW)
Thermal Storage and Ductless Mini-Split Heat Pump	0.1	Thermal Storage and Ductless Mini-Split Heat Pump	0.7
Thermal Storage and Electric Baseboard Heating	0.1	Thermal Storage and Electric Baseboard Heating	0.6
Thermal Storage and Air Source Heat Pump	0.0	Thermal Storage and Air Source Heat Pump	0.2
Thermal Storage and Electric Furnace	0.01	Thermal Storage and Electric Furnace	0.03

The results in Exhibit 153 show the following:

- The thermal storage with TOU measures perform like the equivalent utility-driven measures. For example, the thermal storage with TOU measure with the highest peak demand reduction in 2040 is thermal storage and ductless mini-split heat pump (0.7 MW), which also offers the highest peak demand reduction potential of the utility-driven thermal storage measures.
- Savings for the thermal storage with time-of-use measures are higher than the equivalent utility-driven measures because participation is assumed to be higher when a TVR is involved. Customers can see bill reductions from each weekday in the winter when a TOU rate structure is in place.

[179] 2034 was chosen as a milestone year for reporting purposes because it is the first year in which all thermal storage with TOU measures show peak demand savings.

Commercial Sector

Exhibit 154 shows the peak reduction by measure for the commercial sector in 2034 and 2040.

Exhibit 154: Commercial Thermal Storage with TOU Equipment DR Measures

Measure	2034 Peak Hour Demand Reduction (MW)	Measure	2040 Peak Hour Demand Reduction (MW)
Thermal Storage and Heat Pump Heating	2.4	Thermal Storage and Heat Pump Heating	3.2
Thermal Storage and Electric Furnace Heating	0.2	Thermal Storage and Electric Furnace Heating	0.3
Thermal Storage and Electric Baseboard Heating	0.1	Thermal Storage and Electric Baseboard Heating	0.1

The results in Exhibit 154 show the following:

- As in the residential sector, the commercial sector thermal storage with TOU measures behave the same way as the utility-driven measures relative to each other. The measure with the highest peak demand reduction is thermal storage and heat pump heating, showing 3.2 MW of savings in 2040.
- The commercial sector thermal storage with TOU measures also show higher savings than the commercial utility-driven measures, because commercial customers will see daily savings that would otherwise not be realized without a time varying rate.

Exhibit 155 shows the sector level peak hour demand reduction potential for each measure type. Efficiency and electrification impacts refer to the savings or increase in peak demand as a result of the efficiency and electrification measures, discussed in sections 5 and 6. Electrification impacts are shown as negative savings.

Exhibit 155: Peak Demand Reduction by Sector and Resource Type (MW), (2040)

Sector	Efficiency	Electrification	TOU	CPP	Utility-Driven Equipment	Thermal Storage with TOU Equipment
Residential	36.9	-2.6	4.8	7.9	7.6	1.6
Commercial	25.5	-1.6	1.1	1.5	11.1	3.5
Industrial	9.3	-0.08	0.3	0.3	0.7	-
EVs	-	-	4.7	-	41.0	-
Total[180]	**71.7**	**-4.3**	**10.9**	**9.7**	**60.4**	**5.1**

Of the non-EV demand response measures, the utility-driven equipment DR measures show the highest potential, followed by the CPP, TOU, and thermal storage with TOU measures. Each of these resources provide less peak demand reduction than the efficiency measures but show a higher peak impact than the electrification measures.

Note that the peak demand reduction for the demand response measures is not additive and savings for each measure type are calculated separately. For example, the savings for the TOU rate design measure only consider the savings potential for the scenario where customers use any method to shift peak, whereas the thermal storage with TOU measures assume that customers only use electric thermal storage to shift peak and do not change habits that affect other end uses. Section 7.5 further discusses the methods used to account for overlap and interactive effects between the different measure types.

[180] Total TOU peak reductions increase to 58.9 MW when including the Opt-Out version of the TOU rate for EVs.

7.4 Customer Curtailment Potential

The Study Team developed a conservative, high-level estimate of curtailment potential for NP's rate 2.3 and 2.4 customers and both Utilities' large customers.[181] The estimate is based on current and planned NP and NLH curtailment contracts and programs, consultation with the Utilities, meetings held with NLH's large industrial customers, the 2023 CEUS, and curtailment programs in other jurisdictions.

7.4.1 Eligible Customers

The Study Team identified the following customer groups as eligible for curtailment:

- **Rate 2.4 Existing Energy Curtailment Program (ECP) Participants:** Rate 2.4 customers who are already participating in NP's ECP.[182]
- **Rate 2.4 New ECP Participants:** Rate 2.4 customers who are eligible and likely to participate in the ECP, based on the sector (public or private) and the segment to which they belong.
- **Large Customers:** The Utilities may enter short-term or long-term capacity assistance contracts with large commercial or industrial sector customers.

7.4.2 Curtailment Potential Results

Exhibit 156 shows curtailment potential by customer group. The curtailment potential from large customer contracts was developed with input from the Utilities. Of this potential, 22.5 MW is an early-call curtailment resource, while the remaining 98 MW is treated as a contingency resource. Individual customers are not identified to maintain confidentiality. Curtailment potential is not varied annually in the Study.

Exhibit 156: Curtailment Potential Results (all years)

Customer Group	Curtailable Load/Customer	Number of Customers	Total Curtailment
2.4 Existing ECP participants	500 kW/participant	24	12.0 MW
2.4 New ECP participants	300 kW/participant (30% of peak demand)	8	2.4 MW
Large Customer Contracts	Contract-Specific	3	120.6 MW
	Total	**35**	**135 MW**

Large Industrial Customer Consultation Summary

The Study team and NLH met with the large industrial customers to discuss efficiency, electrification, and curtailment potential. These meetings did not identify additional candidates for curtailment beyond those customers with curtailment contracts currently in place. This finding is consistent with NLH's understanding of curtailment potential among their large industrial customers.

[181] A more detailed estimate is beyond the scope of this Study.
[182] Newfoundland Power, "Energy Curtailment Program," Available: https://www.newfoundlandpower.com/en/Business-Services/Rates-and-Services/Curtailment-Program (Accessed Sept. 4, 2024).

Total curtailment potential (135 MW) represents 7% of the winter peak demand in 2040. Exhibit 157 shows that the curtailment potential is much higher than the medium achievable peak demand reduction potential for the other commercial and industrial sector demand response resources. However, large customers may be asked to curtail their loads only when the IIS is very constrained. Savings from existing and new ECP participants represent 11% of the total curtailment potential.

Exhibit 157: Commercial and Industrial Sector Peak Demand Reduction by Resource (2040)

Resource	Demand Reduction Potential (MW)
Total Curtailment	135
TOU	1.4
CPP	1.8
Utility-Driven Equipment	11.8
Thermal Storage Equipment with TOU	3.5

7.5 Interactive Effects

The Study Team was asked to estimate the interactive effects between the demand response resources. This estimate was required to avoid double-counting savings from resources that target the same reduction on the IIS reference load shape. For example, the residential electricity TOU rate design measure targets the same peak savings as the behind-the-meter solar with smart inverters measure.

The Study Team estimated the interactive effects between the following resources:

- **Efficiency and electrification measures and the demand response measures**: The interactive effects are accounted for in the potential reduction for the demand response measures, as explained in the introduction to section 7.
- **Electricity rate design measures and equipment demand response measures**: These resources are modelled separately, so savings for participants in both measures are double counted unless interactive effects are considered. A sample calculation to estimate the interactive effects between these measure types is provided in section 7.5.1.
- **Equipment demand response measures and ECP participant curtailment**: These resources are modelled separately, so savings for participants in both measures are double-counted unless interactive effects are considered.

The Study Team did not apply electricity rate design measures or equipment DR measures to the large industrial customers, so there was no interaction with curtailment.

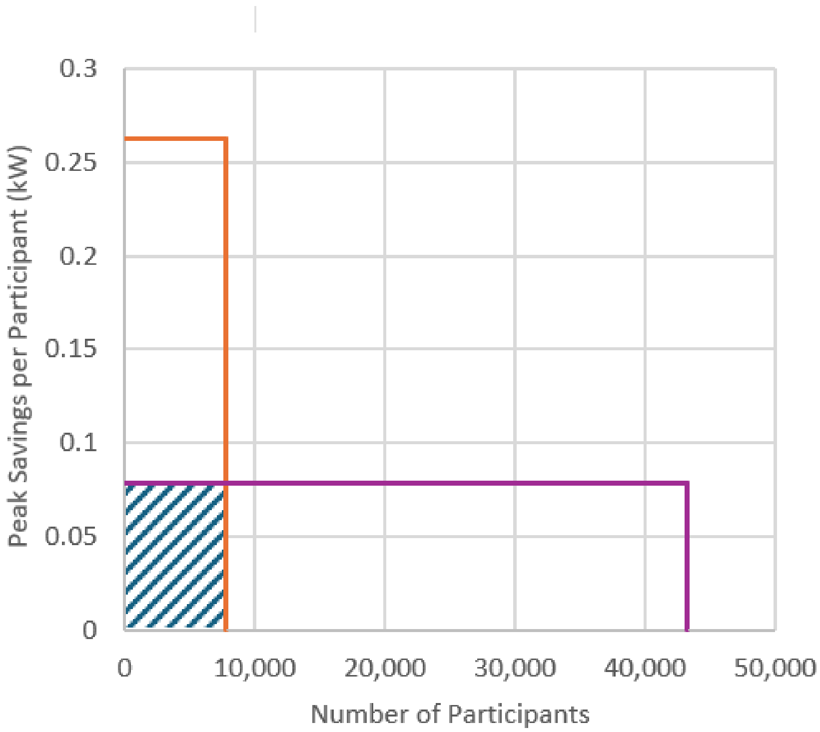
7.5.1 Interactive Effects Sample Calculation

This section includes an example to show how the Study Team estimated the interactive effects between a pair of demand response measures: residential sector TOU and behind-the-meter solar with smart inverters. To estimate the overlap in savings, the Study Team graphed the peak demand savings per participant on the y-axis and the number of participants on the x-axis for each measure. This method produces two overlapping rectangles, where the overlap area represents the magnitude of the savings that would otherwise be double counted.[183]

[183] This is a simplified approach because overlap is not always total. For example, a TOU rate itself may impact both behavior and equipment choices (e.g., like using telematics to manage EV charging time), but more active approaches like utility load control may target the same end-uses and provide additional savings.

The Study Team's approach is illustrated graphically in Exhibit 158 for the residential sector behind-the-meter solar with smart inverters and TOU measures. The overlap in savings is denoted by the rectangle with diagonal dark blue stripes. For this pair of measures, the 2040 savings of 4,828 kW is equal to the savings from the BTM with smart inverters measure (2,032 kW) plus savings from TOU measure (3,405 kW), less the area of the overlap (609 kW).

Exhibit 158: Interactive Effects Example



This Study Team repeated the method described here to estimate and subtract overlap anywhere it is expected to occur between measures. A similar approach was used to estimate the overlap between the managed charging and TOU rate design measures for EVs. [184] The overlap was calculated for every hour to estimate the resulting daily load shape that accounts for interactive effects between the two measures. Should the Utilities decide to implement electricity rate design measures and implement a program with equipment demand response measures, consideration should be given to overlap in savings. This overlap could be estimated by way of program evaluation.

[184] The opt-in TOU rates for EVs were modelled for this analysis. With an opt-in rate of 15%, there were fewer EVs participating in the TOU rates than the managed charging programs. Therefore, it was assumed that all managed charging participants would have also been opting in to the TOU rate. Because of this, only the peak reductions from the managed charging measures are included in the resulting load shape.

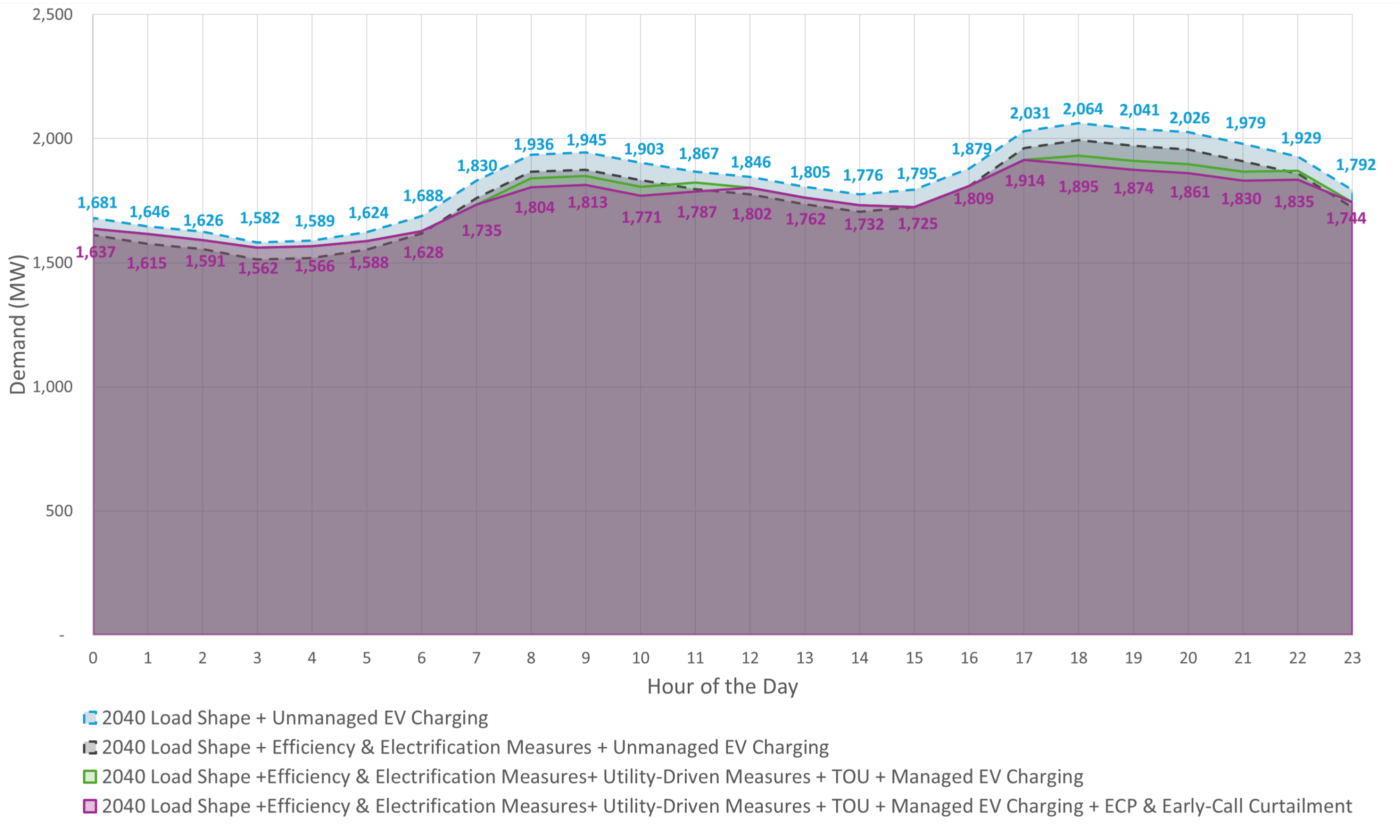
7.6 Resulting Load Shape

Exhibit 159 shows the reference and resulting peak day load shapes for combinations of the of the demand response resources discussed previously. [185] The load shapes in Exhibit 159 are defined as follows:

1. **Light blue load shape**: The 2040 reference load shape with unmanaged EV charging.
2. **Dashed black line load shape**: The 2040 reference load shape with unmanaged EV charging, including peak reductions from efficiency and electrification measures.
3. **Green load shape**: The 2040 reference load shape including peak reductions from efficiency and electrification measures, utility-driven equipment DR measures, TOU, and managed EV charging.
4. **Purple load shape**: Reflects the same reductions as the green load shape and including the curtailment potential from ECP participants and the early-call curtailment resource.

All the load shapes account for interactive effects, eliminating any double counting.

Exhibit 159: Standard and Resulting Peak Day Load Shapes (2040)



[185] A portion of the large customer curtailment is not included here because it is used as a contingency resource.

For additional readability, Exhibit 160 shows the hourly demand during the morning and evening peak periods for each load shape.

Exhibit 160: Hourly Demand for Standard and Resulting Peak Periods (MW)

Peak Period	Hour	Reference (2040 Load Shape + Unmanaged EV Charging)	2040 Load Shape + Efficiency & Electrification Measures + Unmanaged EV Charging	2040 Load Shape +Efficiency & Electrification Measures+ Utility-Driven Measures + TOU + Managed EV	2040 Load Shape +Efficiency & Electrification Measures+ Utility-Driven Measures + TOU + Managed EV + ECP & Early-Call Curtailment
Morning	8am	1,936	1,866	1,840	1,804
	9am	1,945	1,875	1,849	1,813
	10am	1,903	1,833	1,807	1,771
	11am	1,867	1,797	1,823	1,787
	12pm	1,846	1,776	1,802	1,802
Evening	5pm	2,031	1,961	1,914	**1,914**
	6pm	**2,064**	**1,994**	**1,931**	1,895
	7pm	2,041	1,971	1,910	1,874
	8pm	2,026	1,956	1,897	1,861
	9pm	1,979	1,909	1,866	1,830
	10pm	1,929	1,859	1,871	1,835

The following observations can be made on Exhibit 159 and Exhibit 160:

- After the efficiency and electrification measures, the utility-driven equipment DR measures, and managed EV charging are applied, the evening peak period starts at 5 p.m. and ends at 10:59 p.m. (illustrated by the green load shape). This represents a peak period that is one hour longer than the evening peak period for the reference load shape (illustrated by the dashed light blue load shape), which starts at 5 p.m. and ends at 9:59 p.m.
- When the ECP and early-call curtailment are applied during the evening peak period (i.e., 5 p.m. to 9:59 p.m. denoted by the purple load shape), the peak hour occurs at 5 p.m., one hour earlier than in the reference load shape (illustrated by the dashed light blue load shape).

The rightmost column in Exhibit 161 shows the reduction in peak hour demand for each load shape in Exhibit 159 compared to the reference load shape (dashed light blue line) in 2040. For each combination of demand response resources, the addressable peak is equal to the peak reduction. This is because the peak demand is reduced in all cases (i.e., the resources do not create a higher peak than the original peak).

Exhibit 161: Reference and Resulting Peak Demand (2040)

Load Shape	Peak Hour	Peak Demand (MW)	Addressable Peak (MW)	% Reduction
Reference (2040 Load Shape + Unmanaged EV Charging)	6 pm	2,064	-	-
2040 Load Shape + Efficiency & Electrification Measures + Utility-Driven Measures + TOU + Managed EV Charging	6 pm	1,931	132	6.4%
2040 Load Shape + Efficiency & Electrification Measures + Utility-Driven Measures + TOU + Managed EV Charging + ECP & Early-Call Curtailment	5 pm	1,914	149	7.2%

8 Conclusions

The Energy Solutions Potential Study assesses the near term and long-term potential for energy efficiency, electrification, and peak demand management activities led by the Utilities. The Study results leverage the Utilities' knowledge of their customer base, the best available data, and inputs based on extensive research and the Study Team's professional judgement. This section summarizes conclusions for the Study:

- **Energy Efficiency Potential**: The Study identifies opportunities for energy efficiency across the residential, commercial, and industrial sectors.
    - In the residential sector, measures that affect space heating offer the most potential savings. In the early years of the forecast period, these savings are dominated by envelope measures including air sealing and insulation, but by the end of the forecast period, equipment-based measures including heat pumps and HRVs offer the most potential savings. In addition, home energy reports offer residential sector savings throughout the Study period.
    - Initially, lighting measures dominate the commercial sector potential savings, but their savings potential decreases over time as LED lighting becomes saturated and federal lighting standards are introduced. By the end of the forecast period space heating measures including heat pumps and air sealing offer the most potential savings due to their broad applicability.
    - In the industrial sector, there is a broad-based opportunity for cost-effective conservation across end uses.
- **Impact of EVs**: The Study includes three forecast EV scenarios to explore a range of possible futures: natural adoption, intermediate and government targets. The results presented in the Study focus on the intermediate scenario:
    - In the intermediate scenario, EV charging is forecast to increase from 9 GWh in 2023 to 1,000 GWh by 2040. The adoption 162,001 EVs will require an estimated infrastructure investment of 0.84 billion.
    - Peak demand from EV charging is forecast to increase from 1 MW in 2023 to 275 MW in 2040. In 2033, EV charging causes the IIS peak to switch from morning peak to evening peak.
    - Consideration to EV managed charging can mitigate the impacts of EV charging on IIS peak. Shifting personal EV at-home charging could reduce the IIS peak. The opportunity to managed fleet EV charging is more limited than for personal EVs based on their duty cycles. However, certain fleet vehicles will have duty cycles that can accommodate managed charging.
- **Fuel Switching and Off-Road Electrification Potential**: Fuel switching potential is limited in the residential, commercial and industrial sectors because of the high relative fuel share of electric space heating in the base year, and natural electrification that occurs in the reference case.
    - In the higher achievable potential scenario, 49.6 GWh of load growth is forecast by 2040, compared to 13.7 GWh and 12.6 GWh in the medium and lower achievable potential scenarios, respectively.

- The electrification of forklifts and Zambonis is forecast to add 0.3 GWh of load to the IIS by 2040. These vehicles offer air quality improvements for warehouse and arena occupants.
- Dockside electrification will also cause IIS load growth and represents an area for further research.

- **Demand Response Potential**: The Study assesses demand response potential opportunities across three measure types: electricity rate design, equipment demand response, and customer curtailment.
    - The TOU and CPP electricity rate design measures are not cost-effective, due to the high program costs associated with the installation and operation of the AMI infrastructure required to administer them.
    - Several configurations of thermal storage measures are cost-effective for the residential and commercial sectors, with and without TOU rates. Market barriers to adoption could include lack of familiarity with thermal storage, aesthetic considerations for room units, and space constraints.
- **Overall Impacts on IIS Peak Day Load Curve**: In the base year, the IIS peak occurs in the morning. In 2040, the IIS peak is expected to occur at 6 p.m., driven in part by unmanaged EV charging in the intermediate scenario. The Study findings reveal the following impacts on the IIS load curve:
    - Aside from large customer curtailment, energy efficiency measures show the highest potential to reduce IIS peak. For example, in 2040, the efficiency measures reduce the winter morning and evening peaks by 70 MW and 69 MW, respectively. In contrast, the utility-driven measures reduce the winter morning and evening peaks by 23 MW and 18 MW. The TOU electricity rate design measure reduces the winter morning and evening peaks by 6 MW.
    - After the efficiency and electrification measures, the utility-driven equipment DR measures, and managed EV charging are applied, the evening peak period starts at 5 p.m. and ends at 10:59 p.m. This lengthens the evening peak period by one hour compared to the reference load shape.
    - When the ECP and the early-call curtailment are applied during the evening peak period, the peak hour occurs at 5 p.m., one hour earlier than in the reference load shape.
    - For each combination of demand response resources, the addressable peak is equal to the peak reduction. This is because the peak demand is reduced in all cases (i.e., the resources do not create a higher peak than the original peak).

Appendix A Methodological Approach

This appendix presents the Methodological Approach for the Study under the following headings:

- Base Year Energy Use Model Development
- Reference Case Energy Use Forecast Development
- Peak Demand
- Measure Assessment
- Potential Assessment
- Role of Stakeholder Groups
- Data Sources and Assumptions

Base Year Energy Use Model Development

The Study base year reflects the known characteristics of IIS customer electricity consumption in 2023. The Study Team's approach to base year development and calibration for the residential, commercial and industrial sectors is summarized in Exhibit 162.

Exhibit 162: Approach to Base Year Development and Calibration

Step	*Description*
1	Compiled and analyzed available data on NP and NLH's existing customer stock by sector, rate class, and segment.
2	Compiled utility billing data by segment and region.
3	Created sector model inputs with detailed assumptions regarding fuel shares, end use penetrations, equipment saturations and efficiency levels, and generated preliminary results.
4	Adjusted input assumptions for end uses with greater uncertainty until the results closely matched the actual utility billing data. Documented any adjustments for the Utilities' information (see sector-specific calibration steps following the exhibit).
5	Used end-use hours use factors to convert annual electric energy use to electric demand in each selected peak period.
6	Compared the total peak demand from the three sectors to the actual utility peak demand.
7	Adjusted the weather-sensitive hours use factors for all sectors to produce electric demand results that closely matched the actual utility regional peak demand.
8	Developed archetype models for Residential and Commercial segments with characteristics typical of construction and annual consumption that closely approximated the average consumption from the calibrated model for use in measure analysis.

Calibration: The calibration methods implemented to match the base year billing data for each sector are as follows:

Residential Sector:

1. Generated initial model parameters (See Exhibit 178).

2. Adjusted space heating[186] UECs by region and customer account type (domestic or seasonal) to align with the base year consumption.

Commercial Sector:

1. Generated initial model parameters (See Exhibit 179).
2. Adjusted segment UECs to align with the base year consumption by segment.
3. Adjusted the units per customer account to align with the base year consumption by segment and rate class.

Industrial Sector:

1. Generated initial model parameters, except units (See Exhibit 180).
2. Calibrated unit parameter to establish base year production values by segment and rate class.
3. Adjusted segment UECs to align with the base year consumption by segment.
4. For industrial customers, used billing data to determine the base year consumption.

The rest of this section shows the structure for the residential, commercial, and industrial sector models.

Residential Sector Model Structure

Exhibit 163 shows the residential sector model structure by segment, end use, vintage and rate class. Residential segments are divided by electric and non-electric space heating. This differentiation is important for the reference case and potential assessment, because customer account growth and measure applicability vary by space heating fuel. Exhibit 163 also shows two EV charging end uses: battery electric vehicle (BEV) charging and plug-in hybrid electric vehicle (PHEV) charging.

Exhibit 163: Residential Sector Segments, End Uses, Vintages and Rate Classes

Segments (8)	End Uses (20)	Vintages (6)	Rate Classes (1)
• Apartment, electric space heat • Apartment, non-electric space heat • Attached, electric space heat • Attached, non-electric space heat • Other and non-dwellings • Single-Family Detached (SFD), electric space heat	• BEV Charging • Clothes Dryer • Clothes Washer • Computer and Peripherals • Cooking • Dehumidifier • Dishwasher • Water Heating • Freezer • Hot Tubs • Lighting • Other Electronics	• Pre-1965 • 1965 to 1979 • 1980 to 1989 • 1990 to 1999 • 2000 to 2012 • Post-2012	• 1.1

[186] Space heating UECs are the most impactful to overall model output, and one of the most uncertain inputs. Space heating consumption accounts for over 50% of the base year total consumption.

Segments (8)	End Uses (20)	Vintages (6)	Rate Classes (1)
• SFD, non-electric space heat • Vacant and partial	• PHEV Charging • Refrigerator • Small Appliance and Other • Space Cooling • Space Heating • Television • Television Peripherals • Ventilation		

Commercial Sector Model Structure

Exhibit 164 shows the commercial sector model structure by segment, end use and rate class. Some segments are differentiated by size (e.g., offices, non-food retail). This differentiation is important for the potential assessment portion of the Study because measure applicability varies by building size. Exhibit 164 also shows six EV segments (personal EV private charging, personal EV public charging, fleet LDV depot charging, fleet MDV depot charging, fleet HDV depot charging, and fleet bus depot charging) and two EV end uses (BEV charging and PHEV charging).

Exhibit 164: Commercial Sector Segments, End Uses and Rate Classes

Segments (23)	End Uses (17)	Rate Classes (4)
• Arena • Fleet Bus Depot Charging • Fleet HDV Depot Charging • Fleet LDV Depot Charging • Fleet MDV Depot Charging • Food Retail • Healthcare • Large Accommodation • Large Non-Food Retail • Large Office • Large Other Building • Non-Building • Personal EV Private Charging • Personal EV Public Charging • Restaurant • School • Small Accommodation • Small Non-Food Retail	• BEV Charging • Computer Equipment • Computer Servers • Food Service Equipment • General Lighting • High Bay Lighting • HVAC Fans & Pumps • Misc Equipment • Other Plug Loads • Outdoor Lighting • PHEV Charging • Refrigeration • Secondary Lighting • Space Cooling • Space Heating • Street Lighting • Water Heating	• 2.1 • 2.3 • 2.4 • Street Lighting

Segments (23)	End Uses (17)	Rate Classes (4)
• Small Office • Small Other Building • Street Lighting • Universities and Colleges • Warehouse		

Industrial Sector Model Structure

Exhibit 165 shows the industrial sector model structure by segment, end use and rate class. The Large Industrial segment includes only NLH's six large industrial customers.

Exhibit 165: Industrial Sector Segments, End Uses and Rate Classes

Segments (7)	End Uses (12)	Rate Classes (10)
• Fishing and Fish Processing • Large Industrial • Manufacturing • Mining and Processing • Other Industrial • Pulp and Paper • Water and Wastewater	• Air Compressors • Conveyors • Fans and Blowers • General Lighting • HVAC Fans & Pumps • Other • Other Motors • Process Cooling • Process Heating • Process Specific • Pumps • Hydrogen	• 2.1 • 2.3 • 2.4 • Industrial

Transportation Sector

The Study Team developed the base year energy use model for the transportation sector in the following sequence:

1. **Step 1**: Determine the base year vehicle stock for the transportation sector using historical vehicle registrations and data on active EV stock.
2. **Step 2**: Determine the split between personal and fleet LDVs in the base year stock using data from the Reliability and Resource Adequacy Study 2022 Update. Maintain the split (89% personal; 11% fleet) across the forecast horizon.
3. **Step 3**: Multiply vehicle stock by vehicle efficiency and annual vehicle kilometers travelled to determine annual consumption per vehicle.
4. **Step 4**: Integrate transportation sector results with the residential and commercial sectors. In the residential sector, EV consumption is modelled as an end use. In the commercial sector, EV consumption is modelled in segments that represent public, private, and depot charging.

Exhibit 166 shows the transportation sector model structure by ownership type, vehicle type, and powertrain.[187] Two EV charging end uses are modelled for the transportation sector, BEV charging and PHEV charging.

Exhibit 166: Transportation Sector Vehicle Segmentation[188]

Ownership Type	Vehicle Type	Powertrain
Personal	LDV	BEV
	LDV	PHEV
Fleet	LDV	BEV
	LDV	PHEV
	MDV	BEV
	HDV	BEV
	Bus	BEV

[187] Electric micro-mobility was excluded from the Study because its impact is limited and due to a lack of Newfoundland-specific data.
[188] Pictograms at the following links illustrate EV segmentation types Ready, Set, Electric: Vehicle Types and Electric Opportunities | Edison Energy, and 4 Types of Electric Vehicles—Which is Better? | Optiwatt.

Reference Case Energy Use Forecast Development

The reference case forecasts electricity consumption over a sixteen-year (2024-2040) period and represents the baseline against which new potential can be calculated. The Study Team's approach to reference case development and calibration for the residential, commercial and industrial sectors is summarized in Exhibit 167.

Exhibit 167: Approach to Reference Case Development and Calibration

Step	*Description*
1	Compile and analyze Newfoundland and Labrador Hydro's (NLH's) 2023 long-term forecasts. Use Newfoundland Power's (NP's) 5-year Customer, Energy and Demand (CED) forecast to inform rate classes and general service customer counts.
2	Developed detailed technical descriptions of the new stock at the segment, end use, and end-use equipment level.
3	Compiled data on forecast levels of construction, demolition, and natural (non-utility-influenced) efficiency within the existing and new (post 2022) building stock.
4	Created sector model inputs and generated electricity use forecasts with consideration to: • Current consumption patterns and known future changes, including expected customer growth, • Current and known future changes to codes and standards, • Natural turnover of equipment and appliances, and, • Current trends and expected changes in space heating and water heating fuel shares.
5	Exclude conservation from ongoing conservation, demand management, and electrification (CDME) program activities carried out after 2023 and exclude EV load forecast by NLH.
6	Compared generated forecast with utility load forecast data (kWh) by sector.
7	Calibrated as necessary by adjusting input assumptions for end uses with greater uncertainty. Document calibration steps for the Utilities' information (see sector-specific calibration steps following the exhibit).
8	Used end-use hours use factors to convert annual electric energy use to electric demand in each selected peak period.
9	Adjusted the weather-sensitive hours use factors for new construction in all sectors to produce electric demand (kW) results that closely match the actual utility regional peak demand forecast.
10	Developed energy end-use assumptions for typical new construction for all segments (via building energy simulation modelling and/or engineering analysis), calibrating average annual consumption to average consumption from the calibrated model.

Calibration: The calibration methods implemented to match the reference case forecast for each sector are outlined below:

Residential Sector

1. Adjusted customer accounts to model how new construction is segmented (across utilities, dwelling types, and main heating fuel) and the natural electrification of existing homes.[189] Used regional housing starts data to estimate the relative customer account growth across dwelling types. Assumed no demolition rate.
2. Increased the saturation of some end uses over the forecast period. Affected end uses are dishwasher, computer and peripherals, televisions, television peripherals, other electronics, space cooling, and hot tubs. Saturation growth rates were estimated by comparing 2014 REUS and 2022 REUS saturation data.
3. Increased the space heating efficiency input to reflect the adoption of heat pumps in this end use.
4. Modeled changes in UEC for some end uses to reflect improvements in equipment and changes in tertiary load. Affected end uses were dryer, freezer, refrigerator, space heating, and lighting.
5. Adjusted space heating UECs to align with the reference case forecast by utility and customer account type (domestic or seasonal).

Commercial Sector

1. Adjusted customer accounts to establish construction and demolition. New construction was estimated by extrapolating customer forecasts and drawing insights from the electricity consumption growth forecasts by rate class. Although no demolition rate was applied, a decrease in customer account numbers for a given year implied the removal of existing buildings from the system.
2. Increased the space heating fuel shares over the forecast period to better align with the expected increase in electricity consumption per customer account in the reference case forecast (for rate classes 2.1 and 2.3).
3. Adjusted the size parameter for the 2.4 rate class to match the reference case forecast consumption. Commercial buildings in the 2.4 rate class are assumed to be large, akin to industrial buildings, so the size parameter was used to model fluctuations in electricity consumption from production increase and decreases.
4. Slightly adjusted all UECs (within +/-1%) to align with the reference case forecast by utility.

Industrial Sector

1. Using the same approach as commercial, adjusted customer accounts to establish new construction and demolition. New construction was estimated by extrapolating customer forecasts and drawing insights from the electricity consumption growth forecasts by rate class.

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[189] The space heating fuel share is not adjusted in the forecast period because the fuel share for each dwelling type and main heating fuel segment does not change. Instead, the share of electrically heated customer accounts increases over time.

2. Using the same approach as commercial, increased the space heating fuel shares over the forecast period to better align with the expected increase in electricity consumption per customer account in the reference case forecast (for rate classes 2.1 and 2.3).
3. Adjusted the size parameter by segment and rate class to match the reference case forecast consumption for general service and NLH's large industrial customers. Variations in the size parameter indicated fluctuations in production levels.
4. Slightly adjusted all UECs (within +/-1%) to align with the reference case forecast by utility.

Transportation Sector

Because future rates of EV adoption are uncertain, the Study Team modelled three forecast EV stock scenarios instead of one reference case:

1. **Natural Adoption Scenario:** This scenario estimates EV adoption based on current incentives.
2. **Intermediate Scenario:** This scenario includes EV uptake beyond the natural adoption scenario, consistent with additional market interventions like vehicle rebates or accelerated build-out of charging infrastructure for LDV.
3. **Government Targets Scenario:** In this scenario, Federal Government targets for sales shares of LDVs and MHDVs being ZEVs by 2030, 2035, and 2040 are met.[190,191]

The Study Team developed the forecast scenarios in the following sequence:

1. **Step 1:** Estimate the total number of vehicles for the forecast period.
2. **Step 2:** Determine stock decay over time using vehicle survivorship curves.
3. **Step 3:** Forecast future vehicle sales so the total stock over time matches the projection from Step 1.
4. **Step 4:** Determine the number of EV sales by applying the market share curves to the annual vehicle sales forecast for each scenario using data from sources including the 2023 NP REUS.
5. **Step 5:** Multiply vehicle stock by vehicle efficiency and annual vehicle kilometers travelled to determine annual consumption per vehicle.
6. **Step 6:** Integrate results with the residential and commercial reference case forecasts. Forecast EV consumption is apportioned to customer accounts in the same way is it is in the base year.

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[190] 20% of LDV sales as ZEVs by 2026, at least 60% by 2030, and 100% by 2035. 35% of total MHDV sales as ZEVs by 2030 and 100% by 2040.

[191] "The 2030 Emissions Reduction Plan: Canada's Next Steps for Clean Air and a Strong Economy," Government of Canada, Available: https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/emissions-reduction-2030/sector-overview.html#sector6 (Accessed Feb. 24, 2025).

Base Year Peak Demand

Base year peak demand is calibrated to the Utilities' estimate of IIS peak hour demand for the residential, commercial, and industrial sectors in 2023. In the Study, the peak hour is defined as follows:

- **Peak Hour:** The single highest hour of IIS demand, typically occurring on the coldest day in the winter. Depending on the Study year, the single hour peak can occur in the morning or the evening.

The Utilities are also interested in demand outside the peak hour, so two additional peak periods are defined in the Study:

- **Morning Peak Period:** The four-hour period in the morning with the highest average IIS demand, defined as 7 a.m. to 10:59 a.m. for Newfoundland.
- **Evening Peak Period:** The five-hour period in the evening with the highest average IIS demand, defined as 5 p.m. to 9:59 p.m. for Newfoundland.

The rest of this section explains the approach to establish base year peak demand. It begins with the common approach for the residential, commercial, and industrial sectors, then presents the sector-specific approach for transportation.

Residential, Commercial and Industrial Sectors

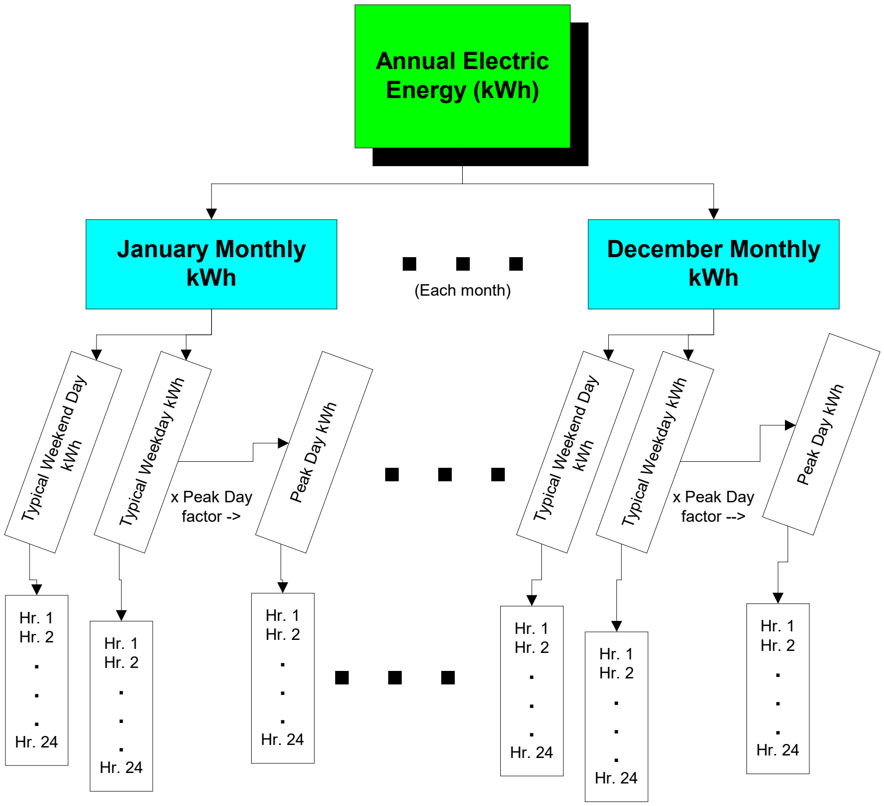
The Study Team used load profiles for each peak period to convert annual electric energy consumption to hourly demand for the residential, commercial, and industrial sectors. This section outlines the method used to develop electric peak end use profiles for the base year (2023) for the residential, commercial, and industrial sectors. The discussion is organized into the following subsections:

- Peak load profile development
- Peak Factors

Peak Load Profile Development

A peak load profile provides greater detail beyond the annual electric energy values. Annual electric energy is broken down into monthly electric energy, then average energy use per day, by day type (weekday, weekend day, peak day) and, finally, hourly demand by day type. Exhibit 168 illustrates the progression that converts annual electric energy to hourly demand. This method is used for the residential, commercial, and industrial sectors.

Exhibit 168: Overview of Peak Load Profile Methodology



Development of the peak load profile employs four specific factors as outlined below:

- **Monthly Usage Allocation Factor**: This factor represents the percent of annual electric energy usage that is allocated to each month. This set of monthly fractions (percentages) reflects the seasonality of the load shape, whether a facility, process or end use, and is dictated by weather, days in the month, or other seasonal factors. This allocation factor can be obtained from either (in decreasing order of priority): (a) monthly consumption statistics from end-use load studies; (b) monthly seasonal sales (preferably weather normalized) obtained by subtracting a "base" month from winter and summer heating and cooling months; or (c) heating or cooling degree days on an appropriate base.
- **Weekend to Weekday Factor**: This factor is a ratio that describes the relationship between weekends and weekdays, reflecting the degree of weekend activity inherent in the facility or end use. This may vary by month or season, though primarily for non-residential facilities. Based on this ratio, the average electric energy per day type can be computed from the corresponding monthly electric energy.
- **Peak Day Factor**: This factor reflects the degree of daily weather sensitivity associated with the load shape, particularly heating or cooling; it compares a peak (e.g., hottest or coldest) day to a typical weekday in that month.
- **Per Unit Hourly Factor**: The relationship of load among different hours of the day for each day type (weekday, weekend day, peak day) and for each month reflects the operating hours of the electric equipment or end use within facilities or residences by sub sector. For example, for

lighting, this would be affected by time of day, season (affected by daylight), and room or business type, where applicable. For the Base Year, lighting is treated on an aggregate basis by total residence/facility.

The four factors (sets of ratios) defined above provide the basis for converting annual energy to any hourly demand specified, including Peak Period #1 defined above. The following equation shows the calculation of the ratio of peak hour demand to annual consumption[192]:

$$DemandRatio = \mathrm{Mo.Allocation}_i * \frac{1}{\mathrm{DaysInMonth}_i * (\frac{5}{7} + \frac{2}{7} * \mathrm{WkendRatio}_i)} * PeakDayFactor_i * \mathrm{PkHourFactor}_i$$

Where: DemandRatio is the ratio of peak demand to annual consumption for the peak period of interest
Mo.Allocation$_i$ is the monthly usage allocation factor for month i, the month in which the peak period occurs
DaysInMonth$_i$ is the number of days in month i
WkendRatio$_i$ is the weekend to weekday factor for month i
PeakDayFactor$_i$ is the peak day factor for month i
PkHourFactor$_i$ is the per unit hourly factor for the peak hour and peak day for month i

In the case of an electric utility, if peak demand is expressed in MW and annual consumption is expressed in MWh, the above ratio would be in MW/MWh. For convenience, the demand ratio is often inverted to produce an hours-use factor, which is in units of hours. The following simple equation gives the hours-use factor:

$$HoursUseFactor = \frac{1}{DemandRatio}$$

The following examples may provide a more intuitive grasp of the hours-use factor:

- An end use with a load that is constant throughout the year would have an hours-use factor of 8760 (because there are 8760 hours in a non-leap year and the end use would therefore use 1/8760 of its annual energy in each hour)
- An end use concentrated in the winter, such as space heating, might have an hours-use factor of 2000 or even 1000. An hours-use factor of 1000 would produce a peak load over 8 times as high as a completely flat load with the same annual consumption.
- An end use that is only used during the peak hour and is never switched on for the rest of the year would have an hours-use factor of 1.
- An end use that is never used during the peak hour (such as an outdoor pool heater in a jurisdiction with a winter peak) effectively has an infinite hours-use factor. To avoid division by zero , we typically use 1×10^{15}.

For most end uses, Posterity Group used the same hours-use factors developed for the 2015 Potential Study. The non-HVAC shapes, which do not tend to vary significantly through time or geographically,

[192] The equation for a peak period with multiple hours would be slightly more complex.

were developed based on load shape research conducted in various North American jurisdictions. The space heating shapes were tailored to the Utilities' jurisdiction using St. John's weather data.

Posterity Group conducted a calibration process to adjust hours-use factors to obtain agreement between our model and the Utilities' peak load estimate for the base year. We adjusted two groups of hours-use factors:

- All the hours-use factors for industry were adjusted by a common adjustment factor to obtain agreement between the modeled peak load of the large industrial customers and the utilities' peak load value for those customers.
- The hours-use factors for HVAC-related end uses in the residential and commercial sector were adjusted by a second adjustment factor to obtain agreement between the overall modeled system peak load and the utilities' peak load value for the system.

For the morning and evening peak periods, Posterity Group determined the average demand during each period and calibrated the space heating peak factors to align the total with the average demand.[193]

Transportation Sector

Base year peak demand for the transportation sector uses 8760 load shapes for each combination of vehicle type and charging location. These load shapes are applied against base year annual energy consumption to determine demand in each hour of the year.

The Study Team identified the day that included the peak hourly EV load, then overlayed that day's 24-hour load shape onto the reference peak day load shape for the residential, commercial and industrial sectors. The overall IIS peak hour is identified based on the resulting aggregated load shape that reflects peak demand for all sectors.

[193] The Study Team adjusted peak factors for the space heating end use in the residential and commercial sectors for the morning and evening peak period calibration because overall demand is driven by space heating in those sectors. The peaks for each period in the industrial sector are the same because overall demand is not driven by space heating.

Reference Case Peak Demand

The rest of this section explains the approach to establish reference case peak demand. It begins with the common approach for the residential, commercial, and industrial sectors, then presents the sector-specific approach for transportation.

Residential, Commercial and Industrial Sector

The Study Team used calibrated peak factors from the base year in each year of the reference case forecast. Therefore, for each combination of end-use and building type, the reference case peak load scales with annual energy consumption for the residential, commercial, and industrial sectors. Aggregating the resulting end-use peak loads provides the forecast single peak hour or average peak demand for each year in the reference case.

Transportation Sector

Like the base year peak demand, reference case peak demand for the transportation sector relies on 8760 load shapes for each combination of vehicle type and charging location. The Study Team applied the load shapes against forecast annual reference case consumption to determine hourly demand in each reference case year.

Measure Assessment

The approach to the measure assessment is summarized in Exhibit 169. The Study Team consulted the following sources to add measures in Step 2 below:

- The 2015 Newfoundland and Labrador Conservation and Demand Management Potential Study and the 2019 Conservation Potential Study,
- The 2022 Ontario Distributed Energy Resource Potential Study,
- Posterity Group's internal measure libraries,
- Technical reference manuals from other North American jurisdictions, and,
- Suggestions from the Utilities and the local External Advisory Committee (EAC).

Exhibit 169: Measure Assessment Approach

Step	Description
1	Reviewed the measure analysis completed for the 2020-2034 Potential Study. Removed measures that have been superseded through market transformation or codes/standards, or that no longer represent significant potential.
2	Added measures that were not examined for the 2020-2034 Study, with a focus on demand management measures.
3	Solicited input from the Utilities regarding measure additions or deletions.
4	Solicited input from the local External Advisory Committee (EAC) stakeholders regarding measure additions or deletions.
5	Established a short list of measures for detailed analysis and inclusion in subsequent study steps.
6	Assessed mass-market measures, including the following parameters for each one[194,195]: **For energy efficiency measures** • Per participant energy reduction • Per participant demand reduction • Differences (if any) between the 'post measures' load shape and the end use load shape, such that associated demand reduction would be disproportionate to the energy savings (for energy efficiency measures) • Measure cost (full or incremental as appropriate) • Participant avoided bill cost • Utility lost revenue • Eligible customers • Previous program results and customer enrollment (participant) rates where appliable.

[194] Interactive effects will be estimated as part of measure savings estimates where relevant.
[195] The measure library deliverable will include all measures assessed in the Potential Study, regardless of their cost-effectiveness. A 'mature market' version of select measures may be developed to represent expected future equipment costs.

Step	Description
	For electrification measures • Per participant energy savings (fossil fuels), and annual consumption (electricity) • Differences (if any) between the 'post measures' load shape and the end use load shape, such that associated demand increase would be disproportionate to the electricity consumption increase • Per participant electricity peak demand increase • Participant avoided bill cost (other fuels) and additional bill cost (electricity) • Utility additional cost of new electricity supply • Utility revenue impact • Eligible customers • Measure cost (full or incremental as appropriate) • Previous program results and customer enrollment (participant) rates where appliable. **For demand response measures** • Per participant demand reduction • Differences (if any) between the 'post measures' load shape and the end use load shape, such that associated demand reduction would be disproportionate to the energy savings (for energy efficiency measures) • Measure cost (full or incremental as appropriate) • Participant avoided bill cost • Utility lost revenue • Eligible customers • Customer enrollment (participant) rates from other jurisdictions. **For transportation sector emerging measures, adoption incentive measures, and infrastructure measures** • Examined research on transportation sector decarbonization technologies and grid integration costs. The sections entitled EV Adoption Incentives and EV Charging Infrastructure that follow provide additional details.
7	For non-mass market measures such as special rate options, used customer data provided by the Utilities, in-depth discussions with Newfoundland and Labrador Hydro's Key Account Manager(s) and jurisdictional research to inform customer enrollment (participant) rates.
8	Create a Newfoundland-specific electronic measure TRM workbook for each sector, containing the parameters developed under step 6 above.

EV Adoption Incentives

This section explains how the Study Team calculated the incremental per-vehicle incentive to lift EV adoption from the natural adoption scenario to the intermediate and government targets scenarios.[196]

Exhibit 170 shows the transportation sector adoption incentive measures. Literature on personal LDV uptake suggest that every $1,000 of incremental per-vehicle incentive increases the sales market share of EVs between 2% and 9% annually. The Study Team used an 8% sales market share increase for every $1,000 of incremental per-vehicle incentive because several studies supported that ratio.[197,198,199]

Exhibit 170: Transportation Sector Adoption Incentive Measures

End Use(s) Affected	Measure Name
EV Charging	• Personal LDV • Fleet LDV • MDV • HDV • Bus

The Study Team calculated the incremental per-vehicle incentive to lift EV adoption from the natural adoption scenario in two steps:

- **Step 1**: Calculated the number of incrementally added vehicles for each forecast year and scenario.
- **Step 2**: Multiplied the ratio of 8% higher sales market share of EVs for every $1,000 of incremental per-vehicle incentive by the increase in sales market share.[200] Because the sales market share difference between the scenarios changes every year, the incremental per-vehicle incentive also changes every year. For this reason, the adoption incentive results presented in section 4.4.3 reflect the median incentive over the forecast period.

[196] If government targets for EV adoption are mandated, the Utilities would not provide incentives.

[197] MIT Center for Energy and Environmental Policy Research, "Providing the Spark: Impact of Financial Incentives on Battery Electric Vehicle Adoption", Available: https://ceepr.mit.edu/wp-content/uploads/2021/09/2019-015.pdf (Accessed Jan. 2024).

[198] Science Direct, "The Impact of state policies on electric vehicle adoption – A panel data analysis," Available: https://www.sciencedirect.com/science/article/abs/pii/S1364032123008729?via%3Dihub (Accessed Jan. 2024).

[199] University of Ottawa Department of Economics, "Assessment of Electric Vehicle Incentive Policies in Canadian Provinces," Available: https://ruor.uottawa.ca/server/api/core/bitstreams/9019befa-ab3e-4458-8473-16df13dd8354/content (Accessed Jan. 2024).

[200] Demand-side management market transformation theory suggests that regulations should supersede incentives as the market intervention used to drive adoption when the sales share of a new technology reaches 75%-80% of the eligible population. As such, the model limits rebate applicability for each EV scenario to the time horizon before this tipping point (75%-80% penetration) is reached. For the government targets and the intermediate scenarios, respectively, the Study Team calculated how much of an incremental per-vehicle incentive was required to lift EV adoption from the natural adoption scenario.

EV Charging Infrastructure

The Study Team's method to determine charging infrastructure requirements is summarized as follows:

- **Step 1**: Started with the vehicle counts from each analysis scenario (i.e., natural adoption, intermediate, and government targets).
- **Step 2**: Used external data sources to determine the number of charging ports required to support vehicle counts and the number of ports per charger type for each scenario.
- **Step 3**: Applied costs per charging port for the various charger types to estimate the magnitude of the investment required to deploy the charging infrastructure. A variety of backward-looking studies that have examined EV early adopters for LDVs suggest that the presence of charging infrastructure can help drive EV uptake. However, the extent to which this is the case (among other driving factors) is uncertain and depends on specific local conditions.[201]
- **Step 4**: For personal LDV,
    - Built bottom-up assumptions for home charging by stipulating the number of ports per home charger (one) and the number of vehicles per charging port (one EV per charging port).[202]
    - Layered these bottom-up assumptions on data about the proportion of vehicles with home charging access and about what charger levels they use. Multiple studies estimate the proportion of home charging at about 78%. For consistency, the Study Team limited input data to two of these studies that provided all the required data points:
        - The International Council on Clean Transportation estimates that 88% of vehicles will have home charging access and that 94% of home charging will occur in single family homes (leaving 6% for MURBs).[203]
        - The National Renewable Energy Laboratory estimates that 26% of home chargers will be L1.[204] The Study Team assumed that all these L1 chargers would be in single family homes, since MURBs would typically require wiring upgrades to support charging in their parking garages. Given growing LDV battery sizes, conducting such a MURB infrastructure upgrade just to install L1 outlets appears imprudent. For **public charging**, the Study Team relied on literature about how many public L2 and DCFC ports may be required to meet LDV fleet sizes. Some disagreement exists across sources, so the Study Team

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[201] MDPI, "Impact of Incentive Policies and Other Socio-Economic Factors on Electric Vehicle Market Share: A Panel Data Analysis from the 20 Countries," Available: https://www.mdpi.com/2071-1050/13/5/2928 (Accessed Jan. 2024).
[202] The average household is likely to only have one EV by the end of the study horizon based on how the scenarios assume the market will transform over time.
[203] The International Council on Clean Transportation, "Charging up America: Assessing the Growing Need for US Charging Infrastructure Through 2030," Available: https://theicct.org/sites/default/files/publications/charging-up-america-jul2021.pdf (Accessed Jan. 2024).
[204] National Renewable Energy Laboratory, "The 2030 National Charging Network: Estimating US Light-Duty Demand for Electric Vehicle Charging Infrastructure," Available: https://www.nrel.gov/docs/fy23osti/85654.pdf (Accessed Jan. 2024).

used the median values extracted across the source materials (since the data is not normally distributed).[205, 206, 207]

- Assumed that PHEVs do not use DCFC, due to their relatively smaller battery sizes compared to BEVs. The number of ports per PHEV relies on the number for BEVs and discounts the number of ports per PHEV by the ratio of the per-vehicle annual energy consumption for PHEVs versus BEVs (from the analysis scenarios). L1 chargers are exempt from this discounting, since each PHEV could theoretically be plugged into a standard 110V DC outlet. The discount factor varies minimally across analysis years. This means that, on average, PHEVs use 45% of the chargers that BEV use.

- **Step 5**: For fleet LDV,
  - For L2 depot charging, assumed one charging port per vehicle based on interviews with fleet operators.
  - For the number of vehicles per port on public DCFC, used the same assumption as for Personal LDV.
    - In the absence of more definitive bottom-up estimates, used the ratio between depot and public L2 chargers to estimate the vehicles per port for depot DCFC from public DCFC.
    - Based on study data from California, assumed that 96% of chargers will be at depots and 4% of chargers will be at public locations. Also assumed that 99% of depot chargers will be L2 and 1% of depot chargers will be DCFC.[208]
  - For fleet PHEVs, used the same method for estimating the charging infrastructure required for personal PHEVs.[209]
- **Step 6**: For MHDV (including buses),
  - Used a top-down approach that relied on study data from California on how many ports were needed in fleet depots and public locations to support MHDV EV fleets.[210,211]

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[205] National Renewable Energy Laboratory, "The 2030 National Charging Network: Estimating U.S. Light-Duty Demand for Electric Vehicle Charging Infrastructure," Available: nrel.gov/docs/fy23osti/85654.pdf (Accessed Jan. 2024).
[206] International Council on Clean Transportation, "Charging Up America: Assessing the Growing Need for U.S. Charging Infrastructure Through 2030," Available: https://theicct.org/sites/default/files/publications/charging-up-america-jul2021.pdf (Accessed Jan. 2024).
[207] Dunsky Energy + Climate Advisors, "Canada's Public Charging Infrastructure Needs", Available: https://natural-resources.canada.ca/sites/nrcan/files/energy/cpcin/2022-ev-charging-assesment-report-eng.pdf (Accessed Jan. 2024).
[208] PowerPoint Presentation (caletc.com)
[209] Based on the discount factor method, fleet PHEVs use on average 24% of the chargers that BEVs use.
[210] PowerPoint Presentation (caletc.com)
[211] California data was used because the state is a leader in fleet vehicle electrification research and programming.

Exhibit 171 summarizes the model inputs developed for the various vehicle segments.

Exhibit 171: Key Charging Infrastructure Model Inputs

Vehicle Segment	Vehicles per Port
Personal LDV	L1 Home - 1 L2 Home - 1 L2 MURB - 1 L2 Public - 12 DCFC Public - 73
Fleet LDV	L2 Depot - 1 L2 Public - 12 DCFC Depot - 6.1 DCFC Public - 73.3
MDV	L2 Depot - 1[212] L2 Public - 33.3 DCFC Depot - 3.7 DCFC Public - 16.7
HDV	L2 Depot - N/A[213] L2 Public - 33.3 DCFC Depot - 1.1 DCFC Public - 9.1
Bus[214]	L2 Depot - 1[212] L2 Public - N/A DCFC Depot - 2.4 DCFC Public - N/A

[212] The Study Team used the same assumption as for Fleet LDV based on interviews with fleet operators that indicate this choice for operational certainty and simplicity.
[213] HDV have sufficiently large batteries to rule out Level 2 depot charging.
[214] School buses, due to their duty cycles, are amenable to Level 2 depot charging. Transit buses, due to their duty cycles, are assumed to use DCFC depot charging only.

Then, the Study Team completed the following steps to calculate charger costs:

- **Step 1**: Consulted two sources (Atlas Policy and NREL) that provided full installed costs per charging port across charger types.
    - NREL includes a meta-analysis of third-party studies and aggregates information to account for uncertainty across these inputs.[215, 216] Since both studies focused on the U.S., the Study Team assumed costs were provided in U.S. dollars.
- **Step 2**: Assumed the same costs from Step 1 in Canadian dollars, since converting the values would have yielded costs that were too high compared to results from stakeholder interviews and audits of select costs in Canada.

Exhibit 172 summarizes the results of these steps.

Exhibit 172: Charger Cost Model Inputs

Charger Topology	Inputs (USD)	Description
L1 Home	$0	• Assume manufacturers include a L1 charging cable with the vehicle • Assume homeowners have a wall plug with free capacity
L2 Home	$1,834	• Average of Atlas Policy and NREL estimates • Atlas Policy represents an average across attached and detached homes
L2 MURB	$3,857	• Reflects the Atlas Policy estimate since it separates MURB costs
L2 Depot/Public	$6,291	• Average of Atlas Policy and NREL estimates
DCFC Depot/Public	$186,731	• Average of Atlas Policy and NREL estimates across charger power levels

[215] Atlas Public Policy, “U.S. Passenger Vehicle Electrification Infrastructure Assessment,” Available: https://atlaspolicy.com/wp-content/uploads/2021/04/2021-04-21_US_Electrification_Infrastructure_Assessment.pdf (Accessed Jan. 2024).
[216] National Renewable Energy Laboratory, “The 2030 National Charging Network: Estimating U.S. Light-Duty Demand for Electric Vehicle Charging Infrastructure,” Available: https://www.nrel.gov/docs/fy23osti/85654.pdf (Accessed Jan. 2024).

Potential Assessment

The approach to the technical and economic potential assessments is shown in Exhibit 173.

Exhibit 173: Technical and Economic Potential Assessment Approach

Step	*Description*
1	Work with the Utilities to establish measure cost-benefit analysis and screening methods that reflect the demand side choices the Utilities and their customers will be faced with over the study period. Document the inputs and equations for the cost-benefit analysis. For efficiency and electrification measures, used the TRC to screen, with a passing threshold of 0.8. Report PCT and PAC. For demand response measures, used the PAC screen, with a passing threshold of 0.8. Report TRC.
2	Develop technical potential estimates of the energy reduction, peak demand reduction, and energy addition (from electrification) that can be achieved in Newfoundland through the implementation of the measures from 2025-2040.
3	Assess cost-effectiveness on a variety of sensitivities for marginal cost, including varying marginal costs throughout different periods of the year, or compared to deferred or nullified capital investment requirements. This sensitivity analysis will require using relatively permissive economic screening criteria at the measure level.
4	Develop separate estimates of economic energy efficiency potential, demand management potential, and electrification potential.
5	Estimate economic potential for screened-in measures at the sector and segment levels to develop comprehensive economic potential estimates. Force pass a list of measures determined in collaboration with the Utilities.[217]

The approach to the achievable potential assessment is shown in Exhibit 174.

Exhibit 174: Potential Assessment Approach

Step	*Description*
1	For efficiency and electrification measures, develop traditional payback/adoption curves. For demand response measures, develop adoption rates based on participation research for similar measures across North America.
2	Use economic potential forecasts using cost-effectiveness tests as screens as input to a simplified achievable potential analysis developed using traditional payback/adoption curves.
3	Discuss the results of the simplified achievable potential analysis for five measures per sector with the Utilities and their stakeholders in workshop format to identify market barriers and opportunities. For mass market energy efficiency options, analyze four main considerations:

[217] Measures that fail the economic screen can be force passed so they will appear in the achievable potential. The electricity rate design measures were force passed, for example, because the Utilities wanted to discuss them in the Study report.

<table>
<tr><th>Step</th><th>Description</th></tr>
<tr><td></td><td>1. What participation rates are feasible given market barriers, incentive levels, eligibility, and the success of existing programs?
2. What types of customers participate?
3. How do savings vary for different customer types?
4. What share of customers can be economically enrolled in a program?</td></tr>
<tr><td>4</td><td>Revise the adoption rates from Step 1 based on input from the Utilities and their stakeholders in Step 3 and based on savings achieved in the Utilities’ existing programs. The Utilities provided the following data to support this Step:
• “Small Technologies Savings”: includes energy (kWh) savings from 2020 to 2023 for the twenty-one residential energy efficiency measures in the Small Technologies program.
• “Business Efficiency Program Participation Results 2019 – 2023”: includes energy (kWh) and demand (kW) savings from 2019 to 2023 for the nineteen commercial and industrial energy efficiency measures in the Business Efficiency Program.
• “Savings for Forecast 2009-2025F”: includes historical (2009 to 2023) and forecast (2024 to 2025) energy (kWh) savings for all energy efficiency programs offered by NP.
• Historical data from NP for the residential Oil to Electric Program.</td></tr>
<tr><td>5</td><td>For efficiency and electrification measures, estimate achievable potential under three scenarios:
• Lower
• Medium
• Higher
For demand response measures, estimate the individual impacts of the following components, then estimate any interactive effects:
1. Electricity rate design measures
2. Equipment-based demand response measures
3. Customer curtailment</td></tr>
<tr><td>6</td><td>Report potential assessment savings in at-the-meter terms, instead of at-the-generator terms. Therefore, savings results exclude line losses in the transmission and distribution network. Line losses are added to the at-the-meter savings to calculate at-the-generator savings, which are used in the TRC calculations.[218]</td></tr>
</table>

[218] "Reliability and Resource Adequacy Study 2024," Newfoundland and Labrador Hydro, Available: https://nlhydro.com/wp-content/uploads/2024/07/2024-07-09_NLH_RRA-Study_2024-RAP.pdf (Accessed: Nov. 15, 2024).

The approach to calculating customer curtailment potential is shown in Exhibit 175.

Exhibit 175: Curtailment Potential Assessment Approach

Step	Description

1	Consult existing data and research to inform the curtailment potential method and inputs, including:
	• Current and planned NP and NLH curtailment contracts and programs, including:
	  ○ Data from NP's Energy Curtailment Program (ECP)
	  ○ The Winter 2023-2024 Capacity Assistance Report
	• Notes from the meetings PG staff held with NLH's large industrial customers and NLH
	• NP and NLH's 2023 Commercial End Use Study
	• Curtailment programs in other jurisdictions, including Green Mountain Power's Flexible Load Management (FLM) 2.0 Pilot and Pacific Gas & Electric Company's (PG&E) Automated Demand Response (ADR) program.

2	Identify eligible rate 2.4 customers and large industrial customers and determine the number of customers likely to participate.
3	Calculate curtailable load per customer and total curtailable load for all participants.
4	Determine program costs and incentives per customer and total program costs and incentives for all participants.

The approach to the peak day analysis is shown in Exhibit 176.

Exhibit 176: Peak Day Analysis Approach

Step	Description
1	Calculated the demand reduction in the single highest hour (this step was not necessary to the peak day analysis, but this value is necessary for cost-effectiveness testing).
2	Calculated the average demand reduction for each demand response resource in the 4-hour morning peak window and the 5-hour evening peak window.
3	Determined the impact after the morning and evening peaks when the average demand reduction from each peak period is added to the hours immediately following them.
4	Estimated the reduction in demand between the original peak hour and the resulting peak hour.

Role of Stakeholder Groups

The Utilities and its stakeholders played an important role in the Potential Study. An External Advisory Committee (EAC) of Stakeholders provided input at two key steps in the Study workflow: measure identification and achievable potential. This input included desktop review of the long list of measures and participation in achievable potential workshops. Four achievable potential workshops were held, one for each sector. The workshop logistics and number of participants are shown in Exhibit 177.

Exhibit 177: Achievable Potential Workshop Logistics and Participation

Workshop	Date and Time	Number of EAC Participants
Residential Sector	May 23, 2024; 9:00 AM – 12:30 PM	14
Transportation Sector	May 23, 2024; 1:00 PM – 4:30 PM	11
Commercial Sector	May 24, 2024; 9:00 AM – 12:30 PM	10
Industrial Sector	May 24, 2024; 1:00 PM – 4:30 PM	5

In addition, NLH's large industrial customers were surveyed to provide insight into their operations and likelihood of measure adoption.

Data Sources and Assumptions

This section lists data sources and assumptions for the Potential Study.

Reference Case Forecast

The reference case forecast aligns with the long-term forecasts developed by Newfoundland and Labrador Hydro for their service territory and Newfoundland Power's service territory. These forecasts were provided in the "3.0 NLH - Long Term Forecasts for NP and Island Rural" MS Excel workbook. Further insights are drawn from the "CED Forecast v10 GRA for Potential Study" and "Historical and Forecast Customer and Energy Sales" MS Excel workbooks for Newfoundland Power and Newfoundland and Labrador Hydro respectively. Lastly, 2023 billing data from both Utilities was used to align to actuals from that year. These sources were consolidated to create a "Master Reference Case Forecast" for each sector.

Residential Sector

The data sources for each key modelling parameter are provided in Exhibit 178.

Exhibit 178: Residential Sector Modelling Sources[219,220]

Parameter	Sources
Customer Accounts[221]	• Master Reference Case Forecast • Newfoundland Power: *CED Forecast v10 GRA for Potential Study* *3.0 NLH – Long Term Forecasts for NP and Island Rural* • Newfoundland and Labrador Hydro: *NLH Residential Monthly* *3.0 NLH – Long Term Forecasts for NP and Island Rural* • Newfoundland Census data (historical)[222]
Units	• Set to 1
Size Factor	• Set to 1
Saturation	• Residential End Use Survey (2022) • 2015 Potential Study • Engineering assumptions
Fuel Share	• Residential End Use Survey (2022) • 2015 Potential Study • Engineering assumptions
Unit Energy Consumption (UEC)	• NRCan – Average annual UEC of major household appliances, 2000-2021[223] • 2015 Potential Study • Engineering assumptions

[219] Italicized sources indicate Excel workbooks.
[220] Several parameters are further calibrated from initial values. See the sections on Base Year Energy Use Model Development and Reference Case Energy Use Forecast Development for details.
[221] Billing data provided by both utilities was used to split out the Master Reference Case Forecast customer accounts and consumption by segment and rate class.
[222] Used to estimate base year vintage breakdown. Vintage data is available in the 2022 REUS, but some segments have very low response rates and so census data is used to improve confidence in base year vintages.
[223] "Comprehensive Energy Use Database," Natural Resources Canada, Available: https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CM&sector=AAA&juris=CA&rn=49&page=2. (Accessed Feb. 1, 2024).

Commercial Sector

The data sources for the key modelling parameters are provided in Exhibit 179.

Exhibit 179: Commercial Sector Modelling Sources[224,225]

Parameter	Sources
Customer Accounts[226]	• Master Reference Case Forecast • Newfoundland Power: *2022 NP Monthly SIC Code Data* *Arenas & Stadiums 2* • Newfoundland and Labrador Hydro: *NLH Island Interconnected Commercial 2022_rev2*
Units	• Initially derived from the 2015 Potential Study
Size Factor	• Set to 1
Saturation	• Commercial End Use Survey • Engineering assumptions
Fuel Share	• Commercial End Use Survey • Engineering assumptions
Unit Energy Consumption (UEC)	• 2015 Potential Study • Improving efficiency in ice hockey arenas (ASHRAE)[227] • Commercial End Use Survey

[224] Italicized sources indicate Excel workbooks.
[225] Several parameters are further calibrated from initial values. See the sections on Base Year Energy Use Model Development and Reference Case Energy Use Forecast Development for details.
[226] Billing data provided by both utilities was used to split out the Master Reference Case Forecast customer accounts and consumption by segment and rate class.
[227] "Improving efficiency in ice hockey arenas," American Society of Heating, Refrigerating, and Air-Conditioning Engineers, Inc., Available: https://bit.ly/40uIdFr (Accessed Feb. 1, 2024).

Industrial Sector

The data sources for the key modelling parameters are provided in Exhibit 180.

Exhibit 180: Industrial Sector Modelling Sources[228,229]

Parameter	Sources
Customer Accounts[230]	• Master Reference Case Forecast • Newfoundland Power: *2022 NP Monthly SIC Code Data* • Newfoundland and Labrador Hydro: *NLH Island Interconnected Commercial 2022_rev2* *4.0 NLH Island Industrial Forecast Requirements*
Units	• Master Reference Case Forecast
Size Factor	• All set to 1
Saturation	• Commercial End Use Survey • Engineering assumptions
Fuel Share	• Commercial End Use Survey • Energy Data Management Manual for the Wastewater Treatment Sector[231] • Engineering assumptions
Unit Energy Consumption (UEC)	• 2015 Potential Study • Commercial End Use Survey

[228] Italicized sources indicate Excel workbooks.
[229] Several parameters are further calibrated from initial values. See the sections on Base Year Energy Use Model Development and Reference Case Energy Use Forecast Development for details.
[230] Billing data provided by both utilities was used to split out the Master Reference Case Forecast customer accounts and consumption by segment and rate class.
[231] "Energy Data Management Manual for the Wastewater Treatment Sector," U.S. Department of Energy, Available: https://www.energy.gov/sites/prod/files/2018/01/f46/WastewaterTreatmentDataGuide_Final_0118.pdf. (Accessed Feb. 1, 2024).

Appendix B List of Measures

This appendix shows the full list of measures in the Study. It is structured as follows:

- Exhibit 181 lists residential sector measures.
- Exhibit 182 lists commercial sector measures.
- Exhibit 183 lists industrial sector measures.
- Exhibit 184 lists transportation sector measures.

Exhibit 181: Residential Sector Measures

End Use(s) Affected	Measure Name
Clothes Dryer	**Efficiency** • Clothes Lines and Drying Racks • ENERGY STAR Clothes Dryer • Heat Pump Clothes Dryer **Demand Response** • Clothes Dryer Direct Load Control (Utility-Driven)
Clothes Washer	**Efficiency** • ENERGY STAR Clothes Washer **Demand Response** • Clothes Washer Direct Load Control (Utility-Driven)
Computer and Peripherals & Other Electronics	**Efficiency** • Advanced Smart Strips and Plugs
Cooking	**Efficiency** • Convection Oven • High-Efficiency Induction Cooktops **Fuel Switching** • Induction Stove
Dehumidifier	**Efficiency** • ENERGY STAR Dehumidifier
Dishwasher	**Efficiency** • ENERGY STAR Dishwasher **Demand Response** • Dishwasher Direct Load Control
Water Heating	**Efficiency** • Domestic Hot Water Pipe Insulation • Faucet Aerator • Heat Pump Water Heater • Heat Pump Water Heater Upgrade • Low Flow Showerhead

End Use(s) Affected	Measure Name
	• On Demand Hot Water Heater • On Demand Hot Water Heater (Central) • Thermostatic Restrictor Shower Valve **Fuel Switching** • Oil Water Heater to Heat Pump Water Heater • Oil Water Heater to High Efficiency Electric Storage Water Heater **Demand Response** • Water Heater Smart Switch (Utility-Driven)
Freezer	**Efficiency** • ENERGY STAR Freezer • Freezer Recycle
Refrigerator	**Efficiency** • ENERGY STAR Refrigerator
Freezer & Refrigerator	**Efficiency** • Appliance Retirement for Extra Refrigerators
Hot Tubs	**Efficiency** • Insulated Hot Tub Cover
Lighting	**Efficiency** • Dimmer Switches • Exterior ENERGY STAR LED Reflector Lamp • Exterior Lighting Controls • Exterior ENERGY STAR LED A-Lamp • Interior ENERGY STAR LED A-Lamp • Interior ENERGY STAR LED Reflector Lamp • Interior Lighting Controls • LED Linear Tube • LED Panel
Small Appliance and Other	**Efficiency** • ENERGY STAR Room Air Purifier
Space Cooling & Space Heating	**Efficiency** • Air Sealing • Air Source Heat Pump - Ductless Mini Split • Air Source Heat Pump - Ductless Mini Split- Cold Climate • Air Source Heat Pump Tune Up • Attic Insulation • Basement Ceiling Insulation • Basement Wall Insulation

End Use(s) Affected	Measure Name
	• Central Ducted Air Source Heat Pump • Central Ducted Air Source Heat Pump - Cold Climate • Crawlspace Ceiling Insulation • Digital Non-Programmable Thermostat (Central) • Digital Non-Programmable Thermostat (Multiple) • Duct Insulation • Duct Sealing • Efficient Windows • ENERGY STAR Doors • Ground Source Heat Pump • Programmable Thermostat (Central) • Programmable Thermostat (Multiple) • Smart Thermostat (Central) • Smart Thermostat (Multiple) • Wall Insulation **Fuel Switching** • Oil Boiler to Air to Water Heat Pump - Space Heating • Oil Boiler to Air to Water Heat Pump - Space Heating – Service Upgrade • Oil Boiler to Cold Climate Ductless Mini Split Heat Pump • Oil Boiler to Cold Climate Ductless Mini Split Heat Pump – Service Upgrade • Oil Boiler to Ductless Mini Split Heat Pump • Oil Boiler to Ductless Mini Split Heat Pump - Partial Switch • Oil Boiler to Ductless Mini Split Heat Pump - Partial Switch – Service Upgrade • Oil Boiler to Ductless Mini Split Heat Pump – Service Upgrade • Oil Furnace to Central Ducted Air Source Heat Pump • Oil Furnace to Central Ducted Air Source Heat Pump – Partial Switch • Oil Furnace to Central Ducted Air Source Heat Pump – Partial Switch – Service Upgrade • Oil Furnace to Central Ducted Air Source Heat Pump – Service Upgrade • Oil Furnace to Cold Climate Central Ducted Air Source Heat Pump • Oil Furnace to Cold Climate Central Ducted Air Source Heat Pump – Service Upgrade • Oil Furnace to Ductless Mini Split Heat Pump

End Use(s) Affected	Measure Name
	• Oil Furnace to Ductless Mini Split Heat Pump – Service Upgrade • Wood Furnace to Central Ducted Air Source Heat Pump • Wood Furnace to Central Ducted Air Source Heat Pump – Service Upgrade • Wood Furnace to Cold Climate Central Ducted Air Source Heat Pump • Wood Furnace to Cold Climate Central Ducted Air Source Heat Pump – Service Upgrade • Wood Furnace to Ductless Mini Split Heat Pump - Partial Switch • Wood Furnace to Ductless Mini Split Heat Pump - Partial Switch – Service Upgrade
Space Heating & Space Cooling & Water Heating	**Fuel Switching** • Oil Boiler to Air to Water Heat Pump - Space Heating and Water Heating
Space Cooling & Space Heating & Ventilation	**Efficiency** • Energy Recovery Ventilator (Ducted) • Energy Recovery Ventilator (Ductless) • Heat Recovery Ventilator (Ducted) • Heat Recovery Ventilator (Ductless)
Space Heating	**Fuel Switching** • Oil Boiler to Electric Boiler • Oil Furnace to Electric Furnace **Demand Response** • Smart Thermostat or Switch for Baseboards or Furnaces (Utility-Driven) • Smart Thermostat or Switch for Central Air Source Heat Pumps (Utility-Driven) • Smart Thermostat or Switch for Ductless Mini-Split Heat Pumps (Utility-Driven) • Thermal Storage and Air Source Heat Pump (Utility-Driven and Thermal Storage with TOU) • Thermal Storage and Ductless Mini-Split Heat Pump (Utility-Driven and Thermal Storage with TOU) • Thermal Storage for Heating (Utility-Driven and Thermal storage with TOU)
Ventilation	**Efficiency** • ENERGY STAR Ceiling Fan

End Use(s) Affected	Measure Name
Four or More End Uses Affected	**Efficiency** • Codes and Standards • Home Energy report • LEED Certified Apartments • New Home - ENERGY STAR • New Home - Net-Zero Ready **Demand Response** • Behind-the-Meter Battery Storage (Utility-Driven) • Behind-the-Meter Solar with Smart Inverters (Utility-Driven) • Critical Peak Pricing (CPP) • Smart circuit breakers or smart panel (Utility-Driven) • Time-of-Use (TOU)

Exhibit 182: Commercial Sector Measures

End Use(s) Affected	Measure Name
Computer Servers	**Efficiency** • ENERGY STAR Server
Water Heating	**Efficiency** • Drain Water Heat Recovery • ENERGY STAR Dishwasher • Faucet Aerator • Heat Pump Water Heater • Low-Flow Showerhead • Pre-Rinse Spray Valve • Thermostatic Restrictor Shower Valve **Fuel Switching** • Oil Water Heater to Heat Pump Water Heater **Demand Response** • Controllable Water Heater (Utility-Driven) • Large Commercial Dual-Fuel Water Heater (Utility-Driven)
Water Heating & Refrigeration	**Efficiency** • Floodwater Deaeration (Non-thermal) - Arena
Food Service Equipment	**Efficiency** • High-Efficiency Cooking Equipment
General Lighting	**Efficiency** • LED A-Lamp (Interior) • LED Luminaire (General) • LED Reflector (Interior, General) • Lighting Controls (Interior), BAS • Lighting Controls (Interior), Daylighting • Lighting Controls (Interior), Occupancy Ceiling • Lighting Controls (Interior), Occupancy Wall • Linear LED T8 Tube (General)
High Bay Lighting	**Efficiency** • LED High Bay Luminaire
HVAC Fans & Pumps	**Efficiency** • Cooling tower fan or pump with VFD • DHW Circulator Pump with EC Motor • Heating Water Circulator Pump with EC Motor • HVAC Electronically Commutated Motor (EC motor) • HVAC Fan or Pump VFD

End Use(s) Affected	Measure Name
	• HVAC Variable Frequency Drive - Motors • Premium Efficiency Motors • Recirculation Pump with Demand Controls
HVAC Fans & Pumps & Space Cooling	**Efficiency** • Advanced Building Automation Systems • Demand Control Ventilation • Kitchen Demand Control Ventilation **Demand Response** • HVAC Fans & Pumps Controls (Utility-Driven)
Miscellaneous Equipment	**Efficiency** • ENERGY STAR Ice Maker • ENERGY STAR Uninterruptible Power Supply • ENERGY STAR Vending Machine **Off-Road Electrification** • Electric Forklift • Electric Zamboni
Other Plug Loads	**Efficiency** • Advanced Smart Strips
Outdoor Lighting	**Efficiency** • LED A-Lamp (Exterior) • LED Parking Garage Fixture (Exterior) • LED Pole Mounted Fixture (Exterior) <= 200 W • LED Pole Mounted Fixture (Exterior) > 200 W • LED Reflector (Exterior) • LED Wall Pack (Exterior) • Lighting Controls (Exterior)
Refrigeration	**Efficiency** • Automatic Door Closers • Brine Pump Controls - Arena • ENERGY STAR Refrigerators and Freezers • Fast Acting Doors (Cooler) • Fast Acting Doors (Freezer) • High Efficiency Compressor • LED Refrigerated Case Lighting • Low Emissivity Ceilings in Arenas • Refrigerated Case Anti-Sweat Door Heater Controls • Refrigerated Case Retrofit • Refrigerated Display Case with Doors

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End Use(s) Affected	Measure Name
	• Refrigerated Walk-ins Door Strip Curtains • Refrigerated Walk-ins EC Motor • Refrigerated Walk-ins Evaporator Fan Control • Refrigeration Floating Head Pressure Control • Schedule for Ice Temperature - Arena
Secondary Lighting	**Efficiency** • LED Luminaire (Secondary) • LED Reflector (Interior, Secondary) • Linear LED T8 Tube (Secondary)
Space Cooling & Space Heating	**Efficiency** • Air Sealing • Air Source Heat Pump – Standard to High Efficiency • Baseboard to Ductless Mini-Split Heat Pump • Baseboard to Packaged Terminal Heat Pump • Cold Climate Air Source Heat Pump • Ductless Mini-Split Heat Pump – Standard to High Efficiency • Electric Furnace to Air Source Heat Pump • Energy Management System • Ground Source Heat Pumps – Standard to High Efficiency • Guest Room Energy Management • Packaged Terminal Heat Pump – Standard to High Efficiency • Programmable Thermostat • Smart Thermostat
Space Cooling	**Efficiency** • Dual Enthalpy Economizer Controls • High Efficiency Electric Chiller • High Efficiency Rooftop Units • High Efficiency Unitary Air Conditioners • Packaged Terminal Air Conditioner – Standard to High Efficiency • Rooftop Unit – Standard to High Efficiency • Room Air Conditioner – Standard to High Efficiency • Server Room Air Conditioner • Unitary Air Conditioner
Space Heating	**Efficiency** • Air Curtains • Efficient Windows • Energy Recovery Ventilator

End Use(s) Affected	Measure Name
	• Radiant Infrared Heaters • Refrigeration Heat Recovery • Roof Insulation • Solar Wall • Wall Insulation • Window Glazing **Fuel Switching** • Oil Boiler - Baseboard Heat • Oil Boiler to Air-to-Water Heat Pump • Oil Boiler to Ductless Mini-Split Heat Pump - Partial Switch • Oil Boiler to Ductless Mini-Split Heat Pump - Partial Switch • Oil Boiler to Electric Boiler • Oil Furnace to Air Source Heat Pump • Oil Furnace to Ductless Mini-Split Heat Pump – Partial Switch • Oil Furnace to Electric Furnace **Demand Response** • HVAC Control (Utility-Driven) • Thermal Storage and Electric Baseboard Heating with TOU • Thermal Storage and Electric Baseboard Heating (Utility-Driven) • Thermal Storage and Electric Furnace Heating with TOU • Thermal Storage and Electric Furnace Heating (Utility-Driven) • Thermal Storage and Heat Pump Heating with TOU • Thermal Storage and Heat Pump Heating (Utility-Driven)
Street Lighting	**Efficiency** • LED Street Light
Four or More End Uses Affected	**Efficiency** • Energy Management System • New Construction (25% more efficient) • New Construction (40% more efficient) • Net-Zero Ready • Retro-commissioning Strategic Energy Manager **Demand Response** • Backup Generation (Utility-Driven) • Behind-the-Meter Battery Storage (Utility-Driven) • Behind-the-Meter Solar with Smart Inverters (Utility-Driven) • Critical Peak Pricing • Customer curtailment

End Use(s) Affected	Measure Name
	• Grid Interactive Efficient Buildings (Utility-Driven) • Time-of-Use Rate

Exhibit 183: Industrial Sector Measures

End Use(s) Affected	Measure Name
Air Compressors	**Efficiency** • Air Leak Survey and Repair • Cycling Refrigerated Air Dryer • Low Pressure Drop Filters • Optimized Distribution System (Incl. Pressure and Air End Uses) - Air Compressor • Optimized Sizes of Air Receiver Tanks • Premium Efficiency ASD Compressor • Sequencing Control • Use Cooler Air from Outside for Make Up Air • Zero Loss Condensate Drain
Conveyors	**Efficiency** • Optimized Conveyor Motor Control • Premium Efficiency Motors - Conveyor
Fans and Blowers	**Efficiency** • Correctly Sized Fans: Impeller Trimming or Fan Selection • Optimized Distribution System (Incl. Pressure Losses) - Fans and Blowers • Premium Efficiency Fan Control with ASDs • Premium Efficiency Motors - Fan or Blower • Synchronous Belts
General Lighting	**Efficiency** • Automated Lighting Controls • Greenhouse Grow Lights • High Efficiency Lighting Design • LED High Bay • LED Luminaire
HVAC Fans & Pumps	**Efficiency** • Air Compressor Heat Recovery • Air Curtains - HVAC • High Efficiency Packaged HVAC • Improved Building Insulation • Reduced Temperature Settings • Refrigeration Heat Recovery • Smart Thermostat • Solar Thermal Wall • Ventilation Heat Recovery

End Use(s) Affected	Measure Name
	• Ventilation Optimization • Warehouse Loading Dock Seals **Fuel Switching** • Comfort HVAC Electrification
HVAC Fans & Pumps, Pumps, Process Cooling, and Process Heating	**Demand Response** • Peak shifting through On-Site Storage (Utility-Driven)
Other	**Off-Road Electrification** • Electric Forklift
Other Motors	**Efficiency** • Adjustable or Variable Speed Drives (Compressor and Fan) • Correctly Sized Motor • Motor Controls – Process • Premium Efficiency Motors - Other
Pumps	**Efficiency** • Correctly Sized Pumps: Impeller Trimming or Pump Selection • Optimization of Pumping System • Premium Efficiency Motors - Pumps • Premium Efficiency Pump Control with ASDs
Process Cooling	**Efficiency** • Air Curtains - Process Cooling • Chiller Economizer • Floating Head Pressure Controls • High Efficiency Chiller • Improve Insulation of Refrigeration System • Improved Ice Production System • Optimized Distribution System - Process Cooling • Premium Efficiency Refrigeration Control System and Compressor Sequencing
Process Heating	**Efficiency** • High Efficiency Oven/Dryer/Furnace/Kiln • High Efficiency Water Heater • Insulation • Process Heat Recovery to Preheat Makeup Water
Process Specific	**Efficiency** • Advanced ‘Predictive’ Process Control Systems • Custom Processes • Process Optimization Efforts - Fishing and Fish Processing

End Use(s) Affected	Measure Name
	• Process Optimization Efforts - Mining and Processing
Process Heating & Process Cooling	**Efficiency** • Heat Pumps
All End Uses Affected	**Demand Response** • Backup Generation at Peak Hours (Utility-Driven) • Behind-the-Meter Battery Storage (Utility-Driven) • Behind-the-Meter Solar with Smart Inverters (Utility-Driven) • Critical Peak Pricing/ Industrial Flexibility • Energy Management Information System (EMIS) • Time-of-Use (TOU)

Exhibit 184 presents transportation sector measures, all of which affect the EV charging end use.

Exhibit 184: Transportation Sector Measures

Measure Type	Measure Name
Managed Charging	**Personal Ownership** • BEV - Electric Vehicle Supply Equipment (EVSE) • BEV – Vehicle Telematics (VT) • PHEV – EVSE • PHEV – VT **Fleet Ownership** • Bus – EVSE • Bus – VT • HDV – EVSE • HDV - VT • Light Duty BEV – EVSE • Light Duty BEV – VT • Light Duty PHEV – EVSE • Light Duty PHEV – VT • MDV – EVSE • MDV – VT
Time-of-Use	**Personal Ownership** • BEV • PHEV
Adoption Incentives	• Bus • Fleet LDV • HDV • MDV • Personal LDV
Infrastructure	**Personal Ownership** • LDV DCFC Public Charger • LDV L2 Home Charger – Multi-Unit Residential Building (MURB) • LDV L2 Public Charger • LDV Level 1 (L1) Home Charger • LDV Level 2 (L2) Home Charger **Fleet Ownership** • Bus DCFC Depot Charger • Bus L2 Depot Charger • HDV DCFC Depot Charger

Measure Type	Measure Name
	• LDV DCFC Public Charger • LDV Direct Current Fast Charger (DCFC) Depot Charger • LDV L2 Depot Charger • LDV L2 Public Charger • MDV DCFC Depot Charger • MDV L2 Depot Charger **Other Ownership** • HDV DCFC Public Charger • HDV L2 Public Charger • MDV DCFC Public Charger • MDV L2 Public Charger

Appendix C Cost-Effectiveness Test Inputs and Measure-Level Results

This appendix includes inputs to the cost-effectiveness test calculations, including retail rates, inflation and discount rates, and avoided costs. It also includes measure-level cost-effectiveness test results for all measures.

Retail Rates

Exhibit 185: Retail Rates by Customer Rate Class

Rate Class	Marginal Energy Cost	Demand Charge	Source(s)
1.1 Domestic Service	$0.13256/kWh	n/a	• Newfoundland Power Schedule of Rates Rules & Regulations, Effective July 1, 2023[232] • Newfoundland and Labrador Hydro Schedule of Rates, Rules and Regulations, Updated July 1, 2023[232]
2.1 General Service	$0.1016/kWh	$9.70/kW from Dec-Mar $7.20/kW for all other months	
2.3 General Service	$0.09385/kWh	$8.15/kVA from Dec-Mar $5.65/kVA for all other months	
2.4 General Service	$0.09305/kWh	$7.82/kW from Dec-Mar $5.32/kW for all other months	
Industrial Firm	$0.0591/kWh	$10.73/kW for all months	Newfoundland and Labrador Hydro Schedule of Rates, Rules and Regulations, Updated July 1, 2023

Notes on Retail Rates

- The marginal energy cost for the commercial sector is weighted by base year consumption for the 2.1, 2.3 and 2.4 general service rate classes. Data on historical CDME participation by rate class was not available for weighting.
- The marginal energy cost for the industrial sector is weighted by base year consumption for the 2.1, 2.3 and 2.4 general service rate classes. Data on historical CDME participation by rate class was not available for weighting. NLH's large industrial customers are excluded from the

[232] The Study uses 2023 rates because the base year is also 2023.

weighting because they have not historically participated in CDME, and this trend is not expected to change during the forecast period.

- The winter demand charge is used for the peak retail rates. Multiplied the weighted average winter retail demand charge by 4 so that it is valued in each of the 4 winter months. Applied 0.75 derating factor to account that customer might not be coincident with utility peak.
- For the demand response measures, because commercial demand is driven by space heating, customers in the commercial sector will see savings 4 times per year, once per winter month. Industrial demand is not driven by space heating and therefore customers in the industrial sector will see savings 12 times per year.

Inflation and Discount Rates

Exhibit 186: Inflation and Discount Rates

Parameter	Value	Source(s)
Inflation	0%	Navigator cannot accommodate inflation.
Participant Discount Rate (Real)	0%	n/a; a 0% discount rate is used because participants do not typically apply discounting to their financial decisions.
Utility Discount Rate (Real)	4%	Newfoundland Power, comment 31 in the NL Potential Study Measure Analysis Comments Log.
Societal Discount Rate (Real)	1%	Government of Canada Update to the Pan-Canadian Approach to Carbon Pollution Pricing 2023-2030, available online.

Avoided Marginal Costs

The source for the avoided costs data is “*2023 Marginal Costs_IIS from Hydro with NP Distribution (Oct 2023 update)*.”

Exhibit 187: Capacity Costs ($/kW)

Year	Generation	Transmission	Distribution	Total
2023	$288.97	$18.17	$23.62	$330.76
2024	$286.15	$18.57	$24.08	$328.80
2025	$290.99	$18.95	$24.54	$334.48
2026	$295.92	$19.34	$25.01	$340.27
2027	$300.93	$19.73	$25.50	$346.16
2028	$306.03	$20.14	$25.99	$352.16
2029	$311.23	$20.55	$26.50	$358.28
2030	$316.52	$20.97	$27.02	$364.51
2031	$321.90	$21.40	$27.55	$370.85
2032	$327.38	$21.84	$28.10	$377.32
2033	$332.96	$22.29	$28.65	$383.90
2034	$338.63	$22.74	$29.22	$390.59
2035	$344.41	$23.21	$29.80	$397.42
2036	$350.30	$23.68	$30.40	$404.38
2037	$356.29	$24.17	$31.00	$411.46
2038	$362.38	$24.67	$31.62	$418.67
2039	$368.59	$25.17	$32.25	$426.01
2040	$374.91	$25.69	$33.14	$433.74
2041	$381.34	$26.22	$33.80	$441.36
2042	$387.89	$26.75	$34.48	$449.12

Exhibit 188: Energy Supply Costs ($/kWh)

Year	Winter Peak	Winter Off Peak	Non-Winter
2023	$172.24	$139.98	$40.46
2024	$144.89	$124.50	$34.21
2025	$122.40	$103.38	$29.95
2026	$84.71	$69.40	$27.05
2027	$62.51	$48.76	$25.44
2028	$61.38	$49.95	$28.39
2029	$58.98	$50.29	$26.72
2030	$54.00	$45.47	$24.56
2031	$50.59	$42.25	$22.02
2032	$50.15	$41.23	$24.48
2033	$54.66	$45.96	$23.64
2034	$56.49	$48.31	$25.09
2035	$51.38	$45.86	$24.66
2036	$48.29	$44.00	$24.46
2037	$48.29	$44.37	$22.08
2038	$46.48	$43.57	$23.88
2039	$49.04	$46.26	$21.40
2040	$47.51	$47.53	$21.41
2041	$56.70	$57.20	$25.62
2042	$55.23	$55.45	$26.18

Measure-Level Cost-Effectiveness Test Results

Exhibit 189 to Exhibit 195 show measure-level cost effectiveness test results for the residential, commercial, industrial and transportation sectors. Two cost-effectiveness test results are shown for the medium achievable potential scenario: the program administrator cost test (PAC), and the total resource cost test (TRC).[233] Results for the electricity rate design and thermal storage with TOU demand response measures reflect costs and benefits incurred during the four-year AMI meter installation period and the 20-year smart meter lifetime.

Exhibit 189: Measure-Level Cost-Effectiveness Test Results, Residential Sector (2025)

Measure	Type	Medium PAC	Medium TRC
Advanced Smart Strips and Plugs	EE	2.6	1.5
Air Sealing	EE	4.8	2.7
Air Source Heat Pump - Ductless Mini Split (DMSHP)	EE	4.2	1.5
Air Source Heat Pump - Ductless Mini Split (DMSHP) - Cold Climate	EE	2.1	0.9
Air Source Heat Pump Tune Up	EE	2.2	1.2
Appliance Retirement for Extra Refrigerators	EE	1.4	0.8
Attic Insulation	EE	2.7	1.5
Basement Ceiling Insulation	EE	4.1	2.3
Basement Wall Insulation	EE	2.5	1.4
Central Ducted Air Source Heat Pump	EE	4.9	2.8
Central Ducted Air Source Heat Pump - Cold Climate	EE	N/A	N/A
Clothes Lines and Drying Racks	EE	5.9	3.3
Codes and Standards	EE	N/A	N/A
Convection Oven	EE	N/A	N/A
Crawlspace Ceiling Insulation	EE	4.8	2.7
Digital Non-Programmable Thermostat (Central)	EE	10.1	5.6
Digital Non-Programmable Thermostat (Multiple)	EE	2.4	1.3
Dimmer Switches	EE	N/A	N/A
Domestic Hot Water Pipe Insulation	EE	23.8	13.2
Duct Insulation	EE	19.9	11.1
Duct Sealing	EE	2.2	1.2
Efficient Windows	EE	1.6	0.9
ENERGY STAR Ceiling Fan	EE	28.5	15.8
ENERGY STAR Clothes Dryer	EE	N/A	N/A
ENERGY STAR Clothes Washer	EE	2.9	1.6
ENERGY STAR Dehumidifier	EE	8.0	4.5
ENERGY STAR Dishwasher	EE	N/A	N/A

[233] The incentive in the medium achievable potential scenario reflects 50% of the incremental cost for replace on burnout measures and 50% of the full cost for retrofit measures.

ENERGY STAR Doors	EE	N/A	N/A
ENERGY STAR Freezer	EE	10.0	10.0
ENERGY STAR Refrigerator	EE	1.7	0.9
ENERGY STAR Room Air Purifier	EE	N/A	N/A
Exterior ENERGY STAR LED Reflector Lamp	EE	14.4	10.0
Exterior Lighting Controls	EE	2.1	1.2
External ENERGY STAR LED A-Lamp	EE	18.5	10.0
Faucet Aerator	EE	89.9	49.9
Freezer Recycle	EE	N/A	N/A
Ground Source Heat Pump (GSHP)	EE	N/A	N/A
Heat Pump Clothes Dryer	EE	N/A	N/A
Heat Pump Water Heater (HPWH)	EE	2.0	1.2
Heat Pump Water Heater (HPWH) - Standard to High Efficiency	EE	N/A	N/A
Heat Recovery Ventilator (Ducted) - Standard to High Efficiency	EE	7.4	4.1
Heat Recovery Ventilator (Ductless) - Standard to High Efficiency	EE	7.5	4.2
High-Efficiency Induction Cooktops	EE	N/A	N/A
Home Energy Report	EE	7.7	7.6
Insulated Hot Tub Cover	EE	N/A	N/A
Interior ENERGY STAR LED A-Lamp	EE	19.4	10.0
Interior ENERGY STAR LED Reflector Lamp	EE	15.2	10.0
Interior Lighting Controls	EE	1.6	0.9
LED Linear Tube	EE	10.2	16.6
LED Panel	EE	1.4	1.5
LEED Certified Apartments	EE	N/A	N/A
Low Flow Showerhead	EE	7.8	4.3
New Home - ENERGY STAR	EE	N/A	N/A
New Home - Net-Zero Ready	EE	N/A	N/A
Oil Boiler to Cold Climate Ductless Mini Split Heat Pump (DMSHP)	FS	0.0	0.4
Oil Boiler to Cold Climate Ductless Mini Split Heat Pump (DMSHP) - Service Upgrade	FS	N/A	N/A
Oil Boiler to Ductless Mini Split Heat Pump - Partial Switch	FS	N/A	N/A
Oil Boiler to Ductless Mini Split Heat Pump - Partial Switch - Service Upgrade	FS	N/A	N/A
Oil Boiler to Electric Boiler	FS	N/A	N/A
Oil Boiler to Electric Boiler - Service Upgrade	FS	N/A	N/A
Oil Furnace to Cold Climate Central Ducted Air Source Heat Pump	FS	N/A	N/A

Oil Furnace to Cold Climate Central Ducted Air Source Heat Pump - Service Upgrade	FS	N/A	N/A
Oil Furnace to Ductless Mini Split Heat Pump (DMSHP) - Partial Switch	FS	N/A	N/A
Oil Furnace to Ductless Mini Split Heat Pump (DMSHP) - Partial Switch - Service Upgrade	FS	N/A	N/A
Oil Furnace to Electric Furnace	FS	N/A	N/A
Oil Furnace to Electric Furnace - Service Upgrade	FS	N/A	N/A
Oil Water Heater to Heat Pump Water Heater	FS	N/A	N/A
Oil Water Heater to Heat Pump Water Heater - Service Upgrade	FS	N/A	N/A
Oil Water Heater to High Efficiency Electric Storage Water Heater	FS	N/A	N/A
Oil Water Heater to High Efficiency Electric Storage Water Heater - Service Upgrade	FS	N/A	N/A
On Demand Hot Water Heater (Distributed)	EE	N/A	N/A
Programmable Thermostat (Central)	EE	29.0	16.1
Programmable Thermostat (Multiple)	EE	6.8	3.8
Propane to Electric Induction Stove	FS	N/A	N/A
Propane to Electric Induction Stove - Service Upgrade	FS	N/A	N/A
Smart Thermostat (Central)	EE	15.3	8.5
Smart Thermostat (Multiple)	EE	6.8	3.8
Thermostatic Restrictor Shower Valve	EE	2.2	1.2
Wall Insulation	EE	N/A	N/A
Wood Furnace to Cold Climate Central Ducted Air Source Heat Pump	FS	N/A	N/A
Wood Furnace to Ductless Mini Split Heat Pump (DMSHP) - Partial Switch	FS	N/A	N/A
Wood Furnace to Ductless Mini Split Heat Pump (DMSHP) - Partial Switch - Service Upgrade	FS	N/A	N/A

Exhibit 190: Measure-Level Cost-Effectiveness Test Results, Residential Sector DR Measures

Measure	Medium PAC	Medium TRC
Critical Peak Pricing (CPP) - Residential	0.2	0.2
Time-of-Use (TOU) - Behaviour Driven - Residential	0.1	0.1
Smart Circuit Breakers or Smart Panel - Utility Driven	0.8	1.0
Smart Thermostat or Switch for Baseboards or Furnaces - Utility Driven	7.4	44.2
Thermal Storage and Ductless Mini-Split Heat Pump - Utility Driven - Residential	2.3	0.4
Thermal Storage and Ductless Mini-Split Heat Pump - Thermal Storage + Time-of-Use - Residential	1.7	0.4
Thermal Storage and Electric Baseboard Heating - Thermal Storage + Time-of-Use - Residential	4.0	0.9
Thermal Storage and Electric Baseboard Heating - Utility Driven - Residential	5.5	0.9
Behind-the-Meter Battery Storage - Utility Driven - Residential	4.6	0.7
Smart Thermostat or Switch for Ductless Mini-Split Heat Pumps - Utility Driven	3.1	18.7
Thermal Storage and Air Source Heat Pump - Thermal Storage + Time-of-Use - Residential	1.7	0.3
Thermal Storage and Air Source Heat Pump - Utility Driven - Residential	2.3	0.4
Smart Thermostat or Switch for Central Air Source Heat Pumps - Utility Driven	3.0	18.0
Thermal Storage and Electric Furnace - Thermal Storage + Time-of-Use - Residential	4.7	1.0
Thermal Storage and Electric Furnace - Utility Driven - Residential	6.7	1.0
Behind-the-Meter Solar with Smart Inverters - Utility Driven - Residential	N/A	N/A
Clothes Dryer Direct Load Control - Utility Driven	N/A	N/A
Clothes Washer Direct Load Control - Utility Driven	N/A	N/A
Dishwasher Direct Load Control - Utility Driven	N/A	N/A
Water Heater Smart Switch - Utility Driven	N/A	N/A

Exhibit 191: Measure-Level Cost-Effectiveness Test Results, Commercial Sector (2025)

Measure	Measure Type	Medium PAC	Medium TRC
Advanced Building Automation Systems	EE	6.9	1.4
Advanced Smart Strips	EE	7.1	3.9
Air Curtains	EE	7.1	3.9
Air Sealing	EE	11.2	6.2
Air Source Heat Pump - Standard to High Efficiency	EE	N/A	N/A
Baseboard to Ductless Mini-Split Heat Pump	EE	7.2	2.3
Baseboard to Packaged Terminal Heat Pump	EE	5.7	2.9
Brine Pump Controls - Arena	EE	9.6	5.3
Cold Climate Air Source Heat Pump	EE	N/A	N/A
Demand Control Ventilation	EE	8.9	5.0
DHW Circulator Pump with EC Motor	EE	5.0	2.8
Drain Water Heat Recovery	EE	6.8	3.8
Dual Enthalpy Economizer Controls	EE	N/A	N/A
Ductless Mini-Split Heat Pump - Standard to High Efficiency	EE	N/A	N/A
Efficient Windows	EE	N/A	N/A
Electric Furnace to Air Source Heat Pump	EE	10.4	5.8
Energy Management System	EE	1.8	1.0
Energy Recovery Ventilator (ERV)	EE	4.9	2.7
ENERGY STAR Dishwasher	EE	28.4	15.8
ENERGY STAR Ice Maker	EE	1.9	1.1
ENERGY STAR Refrigerators and Freezers	EE	3.7	2.1
ENERGY STAR Server	EE	N/A	N/A
ENERGY STAR Uninterruptible Power Supply	EE	13.2	7.3
ENERGY STAR Vending Machine	EE	19.3	10.7
Fast Acting Doors Cooler	EE	10.0	10.0
Fast Acting Doors Freezer	EE	5.9	5.1
Faucet Aerator	EE	186.2	103.4
Floodwater Deaeration (Non-thermal) - Arena	EE	4.8	2.7
Ground Source Heat Pump - Standard to High Efficiency	EE	N/A	N/A
Guest Room Energy Management	EE	1.9	1.1
Heat Pump Water Heater	EE	N/A	N/A
High Efficiency Compressor	EE	26.2	14.5
High Efficiency Electric Chiller	EE	N/A	N/A
High Efficiency Unitary Air Conditioners	EE	N/A	N/A
High Efficiency Window Glazing	EE	5.6	3.1
High-Efficiency Cooking Equipment	EE	3.3	1.8

Measure	Measure Type	Medium PAC	Medium TRC
HVAC electronically commutated motor (EC motor)	EE	5.4	3.0
HVAC Variable Frequency Drive - Motors	EE	2.4	1.3
LED A-Lamp (Exterior)	EE	14.3	9.8
LED A-Lamp (Interior)	EE	10.8	7.2
LED High Bay Luminaire	EE	33.0	18.3
LED Luminaire (General)	EE	4.2	2.3
LED Luminaire (Secondary)	EE	4.0	2.2
LED Parking Garage Fixture (Exterior)	EE	5.0	2.8
LED Pole Mounted Fixture (Exterior) <= 200 W	EE	3.4	1.9
LED Pole Mounted Fixture (Exterior) > 200 W	EE	3.2	1.8
LED Reflector (Exterior)	EE	56.4	10.0
LED Reflector (Interior General)	EE	42.5	10.0
LED Reflector (Interior Secondary)	EE	42.1	10.0
LED Refrigerated Case Lighting	EE	0.4	0.8
LED Street Light	EE	2.3	1.3
LED Wall Pack (Exterior)	EE	1.7	10.0
Lighting Controls (Exterior)	EE	N/A	N/A
Lighting Controls (Interior) BAS	EE	N/A	N/A
Lighting Controls (Interior) Daylighting	EE	2.8	1.6
Lighting Controls (Interior) Occupancy - Ceiling	EE	2.3	1.3
Linear LED T8 Tube (General Lighting)	EE	8.3	9.8
Linear LED T8 Tube (Secondary Lighting)	EE	7.9	9.3
Low Emissivity Ceilings in Arenas	EE	1.7	1.0
Low-Flow Showerhead	EE	94.2	52.4
New Construction (25% more efficient)	EE	7.2	4.0
New Construction (40% more efficient)	EE	4.0	2.2
New Construction (Net-Zero Ready)	EE	2.0	1.1
Oil Boiler to Air-to-Water Heat Pump	FS	0.0	1.8
Oil Boiler to Ductless Mini-Split Heat Pump - Partial Switch	FS	0.0	1.8
Oil Boiler to Electric Boiler	FS	0.0	0.9
Oil Furnace to Air Source Heat Pump	FS	0.0	1.7
Oil Furnace to Ductless Mini-Split Heat Pump - Partial Switch	FS	0.0	1.8
Oil Water Heater to Heat Pump Water Heater	FS	N/A	N/A
Packaged Terminal Air Conditioner	EE	N/A	N/A
Packaged Terminal Heat Pump - Standard to High Efficiency	EE	N/A	N/A
Pre-Rinse Spray Valve	EE	11.6	6.4
Programmable Thermostat	EE	7.1	4.7

Measure	Measure Type	Medium PAC	Medium TRC
Radiant Infrared Heaters	EE	1.9	1.1
Recirculation Pump with Demand Controls	EE	N/A	N/A
Refrigerated Case Anti-Sweat Door Heater Controls	EE	8.8	4.9
Refrigerated Case Retrofit	EE	6.9	3.8
Refrigerated Display Case with Doors	EE	1.4	0.8
Refrigerated Walk-ins Door Strip Curtains	EE	3.8	2.1
Refrigerated Walk-ins EC Motor	EE	6.7	3.7
Refrigerated Walk-ins Evaporator Fan Control	EE	1.5	0.9
Refrigeration Floating Head Pressure Control	EE	2.2	1.2
Refrigeration Heat Recovery	EE	7.1	3.9
Retrocommissioning (RCx)	EE	3.5	2.0
Roof Insulation	EE	2.2	1.2
Rooftop Unit - Standard to High Efficiency	EE	N/A	N/A
Room Air Conditioner - Standard to High Efficiency	EE	N/A	N/A
Schedule for Ice Temperature - Arena	EE	4.8	2.7
Server Room Air Conditioner	EE	2.1	1.1
Smart Thermostat	EE	6.6	5.6
Solar Wall	EE	4.0	2.2
Thermostatic Restrictor Shower Valve	EE	35.1	19.5
Unitary Air Conditioner	EE	5.5	3.4
Wall Insulation	EE	2.5	1.4

Exhibit 192: Measure-Level Cost-Effectiveness Test Results, Commercial Sector DR Measures

Measure	Medium PAC	Medium TRC
Commercial Curtailment	0.0	0.0
Substation Battery	0.0	0.0
Backup Generation at Peak Hours - Utility Driven - Commercial	38.6	83.1
Thermal Storage and Heat Pump Heating - Thermal Storage + Time-of-Use - Commercial	13.3	8.1
Behind-the-Meter Battery Storage - Utility Driven - Commercial	11.7	1.8
Grid Interactive Efficient Buildings (GEB) - Utility Driven	7.9	0.6
Critical Peak Pricing (CPP) - Commercial	0.4	0.4
Thermal Storage and Heat Pump Heating - Utility Driven - Commercial	10.9	7.0
Time-of-Use (TOU) - Behaviour Driven - Commercial	0.3	0.3
HVAC Control - Utility Driven	7.1	24.8
HVAC Fans & Pumps Controls - Utility Driven	4.2	14.8
Thermal Storage and Electric Furnace Heating - Thermal Storage + Time-of-Use - Commercial	13.3	8.2
Thermal Storage and Electric Furnace Heating - Utility Driven - Commercial	10.9	7.0
Thermal Storage and Electric Baseboard Heating - Thermal Storage + Time-of-Use - Commercial	4.6	2.2
Thermal Storage and Electric Baseboard Heating - Utility Driven - Commercial	4.6	1.8
Large Commercial Dual-Fuel Water Heater - Utility Driven	10.9	30.9
Behind-the-Meter Solar with Smart Inverters - Utility Driven - Commercial	N/A	N/A
Controllable Water Heater - Utility Driven	N/A	N/A

Exhibit 193: Measure-Level Cost-Effectiveness Test Results, Industrial Sector (2025)

Measure	Measure Type	Medium PAC	Medium TRC
Custom Processes	EE	N/A	N/A
High Efficiency Oven/Dryer/Furnace/Kiln	EE	N/A	N/A
High Efficiency Water Heater	EE	N/A	N/A
Improve Insulation of Refrigeration System	EE	N/A	N/A
Improved Building Insulation	EE	N/A	N/A
Low Pressure Drop Filters	EE	N/A	N/A
Premium Efficiency Motors - Conveyor	EE	N/A	N/A
Premium Efficiency Motors - Fan or Blower	EE	N/A	N/A
Premium Efficiency Motors - Other	EE	N/A	N/A
Premium Efficiency Motors - Pumps	EE	N/A	N/A
Process Optimization Efforts - Fishing and Fish Processing	EE	N/A	N/A
Ventilation Heat Recovery	EE	N/A	N/A
Ventilation Optimization	EE	N/A	N/A
Warehouse Loading Dock Seals	EE	N/A	N/A
LED High Bay Luminaire	EE	40.9	22.7
Refrigeration Heat Recovery	EE	32.1	17.8
Insulation	EE	28.3	15.7
Process Optimization Efforts - Mining and Processing	EE	10.0	10.0
Reduced Temperature Settings	EE	10.0	10.0
High Efficiency Chiller	EE	16.8	9.3
Adjustable or Variable Speed Drive (Pump)	EE	16.0	8.9
Use Cooler Air from Outside for Make Up Air	EE	13.9	7.7
Correctly Sized Fans: Impeller Trimming or Fan Selection	EE	11.8	6.6
Air Curtains - Process Cooling	EE	11.4	6.3
Floating Head Pressure Controls	EE	10.7	6.0
High Efficiency Packaged HVAC	EE	9.6	5.3
Synchronous Belts	EE	9.2	5.1
Adjustable or Variable Speed Drive (Motor)	EE	8.7	4.9
Optimized Sizes of Air Receiver Tanks	EE	8.5	4.7
Advanced Predictive Process Control Systems	EE	8.4	4.6
High Efficiency Lighting Design	EE	6.2	3.4
Adjustable or Variable Speed Drive (Compressor)	EE	5.9	3.3
Adjustable or Variable Speed Drive (Fan)	EE	5.0	2.8
Optimization of Pumping System	EE	5.0	2.8
Motor Controls - Process	EE	5.0	2.8
Air Leak Survey and Repair	EE	4.9	2.7

Measure	Measure Type	Medium PAC	Medium TRC
LED Luminaire	EE	4.5	2.5
Energy Management Information System (EMIS)	EE	4.0	2.2
Optimized Conveyor Motor Control	EE	4.0	2.2
Air Compressor Heat Recovery	EE	3.7	2.1
Air Curtains - HVAC	EE	3.6	2.0
Comfort HVAC Electrification	FS	0.0	1.6
Optimized Distribution System (Incl. Pressure and Air End-Uses) - Air Compressor	EE	2.8	1.5
Greenhouse Grow Lights	EE	2.7	1.5
Automated Lighting Controls	EE	2.6	1.4
Correctly Sized Motor	EE	2.5	1.4
Optimized Distribution System (Incl. Pressure Losses) - Fans and Blowers	EE	2.2	1.2
Chiller Economizer	EE	1.9	1.1
Process Heat Recovery to Preheat Makeup Water	EE	1.8	1.0
Cycling Refrigerated Air Dryer	EE	1.8	1.0
Improved Ice Production System	EE	1.7	0.9
Zero Loss Condensate Drain	EE	1.6	0.9
Premium Efficiency Refrigeration Control System and Compressor Sequencing	EE	1.6	0.9
Optimized Distribution System - Process Cooling	EE	1.6	0.9
Sequencing Control	EE	1.5	0.8

Exhibit 194: Measure-Level Cost-Effectiveness Test Results, Industrial Sector DR Measures

Measure	Medium PAC	Medium TRC
Behind-the-Meter Battery Storage - Utility Driven - Industrial	5.3	0.5
Critical Peak Pricing (CPP) - Industrial	0.4	0.4
Time-of-Use (TOU) - Industrial	0.4	0.4
Backup Generation at Peak Hours - Utility Driven - Industrial	5.2	21.5
Behind-the-Meter Solar with Smart Inverters - Utility Driven - Industrial	N/A	N/A
Peak shifting through On-Site Storage - Utility Driven - Industrial	N/A	N/A

Exhibit 195: Measure-Level Cost-Effectiveness Test Results, Transportation Sector Managed Charging Measures

Measure Name	Medium PAC	Medium TRC
HDV – VT	86.1	430.5
Bus – VT	30.4	151.9
HDV – EVSE	18.8	12.9
MDV – VT	17.7	88.4
Bus – EVSE	14.8	14.2
MDV - EVSE	5.3	4.0
Light Duty BEV – VT	3.3	16.5
BEV – VT	2.9	14.3
BEV EVSE	2.6	6.3
PHEV – VT	2.3	11.3
PHEV – EVSE	2.0	5.0
Light Duty BEV – EVSE	1.6	1.5
Light Duty PHEV – VT	1.1	5.3
Light Duty PHEV – EVSE	0.6	0.5

Appendix D Marginal Cost Sensitivity

The Study Team was asked to explore the impact of a 40% increase in IIS marginal costs on measure-level cost-effectiveness and achievable potential. This appendix shows the results of the analysis.

Exhibit 196 lists the measures in each sector that become cost-effective with a 40% increase in 2023 IIS marginal costs. None of the transportation sector measures become cost-effective.

Exhibit 196: Cost-Effectiveness Impacts

Measure	Sector	Technical TRC (2023 Marginal Costs)	Technical TRC (1.4*2023 Marginal Costs)
New Home – ENERGY STAR	Residential	0.69	0.95
ENERGY STAR Server	Commercial	0.78	1.1
Energy Management System	Commercial	0.77	1.1
Recirculation Pump with Demand Controls	Commercial	0.71	0.99
Warehouse Loading Dock Seals	Industrial	0.72	1.05
High Efficiency Oven/Furnace/Dryer/Kiln	Industrial	0.69	0.97
Ventilation Heat Recovery	Industrial	0.67	0.94
Improve Insulation of Refrigeration System	Industrial	0.59	0.83
Custom Process	Industrial	0.58	0.81

Exhibit 197 shows the lower, medium and higher achievable potential energy savings estimates for the measures that become cost-effective with a 40% increase in 2023 IIS marginal costs.

Exhibit 197: Achievable Potential Impacts – Energy (2040)

Measure	Sector	Lower Achievable Potential Savings (GWh)	Medium Achievable Potential Savings (GWh)	Higher Achievable Potential Savings (GWh)
New Home – ENERGY STAR	Residential	1.30	1.88	9.14
ENERGY STAR Server	Commercial	0.35	0.46	0.94
Energy Management System	Commercial	4.26	5.65	11.43
Recirculation Pump with Demand Controls	Commercial	1.40	1.85	3.75
Warehouse Loading Dock Seals	Industrial	0.20	0.28	0.53
High Efficiency Oven/Furnace/Dryer/Kiln	Industrial	0.05	0.07	0.14
Ventilation Heat Recovery	Industrial	1.57	2.17	4.17
Improve Insulation of Refrigeration System	Industrial	0.19	0.27	0.52
Custom Process	Industrial	0.50	0.69	1.33

Exhibit 198 the lower, medium and higher achievable peak reduction potential for the measures that become cost-effective with a 40% increase in 2023 IIS marginal costs.

Exhibit 198: Achievable Potential Impacts – Overall Peak (2040)

Measure	Sector	Lower Achievable Potential Savings Estimate (kW)	Medium Achievable Potential Savings Estimate (kW)	Higher Achievable Potential Savings Estimate (kW)
New Home - ENERGY STAR	Residential	307	454	2,422
ENERGY STAR Server	Commercial	14,813	19,699	40,002
Energy Management System	Commercial	352,551	468,848	952,061
Recirculation Pump	Commercial	56,530	75,178	152,659
Warehouse Loading Dock Seals	Industrial	34	48	96
High Efficiency Oven/Furnace/Dryer/Kiln	Industrial	7	10	20
Ventilation Heat Recovery	Industrial	266	373	745
Improve Insulation of Refrigeration System	Industrial	17	23	47
Custom Process	Industrial	75	105	209

Appendix E Distribution Impacts Analysis

This appendix presents the findings from the Study Team's analysis of factors that could influence the adoption of electric vehicles (EVs) and heat pumps across Newfoundland. The findings are based on the approach the Study Team and the Utilities agreed to in July 2024.

In this appendix, the Study Team identifies drivers of adoption and discusses how they may vary across regions. The appendix is structured as follows:

- Approach provides an overview of the approach and any relevant caveats,
- Findings summarizes key findings, and,
- Heat Maps presents heat maps that illustrate the geographical distribution of adoption drivers and their potential impact on EV and heat pump adoption.

Approach

Multivariate Regression Studies from Other Jurisdictions

The Study Team's approach draws on multivariate regression studies from jurisdictions outside Newfoundland that have analyzed factors influencing EV and heat pump adoption. These studies include:

- Providing the Spark: Impact of Financial Incentives on Battery Electric Vehicle Adoption link
- Investigating the factors influencing the electric vehicle market share: A comparative study of the European Union and United States link
- The Impact of state policies on electric vehicle adoption -A panel data analysis link
- Get Connected: Electric Vehicle Quarterly Report 2023 (Q3) link
- Assessment of Electric Vehicle Incentive Policies in Canadian Provinces link
- Impact of Incentive Policies and Other Socio-Economic Factors on Electric Vehicle Market Share: A Panel Data Analysis from the 20 Countries link
- Characterizing air source heat pump market segments: A Canadian case study link
- Modeling Air Source Heat Pump Adoption Propensity and Simulating the Distribution Level Effects of Large-Scale Adoption link
- Pumping up building decarbonisation: The role of policy awareness in heat pump adoption among Canadian homeowners link
- Pumping up adoption: The role of policy awareness in explaining willingness to adopt heat pumps in Canada link

These studies often face limitations, particularly concerning sample sizes for EV adoption, which are generally too small to conduct a robust study for Newfoundland. Additionally, the Study Team was unable to find Newfoundland-specific studies focused on geographically granular heat pump adoption.

Caveats

Backward Looking Data - Early Adopters

One limitation of multivariate regression analysis is that the data primarily reflects early adopters, particularly in the case of electric vehicles (EVs). This data on early adopters pertains to light-duty vehicles. Data for heavier vehicle types, such as medium-duty and heavy-duty vehicles, is not yet available. This data limitation can skew the results, as early adopters of light-duty vehicles may have different characteristics compared to the broader population that will adopt heavier vehicles in the future.

Jurisdictional Differences

Another caveat is the jurisdictional differences between Newfoundland and the other regions studied. Factors such as climate, energy prices, government incentives, and public infrastructure can vary significantly and may influence adoption rates.

Findings

The Study Team recommends that the Utilities monitor the following key drivers when considering future EV and heat pump adoption:

- EV charging infrastructure,
- Population age,
- Population income,
- Population density,
- Average number of rooms per dwelling, and,
- Construction year of houses.

Exhibit 199 shows these drivers and lists the expected influence of each one on EV and heat pump adoption, as determined by multivariate regression studies from other jurisdictions.

Exhibit 199: Key Geographically Granular Adoption Drivers

Driver	Influence on EV Adoption	Influence on Heat Pump Adoption	Comments
EV Charging Infrastructure	High	None	Critical for EV adoption; not relevant for heat pumps.
Population Age	Moderate	Moderate	Younger populations may adopt EVs more readily due to higher openness to new technology, while older populations might have more stable housing situations, making them more likely to invest in heat pumps.
Population Income	High	High	Higher income levels correlate with higher adoption rates for both technologies.
Population Density	High	Moderate	Dense urban areas may see higher EV adoption; heat pumps are increasingly adopted across various regions, particularly where energy efficiency and cost savings are prioritized.[234]
Average Rooms per Dwelling	Low	High	Larger homes are more likely to adopt heat pumps, while EV adoption is less influenced by home size.
Construction Year of Houses	Low	High	Older homes are more likely to adopt heat pumps due to the need for modernization and energy efficiency improvements.

Additional findings include:

- For EVs, infrastructure and population density are critical because proximity to charging stations and the concentration of early adopters in urban areas play significant roles.
- Income is a strong predictor for EV and heat pump adoption because both technologies are still relatively expensive.
- The house construction year is a particularly important driver for heat pump adoption. Older homes tend to be less energy-efficient and often require upgrades to their heating systems, making them prime candidates for heat pump installations. Conversely, newer homes, which are typically equipped with modern heating systems, may have a lower likelihood of adopting heat pumps.

Although the drivers in Exhibit 199 provide a useful framework for understanding regional differences in adoption rates, they only offer a partial explanation. A model built solely on these factors would capture

[234] https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2018/market-snapshot-steady-growth-heat-pump-technology.html, https://climateinstitute.ca/reports/heat-pumps-canada/

some of the trends but may fall short in accurately predicting all regional variations. This limitation underscores the importance of incorporating more detailed customer persona data, such as individual preferences, behaviours, and demographic specifics, which are not publicly available for Newfoundland. Such data could significantly enhance the predictive power of the model, providing a more comprehensive understanding of the factors driving adoption in different regions. The studies we examined suggest that the variables we outlined (combined with some customer persona data that is not publicly available) may predict about 11 to 43% of near-term spatial electric heat pump and 70 to 80% of near-term spatial EV adoption differences.

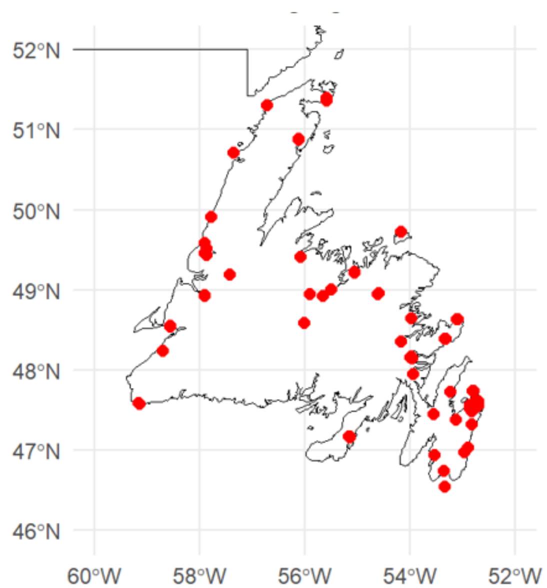
Heat Maps

This section presents six heat maps to illustrate the spatial distribution of key drivers influencing the adoption of electric vehicles (EVs) and heat pumps across Newfoundland.

Electric Vehicle Charging Infrastructure

Exhibit 200 highlights the distribution of EV charging infrastructure across Newfoundland. This driver is important for EV adoption, as the availability of charging stations influences the convenience and practicality of owning an electric vehicle. Areas with dense infrastructure are expected to show higher adoption rates.

Exhibit 200: Public Electric Vehicle Charging Stations in Newfoundland[235]

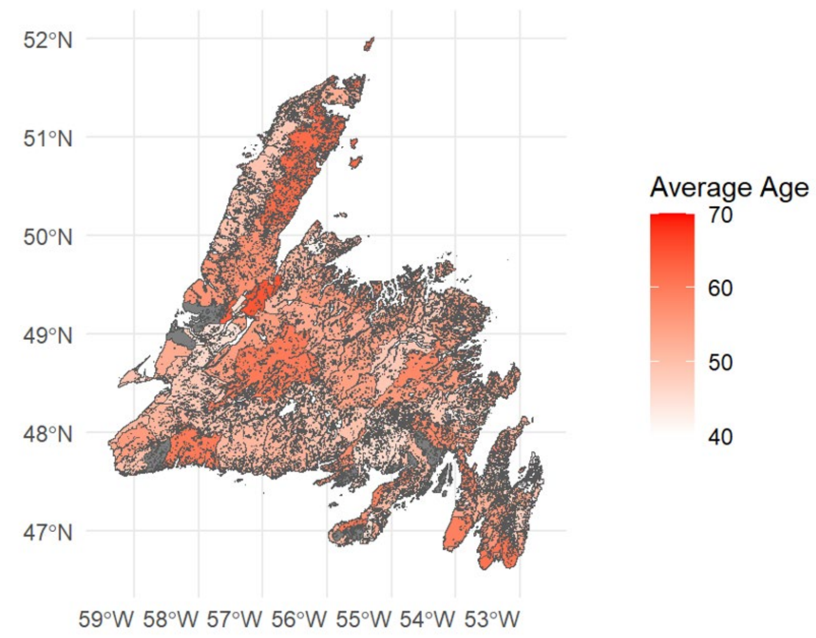


[235] The source data for this map is from the Application Programming Interface to the Alternative Fueling Stations Locator data provided by NRCan (Accessed: Dec. 10, 2024, endpoint URL: https://developer.nrel.gov/api/alt-fuel-stations/v1.json). The map includes all levels of publicly accessible charging stations.

Population Age

Exhibit 201 displays the median population age across the region. Younger populations may be more inclined to adopt new technologies, including EVs, while older populations may have different priorities, such as home heating efficiency, which could influence heat pump adoption.

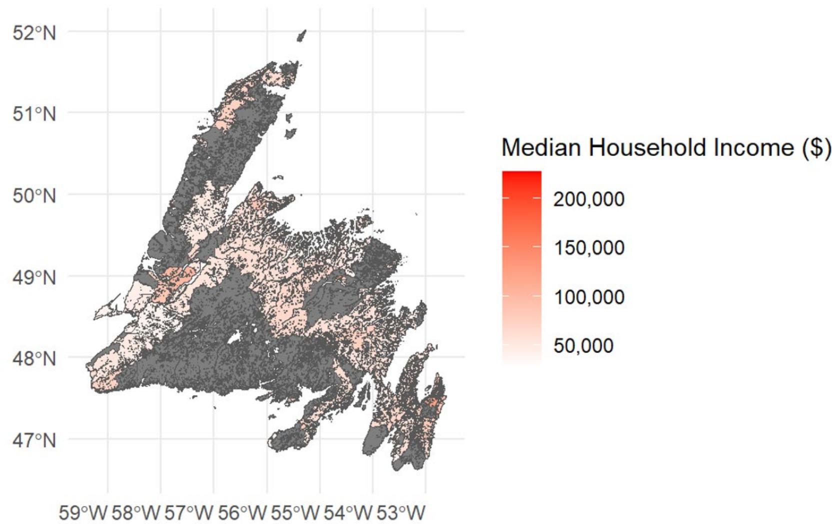
Exhibit 201: Average Age of Population



Median Household Income

Exhibit 202 illustrates the distribution of median household income. Income is a critical factor for both EV and heat pump adoption, as higher income levels correlate with a greater ability to invest in these technologies. This map helps identify regions where economic capacity might drive higher adoption rates.

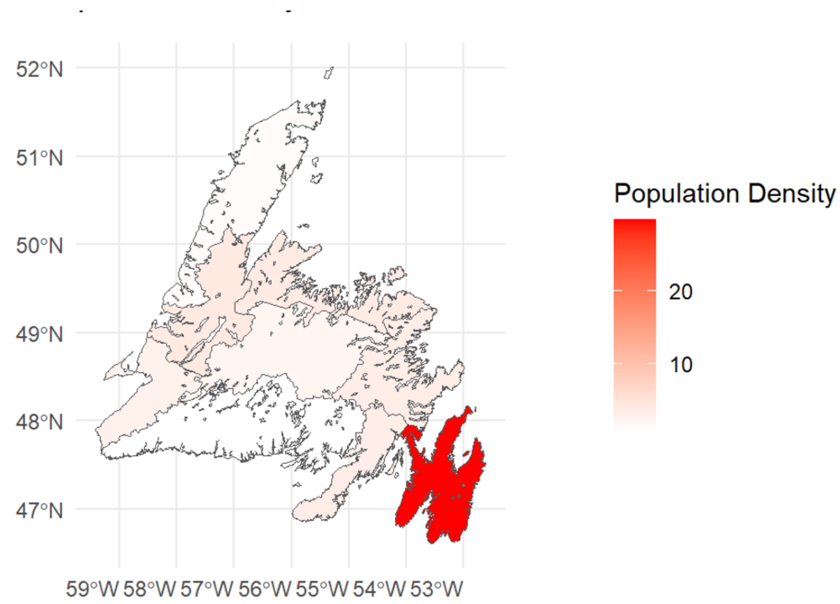
Exhibit 202: Median Household Income



Population Density

Exhibit 203 shows the population density across Newfoundland. Population density impacts the adoption of EVs and heat pumps in different ways. Higher density areas may have better access to infrastructure (e.g., EV charging stations), while lower density areas, often characterized by larger homes and reliance on individual heating systems, typically have higher heating demands. This makes them prime candidates for energy-efficient alternatives like heat pumps, especially in regions with limited access to natural gas infrastructure.

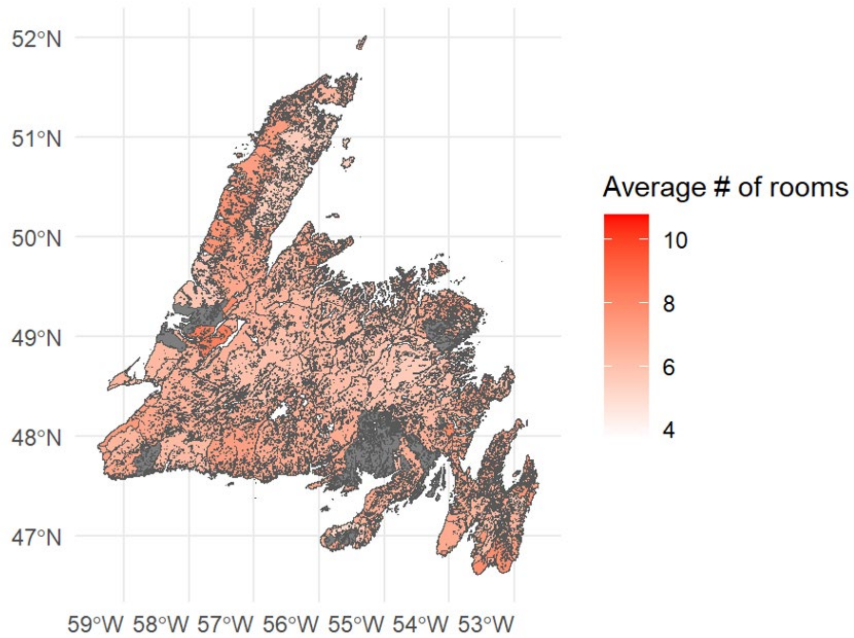
Exhibit 203: Population Density



Average Rooms per Dwelling

Exhibit 204 visualizes the average number of rooms per dwelling, which is particularly relevant for heat pump adoption. Larger homes with more rooms tend to be more likely candidates for heat pump adoption. This driver, however, is less likely to directly influence EV adoption.

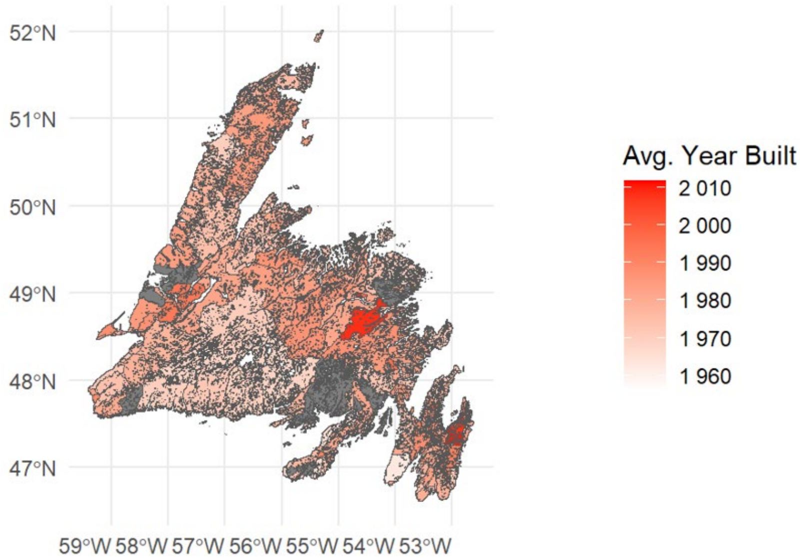
Exhibit 204: Average Rooms per Dwelling



Average Construction Year of Homes

Exhibit 205 displays the average year of construction for houses across Newfoundland. This driver is significant for heat pump adoption, as older homes can have older heating systems and poorer energy efficiency, making them more likely to benefit from heat pump installations. Regions with a higher prevalence of older homes may therefore see higher rates of heat pump adoption.

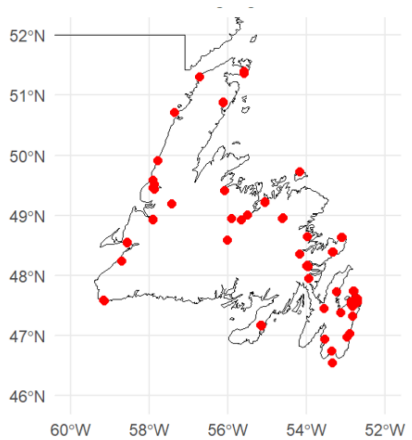
Exhibit 205: Average Construction Year of Homes



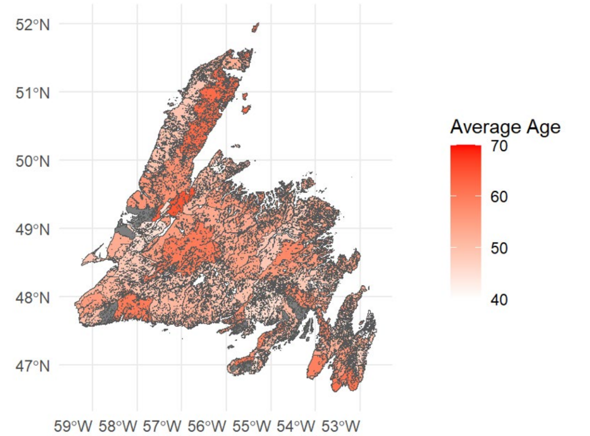
To facilitate comparison, the heat maps from Exhibit 200 to Exhibit 205 are also displayed side by side in Exhibit 206 . This layout allows for a direct comparison of how each driver varies geographically and how these variations might interact to influence adoption rates.

Exhibit 206: Heat Map Comparison

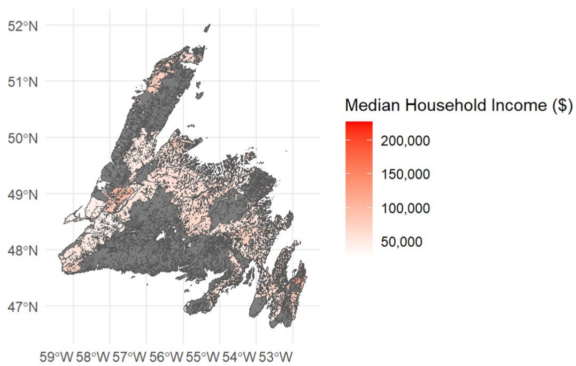
Public Charging Stations



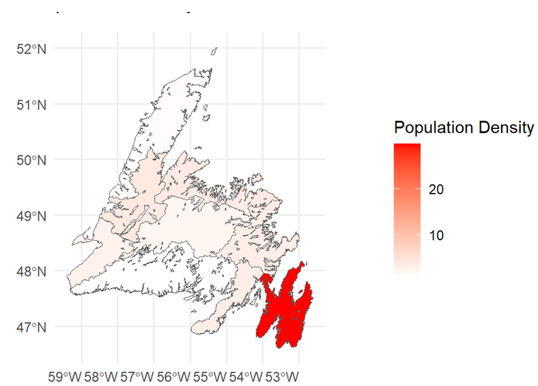
Average Age of Population



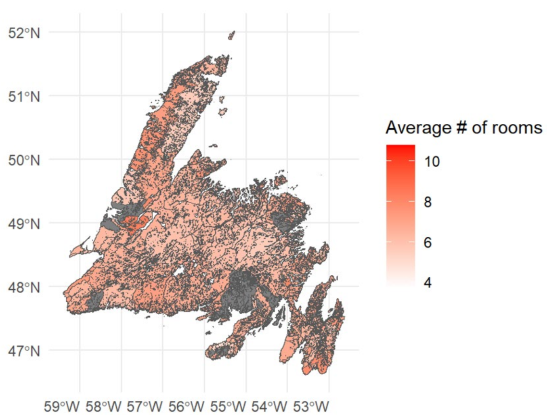
Median Household Income



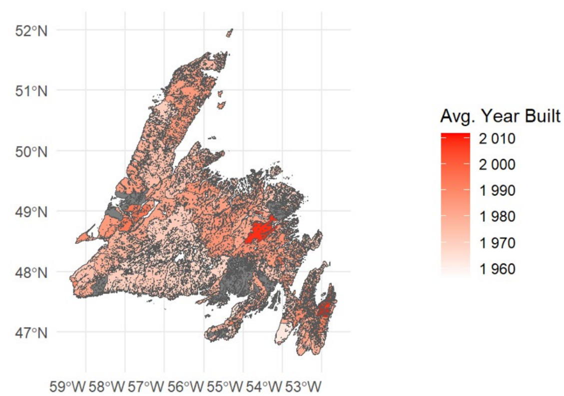
Population Density



Average Rooms per Dwelling



Average Construction Year of Homes



Appendix F Electric Vehicle Managed Charging Sample Calculations

This appendix shows how the Study Team calculated savings for the personal LDBEV (light duty battery electric vehicle) managed charging demand response measure (subsequently referred to as “the measure”) in 2040.

Step 1: Calculate Total Annual Energy Use for at Home BEV Charging

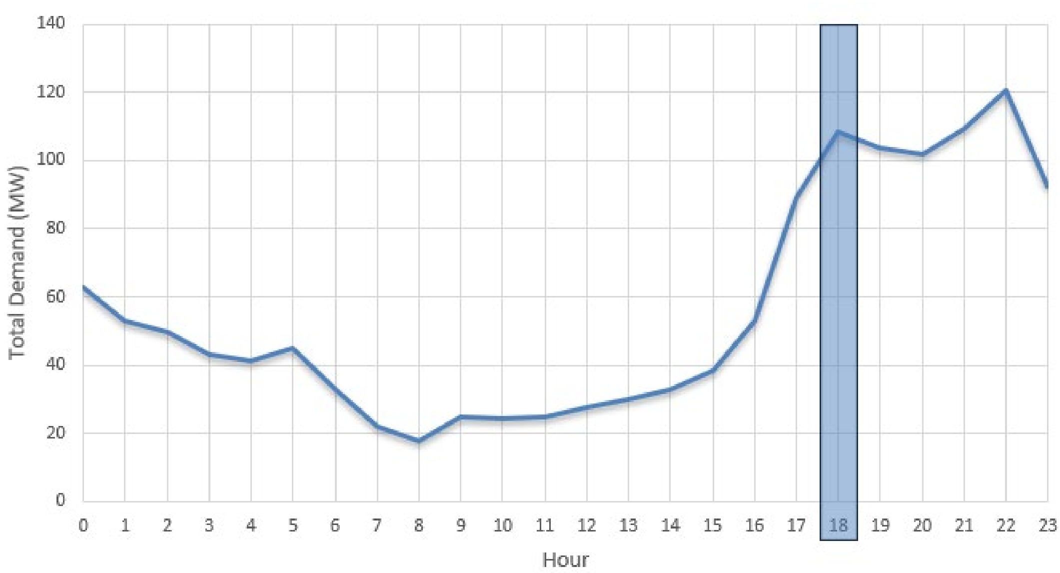
PG calculated the total annual energy use for at home BEV (battery electric vehicle) charging in 2040 using four parameters:

1. Average vehicle kilometres travelled,
2. Vehicle efficiency,
3. The total number of BEVs, and
4. The percentage of charging that occurs at home.

Step 2: Determine 24-Hour Peak Load Shape for at Home Charging

To determine the 24-hour peak load shape for at home charging, the Study Team calculated hourly demand by multiplying total annual energy use by each hour's factor from the 8760-load shape.[236] The Study Team then used the hourly demand to determine the 24-hour load shape for the "peak day", including the "peak hour", as shown in Exhibit 207. The same approach is used to determine the “peak day” and “peak hour” for all other vehicle types and charging locations.

Exhibit 207: Peak Day 24-Hour Load Shape



[236] An 8760-load shape shows the percentage of demand that occurs in each hour of the year.

When including the charging load from other vehicle types and the overall system load shape, the actual peak hour on the system occurs at 6 PM (highlighted by the blue rectangle)***.*** Therefore, the contribution of the at home LDBEV charging to the system peak hour at 6 PM is **108.3 MW**.

Step 3: Calculate Measure-Level Savings

The Study Team calculated measure-level savings for LDBEVs by determining the amount of demand that can be shifted off peak. This demand is divided by the number of vehicles participating in the demand response event to calculate the savings per vehicle.

Amount of Demand that Can be Shifted

Based on studies from other jurisdictions and programs, participating vehicles can shift about **50%** of their load over the duration of a peak event as defined in the Potential Study (five hours from 5 pm to 9:59 pm).

Number of Participants

Only vehicles with access to at home charging can participate in the personal LDBEV managed charging demand response event. The International Council on Clean Transportation estimated this value at 78% in 2025.[237] So for example, if the total LDBEV stock is 200, then 156 vehicles (0.78% x 200 vehicles) have at home charging access.

The Study Team estimated participation for the measure in 2040 at **42.6%** *of all personal LDBEVs* by extrapolating from the 2022 Ontario Distributed Energy Resources Potential Study.[238] This value aligns with findings from Opinion Dynamic's PG&E Electric Vehicle Automated Demand Response Study.[239] This equates to 85 participating vehicles of the total personal LDBEV stock is 200 vehicles.

Therefore, the percentage of vehicles charging at home that participate in the measure is 54.6% (i.e., 85 vehicles/156 vehicles with access to home charging).

Using these values, the Study Team calculated the peak savings for each hour between 5 pm and 9:59 pm. The sample calculation equation below focuses on 6 pm, as this is the system peak hour.

$$Savings = \ Peak_{6pm,at\ home}(\%\ peak\ savings_{per\ vehicle} \times \%\ vehicle\ participation)$$

Where:

- The "at home" charging peak at 6 pm is 108.3 MW (from Step 2),
- The % peak savings per vehicle is 50%, and
- The % vehicle participation is 54.6% (42.6%/78%).

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237 Table 1 on page 16, International Council on Clean Transportation, "Charging up America: Assessing the Growing Need for U.S. Charging Infrastructure Through 2030," Available: https://theicct.org/sites/default/files/publications/charging-up-america-jul2021.pdf (Accessed Jan. 2024).
238 Dunsky Energy + Climate Advisors, "Ontario's Distributed Energy Resources (DER) Potential Study," Available: https://dunsky.com/wp-content/uploads/DER-potential-study-IESO-Dunsky-Vol1.pdf (Accessed Jan. 2024).
239 Pages 34 – 37, Opinion Dynamics. (2022). "PG&E Electric Vehicle Automated Demand Response Study Report," Available: https://opiniondynamics.com/wp-content/uploads/2022/03/PGE-EV-ADR-Study-Report-3-16.pdf (Accessed: Jan. 2024).

$$Savings = 108.3\ MW(50\% \times \frac{42.6\%}{78\%})$$

$$Savings = 29.6\ MW$$

To calculate the savings per participant, the Study Team divided the total savings by the number of participating personal LDBEVs. With a forecast total of 105,295 personal LDBEVs in 2040 and 42.6% of them participating in the demand response program, the total number of participants equates to 44,856. The savings per vehicle (0.659 kW/vehicle) are calculated as follows:

$$Savings\ per\ vehicle = \frac{Savings}{Partcipating\ Vehicles} = \frac{28.0\ MW}{44{,}856\ vehicles} = 0.659\ kW\ per\ vehicle$$

Schedule D
Stakeholder Consultations

Stakeholder Consultations

The planning and implementation cycles for customer programs is a continuous process involving stakeholder consultation at each phase.

The Utilities conducted customer surveys and stakeholder interviews and workshops to inform the development of the Conservation, Demand Management and Electrification Plan 2026-2030 (the "2026 Plan").

An overview of these customer and stakeholder consultations is provided in Table D-1.

Table D-1
2026 Plan Customer and Stakeholder Consultations

Residential End Use Survey	610 customers were surveyed to determine the existing technologies and end uses in their homes.[1] The information gathered was used to assess potential electricity savings and electrification opportunities.
Commercial End Use Survey	463 facilities were surveyed to determine the existing technologies and end uses in commercial buildings.[2] This research provided information on commercial energy use and electrification in the province and the potential opportunities for efficiency and load reduction.
Stakeholder Interviews and Workshops	Industry and subject matter experts were interviewed and participated in workshops to help quantify the potential and possible barriers for electrification and CDM in the province. Stakeholders provided input on the measures that were evaluated in the Potential Study and also participated in workshops in May 2024 to help determine the achievable potential of key technologies in the study.[3] The Potential Study consultant also completed interviews with Hydro's industrial customers as an input into the Potential Study.
Government and Key Stakeholder Consultation	The Utilities meet regularly with the provincial government and other key stakeholders to discuss issues around energy efficiency, load management and electrification.

1 The Residential End Use Survey was completed by MQO Research in 2023. A random sample of respondents was drawn proportionally to the distribution of Newfoundland Power and Hydro customers across three regions: (i) St. John's Census Metropolitan Area (CMA); (ii) Labrador; and (iii) the remainder of the province. A mix mode approach was used, including online and telephone surveys.

2 The Commercial End Use Survey was completed by ICF Consulting Canada in 2023. A statistically valid sample of the Utilities commercial customers responded to mail out and email surveys. This included 92 responses from Hydro customers and 371 responses from Newfoundland Power customers.

3 External stakeholders consulted included commercial customers, trade allies, customer group representatives, provincial government and retail partners.

Initiatives in the 2026 Plan were developed to be flexible to address government policies and funding as well as economic and market conditions. The Utilities will consult with stakeholders and customers the implementation of the 2026 Plan. This collaborative process enables the Utilities to continuously evaluate market trends, advances in technology, customer barriers and program effectiveness.

Schedule E
Marginal Cost Projection of the Island Interconnected System 2025-2044

Marginal Cost Projection of the Island Interconnected System 2025-2044

Table E-1 shows the most recent marginal cost forecasted based on projections by Newfoundland and Labrador Hydro in February 2025.

Table E-1
Marginal Cost Projection
Island Interconnected System
2025-2044

	Energy			Capacity
	Winter On-Peak ($/MWh)	Winter Off-Peak ($/MWh)	Non-Winter ($/MWh)	($/kW)
2025	96.81	83.68	33.20	356.07
2026	97.38	82.75	31.81	362.77
2027	91.92	74.93	29.48	369.61
2028	83.91	65.53	30.07	376.58
2029	75.68	63.02	27.99	383.69
2030	70.94	60.12	24.19	390.94
2031	68.62	56.41	22.45	398.33
2032	68.73	55.39	23.53	405.87
2033	70.60	58.01	23.38	413.56
2034	72.28	61.63	23.25	421.40
2035	71.25	63.11	24.37	429.40
2036	68.83	61.13	25.08	437.55
2037	74.16	64.15	25.46	445.87
2038	74.73	65.21	26.63	454.35
2039	76.48	67.86	26.16	463.00
2040	80.58	74.69	29.29	471.82
2041	78.70	74.57	29.77	480.81
2042	78.41	73.07	29.47	489.99
2043	82.28	75.38	27.81	499.35
2044	85.12	77.92	27.49	508.89

December through March is considered the winter season and April through November is considered the non-winter season. From 7:00 a.m. to 11:00 p.m. is considered on-peak hours. Off-peak hours occur after 11:00 p.m. until 7:00 a.m.

Schedule F
2026 Plan Program Descriptions

2026 Plan Program Descriptions

Insulation and Air Sealing Program

Program Description
The objective of this program is to improve the insulation levels and air tightness of residential homes. The program focuses on insulation levels in residential basements, crawl spaces and attics. It will also include measures to improve air sealing and duct insulation. Increasing the insulation R-value in a home, improving air sealing, and insulating heating ducts will result in space heating energy savings. The program components include rebates, financing, customer education and trade-ally engagement. Residential basement, crawl space and attic insulation rebates have been offered by TakeCharge since 2009. Rebates for air sealing and duct insulation have been offered since 2022.
Target Market: Residential
This program targets residential customers completing retrofit projects at a primary residence. Due to the National Building Code of Canada new homes must be well-insulated, therefore this program is only offered to existing homes. Eligibility will be limited to electrically heated homes.
Eligible Measures
Eligible measures in this program include insulation upgrades to basements, crawl spaces, attics, and heating ducts. It will also include measures which result in better air sealing as demonstrated through a pre- and post-air-selling blower door test.
Delivery Strategy
Program promotion will include partnering with retailers and trade allies in the renovation industry. Initiatives will target both do-it-yourself and professional installers. Tools and tactics will include retail point-of-sale materials, advertising, websites, tradeshows and community outreach. Rebates will be processed through online and mailed customer applications.

Insulation and Air Sealing Program

Market Considerations
Barriers to increased market penetration of insulation include cost of materials and labour, awareness of benefits, difficulties of renovating an existing living space, and a decreasing number of eligible participants. Additional benefits for the air sealing program are the availability of qualified blower door test inspectors and qualified air sealing contractors.
Incentive Strategy
Incentives for this program include rebates and financing. For the insulation portion of the program, customers can receive a rebate of 75% of the cost of the insulation installed in the basement or attic. Rebate amounts are capped at $1,500 for each attic and basement project. Incentives for air sealing will be based upon the level of improvement in a blower-door test completed before and after air sealing measures have been implemented. Customers can receive a maximum rebate of $500 if they show 30% or greater improvement on their air tightness. Duct insulation incentives will cover 50% of the cost to insulate ducts in unconditioned space of electrically heated residential homes. To qualify, a minimum insulation value of R-6 and a maximum insulation value of R-8 must be installed. Eligible homes are those heated primarily through a central electric furnace or central heat pump. The rebate amount will be capped at $500 per home.
Program Monitoring & Evaluation
The program will be monitored for participation levels, service quality, market saturation, and cost effectiveness. A representative sample of installations will be inspected. A third-party evaluation of the program will be completed every three years of operation.

Insulation and Air Sealing Program

Estimated Costs & Energy Savings						
	2026	**2027**	**2028**	**2029**	**2030**	**Total**
Estimated Costs ($000s)	2,607	2,629	2,707	2,999	3,017	13,959
Estimated Cumulative Energy Savings (GWh)	68.0	72.7	77.6	82.7	88.1	389.1
Total Resource Cost						**4.3**

HRV Program

Program Description
The objective of this program is to increase the installation rate of higher efficiency heat recovery ventilators (“HRV”). HRVs provide ventilation while minimizing heat loss. The program components include rebates, financing, customer education and trade-ally engagement. This program has been in place since 2013.
Target Market: Residential
This program targets all residential customers regardless of heat source or age of home.
Eligible Measures
Eligible measures in this program include HRV models that have a sensible recovery efficiency of 70% or greater and meet the minimum fan efficacy requirements. HRVs must be installed by a certified Heating, Refrigeration and Air Conditioning (HRAI) installer.
Delivery Strategy
Program promotion will include partnering with trade allies in the home building and renovation industry, particularly HRAI certified installers. Tools and tactics include website presence, online advertising and tradeshows. Rebates will be processed through online and mailed customer applications.
Market Considerations
The market includes new installations and existing HRV replacements, as long as the unit being replaced is not already a qualifying model. This program faces a number of barriers such as customer understanding of what an HRV is and its purpose in the home. Other barriers are the initial cost, the cost association with using a certified installer, and awareness of the benefits of selecting a more efficient HRV.

HRV Program

Incentive Strategy

Incentives for this program include rebates and financing. The rebate value is $225 for qualifying HRV units. This reflects the incremental cost of a more efficient unit. A $25 incentive is also provided to qualified installers for each approved application. This upstream incentive helps to ensure that installers stock and promote eligible models.

Program Monitoring & Evaluation

The program will be monitored for participation levels, service quality, and cost-effectiveness. A representative sample of installations will be inspected. A third-party program evaluation will be completed every three years.

Estimated Costs & Energy Savings

	2026	**2027**	**2028**	**2029**	**2030**	**Total**
Estimated Costs ($000s)	298	306	310	379	333	1,626
Estimated Cumulative Energy Savings (GWh)	3.6	4.0	4.4	4.8	5.2	22.0
Total Resource Cost						**1.7**

Benchmarking Program

Program Description
Energy social benchmarking is the analysis of a household's energy consumption and comparing its performance with that of similar households. A report is delivered to participating customers via mail and/or email. These reports include a comparison of the customers' electricity usage to similar homes and their own consumption from the previous year and months. The Home Energy Reports and an online web portal provide tips and resources to facilitate energy usage reduction. This program has been in place since 2016. The Benchmarking program is offered to Newfoundland Power customers only.
Target Market: Residential
The Benchmarking program participants are randomly selected across Newfoundland Power's service territory. Customers can choose to opt-out of the program at any time but cannot opt-in due to the requirement to select similar treatment and control groups to analyze savings.
Eligible Measures
A home's energy use is compared anonymously to the usage patterns of other homes that are of similar size, age, heating type, etc. The Home Energy Report is designed to provide information to help homeowners understand their energy use and find ways to make the home more efficient.
Delivery Strategy
The program is delivered largely by a third-party service provider that develops and issues the Home Energy Reports and maintains the online web portal. TakeCharge oversees all aspects of the program to ensure greater customer engagement with their home energy use. The program is available year-round and is supported with TakeCharge marketing efforts, such as contests, to increase participant engagement levels.

Benchmarking Program

Market Considerations

This program allows Newfoundland Power to actively engage with customers using direct home energy consumption information. Cross promotion of existing TakeCharge rebate programs through Home Energy Reports helps drive participation in other residential programs.

Incentive Strategy

No monetary incentive is offered. It has been demonstrated for this type of program that using social norm comparisons drives the greatest changes to household energy consumption.

Program Monitoring & Evaluation

The program will be monitored for participation levels, engagement levels, service quality and cost effectiveness. Each year a third-party evaluator, independent of the program delivery agent will validate the claimed energy savings.

Estimated Costs & Energy Savings

	2026	**2027**	**2028**	**2029**	**2030**	**Total**
Estimated Costs ($000s)	998	893	1,112	1,043	1,158	5,204
Estimated Cumulative Energy Savings (GWh)	14.7	14.3	13.6	13.2	12.6	68.4
Total Resource Cost						**2.7**

Energy Savers Kit Program

Program Description
The objective of this program is to allow access to energy efficient items for customers whose financial circumstances are a barrier to program participation. The program will require customers who qualify under the Utilities' threshold for low income to apply for an energy efficiency kit. The kit will contain measures to save energy on space heating, water heating and lighting. This program also help the Utilities reach low-income customers with energy efficiency education through information included in the kits and online resources. Income levels are determined using the Statistics Canada Low-Income Cutoff thresholds with a 30% buffer built in. This program has existed since 2022.
Target Market: Low income residential
This program targets residential customers who meet the Utilities' low-income threshold. Renters and homeowners will be eligible for this program regardless of heating source. Customers are limited to one kit per household.
Eligible Measures
The kits include items such as LED light bulbs and night lights, high performance showerheads, faucet aerators, water heater pipe wrap, switch and outlet insulation, draft plugs, weatherstripping and window insulation film kits.
Delivery Strategy
This program will be delivered through a third-party vendor who will supply energy efficiency kits, coordinate customer delivery and provide installation support. The Utilities will approve applications and provide marketing, education and other supports as required.

Energy Savers Kit Program

Market Considerations

Barriers to installation of these measures include the upfront cost, lack of awareness of benefits, and difficulty installing certain items, such as weatherstripping.

Incentive Strategy

The Utilities will cover the full cost of the kit and delivery.

Program Monitoring & Evaluation

The program will be monitored for installation levels, service quality and cost effectiveness. A third-party evaluation will be conducted every three years.

Estimated Costs & Energy Savings

	2026	**2027**	**2028**	**2029**	**2030**	**Total**
Estimated Costs ($000s)	636	568	561	695	578	3,038
Estimated Cumulative Energy Savings (GWh)	13.5	15.8	17.9	19.8	21.2	88.2
Total Resource Cost						**3.1**

Business Efficiency Program

Program Description

The objective of the Business Efficiency Program ("BEP") is to help commercial customers become more energy efficient and reduce peak demand. Incentives are provided for upgrades for existing facilities. The program allows customers to implement projects customized to their own facilities. TakeCharge has been offering rebates to commercial customers since 2009.

Target Market: Commercial

This program targets business owners who have an interest in making their business more energy efficient. The program includes a custom approach, but also includes prescriptive rebates for specific energy savings measures such as LED lighting, air source heat pumps, smart thermostats, occupancy sensors, efficient motors and more. The program also targets commercial customers with opportunities to reduce peak demand.

Eligible Measures

There are three components of the BEP: (i) prescriptive rebates; (ii) custom rebates; and (iii) custom demand rebates.

Prescriptive rebates provide money back when customers purchase and install eligible products. The specific measures eligible for per unit rebates include LED screw-in lamps, High Bay LED fixtures, T5 and T8 LED tubes, LED luminaires, LED parking lot lighting, LED exit signs, LED wall packs, high performance showerheads, smart thermostats, occupancy sensors, and rooftop air source heat pump systems

Custom energy rebates involve TakeCharge consulting with a customer on an energy saving project that is customized to individual customer circumstances. Incentives are provided on an individualized basis for projects that can pass the Total Resource Cost test. Rebates are paid on the energy savings the customer achieves in the first year of the project.

The custom demand rebate operates similarly to the custom energy rebates component, except the rebate is determined based on the peak demand reduction the customer achieves after completing the project.

Business Efficiency Program

Delivery Strategy
The delivery strategy for this program is mainly through individual customer interactions. A complimentary on-site or virtual energy assessment helps customers identify efficiency and demand management opportunities. Marketing for this program includes traditional media as well as close partnerships with trade-allies such as lighting distributors and electrical contractors. The program creates business opportunities for these trade allies. The program also targets commercial property owners through direct marketing and through industry associations such as the Building Owners and Managers Association. Tools and tactics include outreach such as presentations to associations, retail point-of-sale materials, website and advertising.
Market Considerations
Barriers to increased market penetration include initial cost, awareness of the program and available incentives, building ownership, budget and planning cycles, technical know-how, customer time constraints and economic circumstances.
Incentive Strategy
Incentives for this program help with the costs for upgrades, energy audits and feasibility studies. The custom stream provides incentives based on project energy savings at 10 cents per kWh for the first-year savings or project demand savings at $250 per kW per month over the December to March period for the first year of participation. Demand savings projects require a minimum of 50 kW savings to be sustainable over at least five years. Incentives of up to $100,000 per site help lower customer project costs. Incentives vary for prescriptive measures. Rebates are processed through mail-in and online submissions.
Program Monitoring & Evaluation
The program will be monitored for installation levels, service quality and cost effectiveness. Custom projects will have a measurement and verification plan to confirm savings achieved are consistent with incentives paid. A third-party evaluation will be conducted every three years.

Business Efficiency Program

Estimated Costs & Energy Savings						
	2026	**2027**	**2028**	**2029**	**2030**	**Total**
Estimated Costs ($000s)	1,695	1,755	1,950	1,848	1,870	9,118
Estimated Cumulative Energy Savings (GWh)	64.1	67.5	70.0	71.5	73.8	346.9
Total Resource Cost						**1.4**

Income-Qualified Heat Pump and Insulation Program

Program Description

The objective of this program is to reduce the heating costs, energy consumption and peak impacts of homes for income-qualified customers. The program will do this in two ways. The first is by addressing the heating system, providing electrically heated homes with a rebate to install a cold-climate ductless mini-split heat pump. Should there be any remaining costs beyond what is covered by the rebate, customers will be able to opt for on-bill financing through their utility. The rebate will cover the installation of a single-head ductless mini spit heat pump unit.

Secondly, the program will provide direct installation of attic insulation for qualifying customers based on their income, their heating source (i.e., electric) and the existing amount of attic insulation in their home. Customers will be connected to an attic insulation installer once their proposed project has been approved by their utility. This program design removes both the cost and effort barriers required to complete this type of project.

Target Market: Residential

This program targets income-qualified residential customers who own their primary residence. Due to the National Building Code of Canada new homes must be well-insulated, therefore the insulation portion of this program is only offered to existing homes built prior to 2014, whereas heat pump eligibility will extend to all ages of homes. Eligibility is limited to electrically-heated homes.

Eligible Measures

Eligible measures in this program include attic insulation upgrades and single-head cold-climate ductless mini-split heat pumps.

Income-Qualified Heat Pump and Insulation Program

Delivery Strategy

TakeCharge will work with a network of insulation and heat pump installers to deliver these programs. Customers will apply for project pre-approval. Once approved and the installation is complete, the installer will direct bill the appropriate utility to avoid the customer incurring any upfront costs. For heat pumps, the customer will have the option to automatically enroll in a utility on-bill financing program or can opt to pay any out-of-pocket expenses directly to the installer. This method of program delivery has been shown to be successful in allowing income-qualified customers to switch from oil heat to electric heat.

Market Considerations

Customers with lower income levels are less likely to have heat pumps compared to those with higher income levels.

Customers with low-income face significant financial barriers to making their homes more energy efficient. However, Customers with low-income are also less likely to own their home, which will limit the overall number of customers who are eligible.

This program aims to remove multiple barriers to adoption of insulation and heat pumps for income-qualified customers. These barriers include the upfront cost and the effort, time and knowledge required to complete these types of projects.

Incentive Strategy

Incentives for this program include rebates and financing. For the insulation portion of the program, approved customers will receive their attic insulation installed free of charge.
For the heat pump portion of the program, customers will receive a rebate of up to $4,000 for their heat pump unit, with the ability to finance any remaining project costs above this amount on their electricity bill.

Costs will be billed directly to the utility and paid to the installer to avoid customers requiring upfront capital to enable their participation in the program.

Program Monitoring & Evaluation

The program will be monitored for participation levels, service quality, market saturation, and cost effectiveness. Projects will require before and after photos from the installer. A third-party evaluation of the program will be completed every three years of operation.

Income-Qualified Heat Pump and Insulation Program

Estimated Costs & Energy Savings						
	2026	**2027**	**2028**	**2029**	**2030**	**Total**
Estimated Costs ($000s)	56	2,379	4,286	6,352	8,244	21,317
Estimated Cumulative Energy Savings (GWh)	-	1.9	5.4	10.6	17.5	35.4
Total Resource Cost						**1.5**

Isolated Community Energy Efficiency Program (ICEEP)

Program Description

The objective of this program is to find new, innovative, and practical solutions to energy related challenges that isolated diesel communities face, and find tangible ways to implement them. Hydro works with many stakeholders including those from Indigenous communities, the provincial government, private sector representatives, and program delivery specialists to develop programs that will help inform Hydro's long-term plan.

The Program provides outreach, education and no-cost or cost-shared energy efficient products to residential and commercial customers in Hydro's 41 remote diesel-system communities throughout Newfoundland and Labrador.

Target Market

This program targets both residential and commercial customers in Hydro's isolated systems. This includes Isolated Diesel systems on the Island, in Labrador, and the L'Anse au Loup system.

Eligible Measures

The program continues to evolve, and offerings can change each year. Direct installs of energy efficient products were the primary program initiative, supplemented by short-term pilot projects and events. Over the years, offerings have grown to include thermostat upgrades, a heat pump pilot, commercial energy audits, commercial lighting replacements, commercial building upgrades and more.

Going forward, a diversified portfolio will focus on energy and capacity savings with accountable and measurable goals. Programs will require a focus on deeper retrofits, energy security, demand response programs and load management strategies for peak impacts on the system. The impacts of new technologies and the societal shift towards a low-carbon economy will need to be considered and understood.

Delivery Strategy

Hydro oversees all aspects of the program and works with a third-party service provider to develop and execute the yearly program plan. The program engages local stakeholders and hires local program representatives to develop, promote and implement programs.

Isolated Community Energy Efficiency Program (ICEEP)

Market Considerations

Availability and awareness of energy efficient technologies continues to be an issue in rural communities and often technologies that may be available are at a higher price than in urban markets.

Hydro's commercial customers tend to be smaller businesses and as such find it challenging to find the time and resources to address energy consumption issues. This program provides the one-on-one interaction needed to assist these customers. This program will allow the utility to reach customers that may not have been able to participate in other incentive programs.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness. A representative sample of direct installations will be surveyed for confirmation of continued installation and use. An evaluator will be involved in developing program guidelines, quality assurance guidelines and procedures and ensure they are aligned with evaluation standards and best practices.

Estimated Costs & Energy Savings

	2026	**2027**	**2028**	**2029**	**2030**	**Total**
Estimated Costs ($000s)	1,169	1,498	1,183	1,124	1,124	6,098
Estimated Cumulative Energy Savings (GWh)	6.1	6.0	5.9	6.0	6.2	30.2
Total Resource Cost						**1.2**

Isolated Systems Business Efficiency Program

Program Description
The objective of the Isolated Systems Business Efficiency Program is to support commercial customers located in Hydro's isolated diesel and L'Anse au Loup service areas to improve the energy efficiency of their facilities. The program uses a customized approach to provide customers with technical support and financial incentives to encourage the implementation of energy efficiency projects.
Target Market: Commercial
This program targets commercial customers in Hydro's isolated systems on the Island, in Labrador, and the L'Anse au Loup system.
Eligible Measures
Incentives are offered on a project-by-project basis for initiatives that demonstrate cost-effectiveness from both the customer's and the utility's perspectives. The program does not support alternative energy solutions or fuel switching. Eligible measures may include, but are not limited to, LED lighting upgrades, building envelope enhancements, motor controls, and heating system improvements.

Isolated Business Efficiency Program

Delivery Strategy
The program is primarily delivered through direct engagement with individual customers. In addition, commercial property owners will be targeted through direct marketing efforts to expand program reach and participation.
Market Considerations
Barriers to increased market penetration include cost, program awareness, availability of energy efficient products, and technical knowledge. This program offers personalized support through one-on-one engagement with staff to address these barriers and guide customers through the process of completing an energy efficient upgrade to their building.
Incentive Strategy
Incentives for this program help with the costs for upgrades, energy audits and feasibility studies. Incentives are offered on a project-by-project basis for initiatives that demonstrate cost-effectiveness. Rebates are calculated based on first-year energy savings, at a rate of $0.40/kWh, covering up to 80% of eligible project costs.

Isolated Systems Business Efficiency Program

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost. Each incented project will have a measurement and verification plan to confirm energy savings achieved are consistent with incentives paid.

Estimated Costs & Energy Savings

	2026	2027	2028	2029	2030	Total
Estimated Costs ($000s)	18	18	18	18	18	90
Estimated Cumulative Energy Savings (GWh)	1.0	1.0	0.9	0.8	0.8	4.5
Total Resource Cost						**1.1**

Industrial Energy Efficiency Program

Program Description
The objective of this program is to support transmission-connected, industrial customers to improve the energy efficiency of their facilities and processes. The program uses a customized approach to provide customers with technical support and financial incentives to enable industrial facilities to identify and implement efficiency projects.
Target Market: Industrial
This program targets existing, transmission level, industrial customers served by Newfoundland and Labrador Hydro.
Eligible Measures
Incentives are offered on a project-by-project basis for initiatives that demonstrate cost-effectiveness. Technologies include, but are not limited to, compressed air, pump systems, process equipment and process controls.
Delivery Strategy
The program is managed internally, with external engineering services used as required. The program is primarily delivered through direct engagement with individual customers.

Industrial Energy Efficiency Program

Market Considerations
This market requires a one-on-one approach to project design and delivery. The program builds on the work already completed by the industrial customers, and addresses their unique barriers to improved efficiency, which include, but are not limited to, access to capital and human resources.
Incentive Strategy
Incentives for this program help with the costs for upgrades, energy audits and feasibility studies. Incentives are offered on a project-by-project basis for initiatives that demonstrate cost-effectiveness based on first-year energy savings.
Program Monitoring & Evaluation
The program will be monitored for participation level, service quality, and cost. Each incented project will have a measurement and verification plan to confirm energy savings achieved are consistent with incentives paid.

Industrial Energy Efficiency Program

Estimated Costs & Energy Savings[1]						
	2026	**2027**	**2028**	**2029**	**2030**	**Total**
Estimated Costs ($000s)	216	216	217	253	217	1,119
Estimated Cumulative Energy Savings (GWh)	31.3	28.1	28.1	5.9	5.9	99.3
Total Resource Cost						-

[1] Hydro reminds its transmission-level industrial customers annually of the availability of this program, but applications are not received every year. As a result of such a small market and budget considerations, participation is extremely variable from year to year and difficult to forecast. Therefore, the Total Resource Cost cannot be forecast but all proposed projects must result in a positive Total Resource Cost.

Schedule G
Conservation and Demand Management Program Forecasts

Conservation and Demand Management Program Forecasts

Table G-1
Conservation Programs
Energy Reduction Estimates: 2026 – 2030 (Includes Prior Years' Savings)
(GWh)

	2026	2027	2028	2029	2030	Total
Insulation and Air Sealing Program	68.0	72.7	77.6	82.7	88.1	**389.1**
Thermostat Program	25.3	25.2	24.7	23.4	22.1	**120.7**
ENERGY STAR Window Program	10.4	10.4	10.4	10.4	10.4	**52.0**
Small Technology Program	70.7	65.2	60.6	54.1	49.1	**299.7**
HRV Program	3.6	4.0	4.4	4.8	5.2	**22.0**
Benchmarking Program	14.7	14.3	13.6	13.2	12.6	**68.4**
Energy Savers Kit Program	13.5	15.8	17.9	19.8	21.2	**88.2**
Isolated Systems Community Program	6.1	6.0	5.9	6.0	6.2	**30.2**
Isolated Systems Business Efficiency Program	1.0	1.0	0.9	0.8	0.8	**4.5**
Income Qualified Heat Pump and Insulation Program	0.0	1.9	5.4	10.6	17.5	**35.4**
Business Efficiency Program	64.1	67.5	70.0	71.5	73.8	**346.9**
Industrial Energy Efficiency Program	31.3	28.1	28.1	5.9	5.9	**99.3**
Total Portfolio	**308.7**	**312.1**	**319.5**	**303.2**	**312.9**	**1,556.4**

Table G-2
Conservation Programs
Demand Reduction Estimates: 2026 – 2030 (Includes Prior Years' Savings)
(MW)

	2026	**2027**	**2028**	**2029**	**2030**
Insulation and Air Sealing Program	29.8	33.1	36.5	40.0	43.8
Thermostat Program	3.4	3.4	3.3	2.9	2.5
ENERGY STAR Window Program	3.2	3.2	3.2	3.2	3.2
Small Technology Program	17.8	15.8	14.3	13.3	12.3
HRV Program	1.1	1.2	1.4	1.5	1.6
Benchmarking Program	5.9	5.8	5.5	5.3	5.1
Energy Savers Kit Program	2.9	3.5	4.0	4.4	4.8
Isolated Systems Community Program	0.9	0.8	0.7	0.6	0.6
Isolated Systems Business Efficiency Program	0.4	0.4	0.4	0.3	0.3
Income Qualified Heat Pump and Insulation Program	0.0	0.5	1.6	3.1	5.1
Business Efficiency Program	14.3	14.9	15.1	15.3	15.8
Industrial Energy Efficiency Program	0.7	0.7	0.7	0.7	0.7
Total Portfolio	**80.4**	**83.3**	**86.7**	**90.6**	**95.8**

Table G-3
Conservation Programs
Program Cost Estimates: 2026 – 2030
($000s)

	2026	2027	2028	2029	2030	Total
Benchmarking Program	998	893	1,112	1,043	1,158	5,204
Energy Savers Kit Program	636	568	561	695	578	3,038
HRV Program	298	306	310	379	333	1,626
Insulation and Air Sealing Program	2,607	2,629	2,707	2,999	3,017	13,959
Business Efficiency Program	1,695	1,755	1,950	1,848	1,870	9,118
Low Income Heat Pump and Insulation Program	56	2,379	4,286	6,352	8,244	21,317
Isolated Business Efficiency Program	18	18	18	18	18	90
Isolated System Community Program	1,169	1,498	1,183	1,124	1,124	6,098
Industrial Energy Efficiency Program	216	216	217	253	217	1,119
Total Programs Portfolio	**7,693**	**10,262**	**12,344**	**14,711**	**16,559**	**61,569**

Table G-4
CDM Programs
Total Resource Cost ("TRC") Test Results

	TRC Results
Benchmarking Program	2.7
Energy Savers Kit Program	3.1
HRV Program	1.7
Insulation and Air Sealing Program	4.3
Business Efficiency Program	1.4
Low Income Heat Pump and Insulation Program	1.5
Isolated Business Efficiency Program	1.1
Isolated System Community Program	1.2
Industrial Energy Efficiency Program	-[1]

[1] Hydro reminds its transmission-level customers annually of the availability of this program, but applications are not received every year. As a result of such a small market and budget considerations, participation is variable from year to year and difficult to forecast. Therefore, the TRC cannot be forecast but all proposed projects must result in a positive TRC to be approved.

Table G-5 Electrification Programs Program Operating Cost Estimates: 2026 – 2030 ($000s)						
	2026	**2027**	**2028**	**2029**	**2030**	**Total**
EV Charging Network Operating Costs	109	112	114	133	136	604

Table G-6 Electrification Programs Charger Station Revenue ($000s)						
	2026	**2027**	**2028**	**2029**	**2030**	**Total**
EV Charging Network Revenue	78	95	112	131	151	567

Schedule H
Thermostat Demand Response Pilot Scope

Thermostat Demand Response Pilot Scope

TakeCharge

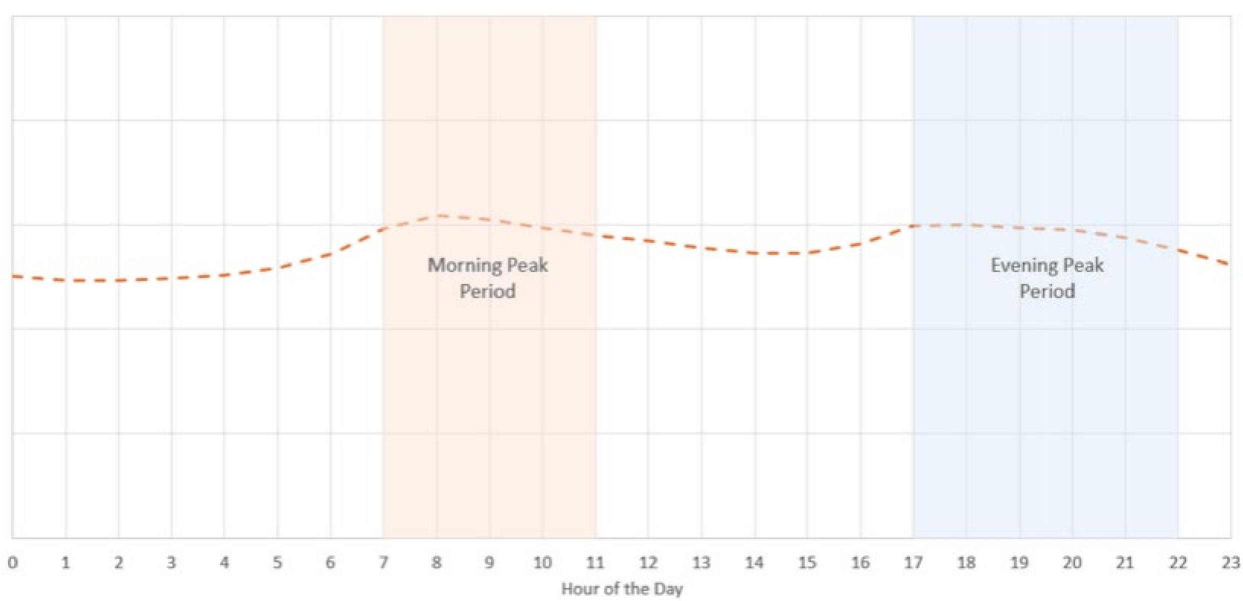
NEWFOUNDLAND POWER
A FORTIS COMPANY

Introduction

Newfoundland Power Inc., under the TakeCharge brand (with support from Newfoundland and Labrador Hydro) has implemented an electric space heating load management pilot using Mysa thermostats for baseboard heaters on the Island Interconnected System ("IIS"). The objective of the pilot project is to assess the peak load reduction impacts, rebound effects after events, customer acceptance of load management strategies and overall cost-effectiveness of using smart thermostats for electric baseboard heat to manage peak load on the system. The results of the study will be used to determine whether investment in load management of electric baseboard heat is a cost-effective approach to managing load growth on the IIS.

Residential space heating represents approximately 60% of electricity usage at peak times. System peak on the IIS typically occurs from 7:00 a.m. to 10:00 a.m. in the morning and 4:00 p.m. and 9:00 p.m. in the evening. Management of space heating load has the potential to provide peak relief during both the morning and evening peak; however the impacts may be constrained by the flatness of the peak day load curve, which makes it difficult to shift space heating load to other periods of the peak day without creating a new or worse peak. Figure 1 shows a demonstrative example of the load on a typical peak day on the IIS.

Figure 1
Demonstrative Peak Load for the IIS



A pilot program is an appropriate approach to assessing heating load management to help inform the scalability and reliability of load reduction from this type of program. The information gathered through this Pilot program will be vital in understanding whether thermostats can become part of a reliable virtual power plant to help reduce investment in electricity system capacity.[1]

Thermostat demand response programs are common in other jurisdictions; however, most programs target customers with central space heating or cooling.[2] The nature of baseboard heating presents complications to demand response programs that do not exist for central heating and cooling programs, both in terms of how baseboards interact with each other to provide heating load to the entire home, and the high number of control points and/or thermostats in a home. Another complication to be considered, unique to the IIS, is how the load curve rises in the morning and stays flat till later in the evening. It will be imperative to consider how management of thermostats will impact the load curve to ensure a new peak is not created. The results of this Pilot will be used to determine the scalability of a demand response program in the future.

The estimated budget for the Pilot is approximately $774,000, of which $258,400 will be covered by the Government of Newfoundland and Labrador Green Transition Fund.

Pilot Scope

The Pilot recruited a combination of customers who already have a Mysa thermostat for baseboard heaters installed in their home. This is typically referred to as a bring your own device ("BYOD") program. Additionally, Mysa provided purchase incentives for new devices that were enrolled into the Pilot. The Pilot enrollment ended with 2,617 thermostats enrolled across 551 households.

The Pilot involved installed whole home metering devices in 120 homes. While most Mysa thermostats show the amount of load reduction connected to the thermostat, it is also important to know the impact on the whole home before, during and after a demand response event. With numerous baseboards installed in homes, it is important to understand if other heaters or heating systems (such as heat pumps or wood stoves) are compensating for the load reduced by the Mysa thermostat during an event. Another critical component will be understanding the impact when the demand response event ends and the electric heat returns to normal room temperature.

To complete this Pilot, a program implementor was selected to coordinate customer participation, to complete installation of necessary metering devices, and to handle customer inquiries and distribution of customer participation rewards. The implementor, Clearesult, was selected via competitive RFP process. Clearesult is working with a third-party distributed energy resources managements system provider, Virtual Peaker, to dispatch demand response events and collect data from the Mysa devices.

A third-party evaluator, Guidehouse, will independently review the parameters of the study and validate the results, including customer satisfaction with the Pilot.

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1 A combination of dispatchable distributed energy resources is commonly referred to as a Virtual Power Plant ("VPP"). VPPs can be a combination of energy efficiency, demand response or supply-side resources such as renewable generation that a utility can rely on to provide firm capacity. The U.S. Department of Energy defines a VPP as "aggregations of clean distributed energy resources that act like a power plant…large enough to be utility scale, and connected, controllable and reliable enough to be utility grade."

2 Mysa thermostats for baseboards are currently used for demand response programs in British Columbia, Quebec, Nova Scotia and Washington State.

Benefits to Homeowners

Mysa thermostats are award-winning smart thermostats designed specifically for electric baseboard heating. Mysa makes it easy for homeowners to set up energy-saving schedules for all the thermostats in their home, reducing electricity consumption. Homeowners will also receive a financial incentive to participate in the program and a discount on new thermostats enrolled into the program.

Benefits to the Province

This initiative represents an innovative partnership between a local technology company, an investor-owned utility, and the provincial government, fostering collaboration and technological innovation. Additionally, the pilot encourages residents of Newfoundland and Labrador to engage in a community-driven initiative, actively participating in the energy transition. The adoption of smart thermostat technology creates the potential for implementing VPP solutions, which could reduce the province's reliance on traditional energy generation methods.

The benefits to the province's electricity system come from the avoided costs of supply. These figures will be calculated using Newfoundland and Labrador Hydro's marginal cost of generation and transmission. Based on the latest updates this ranges from $356 per kW in 2025 to over $472 per kW in 2040.

Timeline

The Pilot was implemented in the 2025-26 winter season. Demand response events were completed between January and March 2026 and will resume in December 2026, allowing four full months of demand response events to collect data from. Completing the Pilot over two winter seasons will also allow Newfoundland Power to understand customer acceptance of being enrolled in the Pilot for more than one season.

Cost

Table 1 provides a breakdown of expenditures proposed for the Thermostat Pilot.

Table 1
Estimated Pilot Costs
($000s)

Category	**Cost**
Labour	50
Pilot Implementor and Aggregator	549
Third-Party Evaluation	175
Total	**774**

Cost Sharing

A cost sharing arrangement between Newfoundland Power, Mysa and the Government of Newfoundland and Labrador has been agreed upon for this Pilot.

Schedule I
Newfoundland Power TakeCharge EV Load Management Pilot 2025 Evaluation Report

Newfoundland Power takeCHARGE EV Load Management Pilot 2025 Evaluation Report

Prepared for:

Newfoundland Power

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Executive Summary

Newfoundland Power's takeCHARGE Electric Vehicle (EV) Load Management Pilot (the Pilot), implemented through Uplight's EV load management platform, seeks to understand the existing charging habits of local EV drivers and determine the potential for shifting charging loads to off-peak periods. Newfoundland Power engaged Guidehouse Inc. (Guidehouse) to evaluate the Year 2 demand impacts associated with different load management strategies, and to conduct analysis on the participant survey results.

Guidehouse's evaluation had the following objectives:

1. Characterize baseline charging behaviour for local EV drivers, i.e., develop charging load shapes in absence of any load management.

2. Quantify and compare the impacts of two different load management strategies – one active and one passive treatment.

3. Provide input and conduct analysis on a participation survey conducted by Newfoundland Power to understand participant satisfaction, charging behaviour, and future interest in a load management program.

Pilot Description

The takeCHARGE EV Load Management Pilot comprised 3 participant groups, developed by Newfoundland Power, to meet its research objectives:

- **Peak Events:** The active demand response (ADR) treatment, or active management treatment, involved discrete demand response (DR) events called during the winter season. Events were called between December 1, 2024 and March 31, 2025.

- **Off-Peak Charging:** The behavioural demand response (BDR) or passive management treatment, where participants were asked not to charge during peak hours. Participants were notified to modify their charging behaviour between December 1, 2024 and March 31, 2025.

- **Monitor:** The control group to inform baseline charging behaviour, where participants were not subject to any treatment. For the purposes of evaluation, data was collected between December 1, 2024 and March 31, 2025.

Methodology

Guidehouse provided recommendations to Newfoundland Power in Year 1 of the Pilot for randomized assignments for each participant group based on analysis of participant demographic data. In Year 2, the new enrollments for EVSE were assigned to the Peak Events group, and the new enrollments for vehicle telematics (VT) were randomly assigned to the 3 groups based on compatibility. The purpose of randomization was to minimize unobserved differences between groups and to enable the use of the Monitor group to develop baseline behaviour and estimate the impact of each treatment. The Year 1 guidelines continued to inform customer recruitment into the Pilot for Year 2.

To estimate impacts, Guidehouse performed an analysis of data provided by Uplight and Newfoundland Power, including: charging telemetry data; event dispatch data, and program enrollment. Our analysis included development of baseline charging load shapes (e.g. PHEV vs BEV) for the Monitor group, regression analysis to determine hourly demand impacts for each treatment, and estimation of program benefits based on average demand impacts during peak periods and the marginal avoided cost of capacity.

Results

A total of 171 devices (BEV + PHEV) with data were enrolled at the end of the Pilot period as of March 31, 2025, as shown in Table ES-1. Most participants had battery electric vehicles (BEVs), while 17 had plug-in hybrid vehicles (PHEVs). Six devices had data collected but were unenrolled at the end of the Pilot period. 11 devices were enrolled that did not have data collected in the Pilot. These enrollment numbers were close to the program target of 200 participants and were primarily driven by substantial increase in Year 2 enrollment in the Pilot.

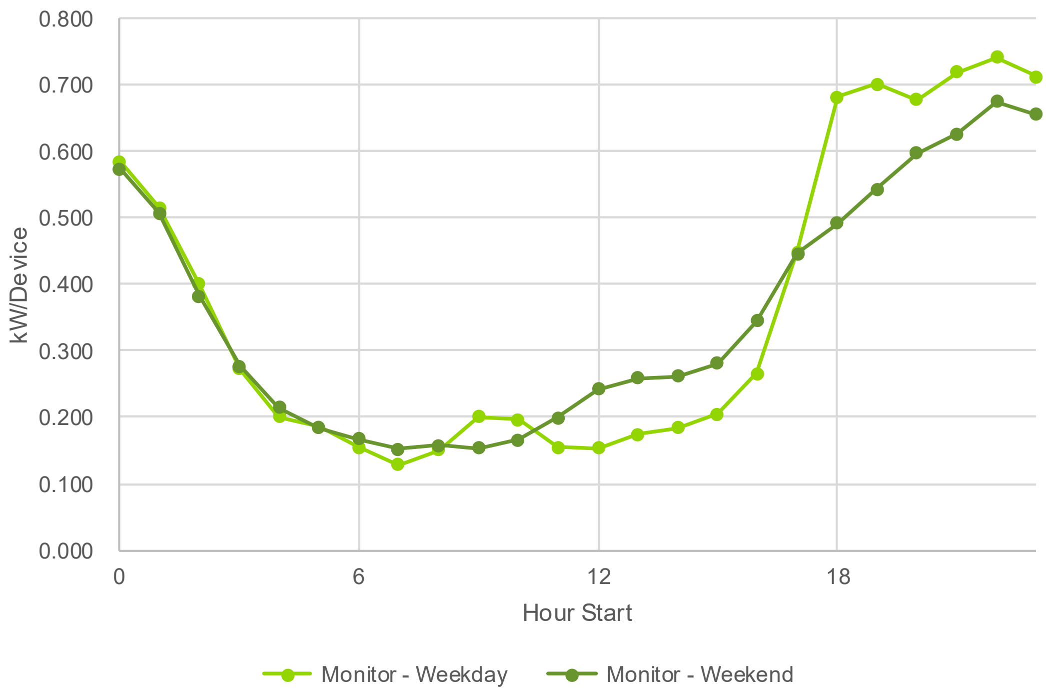
Table ES-1: Enrollment by Pilot Group

Pilot Group	BEV	PHEV	Unenrolled
Monitor – VT	38	15	0
Monitor – EVSE	1	2	0
Off-Peak Charging	51	0	0
Peak Events - VT	16	0	0
Peak Events- EVSE	48	0	0
Unenrolled	0	0	6
Total	**154**	**17**	**6**

Source: Guidehouse

Guidehouse's analysis of the Monitor group shows that charging load ramps up when participants are expected to be arriving home from work. This pattern is illustrated in Figure ES-1, where there is clearly more observed daytime charging on weekends compared with weekdays. The average observed per device charging load was 0.159 kW from 6 AM to 10 AM, and 0.584 kW from 4 PM to 11 PM across all days, with a peak hourly load of approximately 0.73 kW in the evening. This result combined with the fact that many participants had Level 2 chargers, suggests that not all vehicles are expected to be charging every day.

Figure ES-1: Baseline Charging Load Shape for Weekdays and Weekends



Source: Guidehouse

Peak Events impacts, listed in Table ES-2, varied in event length and duration, but statistically significant impacts were estimated for most event times, producing results of up to 0.46 kW per device for an event called between 7 PM and 11 PM. Event times were grouped together by the start and end hour of the event. The variance in observed impacts is likely attributable to the high number of dispatch failures and technical and operational issues experienced during the season (e.g. events not being dispatched correctly).

Table ES-2: Peak Events (ADR) Impacts by Event Time

Event Time	Number of Events	Savings Per Device (kW)	Margin of Error (kW) (90% Confidence Interval)	Relative Precision +/-% (90% Confidence)
5 PM - 8 PM	1	0.05	0.37	777%
5 PM - 9 PM	11	0.25	0.13	52%
5 PM - 10 PM	9	0.37	0.12	33%
6 PM - 10 PM	13	0.41	0.09	23%
7 PM - 11 PM	11	0.46	0.13	28%
6 AM - 10 AM	7	0.06	0.05	84%
7 AM - 10 AM	1	0.10	0.08	89%

Note: A positive savings value indicates that average load was curtailed during the event. A margin of error greater in magnitude than the savings value indicates that the impact estimate is not statistically different than zero.

Source: Guidehouse

There were several technical and operational issues encountered in the second year of the Pilot that affected observed results, dispatch reliability, and participant satisfaction. The issues should be taken into account when interpreting the results of the Pilot. These issues included: difficulty enrolling customers; failed event dispatches (lack of reliability in pausing charging); and data collection issues from vehicles and chargers. Resolution of these issues would be necessary to support potential further development an EV load management program.

Estimated impacts for the Off-Peak Charging treatment are listed in Table ES-3. This treatment showed a clear impact of shifting load from the evening to overnight periods. Guidehouse estimated savings of 0.37 kW per device during the evening peak period (4 PM to 11 PM) and an increase of 0.50 kW per device during the overnight off-peak period (11 PM to 6 AM). This represented a 75% decrease in peak load for the evening peak period, and a 123% increase in peak load for the overnight off-peak. No statistically significant impacts were observed between the period from 6 AM to 10 AM. This may be attributed to the similar demand load shape during the morning peak of the control and treatment groups, in part because most charging takes place in either the evening peak period or morning off-peak period.

Table ES-3: Off-Peak Charging (BDR) Event Impacts by Event Hours and Day Type

Event	Event Hours	Day Type	Savings Per Device (kW)	Margin of Error (kW) (90% Confidence Interval)	Relative Precision +/-% (90% Confidence)
Morning Peak	6 AM - 10 AM	All	-0.01	0.03	332%
Evening Peak	4 PM - 11 PM	All	0.37	0.02	6%
Morning Off-Peak	11 PM - 6 AM	All	-0.50	0.02	4%
Afternoon Off-Peak	10 AM - 4 PM	All	0.07	0.02	31%

Source: Guidehouse

Guidehouse estimated program benefits for the Pilot in terms of avoided cost of capacity associated with demand impacts, using a value provided by Newfoundland Power of $356.07 / kW-year. This value includes the avoided cost of generation, transmission, and distribution. Impacts are reported for each treatment in each peak period (6 AM to 10 AM and 4 PM to 11 PM) in Table ES-4 and Table ES-5. These estimates represent the potential program benefits associated with each device (vehicle or EVSE) for different definitions of system peak, i.e., in different cases where system peak would coincide with the treatment period. The benefits estimated for the Peak Events group reflect the estimated impacts for all events that were called during peak periods, rather than a specific event time.

Table ES-4: Program Benefits for Peak Events (ADR)

Peak Period	Savings Per Device (kW)	Avoided Cost of Capacity Per Device ($/year)
6 AM - 10 AM	0.08	$27.03
4 PM - 11 PM	0.32	$114.81

Note: These savings represent the average of hourly impacts for all events that were called during these time periods, and therefore do not represent the impact of any one type of event that was called.

Source: Guidehouse

Table ES-5: Program Benefits for Off-Peak Charging (BDR)

Peak Period	Day Type	Savings Per Device (kW)	Avoided Cost of Capacity Per Device ($/year)
6 AM – 10 AM	All	-0.01	-$3.07
4 PM - 11 PM	All	0.37	$131.76

Source: Guidehouse

A participant survey was conducted by Newfoundland Power and the analysis was conducted by Guidehouse. The survey had a high response rate of 51%. Respondents of the survey were generally satisfied with the pilot charging platform and program communication. Dissatisfaction due to the charging platform was caused by Hyundai's BlueLink issues and Optiwatt App incompatibility[1]. The Pilot influenced respondents' charging schedules to avoid peak periods but did not change whether they charged at home or at work. The majority of respondents indicated interest in participating in future EV load management programs and most respondents would participate in future programs for an annual incentive amount of $75.

Conclusions

Guidehouse's evaluation of the Pilot yielded evidence of load shifting for both treatments and demonstrated the potential benefits of an EV managed charging program. The development of the Pilot also provided Newfoundland Power with valuable information regarding the issues associated with implementation of different types of treatment (e.g. passive vs active, vehicle telemetry vs EVSE) to inform future program design. The key conclusions from Guidehouse's evaluation are as follows:

- **Both active and passive load management strategies show evidence of successful load curtailment.** The passive treatment group curtailed their load in the evening peak period, with an average reduction of charging demand between 4 PM and 11 PM of 0.37 ± 0.02 kW/device. Active events resulted in an average reduction of charging demand of up to 0.46 kW/device (events called between 7 PM and 11 PM).
- **Load was generally shifted from the evening period to overnight.** This result aligns with the prediction that both treatments delay charging when participants return home and plug in their vehicles. The morning peak period (6 AM to 10 AM) shows less potential for load reduction, as participants do not typically charge their vehicles in the morning, even without any treatment.
- **EV managed charging provides system benefits in the form of avoided cost of capacity**. The exact potential benefits will vary depending on how treatments are ultimately used to target system peak, and how the system peak coincides with the treatment period. Guidehouse estimated the potential range of benefits based on average curtailment during peak periods. For example, in the morning peak period (6 AM to 10 AM) Guidehouse estimated the benefit to be $27.03 / device for Peak Events.

[1] Hyundai Bluelink forced users to update login credentials while users were participating in the pilot program, causing multiple unsuccessful login attempts by Optiwatt's API causing users to be locked out of the Hyundai's Bluelink App. App incompatibility was due to the vendor (Uplight's Optiwatt) app not being compatible with the Tesla software, resulting in the Optiwatt app overriding the Tesla charging schedule. There were time variances between the charging session start and stop times for the OEM app and Optiwatt app.

For the evening peak period (4 PM to 11 PM), benefits were estimated to be $131.76 / device for the Off-Peak Charging treatment, and $114.81 / device for Peak Events.

- **The Off-Peak Charging group demonstrated persistent load shifting behaviour after the Winter 2023/2024 season.** The data from September 2024 to November 2024 showed persistence of some savings during the shoulder season months, which suggests the treatment is still effective in the off-season, absent a direct monthly incentive.
- **Technical and operational challenges reduced program impacts and may be a barrier to future scaling of the program.** For example, there were challenges with customer enrollment and successfully dispatching events with the Uplight platform in Year 2. These types of challenges appeared to have less effect on the passive treatment, which relies more on participants' own behavioural changes rather than the Uplight platform.
- **Year 2 of the Pilot provided additional data and improved certainty of impact estimates**. Increased enrollment in Year 2 of the Pilot provided more data and consolidating the event times for the Peak Events group provided more certain estimates for the Peak Events group compared to Year 1.
- **Survey results suggest that the Pilot was successful in influencing when participants charge, but likely not where they charge.** Survey respondents did not change whether they charge at home or at work, but they did change their charging schedules to avoid peak periods.
- **Participants were generally satisfied with the Pilot charging platform and program communication.** The frequency and method of communication were effective for respondents. Dissatisfaction related to the charging platform was due to Hyundai's BlueLink App issues and Optiwatt App incompatibility.
- **The majority of participants are interested in participating in future EV load management programs.** When respondents were asked for the minimum annual incentive amount that would make them interested in participating, a plurality of respondents said they would desire an annual incentive of up to $100. However, respondents may be overstating their minimum requirement, and could be biased towards selecting the highest incentive amount provided in the survey. In another survey question, when asked if they would be interested in participating in future programs for a $75 annual reward, 80% of respondents said they would be.

Guidehouse provides the following recommendations for Newfoundland Power to inform future program delivery and evaluation.

- **Consider the Off-Peak Charging treatment as a relatively lower complexity option to provide consistent load shift compared with other options.** Based on evaluation of the 2025 season, this passive treatment showed very clear load shifting potential, with fewer technical requirements (e.g. no discrete event dispatch, fewer platform challenges associated with failed events, equipment incompatibilities). Newfoundland Power may consider whether this strategy would meet their long-term demand side management needs, or whether active solutions provide enough incremental benefit to warrant their additional complexity. Newfoundland Power may want to consider using the strategy that presents fewer challenges in implementation.

- **A future program informed by the Pilot would need to consider the program benefits.** The results from Year 2 of the Pilot indicate that the Off-Peak Charging provides the highest potential program benefits if the system peak is in the evening, and the Off-Peak Charging treatment also has less operational challenges compared to the Peak Events treatment. The Peak Events program potential benefits are low due to high number of dispatch failures. The program benefits for the Peak Events may be higher than the Off-Peak Charging treatment if there was more successful participation in events. In addition, the Peak Events treatment can be more flexibly controlled to target specific system peak windows, to offer potentially more system benefits. However, this treatment would still have higher complexity than running a program based on passive treatment.
- **Consider addressing the technical challenges of the managed charging platform prior to further roll out of a full program.** The key challenges to address include: simplifying and improving the enrollment process to get more compatible drivers enrolled in the program; improving reliability in curtailing charging for the Peak Events group throughout the entire duration of the event; and addressing challenges in collecting reliable data.
- **Re-enroll the remaining Smartcar participants with Optiwatt.** The Smartcar data continues to have the data issue of being unable to isolate home charging data. By re-enrolling the remaining Smartcar participants with Optiwatt, this would provide both more granular vehicle telematics data, but also the ability to resolve the remaining issue of isolating home charging data. This would improve the quality of determining passive opt-outs, and improve the accuracy of the load shapes.
- **Clarify the opt-out and incentive process for participants.** During the Pilot, many survey respondents stated that they were unsure when to charge and not charge and when they would be eligible for incentives.
- **Address privacy and data security concerns and software malfunction/incompatibility issues prior to the next EV load management program.** Respondents still had concerns regarding their data security and software malfunction after the Pilot, Newfoundland Power could work to address these concerns to the extent feasible.

1. Introduction

Newfoundland Power designed the takeCHARGE Electric Vehicle (EV) Load Management Pilot (the Pilot), to understand the existing charging habits of local EV drivers and determine the potential for shifting charging loads to off-peak periods. Newfoundland Power also conducted a survey on participant satisfaction of the Pilot. The Pilot is implemented through Uplight's EV load management platform, which enables collection of charging telemetry data from both vehicles and electric vehicle supply equipment (EVSE), as well as control of charging to call demand response (DR) events. Newfoundland Power engaged Guidehouse Inc. (Guidehouse) to evaluate the Year 2 demand impacts associated with different load management strategies, and conduct analysis on the participant survey results. This report describes the methods and results of Guidehouse's evaluation.

1.1 Pilot Objectives

Newfoundland Power's goals for the Pilot were:

1. **Quantify Baseline Charging Behaviour.** Understand the potential energy and peak demand impacts of EV growth without active or passive load management.

2. **Test the Benefits of EV Load Management.** Estimate the demand reduction capability of one or more load management approaches, including active or passive techniques.

3. **Understand the Trade-Offs of Different Load Management Strategies.** Assess the challenges associated with different strategies, for example considering the costs of Level 2 smart charger or telematics device deployment.

Towards achieving these goals, Guidehouse's evaluation had the following objectives:

1. Characterize baseline charging behaviour for local EV drivers, i.e., develop charging load shapes in absence of any load management.

2. Quantify and compare the impacts of two different load management strategies – one active and one passive treatment.

3. Provide input and conduct analysis on a participation survey conducted by Newfoundland Power to understand participant satisfaction, charging behaviour, and future interest in a load management program.

1.2 Program Description

The takeCHARGE EV Load Management Pilot comprised 3 participant groups, developed by Newfoundland Power to meet its research objectives:

- **Peak Events**: The active demand response (ADR) treatment, involving discrete DR events. For the purposes of evaluation, this treatment took place with events between December 1, 2024 and March 31, 2025.

- **Off-Peak Charging**: The behavioural demand response (BDR) or Passive Management treatment, where participants were asked not to charge during peak hours. For the purposes of evaluation, this treatment took place between December 1, 2024 and March 31, 2025 (i.e., when participants were asked to alter their charging behaviour).

- **Monitor**: The control group to inform baseline charging behaviour, where participants were not subject to any treatment. For the purposes of evaluation, data was collected between December 1, 2024 and March 31, 2025.

The participants received up to $230 in incentives which included a $150 enrollment incentive, and a $20 monthly (December – March) participation incentive for the Peak Events and Off-Peak Charging groups, or a $25 completion incentive for the Monitor group The participants received an additional re-enrollment incentive to switch from Smartcar to Optiwatt.

1.2.1 Peak Events

Participants in the Peak Events group were monitored and controlled by either EVSE or vehicle telematics (VT), but not both simultaneously. This treatment involved demand response events during which participant charging was curtailed.

Newfoundland Power continuously monitored weather and system conditions to determine when to call events, within the following parameters:

- Between the hours of 6 AM to 10 AM or 4 PM to 11 PM including holidays; events were generally called on weekdays, with some events also called on holidays or weekends as needed.
- The event length varied between 3 to 5 hours.
- Up to 20 events could have been called per month, inclusive of any system load events. The maximum number of events called in a month was 16 in Year 2 of the Pilot.
- Participants received a notification 24 hours before event start (day-ahead notice), and another reminder an hour before the event; however, in the case of system load requirements, such events may have been called with less than 24 hours' notice, including on weekend days. 2 system load events were called in Year 2 of the Pilot.

Newfoundland Power executed events in the Uplight platform (Optiwatt, Flexsaver[2]), which works as follows:

1. At the start of the event, Uplight’s API partners perform checks to confirm whether a vehicle's charging should be curtailed during the event (event eligibility).
    a. The Smartcar platform performs a location ping to confirm if the participant's EV is within 1,000 ft of their residence and plugged in; the Optiwatt platform similarly checks that a participant’s vehicle is within 200 ft of their residence and plugged in. In the case of an EVSE, the API partners check that a vehicle is plugged in.
    b. The state of charge (SOC) of the vehicle's battery must be above 25% for Smartcar. For Optiwatt participants, the SOC must be above the minimum SOC that the participant selects in the app.

[2] Flexsaver is the app that participants used if their device had data collected via Smartcar, which only applied to participants enrolled in Year 1 of the Pilot and did not switch to Optiwatt in Year 2 of the Pilot.

2. If these conditions are true, the vehicle's charging is 100% curtailed and the vehicle is not allowed to charge during the event. Otherwise, vehicles (e.g. those below 25% SOC or not at home) are allowed to charge normally with no throttling.
   a. For VT control, if a participant comes home and/or plugs in their vehicle after the event has started the EV is allowed to charge.
   b. For VT control, if a participant unplugs their vehicle and plugs it in again during an event, the vehicle is allowed to charge.
   c. For EVSE control, ChargePoint participants were unable to charge for the duration of the event, regardless of plug behaviour. Wallbox participants were able to charge if they plugged in after the event had started.
3. At the end of the event, all curtailed participants have their charging resume as normal.

These rules existed due to limitations in Uplight’s Optiwatt application and was not the preferred behaviour. The preferred behaviour would been to check for event eligibility throughout the entire event, rather than only at the start of the event. It would have also allowed the participant to be able to charge to 25% SOC or their minimum desired SOC, and for the charging curtailment only to occur once that threshold SOC was reached.

Participants that chose to opt-out 3 or more times (3 "strikes") in a given month (including system load events) were not eligible for that month’s participation incentive. Generally, opt-outs refer to a participant’s decision to not participate when they otherwise could have (via email or text), meaning the following exclusions from events did not count as a strike:

1. Exclusion due to insufficient SOC (<25%) at the start of the event for smartcar participants, and below the drivers’ preferred SOC for Optiwatt.

2. Exclusion due to not being at home and/or not plugged in.

1.2.2 Off-Peak Charging

These participants were monitored by VT and received enrollment and monthly participation incentives. For this treatment, participants were asked not to charge during peak hours, 6 AM to 10 AM and 4 PM to 11 PM, 7 days a week. Additional details for this treatment are as follows:

- Participants were reminded bi-weekly to not charge during peak hours, e.g. Monday afternoon at 3 PM.
- Participants were monitored to confirm whether or not a participant charged during peak hours. Charging during peak hours were counted as a "opt-out". Participants could accumulate 2 opt-outs during a month and still receive their monthly participation incentive, i.e., if a participant accumulated 3 or more opt-outs, they were not eligible to receive that month’s incentive.

1.2.3 Monitor

These participants were monitored by VT and EVSE and informed baseline consumption used as a comparison for the Peak Events and Off-Peak Charging groups, i.e., were used as a control group. The participants received enrollment and annual completion incentives. Additional details are as follows:

- Participants were instructed to charge as they regularly do (no change in behaviour).
- For each participant, Uplight confirmed that they were connected and able to transmit data. If data was collected, the participant received a completion incentive when the Pilot was completed.

2. Methodology

2.1 Pilot Participation Groups

Guidehouse provided recommendations to Newfoundland Power in Year 1 of the Pilot on participant group selection. The details of this guidance can be found in Appendix A.4. The principles for assigning participants to groups were carried over from Year 1 to Year 2 of the Pilot. Newfoundland Power added new participants in Year 2 to groups, and the targets for the sizes of each group was similar as in Year 1.

Participants were assigned to participant groups based on the type of vehicle telematics. Group assignments were affected by compatibility considerations, as certain models of vehicle were not necessarily eligible for all groups (e.g. vehicles incompatible with VT were only compatible via EVSE). Participants monitored and controlled by an EVSE were assigned to the Peak Events group (45 were added in Year 2, and 3 EVSE participants were assigned to the Monitor group). PHEV participants were assigned to the Monitor group (13 were added in Year 2). All other EV participants controlled and/or monitored by VT were assigned randomly between the Peak Evenets, Off-Peak Charging and Monitor groups (54 were added in Year 2). There was also an optional re-enrollment to Optiwatt for the Smartcar participants from Year 1 (26 were re-enrolled from Smartcar to Optiwatt).

2.2 Data Collection

For this evaluation, Guidehouse used the following data, received from Uplight and Newfoundland Power.

2.2.1 Vehicle and EVSE Telematics Data

Uplight provided telematics data from different sources depending on the method of control. VT data was provided via the Smartcar and Optiwatt platforms, while EVSE telematics data was provided via the Wallbox and ChargePoint platforms.

- **Vehicle Telematics (Smartcar data):** Telematics data collected via polling participants' vehicles charging at regular (~1 hour) intervals. The data contains information about the state of the vehicle each time it is polled (e.g. whether it is plugged, charging, the vehicle state of charge, and battery capacity). Importantly, the Smartcar data does not capture the exact times associated with plug or charging sessions, e.g., a participant may start charging their vehicle, and the Smartcar platform will only capture data the next time it is scheduled to poll the vehicle. Since the polling frequency is at minimum ~1 hour, there is uncertainty in the exact start and stop time of charging sessions for these participants, as well as the average power delivered. In addition, the data provided by Uplight does not distinguish between home and away charging; therefore, Guidehouse was unable verify that all charging was conducted at home for these participants.

- **Vehicle Telematics (Optiwatt data):** Telematics data was collected from participant's vehicles in 5 minute intervals, and contained information on the vehicle each time it was polled (e.g. whether it is plugged, charging, the vehicle state of charge, and battery capacity, whether it was at home or away). Unlike the Smartcar data, the Optiwatt data captured when the car was plugged in, to the closest 5 minute, which eliminated the uncertainty. The charging and plug in sessions were determined based on the plug in and charging status for each 5-minute interval for the vehicle.

- **EVSE Telematics (Wallbox and ChargePoint data):** Telematics data collected via participants EVSE at regular intervals (every 30 seconds). The data contains information about plug in/out, charging start/stop, and energy delivered. Since the data collected from EVSEs is collected at a very granular time interval, this data does not exhibit the same uncertainty as the VT data.

Guidehouse processed this data to generate a standardized hourly interval data set for each vehicle that contains the average power delivered in each hour. These intervals were determined as follows:

1. Identify all charge sessions, including estimated start and stop time and total energy delivered.

2. Computed the average power delivered through the charge session as the total energy delivered divided by the length of the charge session.

3. Assign the average power to corresponding hours based on charge start and stop time. If a charging session only partially overlaps with an hourly interval (e.g. a participant started charging midway through the hour), the average power was adjusted based on the amount of the interval that was spent charging.

Guidehouse also performed a series of data cleaning steps to remove anomalous or not-relevant values (e.g. blank rows, non-charging data, data for dates not included in the analysis, data without all 24 hours present). More details are included in Appendix A.1.

2.2.2 Participant Data

Newfoundland Power provided a complete enrollment list with final assigned groups, as well as other participant characteristics (e.g. vehicle make and model).

2.2.3 Event Data

Newfoundland Power provided a list of called Peak Events details, including date; event type (i.e., system load vs regular); event start time; and event end time. This is detailed in Table 2-1.

Table 2-1: Peak Events (ADR) Event Date, Times, and Type

Event Number	Event Date	Start Time (Prevailing)	End Time (Prevailing)	Event Type
1	12/2/2024	6 AM	10 AM	Regular
2	12/4/2024	5 PM	9 PM	Regular
3	12/6/2024	6 PM	10 PM	Regular
4	12/8/2024	7 PM	11 PM	Regular
5	12/10/2024	5 PM	9 PM	Regular
6	12/12/2024	6 AM	10 AM	Regular

Event Number	Event Date	Start Time (Prevailing)	End Time (Prevailing)	Event Type
7	12/14/2024	6 PM	10 PM	Regular
8	12/16/2024	7 PM	11 PM	Regular
9	12/20/2024	5 PM	10 PM	Regular
10	12/22/2024	5 PM	10 PM	Regular
11	12/28/2024	5 PM	9 PM	Regular
12	1/1/2025	7 PM	11 PM	Regular
13	1/2/2025	5 PM	10 PM	Regular
14	1/5/2025	5 PM	9 PM	Regular
15	1/7/2025	6 PM	10 PM	Regular
16	1/9/2025	7 PM	11 PM	Regular
17	1/10/2025	5 PM	10 PM	Regular
18	1/13/2025	5 PM	10 PM	Regular
19	1/16/2025	6 PM	10 PM	Regular
20	1/17/2025	7 PM	11 PM	Regular
21	1/18/2025	6 PM	10 PM	Regular
22	1/21/2025	5 PM	9 PM	Regular
23	1/23/2025	7 AM	10 AM	System Load
24	1/23/2025	5 PM	8 PM	System Load
25	1/27/2025	5 PM	9 PM	Regular
26	1/29/2025	6 PM	10 PM	Regular
27	1/31/2025	6 AM	10 AM	Regular
28	2/2/2025	6 AM	10 AM	Regular
29	2/6/2025	6 PM	10 PM	Regular
30	2/8/2025	7 PM	11 PM	Regular
31	2/10/2025	5 PM	9 PM	Regular
32	2/11/2025	6 AM	10 AM	Regular
33	2/14/2025	6 PM	10 PM	Regular
34	2/16/2025	7 PM	11 PM	Regular
35	2/18/2025	6 PM	10 PM	Regular
36	2/19/2025	5 PM	9 PM	Regular
37	2/22/2025	5 PM	10 PM	Regular
38	2/24/2025	7 PM	11 PM	Regular
39	2/26/2025	7 PM	11 PM	Regular
40	2/27/2025	5 PM	9 PM	Regular
41	3/2/2025	6 PM	10 PM	Regular

Event Number	Event Date	Start Time (Prevailing)	End Time (Prevailing)	Event Type
42	3/4/2025	5 PM	10 PM	Regular
43	3/6/2025	5 PM	10 PM	Regular
44	3/7/2025	5 PM	9 PM	Regular
45	3/10/2025	6 PM	10 PM	Regular
46	3/15/2025	6 AM	10 AM	Regular
47	3/18/2025	6 PM	10 PM	Regular
48	3/20/2025	7 PM	11 PM	Regular
49	3/22/2025	6 PM	10 PM	Regular
50	3/23/2025	5 PM	9 PM	Regular
51	3/24/2025	6 AM	10 AM	Regular
52	3/26/2025	7 PM	11 PM	Regular
53	3/30/2025	5 PM	10 PM	Regular

Source: Guidehouse

For each event for the Peak Events group, Uplight provided event dispatch results, which describe whether each participant was successfully curtailed, and if not, why (e.g. technical issues, not at home, opt-out). Guidehouse used this data to determine how many vehicles opted-out of each event, as well as how many vehicles successfully participated.

The Off-Peak Charging treatment took place between December 1, 2024 and March 31, 2025, when participants were asked to alter their charging behaviour to not charge during peak hours. Guidehouse used collected telematics data to determine which participants “opted-out”, or charged during peak hours. However, due to the uncertainty in charge start and stop time associated with the VT data, there is uncertainty in the exact number of opt-outs that occurred throughout this treatment.

2.3 Impact Evaluation

2.3.1 Baseline Charging Behaviour

To characterize baseline charging behaviour, Guidehouse calculated average hourly load shapes for participants in the Monitor (control) group. These load shapes were calculated for different segments of participants and of charging periods, including by vehicle type and by day type (weekday vs weekend).

The comparison of load shapes on non-event days also served the purpose of verifying similarities or potential differences between different participant groups in terms of charging behaviour (e.g. since participants could not be selected truly randomly due to compatibility reasons, they may exhibit some differences). The results informed Guidehouse’s evaluation approach to mitigate the effect of these differences.

2.3.2 Demand Impacts

Guidehouse used regression analysis to estimate average hourly impacts for each treatment group, i.e., Peak Events and Off-Peak Charging, as well as event specific impacts as applicable. For the Peak Events group, Guidehouse estimated average impacts for different event times, where events were grouped by start and end time. Start times were rounded down to the nearest hour, and end times were rounded up to the nearest hour. For the Off-Peak Charging group, Guidehouse estimated impacts over all days, as well as by weekend vs weekday. Guidehouse leveraged the Monitor group to establish baseline behaviour for both treatments; note that PHEVs were not included for this purpose, as all vehicles in the treatment groups were BEVs.

Additional details including the model specifications for each treatment are included in Appendices A.2 and A.3.

2.3.3 Program Benefits

To estimate system benefits associated with the managed charging treatments for the program, Newfoundland Power provided Guidehouse with values for marginal avoided cost of capacity, including the avoided cost of generation, transmission, and distribution, $356.07 / kW-year, and represents the benefit of avoiding demand during the coincident system peak, which Guidehouse understands will likely occur over a short window of hours during the winter (e.g. in the morning or evening peak periods).

Guidehouse multiplied this avoided cost by the average hourly demand impact per device. These results represent potential benefits associated with program impacts, when estimated impacts coincide with system peak. The potential benefits provide an estimate of when the program will provide the most grid value depending on when the system peak occurs.

Impacts are reported for each treatment in each peak period (6 AM to 10 AM and 4 PM and 11 PM), as well as by hour of day included in the Appendix B spreadsheet.

Evaluations of demand-side management programs typically estimate both net and gross savings, and often present a net-to-gross (NTG) ratio based on the evaluated percentage of energy reductions that may be attributed to one or both of:

- Free ridership: Defined as the percentage of savings that would have occurred absent the presence of the program. This effect decreases the NTG ratio.
- Program spillover: Typically defined as incremental savings actions undertaken by a program's participants not directly incented by the program. This effect increases the NTG ratio.

In this analysis, demand reductions are estimated relative to an estimated baseline, determined using the behaviour of the Monitor group, which captures expected participant behaviour absent an event. Absent the Pilot, none of the observed demand reductions associated with the Peak Events program would have taken place, as the events themselves would not have taken place. With respect to the Off-Peak Charging treatment, the Monitor group used to estimate baseline behaviour captures any tendency for participants to manage their own charging absent the program. Therefore, Guidehouse can state that the free ridership is 0.

There may have been some spillover resulting from the program (from participants becoming more aware of their EVs consumption profiles, for example). However, it is impractical to estimate such an effect in a sufficiently robust manner and the assessment of such impacts is beyond the scope of this report.

Therefore, all demand presented in this report should be considered net, with an NTG ratio of 1.

2.4 Participant Survey

Guidehouse developed the participation survey instrument in collaboration with Newfoundland Power along with feedback from MQO Research, who fielded the survey itself. Appendix C contains the full survey instrument, which addressed the following topics:

- Feedback on use of the managed charging platform.
- Satisfaction with program incentives.
- Satisfaction with the override process.
- Satisfaction with program communications.
- Satisfaction with program overall.
- Opportunities for improving program satisfaction.

MQO fielded the survey which was sent to the 180 program participants, which achieved 95 total responses (53%). There were three screen outs (no longer had the vehicle or were not the primary driver) resulting in 92 valid completes (51%).

3. Technical Challenges

There were a number of technical operational and data challenges encountered during the second year of the Pilot that affected observed results, in terms of reliability of the program, participant satisfaction, and impact evaluation results (estimated load shapes and demand impacts). These issues are summarized to provide context when interpreting the results of this evaluation and include:

Operational Issues

- **Event dispatches only at beginning of the event**: Participants controlled via vehicle telematics and Wallbox EVSE in the Peak Events group that were not plugged in at the beginning of the event did not have their charging curtailed. Participants that plugged in after the start of the event could charge without having charging curtailed.

- **Lack of EVSE and EV compatibility**: Lack of EVSE and EV compatibility with the platform made it difficult for participants to continue using their regular charging system. Some interested participants were not able to enroll into the Pilot due to the limitations around compatibility with the Uplight platform.

- **Cumbersome enrollment process**: This process resulted in participants not being able to get their compatible vehicle enrolled citing incompatibility errors. Other issues included: verification code expiry; errors indicating connect service is not set up; experiencing blank screens during the enrollment process; and errors during enrollment connecting to OEMs connected service stating “something went wrong, please try again”. Many survey participants also indicated that the enrollment process was too complicated.

- **Lack of reliability of 3rd party API integration vendors**: This issue was due to lack of permissions from OEMs. For example, in year 1, Ford forced all participants to unenroll citing 3rd party access as unauthorized and a cybersecurity threat. Hyundai and Kia charging could not be paused temporarily, and those devices were eventually moved to the passive (BDR) group. In year 2, Hyundai forced all BlueLink users to reset their passwords citing a cybersecurity threat and revoked 3rd party access to the app. Data collection could not be reinstated until participants re-connected their vehicles to the Optiwatt app. There was no fix given for participants enrolled through Smartcar.

- **EVSE connectivity issues**: Some EVSE connectivity issues could not be rectified even though ChargePoint participants’ network had no issues. The EVSE telemetry data also was not transmitting data early on in Year 2 of the Pilot. This issue was found to be due to Uplight accessing the US ChargePoint portal rather than the Canada ChargePoint portal.

- **Lack of reliability in ability to pause charging**: There were technology limitations for all VT and for the Wallbox EVSE participants in their unreliability and ability to pause charging sessions. For example, vehicles would not retain information that an event/dispatch had started if the vehicle was not plugged in/charging. This issue resulted in late plug-ins not being curtailed during the event, i.e., the vehicles charged as it normally would if it is plugged in just after an event starts.

- **12 V battery drain due to participation in the Pilot**: Some Hyundai participants experienced 12 V battery drain while participating in the Pilot. Although this has not been confirmed that it is due to the Pilot program, it occurred during times that participants were having difficulty with their Hyundai's BlueLink app and received daily app error messages advising of several invalid access attempts.

- **Time variances in charging start and stop**: The charging session start and stop times between OEM app and vendor app were found to be inconsistent for some participants.

- **Many dispatch failures impacting Peak Events group impacts**: About 60% of Peak Events participants had dispatch failures during events throughout the Pilot. This would result in lower impacts than if all participants had successful dispatches. There were also 53 partial participant-events in the Pilot, where an event started with a successful dispatch, but ended with a dispatch failure. This is likely due to the car being unplugged but can also mean that some people are able to charge after the start of the event, which would affect the level of participation in the event.

Data Issues

- **Mixing of home and away charging data**: For the Smartcar data, Uplight was unable to differentiate between home and away charging sessions. As a result, although Guidehouse was able to analyze this data, the results may include some away from home charging. This was partially mitigated in Year 2, due to many of the Smartcar participants migrating to the Optiwatt platform.

- **The Optiwatt data had issues with incorrect data or missing charging data**: There was incorrect data such as charging data over 20 kW which would indicate away from home charging, or under 0 kW. These values were set to 0 kW and removed from the analysis. In addition, data was often incomplete – there were 52 participants with long periods of no charging (0 kW), as well as 13 Optiwatt participants that showed no charging (0 kW) data for the entire Pilot. There were also charging sessions where there was no change in state of charge. In all of these cases, Guidehouse deemed this data to be incomplete and these charging sessions were removed from the analysis.

- **No Optiwatt data was available prior to December 2024**: There were challenges in collecting Optiwatt data prior to the start of the Pilot, which means that only participants enrolled in Year 1 had data in the pre-period leading up to the Pilot. This made the pre-period data less useful since it was not representative of the Pilot period which included the Optiwatt data.

- **The Optiwatt state of charge data was not consistent with the power data:** This is reflected in the data in the form of unrealistically high energy delivered during charging sessions, e.g. much greater than approximately 150 kWh. These charging sessions were removed as the largest battery capacity of any vehicles in the Pilot would likely be less than 150 kWh – the maximum capacity of a Ford F150 Lightning, for example, is approximately 130 kWh.

- **Hyundai BlueLink Issue:** This resulted in no charging data being available for most Hyundai vehicles from January 14 to March 12, 2025. For participants with only 0 kW charging data in this period had the 0 kW data removed from January 14 to March 12, 2025.

- **Some devices had both Smartcar and Optiwatt simultaneously:** This is from participants who were previously enrolled in Smartcar, and were later enrolled in Optiwatt in Year 2 of the Pilot. The Smartcar data continued to be collected even after the Optiwatt data collection began. Guidehouse used the Optiwatt data that was available instead of the Smartcar data starting on December 1, 2024, as the data from Optiwatt was more granular.

4. Impact Evaluation Results

4.1 Enrollment

A total of 171 devices (BEV + PHEV) with data were enrolled at the end of the Pilot period, as of March 31, 2025, as shown in Table 4-1. Most participants had battery electric vehicles (BEVs), while 17 had plug-in hybrid vehicles (PHEVs). Six devices had data collected but were unenrolled at the end of the Pilot period. These enrollment numbers are close to the targets for the program of 200 participants and were driven by substantial increases in Year 2 enrollment of the Pilot. A total of 11 devices were enrolled in the Pilot, but did not have any data. Table 4-2 below shows how the vehicle telematics group enrollment was split by Pilot group for Optiwatt and Smartcar.

Table 4-1: Enrollment by Pilot Group

Pilot Group	BEV	PHEV	Unenrolled
Monitor – VT	38	15	0
Monitor – EVSE	1	2	0
Off-Peak Charging	51	0	0
Peak Events - VT	16	0	0
Peak Events - EVSE	48	0	0
Unenrolled	0	0	6
Total	**154**	**17**	**6**

Source: Guidehouse

Table 4-2: Enrollment by Pilot Group for Vehicle Telematics

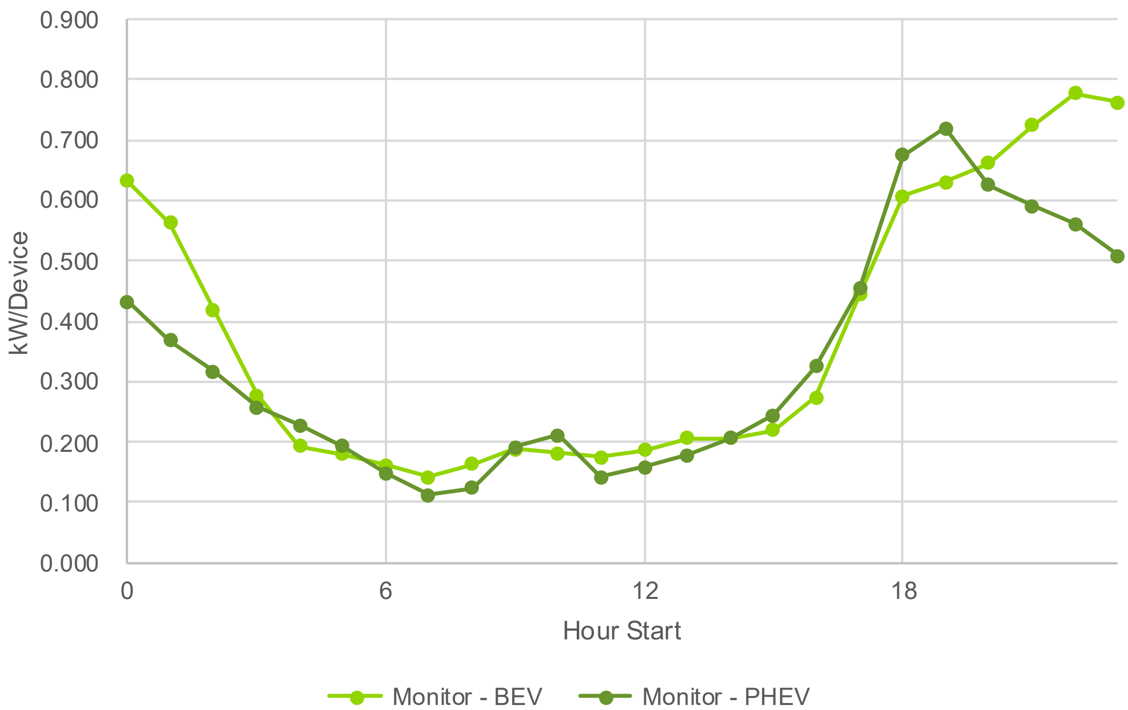
Pilot Group	Optiwatt	Smartcar
Monitor – VT	32	21
Off-Peak Charging	30	21
Peak Events – VT	11	5
Unenrolled	0	6
Total	**73**	**53**

Source: Guidehouse

4.2 Baseline Charging Behaviour (Monitor group)

Figure 4-1 below compares average hourly load shapes between BEV and PHEV vehicles. The BEV group demonstrated a higher average peak per device with a peak of 0.78 kW between 10 PM and 11 PM, compared to the PHEV group which had a peak of 0.72 kW between 7 PM and 8PM. Both groups show that charging load ramp up towards the evening hours, when people would be expected to arrive home from work. The similarity in peak daily load may be influenced by the fact that participants with BEVs likely do not charge every day, which brings down the overall average charging load among participants. The BEV group had more energy delivered per day than the PHEV group, with 9.0 kWh of charging for the BEV group compared to 8.0 kWh for the PHEV group.

Figure 4-1: Baseline Charging Load Shape by Vehicle Type



Source: Guidehouse

Figure 4-2 compares average hourly load shapes by day type, between weekdays and weekends. The weekday load shape had more charging between 6 PM and 12 AM than the weekend load shape, which had more charging that took place between 11 AM and 4 PM. This reflects the fact that participants are more likely to be at home and charging on weekends. The weekday had slightly more energy from charging than the weekend, with 8.8 kWh for the weekday compared to 8.6 kWh for the weekend. The peak was slightly higher per device for the weekday than the weekend, with 0.74 kW for the weekday between 10 PM and 11 PM compared to 0.68 kW for the weekend between 10 PM and 11 PM. The higher load on weekday nights than weekend nights means there may be more opportunity for load to be curtailed on weekdays during the evening than on weekends.

The average observed per device charging load was 0.159 kW from 6 AM to 10 AM, and 0.584 kW from 4 PM to 11 PM across all days, with a peak hourly load of approximately 0.73 kW in the evening. This result combined with the fact that many participants had Level 2 chargers, suggests that not all vehicles are expected to be charging every day.

Figure 4-2: Baseline Charging Load Shape for Weekdays and Weekends

Source: Guidehouse

4.2.1 Charging Metrics

Guidehouse computed a variety of charging metrics for the Monitor group. A selection of these metrics are reported here – refer to the Appendix B spreadsheet for more details and additional metrics. Note that these metrics were computed for all vehicle types and therefore primarily reflect the BEVs that are in the Monitor group.[3] Table 4-3 below shows participant time plugged in (percentage of each day). January saw highest average time plugged in, but all months showed that the participants generally do not leave their vehicles plugged in most of the time, i.e., the vehicles are used for travel away from home and may not be plugged in all the time even when at home.

Table 4-3: Monitor group Percentage of Time Plugged In

% Time Plugged In	Min	Mean	Median	Max
All	0.1%	27.0%	20.1%	79.8%
Dec	0.0%	28.1%	21.7%	100.0%
Jan	0.0%	29.6%	23.9%	89.0%
Feb	0.0%	24.3%	19.1%	88.9%

[3] The relatively small sample of PHEVs (17 vehicles) means that computed metrics for this group alone may not produce meaningful metrics.

% Time Plugged In	Min	Mean	Median	Max
Mar	0.0%	25.7%	15.6%	86.3%

Source: Guidehouse

Table 4-4 below shows the hourly distribution of plug start and stop. The most frequent times for plug in was between 4 PM and 10 PM. The most frequent plug out time was between 7 AM and 9 AM. This result shows that the participants' plug behaviour is likely correlated with their work schedules.

Table 4-4: Monitor group Distribution of Hourly Plug Start and Stop Times

Hour Start	Plug In Start	Plug In End
12 AM	1.2%	0.9%
1 AM	1.0%	0.6%
2 AM	1.1%	0.2%
3 AM	0.5%	0.9%
4 AM	0.4%	0.7%
5 AM	0.3%	1.8%
6 AM	1.0%	3.9%
7 AM	2.4%	10.5%
8 AM	2.0%	11.6%
9 AM	2.2%	7.9%
10 AM	3.1%	6.3%
11 AM	3.5%	6.6%
12 PM	3.1%	6.4%
1 PM	4.3%	4.9%
2 PM	4.2%	6.4%
3 PM	6.8%	4.9%
4 PM	8.0%	3.5%
5 PM	10.2%	4.0%
6 PM	7.8%	4.0%
7 PM	7.8%	2.2%
8 PM	12.3%	6.1%
9 PM	8.6%	2.8%
10 PM	4.6%	1.7%
11 PM	3.6%	1.2%

Source: Guidehouse

Table 4-5 shows number of charge sessions per day per vehicle; Table 4-6 shows the average energy delivered (in kWh) per charging session per vehicle; and Table 4-7 shows the distribution of state of charge (SOC) at charging start and stop among all charge sessions. These metrics show the frequency of charging each day, how much energy is typically delivered to vehicles, and what SOCs participants typically charge between. Note that these numbers include all sessions between December 1, 2024 and March 31, 2025. These results show a pattern of charging behaviour where participants generally plug in their vehicle at whatever SOC their vehicle is at when they return home, and charge to full, or near full, depending on their vehicle settings. Specifically, the SOC at charging start was somewhat evenly distributed between 20% and 100%, while the majority of charging sessions stopped between 70 and 100%. January had the most charging sessions, and also the highest average total kWh per charging session of all months in the Pilot. The metrics suggests that overall charge sessions per day remains fairly steady in each month, but the energy delivered per charging session can vary depending on the month.

Table 4-5: Monitor group Charge Sessions Per Day per Vehicle

Charge Sessions Per Day (per Vehicle)	Min	Mean	Median	Max
All	0.04	0.56	0.30	1.73
Dec	0.00	0.59	0.42	1.87
Jan	0.00	0.64	0.32	2.19
Feb	0.00	0.51	0.36	2.11
Mar	0.00	0.50	0.35	1.87

Source: Guidehouse

Table 4-6: Monitor group Average kWh per Charging Session

Avg kWh per Charge Session	Min	Mean	Median	Max
All	3.08	17.54	12.68	75.02
Dec	3.14	16.43	13.26	79.58
Jan	2.76	17.47	11.11	83.02
Feb	2.82	12.01	10.60	37.65
Mar	2.89	16.32	10.10	72.34

Source: Guidehouse

Table 4-7: Monitor group State of Charge Distribution

SOC Group (%)	SOC Start	SOC Stop
0-9	1.8%	0.1%
10-19	4.5%	0.2%
20-29	12.1%	1.2%
30-39	8.6%	1.9%
40-49	10.9%	3.6%
50-59	10.8%	4.3%
60-69	11.5%	5.6%
70-79	15.6%	22.3%
80-89	10.1%	14.2%
90-100	14.2%	46.5%

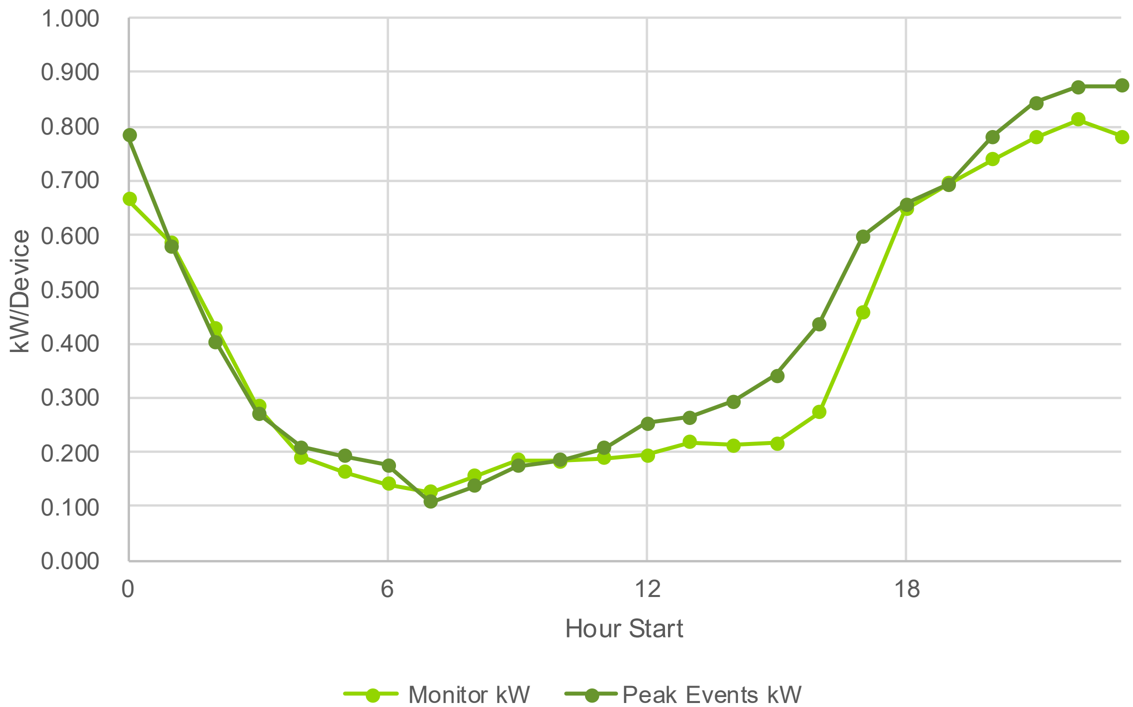
Source: Guidehouse

4.3 Demand Impacts - Peak Events

4.3.1 Randomization Verification

Figure 4-3 shows a comparison of hourly load shapes on non-event days for all months (September 1, 2024 to March 31, 2025) for BEVs between Monitor and Peak Events groups. The randomization control trial (RCT) check demonstrates that the Monitor and Peak Events group are generally similar in terms of charging behaviour, but they do exhibit some differences in behaviour later in the day.

Figure 4-3: Comparison of Average Charging Demand for All Months (Sep 2024 – Mar 2025)



Source: Guidehouse

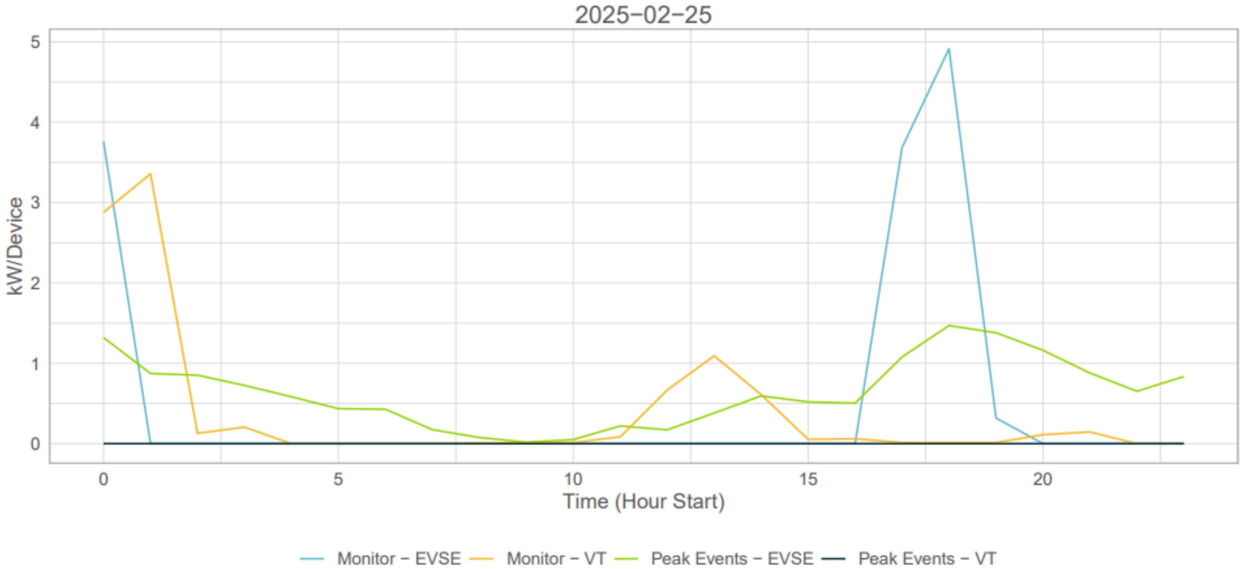
Specifically, the average demand for the Monitor group closely resembles demand for the Peak Events group on non-event days during the morning, and closely during the evening. There is a gap between the Monitor and Peak Events group demand from 12 PM to 6 PM and 7 PM to 1 AM. The differences between the two groups may be due to the small size and the influence of individual charging patterns on average load, as well as the fact that the groups were not truly randomized, due to small sample size and compatibility issues affecting group assignments. Compatibility with the platform led to the control and treatment groups having different distributions of vehicle make and models.

Ultimately, in absence of a better quality Monitor group, Guidehouse concluded that the Monitor group would serve as an appropriate comparison group with which to estimate impacts for both treatments – Peak Events and Off-Peak Charging. For the Peak Events group, Guidehouse concluded that the Monitor group, non-event charging data, and regression analysis approach would be sufficient to produce a robust estimate of savings.

4.3.2 Comparison of Event Load Shapes

Figure 4-4, Figure 4-5, and Figure 4-6 show three representative days that demonstrate the curtailment of the Peak Events treatment. On February 25, 2025, there was a notification sent to the Peak Events group a day ahead of the event. Charging can be seen the day before the event in the Active Management – EVSE group. On February 26, 2025 an event was called between 7 PM and 11 PM. During the 4-hour event, the load was curtailed for the Active Management groups compared to the Monitor group. Guidehouse observed that on the February 26, 2025 event day, very little charging was observed throughout the day, which suggests that participants may intentionally not charge for the whole day in anticipation of the DR event. The Active Management load was increased starting at 11 PM until 4 AM the following day on February 27, 2025. This load increase on the following day shows load shifting behaviour due to the event.

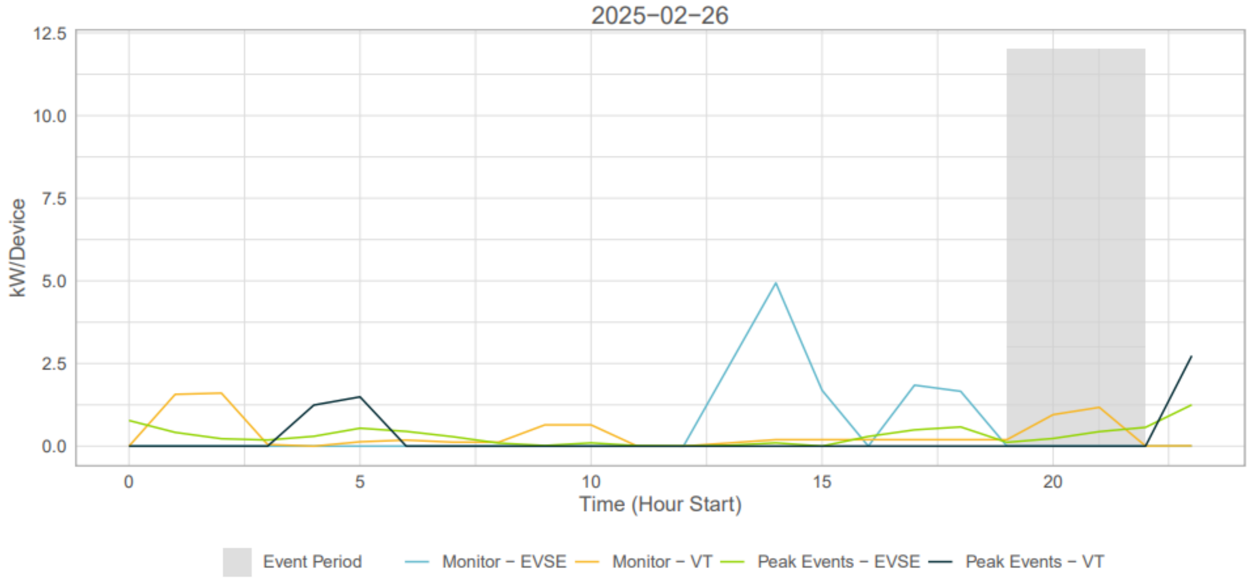
Figure 4-4: Peak Events (ADR) Representative Day for February 25, 2025



Note: This plot reflects an hourly time series, so the values represent the average power in increments of one hour, for each hour start (e.g. the value for hour start 10 represents the average power between 10 AM to 11 AM)

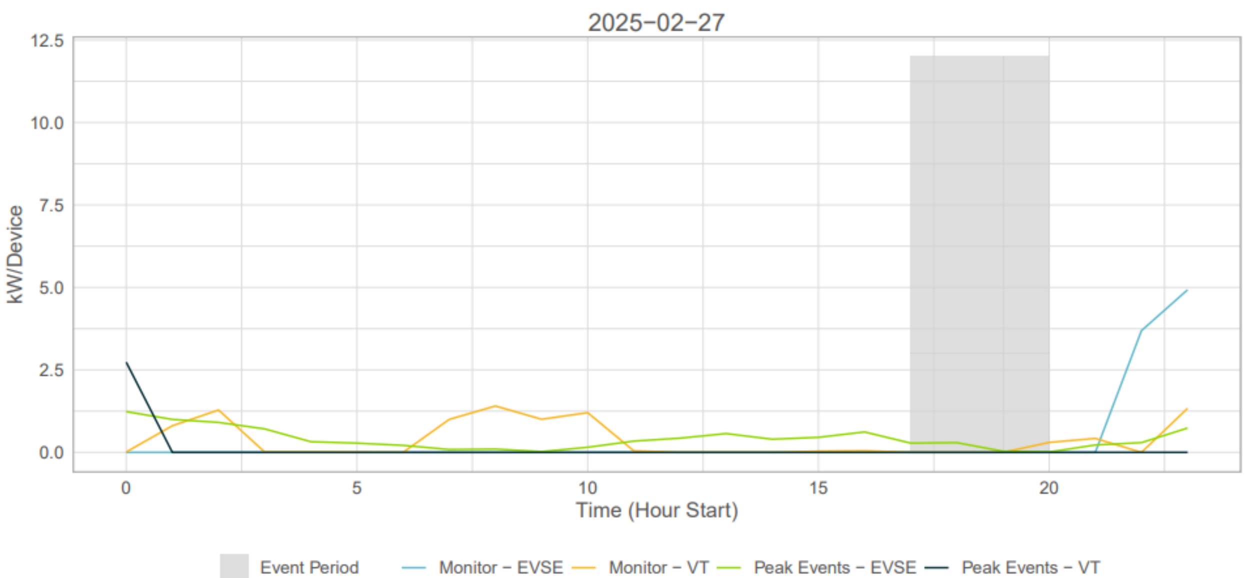
Source: Guidehouse

Figure 4-5: Peak Events (ADR) Representative Day for February 26, 2025



Note: This plot reflects an hourly time series, so the values represent the average power in increments of one hour, for each hour start (e.g. the value for hour start 10 represents the average power between 10 AM to 11 AM)
Source: Guidehouse

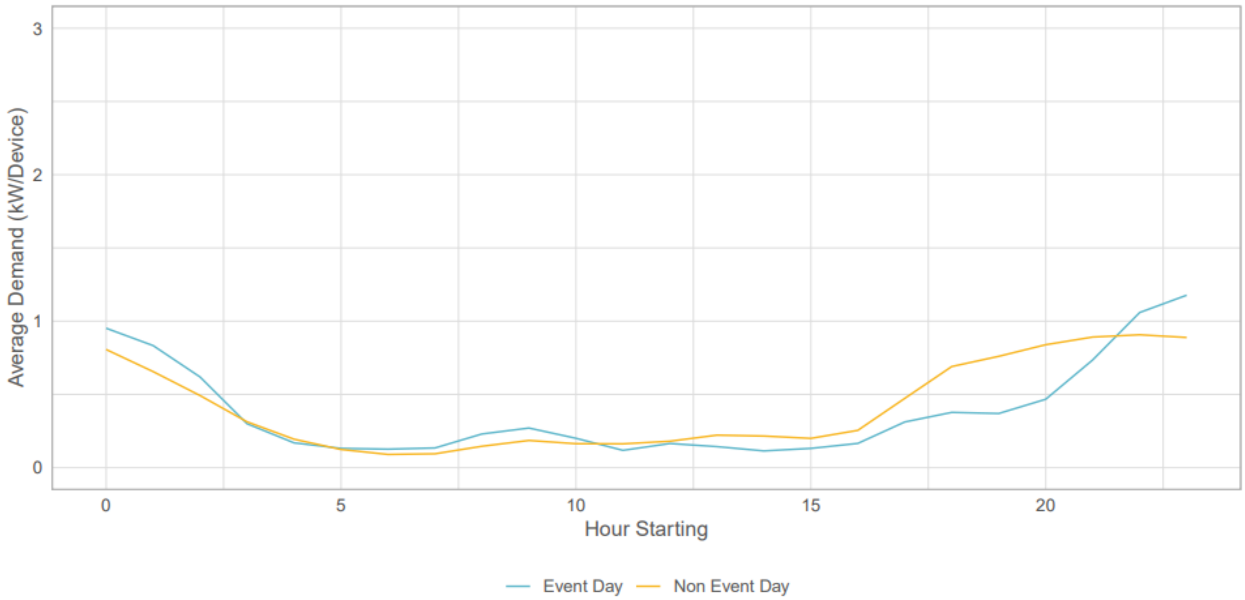
Figure 4-6: Peak Events (ADR) Representative Day for February 27, 2025



Note: This plot reflects an hourly time series, so the values represent the average power in increments of one hour, for each hour start (e.g. the value for hour start 10 represents the average power between 10 AM to 11 AM)
Source: Guidehouse

Figure 4-7 compares the Monitor group load shape on event and non-event days for the Peak Events group. The Monitor group appears to be changing their behaviour as the Monitor group was slightly lower during the evening peak event times and higher in the overnight period, which indicates that some in the Monitor group may have been somewhat aware of the peak event times. However, 90% of respondents in the survey for the Monitor group indicated that the Pilot did not affect their charging behaviour, so the reason for this difference in load shape is inconclusive.

Figure 4-7: Monitor Load Shape by Peak Events Event Day vs. Non-Event Day



Source: Guidehouse

4.3.3 Event Opt-Outs and Dispatch Failures

Table 4-8 below shows a summary of the opt-outs, dispatch failures, number of participants (i.e. successfully dispatched events), partial participants (i.e. successfully started the event but ended the event in a dispatch failure), and unsure (i.e. where there is no dispatch or opt-out data available) by Peak Events number (see Table 2-1 for definitions). There were a total of 10 opt-outs from participants in the Peak Events group. The number of dispatch failures were steady throughout the Pilot. The number of participants increased over the Pilot as the number of unsure decreased. This pattern demonstrates an improvement in Newfoundland Power's capability to successfully dispatch events over the course of the Pilot.

Table 4-8: Peak Events (ADR) Opt-Outs, Dispatch Failures, Participants, Partial Participants, and Unsure by Event

Event Number	Opt-Outs	Dispatches Failures	Number of Participants	Number of Partial Participants	Unsure
1	0	49	6	0	25
2	0	47	14	2	17
3	0	46	18	1	15
4	0	48	17	1	14
5	0	47	17	1	15

Event Number	Opt-Outs	Dispatches Failures	Number of Participants	Number of Partial Participants	Unsure
6	0	50	16	0	14
7	0	44	20	0	16
8	0	47	18	1	14
9	0	46	23	1	10
10	0	48	21	1	10
11	0	50	20	1	9
12	0	50	22	0	8
13	1	51	19	0	9
14	0	50	22	0	8
15	0	49	23	0	8
16	0	49	24	0	7
17	0	50	20	1	9
18	0	50	21	0	9
19	1	50	20	0	9
20	0	47	25	0	8
21	2	46	25	0	7
22	0	51	22	1	6
23	0	52	20	0	8
24	0	49	24	1	6
25	0	49	22	2	7
26	0	52	21	1	6
27	1	50	22	0	7
28	0	51	23	0	6
29	0	48	25	0	7
30	2	48	24	0	6
31	0	50	22	0	8
32	0	53	20	0	7
33	0	49	22	3	6
34	1	50	22	1	6
35	0	42	28	3	7
36	0	49	20	1	10
37	0	45	25	2	8
38	1	49	22	1	7
39	1	51	21	0	7
40	0	49	22	1	8

Event Number	Opt-Outs	Dispatches Failures	Number of Participants	Number of Partial Participants	Unsure
41	0	51	22	1	6
42	0	48	22	3	7
43	0	51	21	0	8
44	0	53	20	0	7
45	0	50	22	0	8
46	0	52	21	0	7
47	0	50	21	0	9
48	0	50	23	0	7
49	0	51	22	0	7
50	0	53	21	0	6
51	0	54	20	0	6
52	0	49	23	2	6
53	0	49	24	0	7

Source: Guidehouse

4.3.4 Estimated Demand Impacts

As described in Section 2.3.2, Guidehouse grouped events by start and end time ("event time") for the purposes of evaluation. Table 4-9 below shows the Peak Events impacts for each event time. Reported impacts reflect the impact of the treatment, inclusive of any opt-outs. Guidehouse estimated statistically significant savings for events that occurred from 5 PM – 9 PM, 5 PM – 10 PM, 6 PM – 10 PM, 7 PM – 11 PM, 6 AM – 10 AM, and 7 AM – 10 AM. Of the 7 event times, savings were estimated ranging from 0.05 kW to 0.46 kW per device. A statistically insignificant increase in demand was observed in the remaining event periods. See the Appendix B spreadsheet for the impacts by hour for each event time.

Variance in observed impacts is likely attributable to the high number of dispatch failures and the technical and operational issues experienced during the season (e.g. events not being dispatched correctly). This can be observed via inspection of event load shapes, which are provided in Appendix B. Estimated impacts will likely be more consistent if events are dispatched more successfully; however overall, the evaluation results show evidence of the intended load shift attributable to the program.

Table 4-9: Peak Events (ADR) Impacts by Event Time

Event Time	Number of Events	Savings Per Device (kW)	Margin of Error (kW) (90% Confidence Interval)	Relative Precision +/-% (90% Confidence)
5 PM - 8 PM	1	0.05	0.37	777%
5 PM - 9 PM	11	0.25	0.13	52%
5 PM - 10 PM	9	0.37	0.12	33%
6 PM - 10 PM	13	0.41	0.09	23%
7 PM - 11 PM	11	0.46	0.13	28%
6 AM - 10 AM	7	0.06	0.05	84%
7 AM - 10 AM	1	0.10	0.08	89%

Source: Guidehouse

4.4 Demand Impacts - Off-Peak Charging

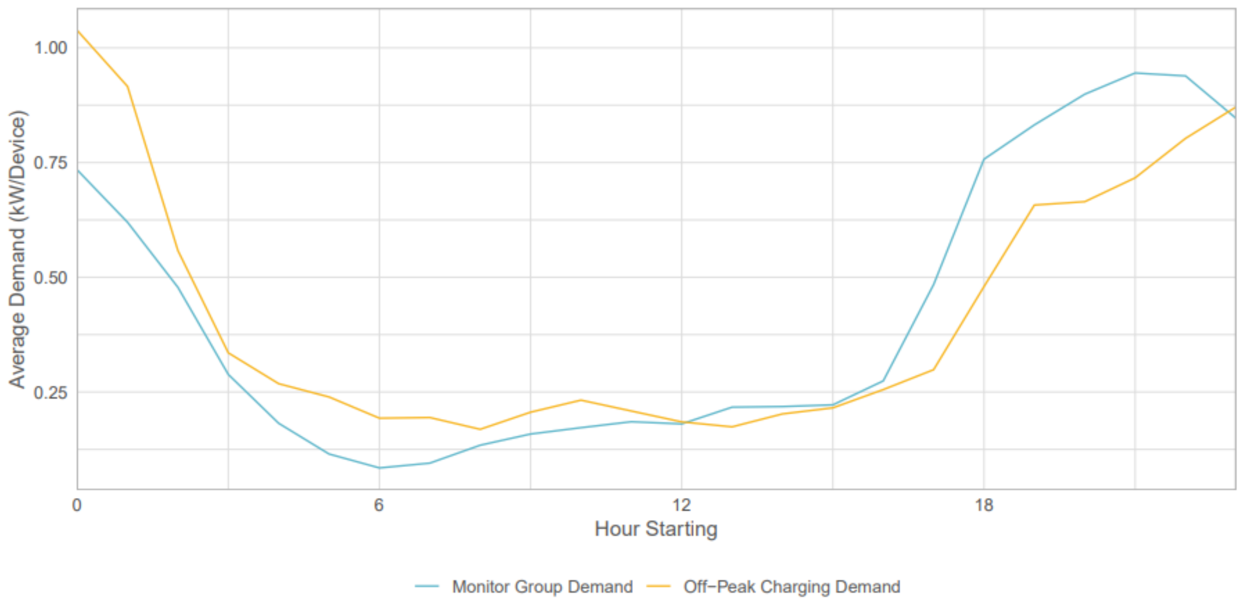
4.4.1 Randomization and Non-Treatment Period Comparison

For the Off-Peak Charging treatment, Guidehouse could not directly verify the randomization of the Monitor and Off-Peak Charging groups, as in Year 1, there were no non-event periods to compare. In general, since VT participants were generally randomly assigned among all groups (assuming compatibility), and nearly all EVSE participants were assigned to the Peak Events group (except for 3 EVSE participants that were assigned to the Monitor group), Guidehouse expects the randomization to be robust for the Off-Peak Charging treatment.

Guidehouse compared charging behaviour between the Off-Peak Charging and Monitor (control) groups during the pre-period (non-treatment period), from September 1, 2024 to November 30, 2024. Due to technical issues (e.g. with Optiwatt), data was only available for the pre-period for participants enrolled in Year 1 of the Pilot, and did not have participants that were enrolled after Year 1 of the Pilot.

Figure 4-8 shows the pre-period load shape comparison, which shows that the Off-Peak Charging group appears to demonstrate modified charging behaviour during the pre-period relative to the Monitor group. This result suggests that behavioural changes that lead to demand impacts during Winter 2024 persisted throughout the year, even without continuing monthly incentives. However, the difference in charging behaviour between the control and treatment group means that the pre-period cannot be used as a counterfactual for the Pilot period, as it does not truly represent an “untreated” period. Therefore, Guidehouse performed our analysis based the 2025 winter pilot season only, under the assumption that the Monitor group would serve as a sufficient comparison group during the Pilot, when including the Year 2 enrolled participants, based on the randomization of assignment as well as the comparison of non-event day loads with the Peak Events group as shown in Section 4.3.1.

Figure 4-8: Off-Peak Charging (BDR) Hourly Load Shape for Pre-Period Before the Pilot



Note: This plot reflects an hourly time series, so the values represent the average power in increments of one hour, for each hour start (e.g. the value for hour start 10 represents the average power between 10 AM to 11 AM)

Source: Guidehouse

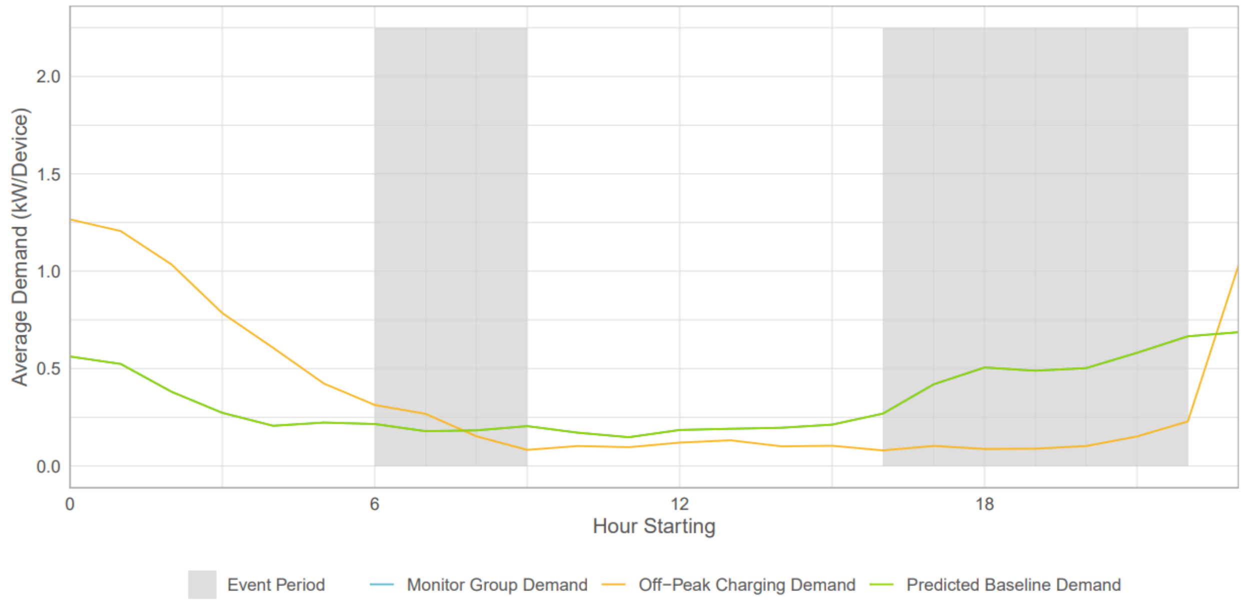
4.4.2 Comparison of Load Shapes

Figure 4-9, Figure 4-10, and Figure 4-11 show comparisons of hourly load shapes overall, for weekdays, and for weekends, respectively, for the Monitor (control) group and the Off-Peak Charging group, as well as the estimated baseline based on regression modeling. These results show a clear response of the Off-Peak Charging group as their charging behaviour is reduced during the evening peak period.

The average demand for the Off-Peak Charging group is highest from approximately 11 PM to 6 AM. Demand for the Monitor group is steady earlier in the day, increasing throughout the late afternoon and evening. No significant reduction in demand was estimated during the morning peak period, but observed demand for both the Passive Management and Monitor groups is around the same level.

The average daily consumption is very similar between the Monitor group demand (in blue) and Off-Peak Charging treatment (in green). There is a slight difference still between the control and treatment group consumption (difference of 0.50 kWh / day), and this difference may be due to differences in the composition of the two groups. For example, Guidehouse noted different proportions of vehicle makes, which may be associated with different battery capacities and charging power. Specifically, the Monitor group had more Chevrolet and other vehicle makes, while the treatment group had more Tesla and Hyundai.

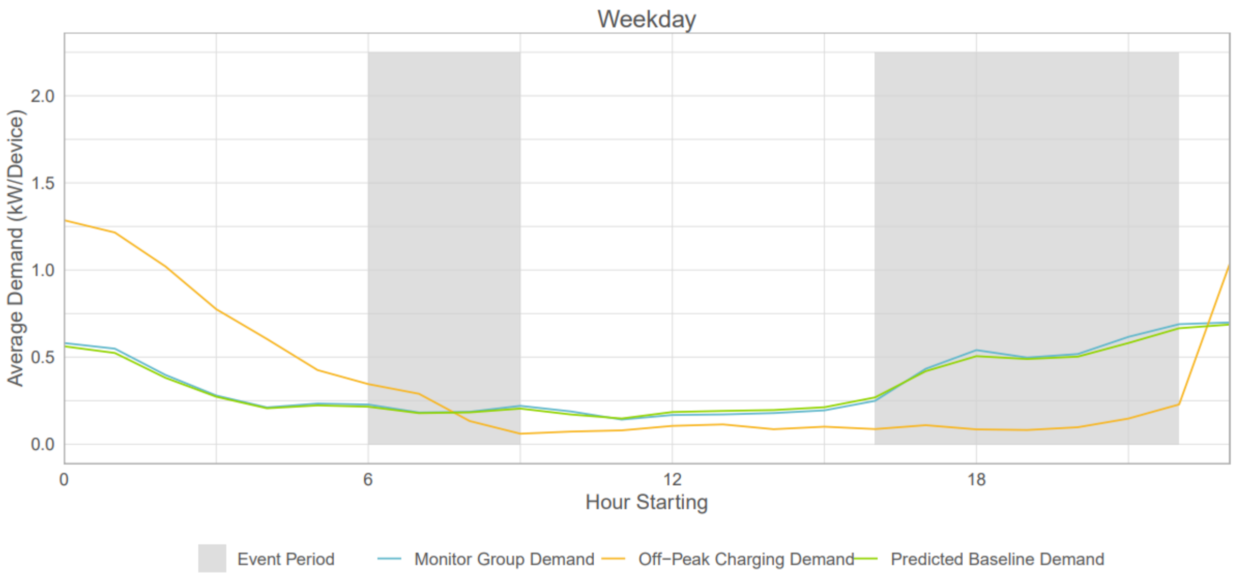
Figure 4-9: Off-Peak Charging (BDR) Hourly Load Shape Overall



Note: This plot reflects an hourly time series, so the values represent the average power in increments of one hour, for each hour start (e.g. the value for hour start 10 represents the average power between 10 AM to 11 AM). The Monitor (control) group (blue) is overlapping with the predicted baseline demand (green), as the Monitor (control) group was used as the predicted baseline demand.

Source: Guidehouse

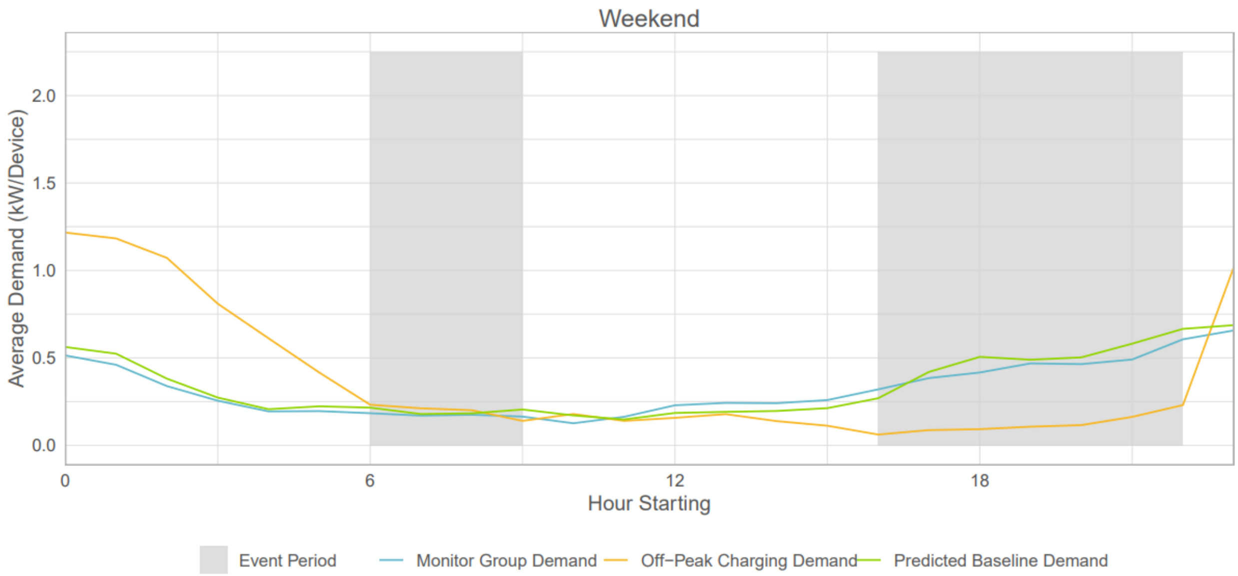
Figure 4-10: Off-Peak Charging (BDR) Hourly Load Shape for Weekdays



Note: This plot reflects an hourly time series, so the values represent the average power in increments of one hour, for each hour start (e.g. the value for hour start 10 represents the average power between 10 AM to 11 AM).

Source: Guidehouse

Figure 4-11: Off-Peak Charging (BDR) Hourly Load Shape for Weekends



Note: This plot reflects an hourly time series, so the values represent the average power in increments of one hour, for each hour start (e.g. the value for hour start 10 represents the average power between 10 AM to 11 AM).
Source: Guidehouse

4.4.3 Opt-Outs

Table 4-10 summarizes opt-outs by device in the Off-Peak Charging group (i.e. those that charged during a peak period). Note that there is uncertainty in start and end times of charging due to the frequency of data polling for the Smartcar data, as described previously in Section 2.2.1. This results in uncertainty regarding which devices truly opted-out during the peak times, as estimated charging start and stop times are uncertain by as much as 1 hour.

The All group summarizes opt-outs based on all potential overlap between peak hours and charging, while the Filtered group uses more lenient criteria to remove some opt-outs relative to the All group. These leniency criteria included reasons such as:

- When one observation was in the off-peak period and the subsequent or preceding observation was in the on-peak period,
- The SOC was below a threshold of 25%, there was a gap of more than 6 hours between charging observations,
- The average on-peak kW was more than 1.5 kW for participants that did not have a L2 charger at home (assumed that charging was away from home).

Note that these opt-outs ultimately do not affect estimated impacts, as all device data is included regardless of apparent participation in Off-Peak Charging. Reported impacts reflect the impact of the treatment, inclusive of any opt-outs.

Table 4-10: Off-Peak Charging (BDR) Opt-Outs

Opt-Outs by Device	Min	Mean	Median	Max
All - Dec	0.0	8.9	5.5	35.0
All - Jan	0.0	7.3	3.5	39.0
All - Feb	0.0	6.1	2.0	56.0
All - Mar	0.0	7.0	4.5	41.0
Filtered - Dec	0.0	5.5	2.5	29.0
Filtered - Jan	0.0	3.9	2.0	24.0
Filtered - Feb	0.0	3.0	1.0	22.0
Filtered - Mar	0.0	4.5	3.5	21.0

Source: Guidehouse

4.4.4 Estimated Demand Impacts

Table 4-11 below lists the impacts by the event hours and day type (weekday vs weekend) for the Off-Peak Charging group. See Appendix B for impacts by hour. One Off-Peak Charging period had statistically significant impacts, specifically the evening peak period from 4 PM to 11 PM. Although the morning off-peak period between 11 PM to 6 AM did not show statistically significant impacts, the point estimate is consistent with the expected load shift of evening to overnight charging. Guidehouse estimated savings of 0.37 kW per device during the evening peak period. This represented a 75% decrease in peak load for the evening peak period, and a 123% increase in peak load for the morning off-peak.

No statistically significant impacts were observed between the period from 6 AM to 10 AM. This may be attributed to the similar demand load shape during the morning peak of the control and treatment groups, in part because most charging takes place in either the evening peak period or morning off-peak period. The saving impacts on weekdays are larger than on weekends. This result can be attributed to the fact that more concentrated charging on weekday evenings (due to work schedules) that can be shifted.

Table 4-11: Off-Peak Charging (BDR) Event Impacts by Event Hours and Day Type

Event	Event Hours	Day Type	Savings Per Device (kW)	Margin of Error (kW) (90% Confidence Interval)	Relative Precision +/-% (90% Confidence)
Morning Peak	6 AM - 10 AM	All	-0.01	0.03	332%
Evening Peak	4 PM - 11 PM	All	0.37	0.02	6%
Morning Off-Peak	11 PM - 6 AM	All	-0.50	0.02	4%
Afternoon Off-Peak	10 AM - 4 PM	All	0.07	0.02	31%
Morning Peak	6 AM - 10 AM	Weekday	-0.00	0.03	1096%
Evening Peak	4 PM - 11 PM	Weekday	0.39	0.03	7%
Morning Off-Peak	11 PM - 6 AM	Weekday	-0.49	0.03	5%
Afternoon Off-Peak	10 AM - 4 PM	Weekday	0.08	0.03	34%
Morning Peak	6 AM - 10 AM	Weekend	-0.02	0.05	236%
Evening Peak	4 PM - 11 PM	Weekend	0.33	0.04	12%
Morning Off-Peak	11 PM - 6 AM	Weekend	-0.53	0.04	8%
Afternoon Off-Peak	10 AM - 4 PM	Weekend	0.06	0.04	74%

Source: Guidehouse

4.5 Program Benefits

Guidehouse estimated system benefits for on-peak periods (6 AM to 10 AM and 4 PM to 11 PM) based on average impacts for each treatment and avoided cost of capacity values provided by Newfoundland Power as described in Section 2.3.3 ($356.07 / kW-year) Table 4-12 and Table 4-13 show program benefits for the Off-Peak Charging (BDR) and Peak Events (ADR) groups, respectively. These estimates represent the potential program benefits associated with each device (vehicle or EVSE) for different definitions of system peak, i.e., in different cases where system peak would coincide with the treatment period. The Appendix B spreadsheet provides more granular hourly program benefit estimates, which may be used to estimate potential benefits for other system peak definitions.

Note that since estimated impacts for some periods were not statistically significant, there is uncertainty in potential benefits. Guidehouse did not remove any estimates when estimating program benefits.

Both the Off-Peak Charging and Peak Events groups were estimated to deliver system benefits, particularly during the evening periods. Off-Peak Charging delivered a benefit of approximately $131.76 per device during the 4 PM to 11 PM event window. During the 6 AM to 10 AM event window, Off-Peak Charging did not have any potential benefits. The benefits estimated for the Peak Events group reflect the estimated impacts for all events that were called during peak periods, rather than a specific event time. The benefits from the Peak Events were less than the Off-Peak Charging group during evening peak but delivered a statistically significant benefit in the morning on-peak and was higher than that of the Off-Peak Charging group, which did not have statistically significant savings during the morning on-peak.

Table 4-12: Program Benefits for Off-Peak Charging Events (BDR)

Peak Period	Day Type	Savings Per Device (kW)	Avoided Cost of Capacity Per Device ($/year)
6 AM - 10 AM	All	-0.01	-$3.07
4 PM - 11 PM	All	0.37	$131.76
6 AM - 10 AM	Weekday	-0.00	-$1.10
4 PM - 11 PM	Weekday	0.40	$143.82
6 AM - 10 AM	Weekend	-0.02	-$8.15
4 PM - 11 PM	Weekend	0.32	$113.25

Source: Guidehouse

Table 4-13: Program Benefits for Peak Events (ADR)

Peak Period	Savings Per Device (kW)	Avoided Cost of Capacity Per Device ($/year)
6 AM - 10 AM	0.08	$27.03
4 PM - 11 PM	0.32	$114.81

Source: Guidehouse

4.6 Comparison of Year 1 and Year 2 Impact Results

Table 4-14 compares impacts between the Year 1 evaluation and the Year 2 evaluation for the Peak Events group. The Peak Events evening savings increased in Year 2 compared to Year 1, for the event times of: 5 PM – 9 PM, 6 PM – 10 PM and 7 PM – 11 PM. Additionally, the estimated savings are more certain in Year 2 than in Year 1 due to the larger sample of participants. The morning Peak Events had about the same savings in Year 2 as in Year 1, but were similarly more certain in Year 2 than in Year 1.

Table 4-14: Peak Events (ADR) Year 1 to Year 2 Comparison

Event Time	Year 1 Savings Per Device (kW)	Year 1 Relative Precision +/-% (90% Confidence)	Year 2 Savings Per Device (kW)	Year 2 Relative Precision +/-% (90% Confidence)
5 PM - 8 PM	N/A	N/A	0.05	777%
5 PM - 9 PM	-0.31	287%	0.25	52%
5 PM - 10 PM	N/A	N/A	0.37	33%
6 PM - 10 PM	-0.08	698%	0.41	23%
6 PM - 11 PM	1.03	48%	N/A	N/A
7 PM - 11 PM	-0.66	233%	0.46	28%
6 AM - 10 AM	0.10	306%	0.06	84%
7 AM - 10 AM	-0.01	3287%	0.10	89%

Note: N/A means there were no applicable event times in that evaluation year.
Source: Guidehouse

Table 4-15 shows a comparison of estimated impacts for the Year 1 evaluation and Year 2 evaluation for the Off-Peak Charging group. Estimated evening peak savings decreased slightly in Year 2 to 0.37 kW compared to 0.48 kW in Year 1, and were also more certain from 79% relative precision in Year 1 to 6% in Year 2. The morning off-peak impacts were lower in Year 2 with -0.50 kW from -0.67 kW in Year 1, and become more certain from 60% relative precision to 4% in Year 2.

Table 4-15: Off-Peak Charging (BDR) Year 1 to Year 2 Comparison

Event	Event Hours	Year 1 Savings Per Participant (kW)	Year 1 Relative Precision +/-% (90% Confidence)	Year 2 Savings Per Device (kW)	Year 2 Relative Precision +/-% (90% Confidence)
Morning Peak	6 AM - 10 AM	-0.17	294%	-0.01	332%
Evening Peak	4 PM - 11 PM	0.48	79%	0.37	6%
Morning Off-Peak	11 PM - 6 AM	-0.67	60%	-0.50	4%
Afternoon Off-Peak	10 AM - 4 PM	-0.16	309%	0.07	31%

Source: Guidehouse

5. Participant Survey Results

5.1 Participant Survey Characteristics

The participant survey achieved a relatively high response rate of 51% (based on 92 completes), with a low screen-out percentage of 2%. See Table 5-1 for the participant survey response rate for each group.

Table 5-1: Participant Survey Response Rate

Group	Number of Participants	Number of valid respondents	Survey Response Rate
Peak Events	79	41	52%
Off-Peak Charging	47	21	45%
Monitor	54	30	56%
All	**180**	**92**	**51%**

Source: Guidehouse

Respondents had the following characteristics based on survey responses:

- 91% own L2 charging equipment at home.
- 65% reported working full-time, part-time or attending school outside their home.
- 72% reported that their household's approximate 2024 total income (before taxes) was $100K or more.

This section summarizes the main findings related to participant charging behaviour, participant satisfaction, concerns, and other feedback. Refer to Appendix D for the full survey analysis.

5.2 Feedback on Pilot Program Implementation

5.2.1 Respondent Satisfaction with the Pilot

When asked about their satisfaction with the overall Pilot, 84% of respondents gave an interest rating of 6 or more (with 10 being "Very satisfied"), indicating a high rate of overall satisfaction. Table 5-2 shows the respondents' satisfaction ratings per group when asked about their overall experience with the Pilot. The Off-Peak Charging group reported the lowest rate of satisfaction, which may suggest that more participants in this group had to change their charging behaviour more drastically or encountered more issues. Some Off-Peak Charging group respondents had complaints about having to wait until 11 PM to charge their vehicles, which may have increased dissatisfaction.

Table 5-2: Satisfaction with Overall Program

Satisfaction Rating[1]	Peak Events group	Off-Peak Charging group	Monitor group	All Respondents
Dissatisfied (1 – 5)	17%	24%	10%	16%
Satisfied (6 – 10)	83%	76%	90%	84%

Source: Guidehouse
[1]Respondents were asked to rate their satisfaction level from 1 to 10 with 10 being “Very satisfied”

Table 5-3 shows the respondents’ satisfaction with various aspects of the Pilot along with the main reasons for why respondents were dissatisfied. Comments related to dissatisfaction represent potential areas for improvement in the delivery of future EV load management programs. In particular, the results indicate that resolving Hyundai’s BlueLink and Optiwatt app incompatibility[4] issues could improve participant satisfaction.

Table 5-3: Satisfaction with Varying Aspects of the Pilot

How satisfied were respondents with the:	Percentage of all respondents generally satisfied[1]	Main reasons for dissatisfaction
Charging platform?	60%	Hyundai’s BlueLink and Optiwatt app incompatibility issues.
Ability to opt-out? [2]	73%	Lack of understanding for when they can opt-out.
Frequency and relevance of the communication?	78%	Too many notifications, especially in the early morning and overnight.
Enrollment process? [3]	78%	Too many steps involved.

Source: Guidehouse
[1]Respondents gave a rating of 6 or higher when asked about satisfaction level with 10 being “Very satisfied”
[2]Ability to opt-out only applies to the Peak Events group and the Off-Peak Charging group
[3]Respondents gave a difficulty rating from 1 – 10 with 10 being “Very easy”

The majority of respondents were satisfied with the communication of the program. The top 3 preferred methods of receiving information were Email, Text message and Mobile App notifications. The top 2 preferred frequencies to hear from the Pilot were once a month and once a week. Newfoundland Power could consider implementing Email and Text message as their main method of communication in future EV load management programs.

[4] Hyundai Bluelink forced users to update login credentials while users were participating in the pilot program causing multiple unsuccessful login attempts by Optiwatt’s API causing users to be locked out of the Hyundai’s Bluelink App. App incompatibility was due to the vendor (Uplight’s Optiwatt) app not being compatible with the Tesla software, resulting in the Optiwatt app overriding the Tesla charging schedule. There were time variances between the charging session start and stop times for the OEM app and Optiwatt app.

5.2.2 Concerns and Issues

The lack of understanding regarding the opt-out process and program mechanics was prevalent when identifying the respondents' concerns and issues. Some respondents did not understand the opt-out process, which led them to charge their vehicle less than they would like. Newfoundland Power could consider revisions to communication of the following program mechanics with more clarity in future EV load management programs to improve satisfaction levels and facilitate easier participation:

- How many times a participant can opt-out in a month and still be eligible for the monthly incentive.
- The incentive amounts for taking part in the Pilot.

Table 5-4 lists different categories of concerns that participants may have had, as well as: (1) the percentage of participants that had these concerns before enrolling; and (2) the percentage that still have these concerns. Participants were not generally initially concerned about the Pilot – 43% of respondents did not have any concerns. For those participants that had some initial concerns, the survey shows that the percentage of respondents who still had concerns has decreased.

Table 5-4: Participant Concerns with the Pilot

Concern	Percentage of all respondents (%)	
	Who had the concern prior to enrolling	Who are still "Very concerned"[1]
Concern about privacy, data security or their location being shared	34%	3%
Concern that their vehicle would not always be charged when they wanted to use	31%	0%
Concern if their vehicle or charging equipment would be eligible for the Pilot	21%	1%
Concern over the effort needed to work or manage their EV's charging schedule	16%	2%

Source: Guidehouse

[1]Respondents were asked if they were "No longer concerned", "Somewhat concerned" or "Very concerned" at the time of the survey. The table identified the respondents who are still "Very concerned".

As seen in the table above, 34% of all respondents noted that they were concerned about their privacy, data security or location being shared prior to enrolling to the program. Currently, 3% of respondents are still "Very concerned" about this, 17% are still "Slightly concerned" and 13% are "No longer concerned". Newfoundland Power could consider reassuring participants that their data will not be shared with external parties to continue to bring down participants' concerns with data security.

When asked how takeCHARGE NL can address participant's concerns, the following answers were provided:

- Respondents would like to receive updates on how the program worked and what action will be taken as a result of this program.
- Respondents would like more EV chargers to be eligible to participate.
- Respondents request that issues that were seen with the OptiWatt App and regarding wear on the car battery (possibly linked to charging control - Hyundai's BlueLink) be solved.
- Respondents in the Off-Peak Group found that 11 PM was too late a time to be expected to charge their car and would like the period to start earlier.
- Respondents found there was a lack of information at the start of the Pilot about the data collection agency.

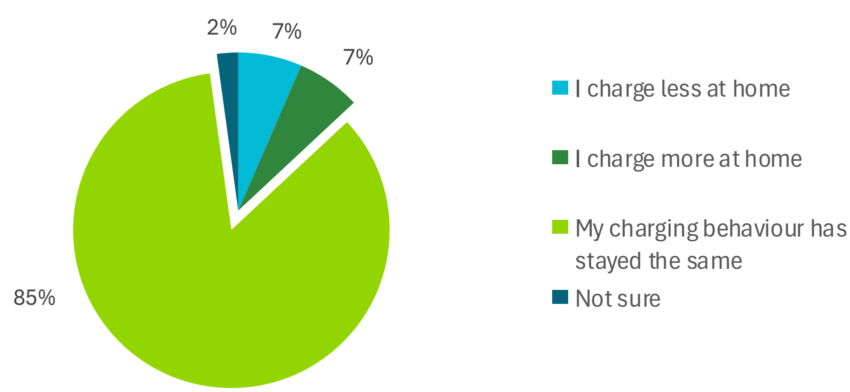
To ensure participants are well informed and to reassure their confidence in the Pilot, Newfoundland Power may consider additional communication around the effect the Pilot will have on a participant's vehicle and the level of effort required from the participant. If possible given platform limitations, expanding the number of vehicles eligible for the Pilot and solving the Hyundai's BlueLink and Optiwatt App issues would also improve participant satisfaction.

5.3 Participant Behaviour Analysis

5.3.1 Change in Charging Behaviour

Most respondents stated that their charging behaviour did not change with respect to where they charge. Figure 5-1 shows the response of all respondents when asked if their charging behaviour has changed.

Figure 5-1: Change in Charging Behaviour of All Respondents



Source: Guidehouse

The Peak Events group had the greatest change in their charging behaviour with 22% of Peak Events respondents indicating they changed where they charge since enrolling with the Pilot (refer to Appendix D for the full survey results analysis). This may indicate that the Peak Events group is the most effective in having participants reconsider their current charging habits and in participants understanding the benefit in changing them. When asked if their charging behaviour changed as a result of the Pilot, 60% of respondents stated it did. Respondents adjusted their charging behaviours by avoiding peak periods, and some respondents noted that the Optiwatt app aided in the change as they were able to program their charging schedule.

The load shape data shows that there was load shifting for both the Peak Events group and the Off-Peak Charging group. The load shifting aligns with the respondents' comments that their behaviour was changed because of the Pilot, both in when they charge and sometimes where they charge. The survey results and load shifting data suggests that the Pilot was successful in changing participants' charging behaviour, and specifically, the Peak Events group saw the greatest change.

5.3.2 Use of the Override Process

Most respondents reported opting out less than three times a month, which some stated was due to technical issues with the charging system and their lack of understanding of when they can opt-out (three Peak Events respondents reported these reasons). The Off-Peak Charging group tended to opt-out more frequently than the Peak Events group and had less comments about their lack of understanding for when they can opt-out. This may indicate that the Off-Peak Charging group found that the Pilot disrupted their regular charging schedule more than the Peak Events group as they chose to opt-out more frequently. Newfoundland Power could consider that the Peak Events group may require less effort from participants, yet load shifting is still seen. Table 5-5 shows the frequency which respondents opted-out according to the survey.

Table 5-5: Number of Opt-Outs per Month

	Peak Events group	Off-Peak Charging group
Less than 3 times a month	83%	57%
3 or more times a month	0%	10%
Not sure	17%	33%

Source: Guidehouse

The actual number of opt-outs (according to load data) indicate that only one participant from the Peak Events group opted-out three or more times in a month (for only one month). The interval data shows that around 40% of Off-Peak Charging group participants opted-out in any month. This roughly aligns with the number of respondents that indicated either three or more times a month or not sure for the survey question.

5.4 Participant Interest in Future Programs

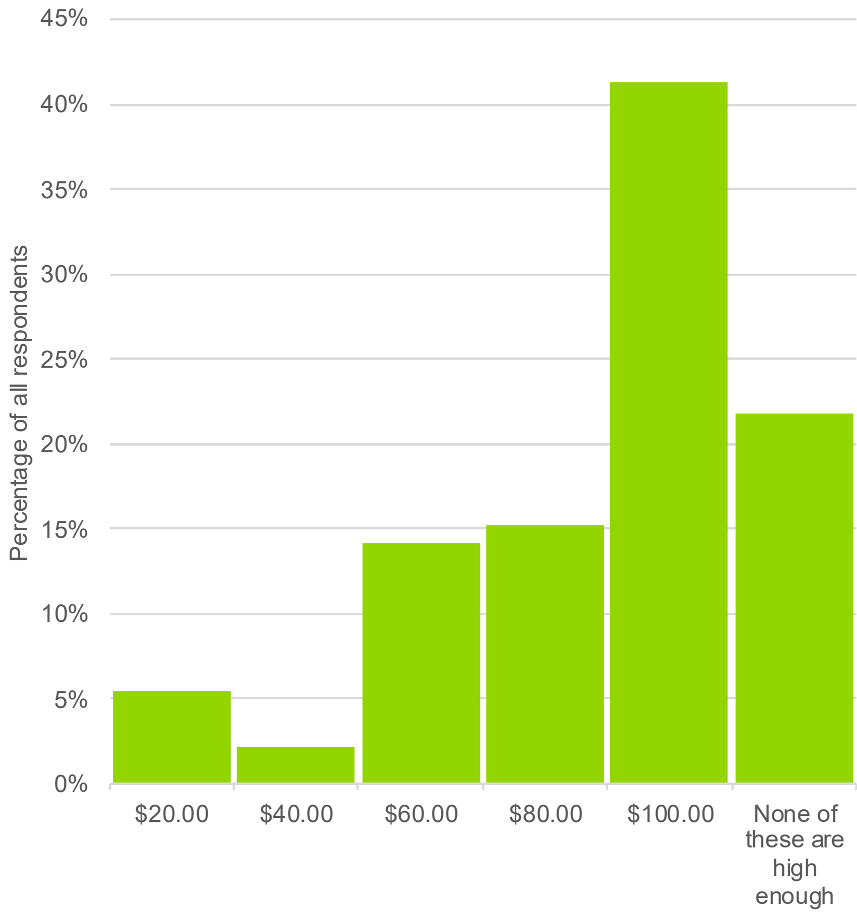
The survey results show that most respondents would be interested in participating in a future EV load management program (all respondents gave a rating of 5 or higher when asked about their future interest, with a rating of 10 being "Very interested").

5.4.1 Annual Incentive

The annual incentive that would motivate participants to join a future EV load management program ranges with 41% of respondents stating that an annual incentive of $100 would be sufficient. Figure 5-2 shows the respondents' answers when asked about their minimum ongoing annual incentive required to make them interested in participating in future programs.

However, respondents may be overstating the minimum amount they would require to participate in future programs. Newfoundland Power could benchmark incentives against other similar programs or conduct a more formal willingness to pay study if desired. Ultimately, program incentive will need to be aligned with the potential benefits, to cost-effectively deliver the program.

Figure 5-2: Minimum Ongoing Annual Incentive Respondents Would Require to Participate in Future Programs



Source: Guidehouse

The Pilot's current incentive is up to $230, and respondents were generally satisfied. In another survey question, when asked if they would be interested in participating in future programs for a $75 annual incentive, 80% of respondents said they would be (giving a rating of 6 or higher when asked about their interest, with 10 being "Very interested"). A few respondents stated that they would prefer cash or credit on their power bill instead of a store purchase card.

Newfoundland Power could consider an annual incentive of $75 to $100 and providing the incentive as a bill credit rather than a store purchase card in future EV load management programs, which may increase satisfaction.

5.4.2 Motivating Factors

Most respondents heard about the Pilot from social media, the takeCHARGE NL website and word of mouth. After being connected to the Pilot, respondents said the most motivating factors for participating in the Pilot were the following:

- The enrollment and additional incentives throughout the Pilot.
- The opportunity to contribute to research on smart EV charging and its possible economic and environmental benefits.

When advertising future EV load management programs, Newfoundland Power can utilize their social media and website to promote the program. Newfoundland Power could consider reaching out to past participants to encourage them to talk about the Pilot with their social connections. When promoting the program, Newfoundland Power could consider focusing on the incentives available and why the opportunity to participate in the program is meaningful and what benefits will be seen because of the program.

6. Conclusions

For the 2025 season, Guidehouse's evaluation of the Pilot showed clear evidence of the desired load shifting impact of both tested treatments, and provides initial quantification of the potential benefits of an EV managed charging program. The development of the Pilot also provided Newfoundland Power with valuable information regarding the issues associated with implementation of different types of treatment (e.g. passive vs active, vehicle telemetry vs EVSE) to inform future program design. Conclusions from Guidehouse's evaluation are:

- **Both active and passive load management strategies show evidence of successful load curtailment.** The passive treatment group curtailed their load in the evening peak period, with an average reduction of charging demand between 4 PM and 11 PM of 0.37 ± 0.02 kW/device. Active events resulted in an average reduction of charging demand of up to 0.46 kW/device (events called between 7 PM and 11 PM).
- **Load was generally shifted from the evening period to overnight.** This result aligns with the prediction that both treatments delay charging when participants return home and plug in their vehicles. The morning peak period (6 AM to 10 AM) shows less potential for load reduction, as participants do not typically charge their vehicles in the morning, even without any treatment.
- **EV managed charging provides system benefit in the form of avoided cost of capacity**. The exact potential benefits will vary depending on how treatments are ultimately used to target system peak, and how the system peak coincides with the treatment period. Guidehouse estimated the potential range of benefits based on average curtailment during peak periods. For example, in the morning peak period (6 AM to 10 AM) Guidehouse estimated the benefit to be $27.03 / device for Peak Events. For the evening peak period (4 PM to 11 PM), benefits were estimated to be $131.76 / device for the Off-Peak Charging treatment, and $114.81 / device for Peak Events.
- **The Off-Peak Charging group demonstrated persistent load shifting behaviour after the Winter 2023/2024 season.** The data from September 2024 to November 2024 showed persistence of some savings during the shoulder season months, which suggests the treatment is still effective in the off-season, absent a direct monthly incentive.
- **Technical and operational challenges reduced program impacts and may be a barrier to future scaling of the program.** For example, there were challenges with customer enrollment and successfully dispatching events with the Uplight platform in Year 2. These types of challenges appeared to have less effect on the passive treatment, which relies more on participants' own behavioural changes rather than the Uplight platform.
- **Year 2 of the Pilot provided additional data and improved certainty of impact estimates**. Increased enrollment in Year 2 of the Pilot provided more data and consolidating the event times for the Peak Events group provided more certain estimates for the Peak Events group compared to Year 1.
- **Survey results suggest that the Pilot was successful in influencing when participants charge, but likely not where they charge.** Survey respondents did not change whether they charge at home or at work, but they did change their charging schedules to avoid peak periods.

- **Participants were generally satisfied with the Pilot charging platform and program communication.** The frequency and method of communication were effective for respondents. Dissatisfaction related to the charging platform was due to Hyundai's BlueLink App issues and Optiwatt App incompatibility.
- **The majority of participants are interested in participating in future EV load management programs.** When respondents were asked for the minimum annual incentive amount that would make them interested in participating, a plurality of respondents said they would desire an annual incentive of up to $100. However, respondents may be overstating their minimum requirement, and could be biased towards selecting the highest incentive amount provided in the survey. In another survey question, when asked if they would be interested in participating in future programs for a $75 annual reward, 80% of respondents said they would be.

Guidehouse provides the following recommendations for Newfoundland Power to inform future program delivery and evaluation.

- **Consider the Off-Peak Charging treatment as a relatively lower complexity option to provide consistent load shift compared with other options.** Based on evaluation of the 2025 season, this passive treatment showed very clear load shifting potential, with fewer technical requirements (e.g. no discrete event dispatch, fewer platform challenges associated with failed events, equipment incompatibilities). Newfoundland Power may consider whether this strategy would meet their long-term demand side management needs, or whether active solutions provide enough incremental benefit to warrant their additional complexity. Newfoundland Power may want to consider using the strategy that presents fewer challenges in implementation.
- **A future program informed by the Pilot would need to consider the program benefits.** The results from Year 2 of the Pilot indicate that the Off-Peak Charging provides the highest potential program benefits if the system peak is in the evening, and the Off-Peak Charging treatment also has less operational challenges compared to the Peak Events treatment. The Peak Events program potential benefits are low due to high number of dispatch failures. The program benefits for the Peak Events may be higher than the Off-Peak Charging treatment if there was more successful participation in events. In addition, the Peak Events treatment can be more flexibly controlled to target specific system peak windows, to offer potentially more system benefits. However, this treatment would still have higher complexity than running a program based on passive treatment.
- **Consider addressing the technical challenges of the managed charging platform prior to further roll out of a full program.** The key challenges to address include: simplifying and improving the enrollment process to get more compatible drivers enrolled in the program; improving reliability in curtailing charging for the Peak Events group throughout the entire duration of the event; and addressing challenges in collecting reliable data.
- **Re-enroll the remaining Smartcar participants with Optiwatt.** The Smartcar data continues to have the data issue of being unable to isolate home charging data. By re-enrolling the remaining Smartcar participants with Optiwatt, this would provide both more granular vehicle telematics data, but also the ability to resolve the remaining issue of isolating home charging data. This would improve the quality of determining passive opt-outs, and improve the accuracy of the load shapes.

- **Clarify the opt-out and incentive process for participants.** During the Pilot, many survey respondents stated that they were unsure when to charge and not charge and when they would be eligible for incentives.
- **Address privacy and data security concerns and software malfunction/incompatibility issues prior to the next EV load management program.** Respondents still had concerns regarding their data security and software malfunction after the Pilot, Newfoundland Power could work to address these concerns to the extent feasible.

Appendix A. Impact Evaluation Approach

Guidehouse's impact evaluation focused on characterizing baseline charging behaviour and quantifying the demand impacts of the two treatments in the Pilot. This section provides additional details regarding data cleaning of charging telemetry data, as well as regression analysis to develop estimated impacts for the Off-Peak Charging and Peak Events treatments.

A.1 Data Cleaning

Table A-1 below summarizes the main data cleaning steps taken for the four sources of data used for this evaluation – Smartcar vehicle telematics, Wallbox EVSE telematics, ChargePoint EVSE telematics, and Optiwatt vehicle telematics.

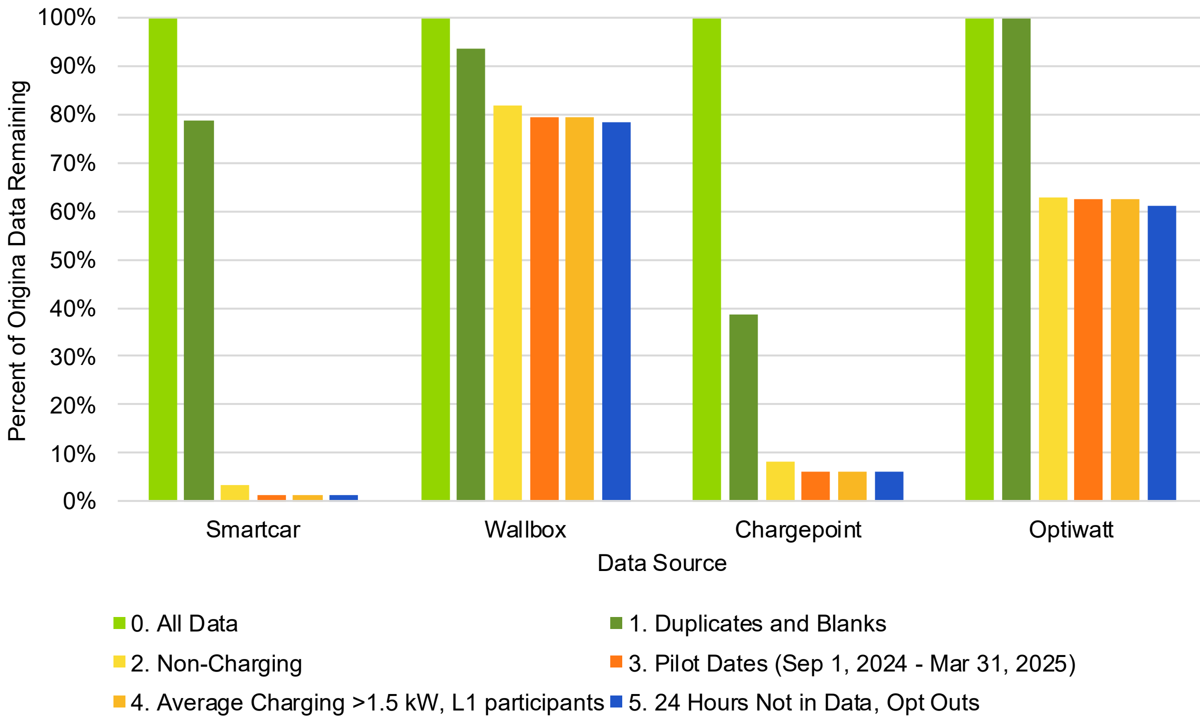
Table A-1: Data Cleaning Steps

Step	Step Description	Details
1	Remove Duplicate and Blanks	Smartcar: Assumed charging happens whenever there was an increase in vehicle state of charge (SOC). Removed duplicates, blanks and missing data where SOC was missing and calculated kWh and hours between observations. Wallbox, ChargePoint, Optiwatt: Removed duplicates, blanks in charging data.
2	Remove non-charging data	Smartcar: Remove the non-charging data. Wallbox and ChargePoint: Remove data where the kW between observations was negative. Optiwatt: Remove away from home plug in sessions, data where Hyundai vehicles had 0 charging from January 14 – March 12, 2025 due to the Hyundai's BlueLink issue, and remove data for months where there was only 0 charging data.
3	Remove data before Sep 1, 2024 and after Mar 31, 2025	The Pilot and pre-period only applied for data between Sep 1, 2024 and March 31, 2025. For Smartcar, removed data Dec 1, 2024 and later where there was Optiwatt data that could be used instead.
4	Remove high power charging for participants with L1 charger at home	Sessions with average demand more than 1.5 kW for participants in the Off-Peak Charging group with an L1 charger at home were removed from the data. For Smartcar, removed charging sessions with more than 20 kW of average session charging. This was assumed to indicate fast charging which took place away from home.
5	Remove data where not all 24 hours are in the data for a given day, Opt-outs	Any days with fewer than 24 hours of data in a day were removed from the data. For Smartcar and Chargepoint, removed any data associated with known active group opt-outs.

Source: Guidehouse

Figure A-1 below shows a summary of the data attrition (i.e. how much of the original data was removed via cleaning).

Figure A-1: Data Attrition



Source: Guidehouse

The majority of data that was removed from analysis was due to blank state of charge or non-charging observations (e.g. for the Smartcar data, there were records for polling events when no charging is occurring). As a result, the remainder of the data after cleaning contains the majority of data related to energy delivered, which is the information of interest for Guidehouse's analysis.

A.2 Impact Evaluation Approach – Peak Events

For the active management, Peak Events group, demand impacts (kW per device) were estimated in each hour on event days, before, during, and after events. The analysis estimated the average treatment effect (ATE), in which impacts are estimated for all enrolled participants, regardless of participation. Therefore, the reported impacts include the effect of participants who were enrolled in the program, but may not have curtailed during events. Due to sample size for the Peak Events group, Guidehouse reports only the ATE. Guidehouse has provided average load shapes by event and for EVSE vs VT in Appendix B, to provide additional context into the difference in response between event dates and control equipment.

Guidehouse used a regression model to estimate impacts described in Equation 1, leveraging the Monitor group.

Equation 1. Peak Events Model Specification

$$kW_{it} = \alpha_i + \lambda_t + \sum_k \beta_{1kt} Pre_{kt} Treat_i + \sum_j \beta_{2kt} Event_{kt} Treat_i + \sum_m \beta_{3kt} Post_{kt} Treat_i + \varepsilon_{it}$$

Where:

kW_{it}	is charging demand for participant i during period t (i.e., hours 1-24)
α_i	is a device-specific fixed effect for participant *i*; this picks up all device-specific characteristics that do not change through time
λ_t	is a series of time-specific fixed effects for period *t;* these pick up temporal differences, specifically hour of day and day of week (i.e., Monday, Tuesday, etc.)
Pre_{kt}	is a set of binary variables taking a value of 1 when *t* is in the kth period preceding an event (in the same day) and 0 otherwise
$Event_{jt}$	is a set of binary variables taking a value of 1 when *t* is in the jth period of an event and 0 otherwise
$Post_{mt}$	is a set of binary variables taking a value of 1 when *t* is in the mth period following an event (in the same day) and 0 otherwise
$Treat_i$	is a binary variable taking a value of 1 when participant i is in the Peak Events group and 0 if they are in the Monitor group
ε_{it}	is the error term for participant *i* during period *t*

A.3 Impact Evaluation Approach – Off-Peak Charging

For the passive management, Off-Peak Charging group, since there were no true events, Guidehouse estimated hourly demand impacts to show the difference in average charging behaviour between treatment and control groups. The analysis estimated the ATE, in which impacts are estimated for all enrolled participants, regardless of participation. Therefore, the reported impacts include the effect of participants who are enrolled in the program, but may have charged during peak hours on some days. Due to uncertainty around opt-outs for this program, Guidehouse reports only the overall ATE.

Guidehouse used the regression model specifications described in Equation 2 and Equation 3, leveraging the Monitor group, to estimate overall impacts as well as impacts by weekend vs weekday.

Equation 2. Off-Peak Charging Model Specification (All Day Types)

$$kW_{it} = \sum_{k=1}^{24} \beta_{1kt} hour_{kt} + \sum_{k=1}^{24} \beta_{2kt} hour_{kt} Treat_i + \varepsilon_{it}$$

Equation 3. Off-Peak Charging Model Specification (Weekend vs Weekday)

$$kW_{it} = \sum_{k=1}^{24} \sum_{\substack{j=Weekday,\\ Weekend}} \beta_{1kt} hour_{kt} DayType_{jt} + \sum_{k=1}^{24} \sum_{\substack{j=Weekday,\\ Weekend}} \beta_{2kt} hour_{kt} DayType_{jt} Treat_i + \varepsilon_{it}$$

Where:

kW_{it} is charging demand for participant i during period t (i.e., hours 1-24)

$hour_{kt}$ is a set of binary variables taking a value of 1 when *t* is in the k^{th} hour of the day and 0 otherwise

$DayType_{jt}$ is a set of binary variables taking a value of 1 when *t* is in the j^{th} day type (i.e., weekday or weekend) and 0 otherwise

$Treat_i$ is a binary variable taking a value of 1 when participant *i* is in the Off-Peak Charging group and 0 if they are in the Monitor group

ε_{it} is the error term for participant *i* during period *t*

A.4 Pilot Participation Groups

Guidehouse provided recommendations to Newfoundland Power regarding how to assign interested drivers to participant groups for the Pilot, in Year 1 of the Pilot. Due to compatibility with Uplight's platform, not all potential participants were eligible for all groups. For example, some participants may only be able to be monitored via vehicle telematics but not controlled, and only certain EVSE are compatible with Active Management. Participant groups were recommended considering compatibility, Pilot study objectives, and expected robustness of estimated impacts.

The following Newfoundland Power objectives informed Guidehouse's recommendations:

- Newfoundland Power targeted a total of 200 participants for the Pilot.
- Understanding the relative performance of Active Management via EVSE vs VT was a priority.

- Understanding baseline EV charging load shapes, including PHEVs, was a priority.

Based on these objectives, Guidehouse provided the following recommendations:

- Assign an equal amount of participants controlled via EVSE and VT, to enable comparison of impacts.
- Prioritize the size of the Monitor group to maximize the usefulness of baseline load profiles.
- Include PHEVs in the Monitor group, to maximize the sample and prioritize understanding their baseline charging behaviour.

A key assumption of Guidehouse's recommendations is that we assume the set of interested drivers for the Pilot is representative of the wider population of EVs in Newfoundland. A caveat of this assumption is that the universe of EVs and drivers (e.g. earlier vs later adopters) is likely to evolve over time.

Guidehouse developed recommended participant groups as follows:

1. Develop recommended group sizes, listed in Table A-2.
2. Assign Active Management group – all compatible EVSE participants and a random selection of compatible VT participants.
    - A random selection of 30 participants from those interested in swapping their EVSE for a compatible EVSE were reserved to ensure that enough participants were available for the EVSE group. 20 participants had a compatible EVSE, therefore up to 50 potential participants will be eligible for the EVSE Active Management group.
3. Assign Passive and Monitor groups – random selection among remaining compatible participants (VT Monitor + control or VT Monitor only).

Table A-2: Recommended Participant Group Sizes

Group	Method of Control	Notes
Peak Events (ADR)	30 EVSE and 30 VT	Enable comparison of EVSE vs VT for Active Management; BEV only
Off-Peak Charging (BDR)	VT Only	BEV only
Monitor	VT Only	20 PHEV and 60 BEV

Source: Guidehouse

Potential participants that own multiple EVs that charge at the same household were counted as a single participant.

Due to the random selection of participants for each participant group, baseline charging behaviour is expected to be similar across groups. As a further robustness check, after selecting participant groups, Guidehouse checked the similarity of these groups across key variables that are likely to be correlated with charging behaviour, specifically vehicle make, and average vehicle kilometers traveled (weekdays and weekends). Newfoundland Power used Guidehouse's recommended participant groups to inform customer recruitment; actual enrolled group sizes are provided in Guidehouse's evaluation results.

Appendix B. Detailed Results Spreadsheet

Provided Separately as “NFP EV LM Appendix B - Detailed Results 2025-05-23.xlsx”

Appendix C. Survey Instrument

takeCHARGE EV Load Management Pilot Program

Newfoundland Power

1. SURVEY OBJECTIVES

The survey will be fielded in March 2025. The primary objectives of the survey are to assess:

- Feedback on use of the managed charging platform (Section E, F)
- Satisfaction with program incentives (Sections B and E)
- Satisfaction with the override process (Sections D and G)
- Satisfaction with program communications (Section H)
- Satisfaction with program overall (Section I)
- Opportunities for improving program satisfaction (Section C, E, and I)
- Customer interest in future program participation (Section E)

2. SAMPLE VARIABLES

The survey uses the following sample variables, denoted with the <> symbols and highlighted in yellow.

- First name
- Last name
- Make
- Model
- Year
- Home Address
- Pilot Group:
  - 1 = Peak Events
  - 2 = Off-peak charging
  - 3 = Monitor

3. ONLINE INVITE

Dear <fname> <lname>,

MQO Research is conducting a survey on behalf of Newfoundland Power to obtain feedback and insights on the takeCHARGE EV Load Management Pilot Program. We ask that the person who is the primary driver of the EV to complete the survey.

Survey Length: 12-15 minutes

If you require assistance in completing the survey, please reply to this email, and the survey administrator will respond to any technical issues or concerns you may have.

When you are ready to begin, please click on the link below:

<Add Link>

Thank you in advance for your participation in this research.

4. ONLINE INTRODUCTORY SCREEN

Thank you in advance for your participation in this research. We appreciate your responses. The survey should take about 12-15 minutes to complete.

Your individual responses will remain anonymous and confidential.

This study is managed by MQO Research and is registered with the Canadian Research Insights Council (CRIC) Research Verification Service (RVS).

You can verify the details of this study using the CRIC RVS portal: https://www.canadianresearchinsightscouncil.ca/rvs/

Project code: <Add>

Please click to continue.

5. SECTION A: SCREENING AND QUOTA MANAGEMENT

A1. Are you the primary driver of the <Year> <Make> <Model>?

SINGLE-SELECT

1. Yes, I am the primary driver
2. Another member of my household and I use the vehicle equally often
3. No, another member of my household is the primary driver of the vehicle
4. We no longer have that vehicle [TERMINATE]

A2. **If A1 = 3**: What is the email address of the primary driver of the vehicle?

[NAME] [EMAIL ADDRESS] [TERMINATE]

A3. What type of charging equipment do you have in your home?

SINGLE-SELECT

1. Level 1 (standard, around 1.2 kW)
2. Level 2 (faster charging, typically recharge a fully depleted battery overnight, and 6.2 to 19.2 kW)
3. Both types

98. Not sure

TERMINATE MESSAGE: Thank you for your time. Have a great day.

6. SECTION B: MOTIVATIONS AND EXPECTATIONS

B1. How did you first hear about the takeCHARGE EV Load Management Pilot Program? Select all that apply. [Randomize 1-6]

MULTI-SELECT

1. Social media post from takeCHARGE NL
2. Email from takeCHARGE NL
3. takeCHARGE NL website
4. Newfoundland Power customer service representative
5. Word of mouth (family, friends, colleagues)
6. EVSE (charger) In-App notification or message
7. Other; please describe: [OPEN ENDED]

B2. How motivating were the following factors in your decision to enroll in this EV pilot? Matrix style question; 1-10 rating, end points labelled “Not at all motivating (1)” and “Extremely motivating (10).” Randomize 1-4.

7. The enrollment and additional rewards throughout the pilot program
8. Opportunity to reduce negative environmental impact of EV charging
9. Opportunity to reduce demand on the electricity grid to reduce outages and lower overall bills
10. Opportunity to contribute to research on smart EV charging and its possible economic and environmental benefits

11. SECTION C: BARRIERS AND CONCERNS

C1. **If <group> = 1 or 2:** Prior to your decision to enroll in this pilot, what types of concerns did you have about participating in the pilot, if any? Select all that apply. [Randomize 1-4]

MULTI-SELECT

1. I was concerned that it would take too much effort or work to manage my EV’s charging schedule

2. I was worried that my vehicle would not always be charged when I wanted to use it
3. I was unsure whether my vehicle or charging equipment would be eligible for the pilot
4. I was concerned about privacy, data security, or my location being shared
5. I did not have any concerns about participating in the pilot
6. Other; please describe: [OPEN ENDED]

C2. **If <group> = 3:** Prior to your decision to enroll in this pilot, what types of concerns did you have about participating in the pilot, if any? Select all that apply. [Randomize 1-2]

MULTI-SELECT

1. I was unsure whether my vehicle or charging equipment would be eligible for the pilot
2. I was concerned about privacy, data security, or my location being shared
3. I did not have any concerns about participating in the pilot
4. Other; please describe: [OPEN ENDED]

C3. **If (C1 = 1, 2, 3, 4, or 6) and <group> = 1 or 2:** Is there any additional information that takeCHARGE NL could provide to you to help mitigate these concerns?

SINGLE-SELECT

1. Yes; please describe: [OPEN ENDED]
2. No
3. Not sure

C4. If **(C1 = 1, 2, 3, 4) and <group> = 1 or 2:** To what extent do you still have these concerns?

Matrix style question, limit rows to responses selected in C1

	No longer concerned	Somewhat concerned	Very concerned
C4a. I was concerned that it would take too much effort or work to manage my EV's charging schedule			
C4b. I was worried that my vehicle would not always be charged when I wanted to use it			
C4c. I was unsure whether my vehicle or charging equipment would be eligible for the pilot			
C4d. I was concerned about privacy, data security, or my location being shared			

C5. **If (C2 = 1, 2, or 4) and <group> = 3:** Is there any additional information that takeCHARGE NL could provide to you to help mitigate these concerns?

<u>SINGLE-SELECT</u>

1. Yes; please describe: [OPEN ENDED]
2. No
3. Not sure

C6. If **(C2 = 1, 2) and <group> = 3:** To what extent do you still have these concerns?

<u>Matrix style question, limit rows to responses selected in C1</u>

	No longer concerned	Somewhat concerned	Very concerned
C6a. I was unsure whether my vehicle or charging equipment would be eligible for the pilot			
C6b. I was concerned about privacy, data security, or my location being shared			

12. SECTION D: KNOWLEDGE

The next set of questions is designed to assess how effective the messaging from the takeCHARGE EV Load Management Pilot Program pilot has been at explaining the purpose of the pilot, its possible benefits, and how the pilot works.

D1. **If <group> = 1:** How well do you understand the following aspects of your participation in the pilot? Please use a 1-10 scale in which 1 means "No understanding" and 10 means "Full understanding." [Randomize 1-10]

<u>Matrix style question, 1-10 rating</u>

1. Know when peak events are happening
2. How you can opt out of events if necessary
3. How many times you can opt out in a month and still be eligible for the monthly reward
4. Know the reward amounts for taking part in the pilot
5. Know which months the peak events apply (i.e. December to March)

D2. **If <group> = 2:** How well do you understand the following aspects of your participation in the pilot? Please use a 1-10 scale in which 1 means "No understanding" and 10 means "Full understanding." [Randomize 1-4]

<u>Matrix style question, 1-10 rating</u>

1. Know when to charge and not to charge (on peak vs. off peak times)
2. How many times you can opt out in a month and still be eligible for the monthly reward
3. Know the reward amounts for taking part in the pilot
4. Know which months the off-peak hours apply (i.e. December to March)

D3. **If <group> = 3:** How well do you understand the following aspects of your participation in the pilot? Please use a 1-10 scale in which 1 means "No understanding" and 10 means "Full understanding."

Matrix style question, 1-10 rating

1. Know the reward amounts for taking part in the pilot

13. SECTION E: PILOT EXPERIENCES

The next set of questions is about your experiences with the pilot so far and your preferences for communication.

E1. How easy or difficult was it to enroll in the pilot? Please rate on a 1-10 scale where 1 means "very difficult" and 10 means "very easy."

[1-10 RATING]

E2. **If <group> 1 or 2:** How satisfied were you with using the managed charging platform (i.e. FlexSaver and/or OptiWatt)? Please rate on a 1-10 scale where 1 means "very dissatisfied" and 10 means "very satisfied."

[1-10 RATING]

E3. **If <group> 3:** How satisfied were you with using the managed charging platform (i.e. FlexSaver)? Please rate on a 1-10 scale where 1 means "very dissatisfied" and 10 means "very satisfied."

[1-10 RATING]

E4. How interested would you be to participate in a future EV load management program? Please rate on a 1-10 scale where 1 means "not interested" and 10 means "very interested."

[1-10 RATING]

E5. If you were offered a $75 annual participation reward, how interested would you be to participate in a future EV load management program? Please rate on a 1-10 scale where 1 means "not interested" and 10 means "very interested."

[1-10 RATING]

E6. What is the minimum ongoing annual reward that would make you interested in participating in a future EV load management program?

1. $20
2. $40
3. $60
4. $80
5. $100
6. None of these are high enough

14. SECTION F: CHARGING BEHAVIOURS

F1**. If <group> = 1 or 2:** How much impact did participation in the program have on your ability to use your car? (e.g. less range than desired on your vehicle when you wanted to use it, or it changed the times you used your vehicle) Please rate on a 1-10 scale where 1 means "no impact" and 10 means "very impacted."

[1-10 RATING]

F2. How often do you charge at home?

SINGLE-SELECT

1. 0-25% of the time
2. 25-50% of the time
3. 50-75% of the time
4. 75-100% of the time

F3. Do you have access to workplace charging?

SINGLE-SELECT

1. Yes
2. No

98. I'm not sure or N/A

F4. **If F3 = 1:** How often do you charge at work?

SINGLE-SELECT

1. 0-25% of the time
2. 25-50% of the time
3. 50-75% of the time

4. 75-100% of the time

F5. Since enrolling in this program, has your charging behaviour changed?

SINGLE-SELECT

1. My charging behaviour has stayed the same
2. I charge more at home
3. I charge less at home
4. I'm not sure

F6. **If F5 = 2 or 3 and <group> = 1:** If your charging behaviour has changed, did it change as a result of the takeCHARGE EV Load Management Pilot Program? (e.g. leaving your vehicle plugged in and letting the program control your charging schedule)

SINGLE-SELECT

1. Yes
2. No

98. I'm not sure

F7. **If F5 = 2 or 3 and <group> = 2:** If your charging behaviour has changed, did it change as a result of the takeCHARGE EV Load Management Pilot Program? (e.g. setting a schedule to avoid peak charging)

SINGLE-SELECT

1. Yes
2. No

98. I'm not sure

F8. **If (F6 = 1 or F7 = 1) and <group> = 1 or 2:** How and why has your charging behaviour changed as a result of the takeCHARGE EV Load Management Pilot Program?

[OPEN ENDED]

15. SECTION G: OPT OUT BEHAVIOURS

G1. **If <group> = 1:** How often did you opt out of peak events by charging?

SINGLE-SELECT

1. Less than 3 times per month
2. 3 or more times per month

98. I'm not sure

G2. **If <group> = 2:** How often did you opt out by charging during peak hours?

SINGLE-SELECT

1. Less than 3 times per month
2. 3 or more times per month
99. I'm not sure

G3. **If (G1 = 2) and <group> = 1:** What were your primary reasons for opting out? Select all that apply. [Randomize 1-3]

MULTI-SELECT

1. Something unexpected came up
2. I forgot and charged during the peak events
3. I was concerned my vehicle would not be fully charged when I needed it
97. Other; please describe: [OPEN ENDED]

G4. **If (G2 = 2) and <group> = 2:** What were your primary reasons for opting out? Select all that apply. [Randomize 1-3]

MULTI-SELECT

1. Something unexpected came up
2. I forgot and charged during the peak hours
3. I was concerned my vehicle would not be fully charged when I needed it
97. Other; please describe: [OPEN ENDED]

G5. **If <group> = 1 or 2:** How satisfied are you with your ability to opt out of the charging schedule if necessary? Please rate on a 1-10 scale where 1 means "very dissatisfied" and 10 means "very satisfied."

[1-10 RATING]

16. SECTION H: COMMUNICATION PREFERENCES

H1. **If <group> = 1 or 2:** How satisfied are you with the frequency of the notifications for the pilot? Please rate on a 1-10 scale where 1 means "very dissatisfied" and 10 means "very satisfied."

[1-10 RATING]

H2. **If <group> = 1 or 2:** How helpful were the notifications for the pilot? Please rate on a 1-10 scale where 1 means "not helpful" and 10 means "very helpful."

[1-10 RATING]

H3. How do you prefer to receive information about your participation in the pilot? Select all that apply. [Randomize 1-6]

MULTI-SELECT

1. Email
2. Phone call
3. Text message
4. Website
5. Mobile app notifications
6. Mobile app without notifications
97. Other [OPEN ENDED]

H4. How frequently would you like to hear from the pilot?

SINGLE-SELECT

1. Daily
2. Several times a week
3. Once a week
4. More than once a month
5. Once a month
6. Less frequently than that

H5. How satisfied are you with the communication that you've received from takeCHARGE NL, and the pilot delivery partners regarding your participation in the pilot so far? Please rate on a 1-10 scale where 1 means "very dissatisfied" and 10 means "very satisfied."

[1-10 RATING]

17. SECTION I: OVERALL SATISFACTION

I1. How satisfied are you with your overall experience in the pilot so far? Please rate on a 1-10 scale where 1 means "very dissatisfied" and 10 means "very satisfied."

[1-10 RATING]

I2. Do you have any other feedback that you'd like to share about the takeCHARGE EV Load Management Pilot Program before the end of the survey?

1. Yes; please specify: [OPEN ENDED]
2. No additional comments

18. SECTION J: DEMOGRAPHICS

The last few questions are about you and your household. As a reminder, your responses are confidential and anonymous.

J1. Do you own or rent this home at <HomeAddress>?

SINGLE-SELECT

1. Own
2. Rent
3. Prefer not to answer

J2. What was the highest level of education that you completed?

SINGLE-SELECT

1. Less than high school graduate
2. High school
3. Some University or trade school
4. University graduate
5. Post-graduate
6. Prefer not to answer

J3. Which of the following descriptions most closely matches your current Employment/caregiving status?

SINGLE-SELECT

1. Working full-time outside of the home
2. Working part-time outside of the home
3. Working at home
4. Stay at home parent/caregiver
5. Attending school outside of the home
6. Attending school virtually at home
7. Retired
8. Not currently working or attending school

97. Other; please describe: [OPEN ENDED]

9. Prefer not to answer

J4. What was your household's approximate total income (before taxes) in 2024?

SINGLE-SELECT

1. Less than $25,000
2. $25,000 to less than $50,000
3. $50,000 to less than $75,000
4. $75,000 to less than $100,000
5. $100,000 to less than $125,000
6. $125,000 to less than $150,000
7. $150,000 to less than $175,000
8. $175,00 to less than $200,000
9. $200,000 or more

10. Prefer not to answer

Thank you for your time. Have a great day.

Appendix D. Survey Analysis Spreadsheet

Provided Separately as “NFP EV LM Appendix D - Survey Analysis 2025-05-23.xlsx” guidehouse.com